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GULF POWER
A SOUTHERN COMPANY

October 12, 2006

Ms. Blanca S. Bayo, Director
Division of the Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee FL 32399-0870

Dear Ms. Bayo: 060000

Enclosed are an original and fifteen copies of Gulf Power Company's Electric Utility Overhead/Underground Residential Differential Cost Data (Form PSC/EAG 13).

Sincerely,

Susan D. Ritenour

lw

Enclosures

cc: Beggs and Lane
Jeffrey A. Stone, Esquire

ELECTRIC UTILITY OVERHEAD/UNDERGROUND RESIDENTIAL DIFFERENTIAL COST DATA

FOR GULF POWER COMPANY

Florida Public Service Commission
Form PSC/EAG 13
(10/97)

PSC/EAG FORM 13 FOR REPORTING
THE OVERHEAD/UNDERGROUND RESIDENTIAL DIFFERENTIAL COST DATA
RULES 25-6.074 THROUGH 25-6.083

Notes:
* Mark all schedules from 2 through 13 which do not apply to the current filing as not applicable. Attach additional sheets for clarification and justification if necessary.
* The signature page, Schedule 14, must be filed with every filing.

PSC/EAG Form 13 (10/97)

Gulf Power Company
Overhead VS Underground
Summary Sheet
Cost Per Lot
210 Lot Single Family Residential

April 1, 2004 Filing

Item	Overhead	Underground	Differential
Labor	552	738	186
Material	389	616	227
Total	941	1,354	413

October 15, 2004 Filing

Item	Overhead	Underground	Differential	% Difference
Labor	595	779	184	
Material	414	609	195	
Total	1,009	1,388	379	
				-8.23%

October 15, 2005 Filing

Item	Overhead	Underground	Differential	% Difference
Labor	602	800	198	
Material	437	643	206	
Total	1,039	1,443	404	
				-2.18%

October 15, 2006 Filing

Item	Overhead	Underground	Differential	% Difference
Labor	749	921	172	
Material	520	830	310	
Total	1,269	1,751	482	
				16.71%

Schedule 14

I certify that I am the person responsible for submitting Form PSC/EAG 13 and that I have examined the attached schedule(s); that to the best of my knowledge, information, and belief, all statements of fact contained n the schedule(s) are true.

I am aware that Section 837.06 of Florida Statutes provides:

Whoever knowingly makes a false statement in writing, with the intent to mislead a public servant in the performance of his official duty, shall be guilty of a misdemeanor of the second degree, punishable as provided in s.775.082 and s.775.083.

Date: October 5, 2006

Name: Jonathan A. McQuagge

Signature: J. A. McQuagge
Power Delivery Services Manager
Gulf Power Company

ORIGINAL

RECEIVED-FPSC

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COMMISSION CLERK

October 13, 2006

Florida Public Service Commission
Lisa Polak Edgar, Chairman
Matthew Mark Carter II, Commissioner
J. Terry Deason, Commissioner
Isilio Arriaga, Commissioner
Katrina J. Tew, Commissioner

Division of the Commission Clerk and Administrative Services,
2540 Shumard Oak Boulevard,
Tallahassee, Florida 32399-0850,

RE: Opposition to Florida Power & Light's Petition for Exemption from RFP Solicitation Requirements (PSC DOCKET NUMBER 060426)

Dear Commissioners,

Florida Power & Light (FPL) has petitioned the Florida Public Services Commission (PSC) for an exemption from its obligation under Florida Administrative Code Rule (FAC) 25-22.082 to issue a request for proposal (RFP) for each proposed generating unit. On September 19, 2006, the PSC proposed to grant FPL's petition. *See* Order No. PSC-06-0079-PAA-EI, Notice of Proposed Agency Action, Order Granting Exemption from Bid Rule (Sept. 19, 2006) ("Exemption Order"). The RFP process is an important part of the regulatory safeguards intended to protect Florida's consumers, and the PSC should not toss these important protections aside. In this case, FPL has failed to make an adequate showing that an exemption is appropriate, and the PSC has not thoroughly evaluated the true scope of the potential impact of such an exemption.[1] The undersigned organizations believe that granting FPL's request for exemption is a mistake that threatens the integrity of Florida's PSC process and sends a dangerous message to utility companies.

The PSC Should Not Grant FPL's Petition

The RFP process required by Florida Administrative Code Rule (FAC) 25-22.082 serves a vital function in the power plant approval process. As Florida regulations themselves express, "[t]he use of a Request for Proposals (RFP) process is an appropriate means to ensure that a public utility's selection of a proposed generation addition is the most cost-effective alternative available." FAC 25-22.082(1). This requirement is appropriate for every power plant proposal in order to ensure that *each individual unit* provides the electric generation capacity (where it is needed) in a manner that is *truly* most cost-effective – taking into consideration *all* relevant case-specific factors, the changing characteristics of the power industry, and relevant technological advances.

MP ____
OM 5____
TR ____
CR ____
CL ____
PC ____
CA ____
CR ____
GA ____
EC 1____
TH ____

[1] Susan Glickman of the Natural Resources Defense Council offered testimony that touched on many of the issues raised in this letter at the August 29, 2006 PSC hearing on FPL's petition.

DOCUMENT NUMBER-DATE

09538 OCT 16 8

FPSC-COMMISSION CLERK

In general, approving what amounts to an exclusive, "no-bid" contract for electric power generation is fundamentally contrary to the public interest that the PSC exists to serve. This approach undermines the regulatory mechanism that the State relies upon to ensure the competitiveness of its electricity pricing, and the tool that otherwise ensures that power generation projects accurately reflect market conditions. It is, in our view, contrary to the mission and responsibility of the PSC for it to waive the RFP requirements in this case, especially given that the power plant at issue will be the first investor-owned utility coal plant project in Florida in a decade and it will employ a technology that is not being used in the U.S. at this time and that does not offer the long-term cost benefits of other advanced coal technologies that are currently being deployed by utilities around the country.

Nonetheless, FAC 25-22.082 allows, in limited circumstances, an exemption from the RFP requirement:

> Upon a showing by a public utility and a finding by the Commission that a proposal not in compliance with this rule's provisions will likely result in a lower cost supply of electricity to the utility's general body of ratepayers, increase the reliable supply of electricity to the utility's general body of ratepayers, or otherwise will serve the public welfare, the Commission shall exempt the utility for compliance with the rule or any part of it for which such justification is found.

Here, however, FPL has failed to make the demonstration required to receive an exemption from the RFP process. As a result, the PSC has not considered the full range of relevant factors in reaching its decision. Moreover, because FPL made its request for an exemption before it even had a power plant proposal on the table, the PSC was effectively incapable of adequately examining whether an exemption would be appropriate.

FPL Has Not Shown That an Exemption Will Reduce Costs to Consumers

FPL argues that an exemption from the RFP requirements will provide it with the opportunity to "stay on schedule for the first unit's planned 2012 in-service date." According to FPL, this will allow "cost-saving measures to be gained from building a second unit, in 2013, at the same site." FPL estimates its capital cost savings at between $400 and $600 million, assuming that FPL files a needs determination for both units by May 1, 2007. However, the PSC has concluded that if FPL does not file a need determination within the estimated time frame, there will be no benefits associated with the RFP exemption; therefore, the Commission limited the exemption to May 1, 2007.

While FPL has argued that an exemption will save the company $400 to $600 million in capital costs, it has provided no explanation of how this capital cost savings will translate into cost savings to consumers, and FPL and the PSC have failed entirely to address the potential saving to consumers from alternative projects that might be identified in the competitive bid process. In particular, both FPL and the PSC have ignored the potential life cycle cost of FPL's power plant projects compared to other options that might emerge as a result of an RFP. Indeed, if capital cost savings alone were enough to justify an exemption from the RFP requirements, those requirements would quickly cease to have any meaning.

Consistent with its responsibility to place the interest of Florida's consumers first, the PSC should closely scrutinize FPL's request to bypass the existing regulatory process.[2] In so doing, the PSC must meaningfully evaluate not just the initial capital costs to FPL, but also the longer term life cycle costs associated with FPL's coal plant proposals, which include operating costs, fuel costs, maintenance costs and future environmental regulations – and the significant beneficial impact that a competitive bid process may have on these long-term costs.

Among other things, regulation of carbon dioxide (CO_2) emissions are virtually inevitable; the only questions that remain are when such limits will become effective and what they will look like. When these requirements emerge they will make the operation of carbon intensive power generation units – like the ones that FPL proposes to build – much more expensive (requiring either the purchase of CO_2 credits to offset emissions, or the direct control of CO_2 output).[3] This eventuality means that an investment now in carbon intensive-technology, like pulverized coal, is a poor decision. The PSC should take this opportunity to explore other options through the RFP process.

It has become abundantly clear that CO_2 emissions, from sources such as coal-fired power generation, are creating a serious threat of dramatic climate disruption. The international community has already begun to take action to curb such emissions,[4] and more recently certain States have also taken concrete steps to reduce their carbon footprint.[5] Moreover, Congress has introduced numerous bills, amendments, and resolutions specifically addressing global warming, and the Senate last year passed a resolution finding that "mandatory steps will be required to slow or stop the growth of greenhouse gas emissions."[6] The general consensus is that federal CO_2 emission controls are only a matter of time – notably, the utility industry as well has begun to recognize that

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[2] We note that the PSC rejected FPL's assertion that "an RFP for coal capacity would not result in valid bids," observing that there is "a willingness from independent providers to participate in an RFP process for coal capacity." Exemption Order at 2-3.

[3] *See* Gambling with Coal, How Future Climate Laws Will Make New Coal Power Plants More Expensive, Union of Concerned Scientists (Sept. 2006), available at: http://www.wvecouncil.org/issues/gambling_with_coal.

[4] 190 countries have joined the United Nation's Framework Convention on Climate Change, and most have ratified the Kyoto Protocol (the U.S. and Australia alone among the industrialized countries have not).

[5] For example, several Northeast States have formed the Region Greenhouse Gas Initiative (RGGI) to reduce carbon emission that part of the country. See www.rggi.org. The state of California also has passed greenhouse gas legislation and taken steps to prevent importation of electricity produced at carbon intensive facilities, and several Western and Midwest States are contemplating action to limit greenhouse gases.

[6] See www.aip.org/fyi/2005/114.html. In May of this year the House Appropriations Committee approved similar language. See www.pewclimate.org/what_s_being_done/in_the_congress/index.cfm for more information on Congressional action on global warming.

national carbon emission limits are both necessary and desirable.[7] Because power generation is the single most significant source of CO_2 in the United States (accounting for nearly 40% of U.S. emission), this industry – and coal-fired power generation in particular – is likely to feel the greatest pinch from future carbon regulation.

Given that large convention coal-fired power plants, like the one FPL plans to build, will emit in the range of 10-15 million tons of CO_2 each year over their entire 40+ year operational life (totaling at least 400 million tons), it is clear that these facilities represent the low hanging fruit when it comes to regulating carbon emissions. However, such regulation will add significantly to the cost of generating power.[8] By some estimates, the price of coal-fired electricity could increase by some 66% for conventional coal-fired power plants, which are incapable of economically capturing their CO_2 emissions. Other technologies, however, such as integrated gasification combined-cycle (IGCC), a technology that processes coal into a fuel that can be burned in a combined-cycle power block much like natural gas,[9] can capture CO_2 at a much lower cost than conventional coal plants.[10] In a world that will soon insist upon significant reductions in carbon emissions, IGCC is a much more appropriate technology choice for coal-based power generation.[11]

In addition to benefits related to carbon emission control, IGCC also provides additional fuel flexibility,[12] and product flexibility.[13] Moreover, an IGCC plant can achieve greater reductions in conventional pollutants, produces less (and more manageable) solid waste, and uses less water. These collective benefits are the main

[7] For example, executives from AEP and NRG have recently made statements strongly supporting the idea of national carbon limits, and emphasizing the responsibility of the electric power sector to take action to address global warming. *See, e.g.*, http://www.cleartheair.org/proactive/newsroom/release.vtml?id=25835.
[8] The cost of carbon credits in Europe, where CO_2 is already being regulated, has ranged from \$30 to \$60 per ton over the past year. *See* http://pubs.acs.org/subscribe/journals/esthag-w/2006/jul/business/mb_carbonprices.html. Estimates for CO_2 costs under expected U.S. regulations range from \$8 to about \$60 per ton. This would add considerably to the operation of a facility emitting more than 10 million ton of CO_2 per year (for example at \$12/ton it would add \$120 million per year).
[9] For a description of IGCC see: http://www.gasification.org/gasproc.htm. More information is also available at: http://www.netl.doe.gov/technologies/coalpower/gasification/index.html. Presentations from vendors and others from the recent gasification technologies conference in Washington D.C. are available on-line at: http://www.gasification.org/Presentations/2006.htm.
[10] CO2 would then need to be sequestered in deep geologic formations for permanent storage. Estimates suggest that IGCC may be able to meet future CO_2 limits with an impact on electricity prices that is significantly less than that for conventional coal plants. Indeed, EPA explains that IGCC is "one of the most promising technologies in reducing environmental consequences of generating electricity from coal." *See* Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, EPA (July 2006): available at http://www.gasification.org/Docs/News/2006/EPA%20-%20IGCC%20cf%20PC.pdf
[11] One of the primary reasons for the RFP process is "to ensure that a public utility's selection of a proposed generation addition is the most cost-effective alternative available." This necessary should include an examination of the life-cycle cost of any given proposal.
[12] With relatively minor modifications an IGCC unit can be re-tooled to burn different coal types, petcoke, or renewables such as switchgrass.
[13] An IGCC unit can co-produce pure hydrogen, synthetic gas that can be fed into a natural gas pipeline, and other products in addition to electricity.

reasons why more and more utility companies are proposing IGCC instead of conventional coal plants.[14]

Finally, Florida sits on the front-lines of the battle against global warming and its potentially devastating effects, and therefore should have a particular interest in leading the charge to reduce carbon emissions. The overwhelming consensus among climate scientists is that global warming, if it remains unchecked, will cause serious climate disruption including more intense hurricanes, more frequent and more severe floods, and potentially catastrophic sea level rise – effects that the citizens of Florida are likely to feel acutely. Certainly a strong policy to facilitate reduction of CO_2 emissions would serve the public welfare in a state with 2,276 miles of tidal coastline and a mean elevation of only 100 feet above sea level. The PSC should not elect to sacrifice an opportunity to examine in detail alternative projects that might be more compatible with important efforts to address global warming – and certainly such a sacrifice is not justified by the speculative cost savings that FPL and the PSC rely on for this exemption.

In sum, the PSC's decision to excuse FPL from its regulatory obligations in this case does not adequately address long-term, life-cycle plant costs. The potential for life-cycle cost saving associated with an IGCC plant far outweighs the cost saving that FPL assumes as a result of this exemption. And a detailed examination of alternatives would serve the public interest. Accordingly, from both a cost and public welfare perspective, it is in the best interest of the ratepayers to allow the RFP process to proceed. At the very least, the PSC should evaluate more closely the broader cost implications of this exemption before it allows FPL to move forward.

We are aware that the PSC will probe additional issues regarding FPL's proposed coal facility during the needs determination;[15] however, there are important issues at stake here that are uniquely related to the RFP process. In particular, this is the only opportunity to specifically compare FPL's proposed project to other projects at a meaningful level of detail.[16] Relieving FPL of the obligation to solicit competitive bids means that Florida (and its energy consumers) will loose an important opportunity to benefit from proposals that may more appropriately factor in the critical considerations described above.

Florida's Interest in Fuel Diversity Does not Justify Granting an Exemption

A perceived need to diversify Florida's fuel mix is a poor excuse for setting aside important regulatory safeguards. More significantly, Florida's electricity consumers will not benefit from the PSC's effort to rush through the process a power plant project that

[14] There are currently some 28 proposals for IGCC plants nationwide.

[15] In particular, at that stage the PSC must thoroughly examine opportunities to improve efficiency instead of building more power plants, and the availability of alternatives involving renewable sources of energy.

[16] This kind of detailed comparative examination, which is not required at the needs determination stage, is especially important here, where FPL has proposed a type of facility that is not currently in use in the U.S. (making cost assumption somewhat uncertain), and where other significantly more promising technologies are available. At the very least, FPL should be required to submit detailed facility information, including cost assumptions and analysis, for the PSC's consideration before any exemption is granted.

may ultimately prove to be an economic blunder. The PSC's rationale for granting FPL's exemption petition boils down to little more than a finding that new coal capacity should be fast-tracked regardless of the potential consequences (which, as discussed above, the PSC did not meaningfully examine). The Exemption Order states:

> We believe that FPL will be unable to meet a June 2012 in-service date if an RFP is issued at this late date.... If FPL does not begin construction as planned, coal will no longer be an option for meeting FPL's 2012 capacity needs. FPL's customers will be exposed to the risk of potentially higher-cost alternatives with shorter lead times, such as purchased power or additional natural gas-fired capacity. . . . We find that removing the administrative hurdle of an RFP will provide FPL with the opportunity to stay on schedule to meet a June 2012 in-service date. While an RFP would be a valid tool for obtaining information on the availability and cost of capacity alternatives to FPL's proposed coal unit, the usefulness of this information must be balanced against the benefits of keeping FPL on schedule. . . . We find in this case that the interests of FPL's customers and the public welfare will best be served by granting FPL's request for an exemption from the RFP requirement."[17]

In our view, the PSC's assumption that FPL can meet its in-service target dates, even with an exemption from the RFP requirement, is speculative at best. Before FPL can even begin construction on any proposed new facility, it must complete the power plant siting and approval process, including the needs determination process and the process of obtaining applicable environmental permits (which are likely to be controversial and may be challenged administratively and in court).

Even assuming the validity of the State's desire to diversify its fuel mix because of price volatility in the natural gas market (a premise that is certainly debatable), we believe that it is a mistake for the PSC to waive the RFP process, and therefore fail to even solicit possible alternative projects for consideration.[18] The *only* justification identified in the PSC's analysis for the need to keep FPL "on schedule" is the "risk of potentially higher cost alternatives" during any possible period of delay attributable to the RFP process (which would be relatively short). As discussed above, the potential long-term cost benefits of a more sensible alternative project far outweigh the speculative, short-term impacts that the PSC relies upon in its proposed decision. For these reasons, the PSC should reconsider its decision and deny FPL's petition, or at the very least suspend its decision until it has fully examine the potential for long-term cost impacts on consumers.

The PSC Made Its Determination Without the Benefit of a Concrete Proposal

Even aside from the cost implications of upcoming carbon legislation, FPL petition in this case is contrary to language and intent of the governing regulations. FAC 25-22-082 requires competitive proposals "to provide the Commission information to

[17] Exemption Order at 4.
[18] In particular, the PSC should specifically request submission of bids for IGCC proposals.

evaluate a public utility's decision regarding the addition of generating capacity" and "to ensure that a public utility's selection of a proposed generation addition is the most cost-effective alternative available." The RFP must address "the *next generating unit* addition *planned for construction* by a public utility," and the RFP itself must contain "the *price and non-price attributes* of its next planned generating unit in order to solicit and screen . . . competitive proposals."

Among other things, the RFP must include "A general description of the public utility's next planned generating unit, including its planned in-service date, *MW size, location, fuel type and technology*," as well as a "*detailed technical description* of the public utility's next planned generating unit or units on which the RFP is based, as well as the *financial assumptions* and parameters associated with it," including thirteen enumerated items of information. Not surprisingly, much of the required information is *site-specific*, bearing on the particular characteristics of the proposed plant that will influence its initial and ongoing costs. *See* FAC 25-22.082(5).

In this case, however, FPL did not even have a detailed power-plant proposal on the table when it requested an exemption from the RFP process. Only after the hearing on FPL's petition did FPL announce publicly that it planned to build a 1960 megawatt ultra super critical pulverized coal plant in Glades County. Even now, however, FPL has provided precious few details about that proposed plant – such as those specifically required in connection with an RFP – and such details are essential to the PSC's evaluation of costs and potential impacts on ratepayers. Thus, in essence, FPL's petition asked for the PSC to issue a blank-check for it to build some *unspecified* future power plant (identified only by fuel-type and size) without any obligation to do so in a competitive environment.

Clearly, Florida's regulations contemplate the existence of an *actual proposal* – a specific project that can be scrutinized and compared with competitive alternatives based on site-specific factors. FPL's request to skip the competitive process for a project that exists only as a nebulous hypothetical was not only inappropriate, but inconsistent with applicable regulations. Consequently, the PSC should, at the very least, specifically examine the implications of the specific project that FPL is proposing, and fully evaluate the potential costs and other potential impacts on consumers of waiving the RFP process.[19]

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[19] We note in this regard that FPL has proposed to build a type of unit (an ultra super critical coal boiler) that is even less tested in the U.S. than IGCC, and that no other utility in the country is proposing to build. In this case, IGCC is an even more attractive option, as that technology will advance very rapidly as many of the currently proposed IGCC projects move forward. *See,* Jonathan Hunt, *AEP seeking permits for clean coal plant in both Ohio, W.Va.*, Athens NEWS (Oct. 9th, 2006), available at: http://athensnews.com/index.php?action=viewarticle&section=news&story_id=26136.

Conclusion

Thank you for your serious consideration of the issues we raise in the above discussion. We hope that your commitment to act in the best interest of the people of Florida prevails, and that you will reconsider your decision to allow FPL to sidestep an important part of the power plant approval process. We look forward to working with you in the future to ensure the brightest energy future for the people of Florida.

Patrice L. Simms
Susan Glickman
Natural Resources Defense Council
1200 New York Ave., NW
Washington, D.C. 20005
(202) 289-2437

Bill Newton, Executive Director
Florida Consumer Action Network

Brad Ashwell, Legislative Advocate
Florida Public Interest Research Group

ATTACHEMENTS

1. *Current Carbon Emissions in Context: Final Report to the National Commission on Energy Policy*, **Battelle Memorial Institute**

2. *Gambling with Coal, How Future Climate Laws Will Make New Coal Power Plants More Expensive*, **Union of Concerned Scientists (Sept. 2006)**

3. *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning*, **Synapse Energy Economics, Inc (May 18, 2006)**

Union of Concerned Scientists

Gambling with Coal

How Future Climate Laws Will Make New Coal Power Plants More Expensive

by Barbara Freese and Steve Clemmer
Union of Concerned Scientists[1]
September 2006

Abstract

New conventional coal plants are an imprudent financial investment. The world scientific community warns that carbon dioxide (CO_2) emissions from our use of fossil fuels, especially coal, is leading to dangerous global warming. Policies to reduce CO_2 emissions are emerging at every level of government, including in the US Congress, which is actively considering several mandatory, market-based CO_2 proposals with increasing support from the private sector. Laws requiring coal plants to pay to emit CO_2 will be adopted in the next few years, substantially raising the costs of coal power.

Nevertheless, many utilities have proposed investing in new conventional coal plants that will operate for decades, ignoring the economic impact of these virtually inevitable CO_2 reduction laws, perhaps because they believe they will be able to pass these costs on to ratepayers. Utility managers and shareholders should reconsider the financial risks to their companies and customers. Regulators should prevent utilities from making these major investment mistakes by refusing to approve the construction of new conventional coal plants and by requiring them to invest in cleaner alternatives, or at the very least, by warning utilities that CO_2 costs must be borne by their shareholders, not by ratepayers.

Executive summary

It is now virtually inevitable that America will adopt a federal law limiting global warming pollution from power plants. Indeed, given the momentum of emerging policy responses to global warming on the local, state, and regional levels in the United States (as well as internationally), federal legislation will probably be adopted within the next five years. This document discusses why such a law is so likely, what kind of new costs coal plants will face as a result, and how these future costs make building new, conventional coal plants a reckless financial gamble.

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[1] We would like to thank the Garfield Foundation for providing funding for this work.

The need for legal limits to America's global warming pollution is undeniable. Scientists have long known that the burning of fossil fuels releases heat-trapping carbon dioxide (CO_2) into the air, where it is building up. Scientific concern that this buildup could disrupt our climate has been growing steadily since the late 1980s. Every year, the science has become even more compelling: Earth continues to experience record-breaking warmth, humans' dominant role in this warming becomes clearer, and we see the planet reacting to the warming in troubling ways.

Most developed nations have responded to this evidence by ratifying the Kyoto Protocol, which requires them to reduce their CO_2 emissions. The United States has not ratified Kyoto, but as the world's largest emitter of heat-trapping gases by far, it is under increasing international pressure to act. Along with almost every other nation in the world, the United States did ratify the 1992 Framework Convention on Climate Change, a treaty with the objective of preventing dangerous global warming. And in 2005 the U.S. Senate passed a landmark resolution stating that mandatory federal CO_2 limits should be enacted. Several proposals establishing CO_2 limits are being considered by Congress, and a series of hearings have been held in the Senate to discuss the design of such limits.

The congressional response is being spurred in part by a growing policy response on the state and regional level, including the regional CO_2 limits and trading system being established by eight northeastern states. Within the last year or two, a substantial number of major companies—including half of America's 10 largest power companies—have called for such regulation, and most utility executives believe that such regulation is coming.

There is no doubt that the burden of future CO_2 regulations will fall heavily on coal plants. Power plants are the largest source of U.S. CO_2 emissions, accounting for 39 percent of the nation's energy-related emissions, and most of these emissions come from coal plants. In fact, coal plants produce one-third of America's CO_2 emissions—about the same amount as all our cars, SUVs, trucks, buses, planes, ships, and trains combined.[2]

Each new coal plant represents an enormous long-term increase in global warming emissions. A 500-megawatt (MW) plant, for example, produces the annual global warming emission equivalent of roughly 600,000 cars,[3] but unlike a car, a coal plant is designed to operate for 40 to 50 years (and they often operate even longer). Global warming cannot be effectively addressed without limiting coal plant emissions, so the congressional proposals under consideration all target coal plants.

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[2] U.S. Environmental Protection Agency (EPA), "Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2004," April 2006. Online at *http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2006.html*. Also see U.S. Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2004*, December 2005, 20–22. Online at *ftp://ftp.eia.doe.gov/pub/oiaf/1605/cdrom/pdf/ggrpt/057304.pdf*.

[3] Based on average annual emissions of 13,500 lbs/vehicle as estimated by the EPA (*http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterToolsGHGCalculator.html*) and annual emissions of 4.1 million tons from a 500 MW plant as estimated by the Public Service Commission of Wisconsin (*http://psc.wi.gov/utilityinfo/electric/cases/weston/document/Volume1/W4_FEIS.pdf*).

It is widely expected that future CO_2 regulations will take the form of a "cap-and-trade" system, similar to the national law for controlling the sulfur dioxide (SO_2) emissions that cause acid rain. Such a system would establish a national cap on CO_2 emissions, and power plant operators would have to own an "allowance" for each ton of CO_2 they emit. Operators could buy and sell these allowances for a price established by market forces. Economists believe such a cap-and-trade system would provide the flexibility and incentives to meet a given CO_2 cap at the lowest cost.

Utilities are increasingly quantifying the risk they face from future CO_2 allowance costs in their planning documents. In some cases, they do so because state regulators demand it, and in other cases they do it at their own initiative. Studies forecasting the price of future CO_2 allowances range widely, but useful estimates are emerging from the literature. These estimates indicate that coal plants face CO_2 costs that will increase the cost of coal power substantially and perhaps severely. Mid-range projections of CO_2 allowance prices could increase the cost of electricity from the average new coal plant by roughly half.[4] Because coal plants are designed to last for decades, these added financial costs—along with the environmental costs created by coal plants—will be borne by both the present and future generations.

These allowance price forecasts generally assume the adoption of federal policies that aim for modest CO_2 emission reductions at best. However, the science now indicates that if we hope to avoid dangerous global warming, developed nations will need to reduce their CO_2 emissions dramatically—as much as 60 to 80 percent or more—by 2050.[5]

This evidence has prompted governments including California, New Mexico, the New England states, the eastern Canadian provinces, the United Kingdom, and the European Union to adopt long-term CO_2 emission reduction targets in the 60 to 80 percent range. It is therefore reasonable to expect that even if the emission cap initially enacted establishes only modest, short-term targets, it will be followed with increasingly strict national caps in the decades ahead—that is, throughout the operating lifetime of coal plants proposed today.

Meanwhile, climate policies are likely to accelerate the development of energy resources that significantly reduce heat-trapping emissions (reducing the cost of these resources relative to coal) and the development of energy efficiency technologies (reducing electricity demand below currently projected levels). In all likelihood, these changes will improve the economics of coal alternatives just as ever-tightening emission caps are worsening the economics of coal plants.

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[4] For CO_2 price projections see Synapse Energy Economics, "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning," May 18, 2006. Online at *http://www.synapse-energy.com.*

[5] European Environment Agency, "Climate Change and a European Low-Carbon Energy System," Copenhagen, 2005. Online at *http://reports.eea.eu.int/eea_report_2005_1/en/Climate_change-FINAL-web.pdf.*

Given these highly foreseeable trends, why are so many utilities still proposing to lock themselves into capital-intensive coal plants rather than investing in options that do not expose them to such financial risk? These utilities may be betting on their ability to pass the risk on to ratepayers in the form of higher electric rates—the same way they routinely pass through environmental compliance costs today. Utilities holding this belief have little incentive to assess and avoid the risks of future CO_2 regulation. That places on state utilities regulators an enhanced responsibility to assess for themselves the risks associated with gambling huge amounts of money on a large, multi-decade source of CO_2 emissions just as the nation is about to launch a large, multi-decade effort to reduce CO_2 emissions that will surely target coal power.

Utilities may also be ignoring these political developments under the reckless assumption that any plant built before a federal CO_2 cap is adopted will be allocated allowances for free. This gamble ignores the growing opposition to granting such a windfall to utilities (particularly those that could avoid new allowance costs by simply investing in alternatives to coal). The Northeast Regional Greenhouse Gas Initiative (RGGI) model rule, for example, requires that at least 25 percent of allowances be auctioned rather than allocated,[6] and Vermont, the first Northeast state to pass enabling legislation, requires *all* allowances to be auctioned.[7] In fact, 28 different stakeholders in the RGGI model rule draft—including businesses, consumer groups, environmental organizations, state agencies, and an electricity distribution company—supported auctioning 50 to 100 percent of allowances.[8]

At the federal level, Senators Pete Domenici (R-NM) and Jeff Bingaman (D-NM) issued a white paper describing the design elements of a mandatory system to reduce emissions. The paper notes that auctioning off all allowances would minimize the costs to the U.S. economy as a whole, streamline the administrative process, and avoid unintended competitive advantages and windfall profits for certain market participants.[9] A recent Wall Street study also predicts that the United States will have an auction-based rather than allocation-based cap-and-trade system.[10]

If regulators do authorize the construction of a new coal plant, they should notify the utility up front that it will not be allowed to pass future CO_2 compliance costs on to ratepayers. The last time the nation's utilities embarked on a large-scale campaign to build new baseload plants (plants that operate most of the time) was the 1960s and 1970s; the result was scores of abandoned nuclear projects and a great deal of excess generating capacity. Disputes over whether ratepayers or utility shareholders should pay for these

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[6] Regional Greenhouse Gas Initiative (RGGI) Model Rule, subpart XX-5.3. Online at http://www.rggi.org/docs/model_rule_8_15_06.pdf.
[7] The Vermont law (H. 860) is online at http://massclimateaction.org/RGGI/VTRGGISignedMay06.pdf.
[8] Environment Northeast, Natural Resources Defense Council, and Pace Law School Energy Project, "Summary of Comments on the RGGI Model Rule Draft," 2006.
[9] Sen. Pete V. Domenici and Sen. Jeff Bingaman, "Design Elements of a Mandatory Market-Based Greenhouse Gas Regulatory System," February 2006.Online at http://www.nam.org/s_nam/bin.asp?CID=43&DID=236483&DOC=FILE.PDF.
[10] Hugh Wynne, "U.S. Utilities: The Prospects for CO_2 Emissions Limits in the United States and Their Implications for the Power Industry," Bernstein Research, April 19.

investment mistakes led to a series of decisions requiring shareholders to pay for at least a portion of the losses. Those decisions stressed the importance of forcing utilities to assume financial risk in order to give them an incentive to track events that could increase the cost of construction projects and to reassess the viability of those projects as conditions warrant.

Given the momentum now driving the nation toward CO_2 limits—and the substantial impact such limits will have on the cost of coal power—it has never been more critical to ensure that utility managers are staying abreast of current developments. Placing the financial risk of future CO_2 costs on shareholders, clearly and up front, will create that incentive. This regulatory approach is not only fully consistent with rate-making principles, but also builds on the lessons learned from the expensive investment mistakes of the past.

I. Scientific evidence clearly establishes the need for policies limiting CO_2 emissions now and reducing them dramatically over a period of decades.

A. The scientific consensus about the reality of global warming is strong and growing stronger.

The world scientific community spoke with one voice recently to deliver an unprecedented and remarkably pointed message to world leaders. Eleven of the world's most respected national science academies, including the U.S. National Academy of Sciences (NAS), issued this joint statement in anticipation of the 2005 G8 Summit:

> *"Climate change is real. There will always be uncertainty in understanding a system as complex as the world's climate. However, there is now strong evidence that significant global warming is occurring."*[11]

The statement called on world leaders to acknowledge that "the threat of climate change is clear and increasing," and urged all nations "to take prompt action to reduce the causes of climate change."[12]

The NAS is generally considered America's preeminent scientific association. It was chartered by Congress in 1863 and tasked with the role of advising the nation on scientific matters. Its 2,000 members—all elected to the academy in recognition of their distinguished achievements in original research—include the nation's most respected scientists; roughly 10 percent have won a Nobel Prize.[13] When the Bush administration

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[11] The "Joint Science Academies' Statement: Global Response to Climate Change" was issued by the NAS and its counterpart academies in Brazil, Canada, China, France, Germany, India, Italy, Japan, Russia, and the United Kingdom. Online at *http://nationalacademies.org/onpi/06072005.pdf*.
[12] Ibid.
[13] See the NAS website: *http://www.nasonline.org/site/PageServer?pagename=ABOUT_main_page*.

took office in 2001, it asked the NAS for confirmation that our heat-trapping emissions are causing global warming, and it received that confirmation.[14]

This joint statement follows a growing number of statements and reports reflecting concern about global warming from the NAS, the American Geophysical Union, the American Association for the Advancement of Science, the American Meteorological Society—indeed every scientific association in the nation whose membership has expertise directly relevant to the issue.[15] The consensus on the reality of climate change is so strong that a review of 928 papers published in peer-reviewed scientific journals between 1993 and 2003 did not find a single paper that disagreed with the consensus view.[16]

The scientific consensus has been gaining strength at the international level as well. Since 1988, thousands of scientists have been part of a formal process—under the auspices of the Intergovernmental Panel on Climate Change (IPCC)—for methodically and collectively looking at the climate science and publishing reports to help the world's policy makers determine the scope of the global warming threat. The IPCC has published three major assessments to date (1990, 1995, and 2001), each time expressing greater concern about the certainty and potential danger of global warming.[17] Given the record-breaking warmth the planet has continued to experience since the 2001 IPCC report and subsequently published scientific assessments,[18] it is widely expected that the IPCC's upcoming 2007 report will continue that trend.[19]

Evidence that we are changing the climate and that the planet is responding in worrisome ways is now so strong that many who have dismissed global warming in the past have recently changed positions. Prominent members of the media who formerly declared themselves skeptical of the threat have quite publicly "switched sides."[20] Even

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[14] NAS, "Climate Change Science: An Analysis of Some Key Questions," 2001. Online at *http://fermat.nap.edu/books/0309075742/html*.

[15] Ibid. Also see NAS, "Understanding and Responding to Climate Change: Highlights of National Academies Reports," 2006 (online at *http://dels.nas.edu/basc/Climate-HIGH.pdf*); American Geophysical Union, "Human Impacts on Climate," December 2003 (online at *http://www.agu.org/sci_soc/policy/climate_change_position.html*); Atlas of Population and Environment by the American Association for the Advancement of Science, "Climate Change" (online at *http://www.ourplanet.com/aaas/pages/atmos02.html*); American Meteorological Society Council, "Climate Change Research: Issues for the Atmospheric and Related Sciences," February 9, 2003, *Bulletin of the American Meteorological Society* 84, 508–515 (online at *http://www.ametsoc.org/POLICY/climatechangeresearch_2003.html*).

[16] Naomi Oreskes, "Beyond the Ivory Tower: The Scientific Consensus on Climate Change," *Science*, December 3, 2004, 1686. Online at *http://www.sciencemag.org/cgi/content/full/306/5702/1686*.

[17] Intergovernmental Panel on Climate Change (IPCC), "16 Years of Scientific Assessment in Support of the Climate Convention," December 2004. Online at *http://www.ipcc.ch/about/anniversarybrochure.pdf*.

[18] For example, see Scientific Symposium on Stabilisation of Greenhouse Gases, "Avoiding Dangerous Climate Change," Executive Summary of the Conference Report, February 1-3, 2005, 2. Online at *http://www.defra.gov.uk/environment/climatechange/internat/dangerous-cc.htm*.

[19] Roger Harrabin, "Consensus Grows on Climate Change," BBC News, March 1, 2006. Online at *http://news.bbc.co.uk/1/low/sci/tech/4761804.stm*.

[20] Gregg Easterbrook recently wrote in the *New York Times*, "[a]s an environmental commentator, I have a long record of opposing alarmism. But based on the data I'm now switching sides regarding global

ExxonMobil, which has for years disputed the mainstream climate science more aggressively than any corporation in America, now admits "that the accumulation of greenhouse gases in the Earth's atmosphere poses risks that may prove significant for society and ecosystems. We believe that these risks justify actions now, but the selection of actions must consider the uncertainties that remain."[21] The company continues to exaggerate the uncertainties, to fund groups that cast doubt on the science (to the growing dismay of investors[22]), and to resist government regulation, but the science is now so strong that it can no longer deny that the risks justify an immediate response.[23]

B. The evidence establishes that global warming is already harming the planet, and that we face much greater levels of damage in the century ahead.

The basics of global warming science have been understood for a long time. Heat-trapping or "greenhouse" gases, of which CO_2 is the most important, allow the sun's light to penetrate to Earth's surface, where some of it is absorbed and converted into heat. These gases then prevent that heat from radiating back out to space, thereby keeping the planet warm enough to support life.

When we burn fossil fuels, the carbon in those fuels is converted into CO_2; since coal contains the most carbon, it creates the most CO_2 for every unit of energy released.[24] Humans have emitted enough CO_2 to raise background concentrations of this critical heat-trapping gas by about one-third above pre-industrial levels, and concentrations continue to rise.[25] Once concentrations rise, it takes centuries for natural processes to bring them back down again.[26]

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warming, from skeptic to convert." ("Finally Feeling the Heat," May 24, 2006. Online at http://select.nytimes.com/gst/abstract.html?res=F40B1EF63B5A0C778EDDAC0894DE404482; subscription required). A few days earlier, Michael Shermer wrote in *Scientific American*, "environmental skepticism [on climate change] was once tenable. No longer. It is time to flip from skepticism to activism." ("The Flipping Point: How the Evidence for Anthropogenic Global Warming Has Converged to Cause this Environmental Skeptic to Make a Cognitive Flip," June 2006, 28. Online at http://www.sciam.com/article.cfm?articleID=000B557A-71ED-146C-ADB783414B7F0000&sc=I100322.)

[21] ExxonMobil, 2005 Corporate Citizenship Report, May 2006, 22. Online at http://www.exxonmobil.com/Corporate/Citizenship/citizenship.asp.

[22] Andrew Logan and David Grossman, "ExxonMobil's Corporate Governance on Climate Change," CERES and Investor Network on Climate Risk, May 2006, 2. Online at http://www.ceres.org/pub/docs/Ceres_XOM_corp_gov_climate_change_052506.pdf.

[23] Other major oil companies publicly accepted the reality of climate change years ago, and are more direct in their recognition of the risks it poses. The head of BP Amoco said to the British House of Lords in 2002, "Very few people now deny that climate change is a serious risk to the whole of the world" (online at http://www.bp.com/genericarticle.do?categoryId=98&contentId=2000291). Also see the climate statements on the websites of Royal Dutch Shell (www.shell.com) and Chevron (www.chevron.com).

[24] Coal contains nearly 90 percent more carbon per unit of energy than natural gas. However, a new conventional (supercritical) coal power plant produces nearly 150 percent more CO_2 than a new natural gas combined-cycle power plant, which is much more efficient. Based on data from EIA, *Assumptions to Annual Energy Outlook 2006*, Table 38, March 2006, 73. Online at http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2006).pdf.

[25] IPCC Third Assessment Report (TAR), Climate Change 2001: Report of Working Group 1, Summary for Policymakers, 7. Online at http://www.ipcc.ch.

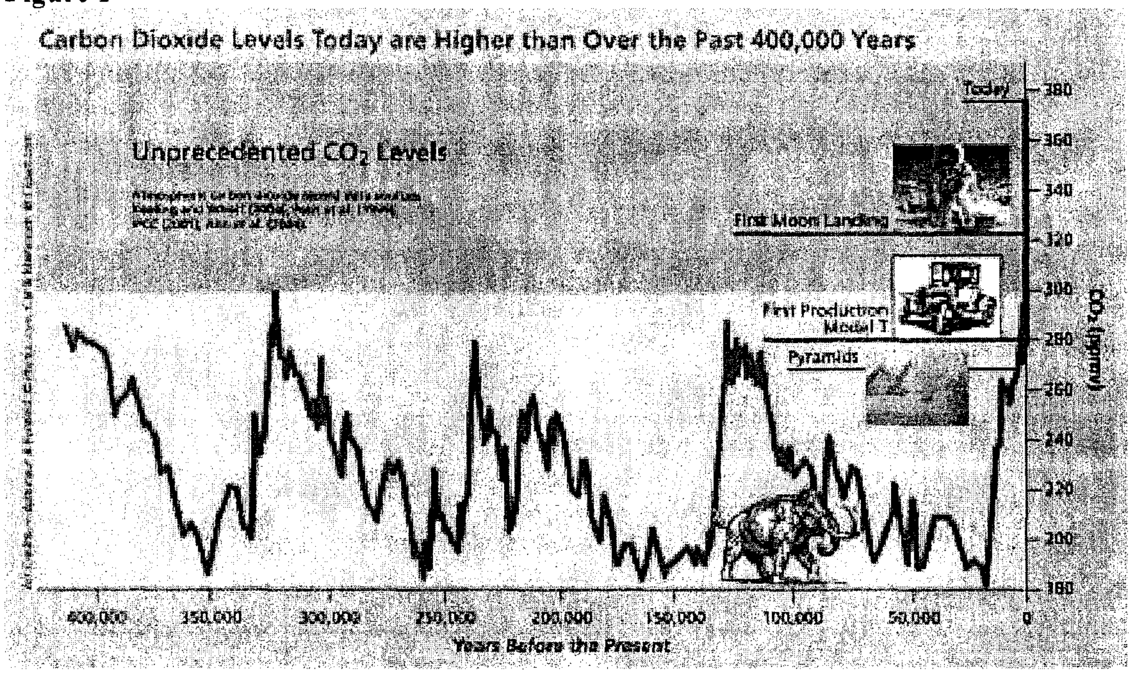
[26] Ibid, 17.

In recent years, scientific concern over global warming has grown both because our understanding of Earth's climate has improved and because the warming trend has continued. The National Aeronautics and Space Administration (NASA) reports that 2005 was the warmest year on record.[27] The five warmest years have all occurred since 1997 (including each of the last four years).[28] In 2001 the IPCC concluded that global average temperatures rose 0.6 degree Celsius (1.1 degrees Fahrenheit) in the twentieth century.[29] However, due to steady warming in this century, total warming over the last 100 years is now up to 0.8 degree Celsius (1.4 degrees Fahrenheit), with most of that increase (0.6 degree Celsius or 1.1 degree Fahrenheit) occurring in just the last 30 years.[30] Scientists have a high level of confidence that the present time is warmer than any period in at least 400 years.[31]

Scientists have been looking for natural causes that would explain the steep warming trend of recent years and have been unable to find them; indeed, it appears that natural causes alone (e.g., solar variation and volcanic activity) should have led to stable or slightly cooler average global temperatures in recent decades.[32] Computer models can only duplicate the recent warming by including today's phenomenally high concentrations of heat-trapping gases, especially CO_2.[33] Figure 1 compares today's CO_2 levels with those occurring over the last 400,000 years. New ice core data go back even further, and show that global CO_2 levels are 27 percent higher than they have been at any time in the past 650,000 years.[34]

[27] National Aeronautics and Space Administration (NASA), "2005 Warmest Year in Over a Century," January 24, 2006. Online at *http://www.nasa.gov/vision/earth/environment/2005_warmest.html*.
[28] Ibid.
[29] IPCC TAR, Summary for Policymakers, 2.
[30] NASA, 2006.
[31] National Research Council, *Surface Temperature Reconstructions for the Last 2000 Years*, National Academies Press, 2006, 3. Online at *http://www.nap.edu/catalog/11676.html#toc*.
[32] IPCC TAR, Summary for Policymakers, 10–11.
[33] Ibid.
[34] Urs Siegenthaler, et al., "Stable Carbon Cycle-Climate Relationship during the Late Pleistocene," 2005, *Science* 310:1313–1317.

Figure 1



Sources: UCS, "Past, Present and Future Temperatures: the Hockeystick FAQ," online at *http://www.ucsusa.org/global_warming/science/hockeystickFAQ.html.*

Other geologic evidence indicates that current CO_2 levels are probably higher than at any time in the last 20 million years.[35] Projections show that in the years ahead, unless actions are taken to reduce emissions, CO_2 levels could rise to 750 parts per million by volume (ppmv) or higher[36]—well beyond the scale used in Figure 1. In other words, we have already dramatically increased the atmospheric concentrations of a gas that plays a critical role in determining Earth's climate, and much more dramatic changes lie ahead if current trends continue.

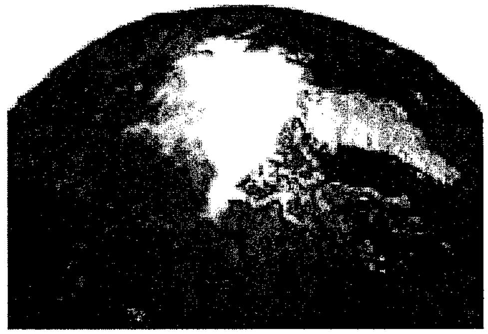
The consequences of global warming are now evident around the world, and in many respects Earth is responding to the warming at a faster rate than scientists predicted just a few years ago. The effects of climate change are now visible in most ecosystems and appearing more rapidly than predicted.[37] Recent studies have suggested a link between global warming, higher sea surface temperatures, and an unexpected increase in hurricane strength.[38] Mountain glaciers are in widespread retreat, enormous ice shelves in

[35] IPCC TAR, Summary for Policymakers, 7.
[36] Ibid., 14.
[37] Hans Joachim Schellnhuber, ed., *Avoiding Dangerous Climate Change*, Chapter 12, Cambridge University Press, 2006. Online at *http://www.defra.gov.uk/environment/climatechange/internat/dangerous-cc.htm.*
[38] Kerry Emanuel, "Increasing Destructiveness of Tropical Cyclones Over the Past 30 Years," August 4, 2005, *Nature* 436:686 (online at *http://www.nature.com/nature/journal/vaop/ncurrent/abs/nature03906.html*); Georgia Institute of Technology, "Hurricanes are Getting Stronger, Study Says," press release, September 15, 2005 (online at

Antarctica have collapsed with surprising suddenness, and Arctic permafrost and northern polar sea ice are melting dramatically.[39] Satellites show that perennial sea ice in the Arctic shrunk at a rate of nine percent per decade between 1979 and 2003 (Figure 2).

Figure 2: Arctic Sea Ice Is Retreating

Arctic sea ice in 1979



Arctic sea ice in 2003

Source: NASA Goddard Space Flight Center, online at *http://earthobservatory.nasa.gov/Newsroom/NewImages/images.php3?img_id=16340*.

Earth's response to the warming we have experienced thus far increases concerns about how the planet will respond to the much greater warming expected in the century ahead. The IPCC's 2001 assessment predicts warming of another 1.5 to 5.8 degrees Celsius (2.7 to 10.4 degrees Fahrenheit) by 2100.[40] Figure 3 compares this warming with observed temperatures during the previous century and with estimated temperatures of the last 1,000 years.

The range of warming estimates for the next century reflects uncertainties about Earth's climate system as well as uncertainty about the future rate at which heat-trapping gases will be emitted. Recent studies of how natural systems release more heat-trapping gases in response to warming, amplifying the effect of human-made emissions, suggest the 2001 predictions may be conservative.[41]

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http://www.gatech.edu/news-room/release.php?id=654); National Center for Atmospheric Research, "Global Warming Surpassed Natural Cycles in Fueling 2005 Hurricane Season, NCAR Scientists Conclude," press release, June 22, 2006.

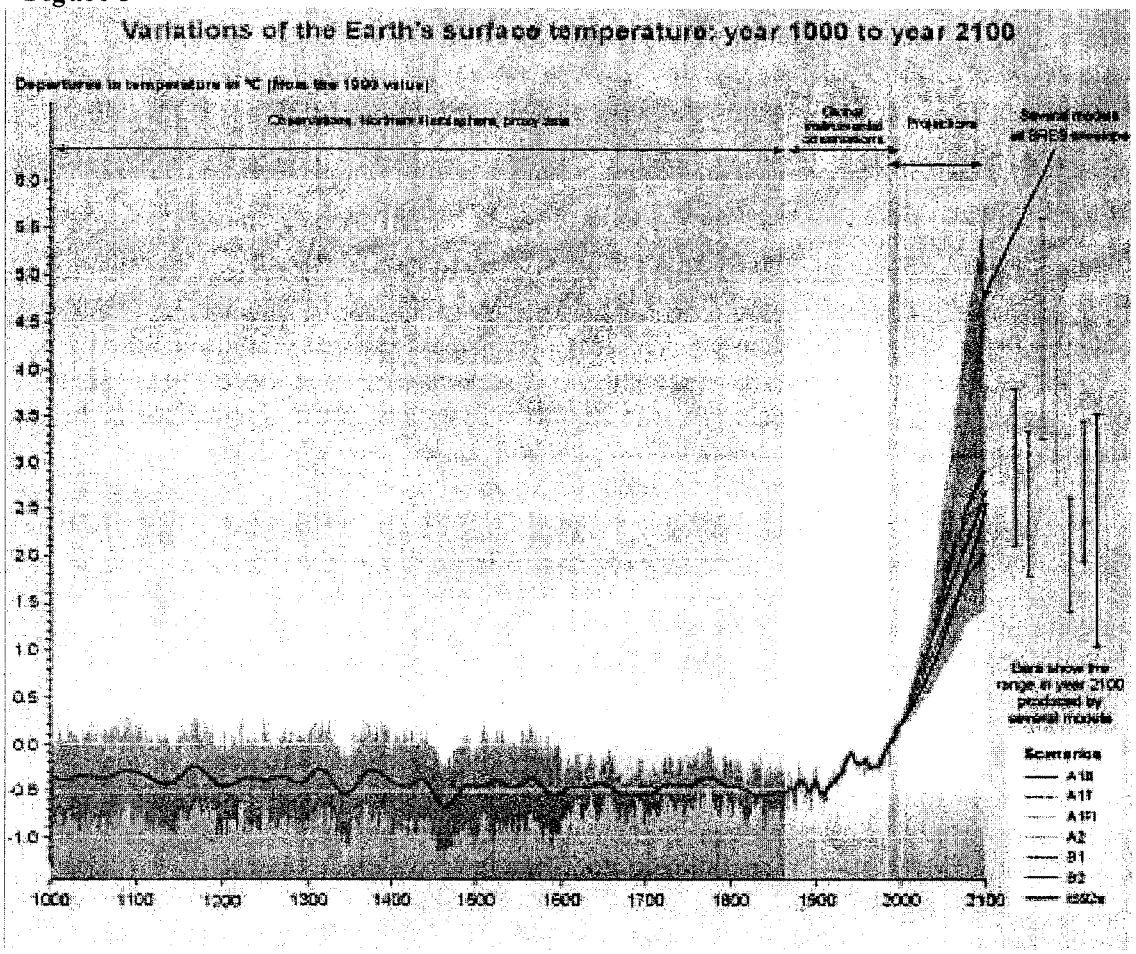
[39]IPCC TAR, Summary for Policymakers, 4; Arctic Climate Impact Assessment: Impacts of a Warming Arctic, Cambridge University Press, 2004 (online at *http://amap.no/acia*); Ice shelf collapses described by the National Snow and Ice Data Center (online at *http://nsidc.org/sotc/iceshelves.html*).

[40] IPCC TAR, Summary for Policymakers, 13.

[41]Margaret S. Torn and John Harte, "Missing Feedbacks, Asymmetric Uncertainties, and the Underestimate of Future Warming," 2006, *Geophysical Research Letters* 33:L10703; Lawrence Berkeley National Laboratory, "Feedback Loops in Global Climate Change Point to a Very Hot 21st Century," press release, May 22, 2006 (online at *http://www.lbl.gov/Science-Articles/Archive/ESD-feedback-loops.html*); American Geophysical Union, "Greenhouse Gas/Temperature Feedback Mechanism May Raise Warming Beyond Previous Estimates," press release, May 22, 2006 (online at *http://www.agu.org/sci_soc/prrl/prrl0617.html*).

Moreover, the NAS and others warn that future warming could occur in abrupt and unpredictable ways. Evidence of past climate changes show the planet has a history of quickly lurching from one climate pattern to another in a way that would make it far harder for nature and society to adapt.[42]

Figure 3



Source: IPCC, "Climate Change 2001:Synthesis Report," Summary for Policymakers, 34.

C. Evidence indicates that dramatic reductions in CO_2 levels will be required in the decades ahead.

Currently, much of the scientific and policy discussion occurring globally focuses on how deeply and quickly CO_2 emissions need to be cut in order to avoid triggering dangerous global warming.[43] The international community has been treaty-bound to work

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[42]National Research Council, *Abrupt Climate Change: Inevitable Surprises*, National Academies Press, 2002. Online at http://www.nap.edu/catalog/10136.html?onpi_newsdoc121101.

[43] Scientific Symposium on Stabilisation of Greenhouse Gases, 2005.

toward this goal since the Framework Convention on Climate Change was adopted in 1992 and ratified by 188 nations (including the United States).[44]

Evidence of the dangers associated with warming greater than two degrees Celsius above pre-industrial levels has been compelling enough to persuade the European Union (EU) to adopt the goal of limiting planetary warming to this level.[45] Studies show that to have a reasonable chance of achieving this goal, net heat-trapping emissions for both developed and developing countries must be reduced at least 15 to 50 percent below 1990 levels by 2050.[46] The European Parliament has adopted a resolution pushing for developed nations to reduce emissions 30 percent by 2020 and 60 to 80 percent by 2050.[47] The United Kingdom adopted a similar target in 2003: 20 percent reductions by 2010 and 60 percent by 2050.

In this country, two states have already adopted similarly ambitious goals. California has adopted a target of reducing heat-trapping emissions by 80 percent (below 1990 levels) by 2050,[48] and New Mexico seeks a 75 percent reduction (below 2000 levels) by 2050.[49] A regional goal was set in 2001 when the Conference of New England Governors and Eastern Canadian Premiers adopted a long-term target of reducing global warming emissions 75 to 85 percent below 2001 levels.[50]

In the discussion that follows it is important to keep this science in mind. Most of the policies currently in place or being debated, internationally and domestically, aim to achieve relatively modest targets that will have to be followed with more aggressive reductions in the years ahead if we are to avoid dangerous warming over the long term. Today's policy proposals must therefore be seen as the first steps in a much longer global process.

Ultimately, emission reductions of the magnitude needed will require a historic, worldwide transition away from the energy technologies that we rely on today, and particularly away from conventional coal plants, during the next four and a half decades—roughly during the operating lifetime of a new coal plant.

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44 Framework Convention on Climate Change," Article 2. Online at *http://unfccc.int/resource/docs/convkp/conveng.pdf*.

45 European Environment Agency, 2005, 10.

46 European Environment Agency, 2005, 7 and Chapter 3.

47 European Parliament Resolution on Climate Change, January 18, 2006. Online at *http://www.europarl.europa.eu/omk/sipade3?PUBREF=-//EP//TEXT+TA+P6-TA-2006-0019+0+DOC+XML+V0//EN&L=EN&LEVEL=1&NAV=S&LSTDOC=Y&LSTDOC=N*.

48 Executive Order S-3-05, June 1, 2005. Online at *http://www.climatechange.ca.gov/index.html*.

49 Office of Governor, State of New Mexico, "Governor Bill Richardson Announces Historic Effort to Combat Climate Change," press release, June 9, 2005. Online at *http://www.governor.state.nm.us/press/2005/june/060905_3.pdf*.

50 New England Governors/Eastern Canadian Premiers, "Climate Change Action Plan 2001," August 2001. Online at *http://www.neg-ecp-environment.org/page.asp?pg=46*.

II. The global warming policy response is mounting at every level.

A. Other developed nations are deepening their commitments to emission cuts.

The global policy response to climate change has increased along with scientific concern. As noted above, in 1992 the United States and most other nations entered into the Framework Convention on Climate Change. That treaty commits developed nations to adopt policies limiting global warming emissions, but its emission reduction target is not binding.[51] The world community then negotiated the Kyoto Protocol, under which developed nations must reduce their emissions an average of five percent below 1990 levels by the period 2008 to 2012. The protocol went into effect in February 2005 despite the United States' refusal to ratify it.

Almost every other developed nation did ratify Kyoto, so that currently nearly half of the global economy is committed to emission reductions under its provisions.[52] Many nations, particularly within the EU, have already adopted mandatory emission limits. The EU itself is limiting CO_2 emissions with a multinational cap-and-trade system, a market-based regulatory approach pioneered in the United States (see part II, section C), and the European Parliament has also endorsed steep, long-term emission reductions.

The United States' refusal to ratify Kyoto or otherwise limit its global warming emissions leaves it nearly isolated within the developed world—a conspicuous position for a country that is the world's richest and also emits roughly one-quarter of the world's heat-trapping emissions, far more than any other nation.[53] The only other developed country that has refused to be bound by Kyoto is Australia.[54]

Over the years, pressure has mounted on the United States to reduce its emissions. At the 2005 G8 Summit, climate change was at the top of the agenda, and the United States was persuaded to sign a statement pledging to "act with resolve and urgency" in reducing emissions.[55] In November 2005, the European Parliament passed a resolution stating that it "[d]eplores the non-implementation by the current U.S. administration" of the Framework Convention and America's failure to ratify Kyoto.[56]

Industrial nations currently subject to the Kyoto limits helped sustain the protocol's momentum by agreeing in December 2005 to negotiate deeper cuts in global

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[51] Framework Convention on Climate Change, article 4, section 2(a).

[52] Innovest Strategic Value Advisors, "Carbon Disclosure Project 2005," 19. Online at *http://www.cdproject.net/aboutus.asp*.

[53] EPA, Global Warming Emissions: Inventory. Online at *http://yosemite.epa.gov/OAR/globalwarming.nsf/content/EmissionsInternationalInventory.html*.

[54] The status of each nation's ratification of the Kyoto Protocol is available on the United Nations Framework Convention on Climate Change website (*http://unfccc.int/essential_background/kyoto_protocol/status_of_ratification/items/2613.php*).

[55] Gleneagles Communiqué, "Climate Change, Energy, and Sustainable Development," July 2005. Online at *http://www.fco.gov.uk/Files/kfile/PostG8_Gleneagles_Communique.pdf*.

[56] European Parliament, "Winning the Battle Against Global Climate Change," (2005/2049(INI)), November 16, 2005. Online at *http://www.europarl.eu.int/news/expert/infopress_page/064-2439-320-11-46-911-20051117IPR02438-16-11-2005-2005-false/default_en.htm*.

warming emissions for the years after Kyoto compliance ends in 2012.[57] As these and other nations deepen and extend their commitments to mandatory emission cuts, pressure will continue to increase on the United States to do likewise.

B. U.S. states, regions, and cities are enacting their own climate policies.

In the absence of federal limits on heat-trapping emissions, many states have moved forward with their own climate-related policies, including cap-and-trade systems now emerging on both coasts. The most developed of these is the Regional Greenhouse Gas Initiative (RGGI) being undertaken by several northeastern and mid-Atlantic states. In December 2005, Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont formally agreed to launch the nation's first regional program imposing a mandatory cap on heat-trapping emissions from power plants.[58] In April 2006, Maryland joined RGGI as well.[59] Under the agreement, beginning in 2009, the states will stabilize power plants' CO_2 emissions and then cut them 10 percent by 2019.[60] The RGGI model rule was adopted in August 2006 to implement the agreement.[61]

On the West Coast, the California legislature passed a bill on August 31, 2006 that sets in place the nation's most comprehensive, economy-wide global warming emissions reduction program. The bill requires the state's global warming emissions to be reduced to 1990 levels by 2020. This reduction will be accomplished through an enforceable statewide cap on global warming emissions that will be phased in starting in 2012. The bill would also coordinate the efforts of various state agencies, including a pending proceeding at the Public Utilities Commission to establish a load-based cap on the three large investor-owned utilities as well as other jurisdictional utilities in the state. Governor Schwarzenegger has indicated that he will sign the bill into law.[62]

California has also taken the lead in fighting climate change by requiring utilities to make aggressive investments in energy efficiency as well as factor future CO_2 regulatory costs into their resource choices (see part V, section A) and by pursuing a performance standard for global warming emissions that would prevent the procurement of power from conventional coal plants.[63] Other efforts California has taken to reduce global warming emissions include the adoption of motor vehicle standards requiring a 30

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[57] Union of Concerned Scientists, "World Moves Forward on Global Warming, Bush Administration Stays Behind," press release, December 10, 2005. Online at *http://www.ucsusa.org/news/press_release/world-moves-forward-on-global-warming-MONTREAL.html*.
[58] See the RGGI website (*www.rggi.org*).
[59] *New York Times*, "Pollution Pact Gets Maryland as 8th Member," April 7, 2006. Online at *http://select.nytimes.com/search/restricted/article?res=FA0E15FD3A540C748CDDAD0894DE404482*.
[60] RGGI Memorandum of Understanding.
[61] Regional Greenhouse Gas Initiative (RGGI) Model Rule. Online at *http://www.rggi.org/docs/model_rule_8_15_06.pdf*.
[62] *Sacramento Bee*, "Schwarzenegger, lawmakers strike deal on greenhouse gases," August 31, 2006. Online at http://www.sacbee.com/content/politics/story/14312261p-15214839c.html.
[63] California PUC, "Policy Statement on Greenhouse Gas Performance Standards," April 12, 2006. Online at *http://www.cpuc.ca.gov/word_pdf/REPORT/50432.doc*.

percent reduction in CO_2 emissions from vehicles by the period 2013 to 2016.[64] As of June 2006, 10 other states plus Canada—representing approximately one-third of automobile sales in North America—had adopted California's standards.[65]

These efforts are part of a wider trend among states to respond to global warming. Twenty states and the District of Columbia, for example, have already adopted renewable energy standards covering approximately 40 percent of the electricity used in the United States,[66] partly in response to global warming. Massachusetts, New Hampshire, Oregon, and Washington have already passed laws limiting power plant CO_2 emissions or requiring plant owners to purchase offsets.[67] California, Oregon, and Washington have also joined forces on the West Coast Governors' Global Warming Initiative, which involves a variety of steps for reducing global warming emissions.[68]

The policy response to climate change is also accelerating at the local level. Mayors of more than 270 cities, representing more than 48 million Americans, have endorsed the US Mayors Climate Protection Agreement. Under this agreement they commit to working within their own communities to achieve the emission reduction targets of the Kyoto Protocol, and to urge the federal government to adopt a global warming emission trading system.[69] More than 150 local governments participate in another initiative to inventory their heat-trapping emissions, develop emission reduction targets, and implement policies to meet them.[70]

All of these state and local efforts increase the calls for and the likelihood of a climate response at the federal level, which would avoid a patchwork of different standards around the nation.

C. Congress is moving toward mandatory cap-and-trade CO_2 limits.

Momentum behind mandatory federal limits on CO_2 emissions continues to grow in Congress. In 2005, the Senate (with bipartisan support) passed a resolution finding that accumulating global warming emissions are causing temperatures to rise beyond natural variability and posing a "substantial risk" of rising sea levels and more frequent and severe droughts and floods. It states that "mandatory steps will be required to slow or stop the growth" of global warming emissions and that "Congress should enact a

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[64] California Air Resources Board, "Climate Change Emission Control Regulations." Online at *http://www.arb.ca.gov/cc/factsheets/cc_newfs.pdf*.
[65] See the California Clean Cars Campaign website (*http://www.calcleancars.org/news.html#senators*).
[66] Minnesota also has a renewable energy requirement for one utility, Xcel Energy (see *http://www.ucsusa.org/clean_energy/renewable_energy/page.cfm?pageID=47*). Also see Ryan H. Wiser, "Meeting Expectations: A Review of State Experience with RPS Policies," Lawrence Berkeley National Laboratory, March 2006. Online at *http://eetd.lbl.gov/ea/ems/reports/awea-rps.pdf*.
[67] Massachusetts Department of Environmental Protection, "Emissions Standards for Power Plants," 310 CMR 7.29; New Hampshire Revised Statutes Annotated. "Multiple Pollutant Reduction Program," Chapter 125-O; Washington Revised Code, "Carbon Dioxide Mitigation," Chapter 80.70; Oregon Revised Statutes, Carbon Dioxide Emissions Standard, § 469.503.
[68] West Coast Governors' Global Warming Initiative. Online at *http://www.ef.org/westcoastclimate*.
[69] US Mayors Climate Protection Agreement. Online at *http://www.seattle.gov/mayor/climate/*.
[70] Cities for Climate Protection. Online at *http://www.iclei.org/index.php?id=1118*.

comprehensive and effective national program of mandatory, market-based limits and incentives on emissions of greenhouse gases." The program goal would be to eventually reverse the growth of such emissions in a way that would not harm the U.S. economy and would encourage comparable action by major trading partners.[71] In May 2006, an identically phrased resolution was adopted with bipartisan support by the powerful House Appropriations Committee.[72]

It is widely understood that by using the phrase "mandatory, market-based limits," the Senate was referring to a particular kind of regulatory approach known as cap-and-trade. Under such a program, a cap would be established limiting how many tons of CO_2 could be emitted nationwide, and the same number of "allowances" would be issued, each one granting its owner the right to emit one ton of CO_2.

A market price for CO_2 allowances would emerge as operators begin buying and selling them. In practice, power plants that could reduce CO_2 emissions at a lower cost than the market price of an allowance would do so; those that could not would purchase additional allowances to cover their emissions. This system of regulation was pioneered in 1990 to reduce power plants' emissions of sulfur dioxide and other pollutants that cause acid rain, and it proved so successful and efficient that virtually every proposal to regulate CO_2—whether international, regional, or federal—has included some form of cap-and-trade.[73]

As of July 2006, there are at least seven proposals[74] under consideration that would establish a cap-and-trade system for CO_2, including the Climate Stewardship and Innovation Act (S. 1151) introduced by Senators John McCain (R-AZ) and Joseph Lieberman (D-CT) and a proposal sponsored by Senator Jeff Bingaman (D-NM) modeled after a proposal of the National Commission on Energy Policy (NCEP).[75] The Senate Energy and Natural Resources Committee also conducted extensive hearings on the design features of a cap-and-trade system based on the NCEP model in April 2006, accepting comments from many different stakeholders. Many members of the power industry participated in these hearings, including companies that support mandatory regulations and those that, while still opposed to mandatory limits, now consider them inevitable and want to have a say in shaping them (see part III). Two of the most

[71] Sense of the Senate on Climate Change, H.R.6 §1612, Energy Policy Act of 2005. This resolution passed by a vote of 54-43.
[72] See Senate Committee on Energy and Natural Resources, "Chairman Domenici and Senator Bingaman React to House Committee Vote on Climate Change," press release, May 10, 2006. Online at *http://energy.senate.gov/public/index.cfm?FuseAction=About.Subcommittee&Subcommittee_ID=7*.
[73] Another regulatory option, though one with much less political momentum, is enactment of a carbon tax. By setting a price on CO_2 emissions, the effect on coal plant risks would be the same as a cap-and-trade system that results in equivalent allowance prices, and the arguments in this paper would still apply.
[74] In addition to those mentioned in the text, these proposals include the Clean Air Planning Act of 2006 (S. 2724) introduced by Senator Thomas Carper (D-DE); the Keep America Competitive Global Warming Policy Act of 2006 (H.R. 5049), introduced by Representatives Tom Udall (D-NM) and Tom Petri (R-WI); and the Strong Economy and Climate Protection Act, announced and circulated for discussion by Senator Dianne Feinstein (D-CA) but not yet introduced.
[75] The NCEP proposal is set forth in "Ending the Energy Stalemate" (online at *http://www.energycommission.org/site/page.php?report=13*).

ambitious bills -- the Global Warming Pollution Reduction Act (S. 3698) introduced by Senator Jim Jeffords (I-VT) and the Safe Climate Act (H.R. 5642) introduced by Representatives Henry Waxman (D-CA) and Maurice Hinchey (D-NY)-- would aim to reduce heat-trapping emissions 80 percent below 1990 levels (in line with scientific estimates of what is needed to avoid dangerous global warming).[76]

Political support for a cap-and-trade system is extremely broad, encompassing major U.S. environmental advocacy groups and those in industry that support CO_2 regulation in general. This method of regulation has even been explicitly endorsed by a substantial segment of the U.S. evangelical Christian movement. Several dozen evangelical leaders recently issued a statement declaring that the need for action on global warming is urgent and calling for national legislation requiring CO_2 reductions through "cost-effective, market-based mechanisms such as a cap-and-trade program." They stress that we need urgent action because we are making long-term decisions today that will determine CO_2 emissions in the future, including "whether to build more coal-burning power plants that last for 50 years rather than investing more in energy efficiency and renewable energy."[77]

Utilities may be ignoring these political developments under the reckless assumption that any plant built before a cap-and-trade system is adopted will be allocated allowances for free. This gamble ignores the growing opposition to granting such a windfall to utilities (and particularly those who could avoid new allowance costs by simply investing in alternatives to coal).

The RGGI model rule, for example, requires that at least 25 percent of allowances be auctioned rather than allocated, and Vermont, the first Northeast state to pass enabling legislation, requires auctioning 100 percent of allowances.[78] In fact, 28 different stakeholders in the RGGI model rule draft, including businesses, consumer groups, environmental organizations, state agencies, and an electricity distribution company, supported auctioning 50 to 100 percent of allowances.[79] The proceeds from such an auction would be used to fund investments in energy efficiency, renewable energy, and other low-carbon energy technologies, as well as direct rebates to consumers.

On the federal level, Senators Bingaman and Pete Domenici (R-NM) issued a white paper describing the design elements of a mandatory system to reduce CO_2 emissions. The paper notes that auctioning off all allowances would minimize the costs to the U.S. economy as a whole, streamline the administrative process, and avoid unintended competitive advantages and windfall profits for certain market participants.[80]

[76] See Senator Jeffords' website (*http://jeffords.senate.gov/~jeffords/press/06/07/072006climatebill.html)* and Representative Waxman's website (*http://www.house.gov/waxman/safeclimate/index.htm*).
[77] Evangelical Climate Initiative, "Climate Change: An Evangelical Call to Action." Online at *http://www.christiansandclimate.org/statement*.
[78] RGGI Model Rule. A bill pending in Massachusetts would begin with 50 percent auctioning and increase 10 percent a year (reaching 100 percent auctioning in year six). New York Attorney General Eliot Spitzer is calling for 100 percent auctioning. For more information, see *http://massclimateaction.org/RGGI.htm*.
[79] Environment Northeast, Natural Resources Defense Council, and Pace Law School Energy Project, 2006.
[80] Domenici and Bingaman, 2006.

A recent Wall Street study further predicts that the United States will have an auction-based rather than allocation-based cap-and-trade system.[81]

In short, not only is it now virtually inevitable that a federal program limiting CO_2 emissions will be approved in the next few years, but it is also fairly certain that this program will take the form of a cap-and-trade system under which every ton of CO_2 emitted will come with a cost, determined by the forces of supply and demand for CO_2 allowances.

D. Coal plants will certainly be covered by future climate regulations.

While the scope of a federal program limiting global warming emissions is under active discussion, every climate bill that has been proposed would cover CO_2 emissions from coal plants—for good reason. Coal plants are by far the largest individual sources of CO_2 emissions, representing nearly one-third of U.S. energy-related CO_2 emissions (the entire power sector accounts for 39 percent of such emissions). Coal plants emit about the same amount of CO_2 as all petroleum-based emissions from cars, trucks, trains, and planes combined, which represent another third of U.S. energy-related CO_2 emissions. The remaining third comes from a variety of technologies and sources including, most notably: industrial use of petroleum, natural gas, and coal; residential use of natural gas; and the electricity sector's use of natural gas.[82]

Not only are coal plants a dominant source of CO_2, but they are also relatively few in number compared with the millions of sources in other sectors, making them far easier for any federal program to regulate. A single new 500 MW conventional coal plant, for example, can emit the annual CO_2 equivalent of more than 600,000 cars.[83] All of the federal regulatory proposals described above would limit CO_2 emissions from coal plants; the only question is whether they would also attempt to regulate other sectors of the economy as well.

Additionally, analysis by the U.S. Energy Information Administration (EIA) shows that the electricity sector accounts for many of the most cost-effective reduction options.[84] While power plants account for 39 percent of U.S. energy-related CO_2 emissions, they have the potential to account for somewhere between 66 and 85 percent

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[81] Wynne, 2006.
[82] EPA, 2006; EIA, 2005. Energy-related emissions of CO_2 represent 97 percent of total U.S. emissions of CO_2.
[83] According to the EPA, annual vehicle emissions are about 13,500 lbs/vehicle; see the EPA Personal Greenhouse Gas Calculator (*http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterToolsGHGCalculator.html*). Power plant CO_2 emissions of 4.1 million tons for a new 500 MW plant are based on the Public Service Commission of Wisconsin's Final Environmental Impact Statement for Weston Unit 4 Power Plant, Volume 1, July 2004, 145 (online at *http://psc.wi.gov/utilityinfo/electric/cases/weston/document/Volume1/W4_FEIS.pdf*).
[84] EIA, "Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals," March 2006. Online at *http://www.eia.doe.gov/oiaf/servicerpt/agg/pdf/sroiaf(2006)01.pdf*.

of energy-related CO_2 emission reductions according to computer models designed to show the least expensive options for complying with various CO_2 regulations.[85]

The most significant change from the EIA's "business-as-usual" scenario to its carbon reduction scenarios is the resulting impact on coal generation. In the business-as-usual scenario, approximately 174 gigawatts (GW) of new coal capacity (the equivalent of 290 new 600 MW coal plants) are added by 2030. By contrast, in the two deepest carbon reduction scenarios EIA analyzed, *not a single new conventional coal plant is added beyond those already under construction.*[86] In other words, the construction of any additional conventional coal plants would make it more expensive to achieve the carbon reduction targets.[87]

III. The power industry increasingly supports federal CO_2 limits.

Over the years, most of the power industry has been strongly opposed to federal CO_2 limits from power plants, but that attitude has been changing rapidly, especially in 2006. Many prominent power companies now openly support the federal regulation of CO_2 from coal plants. The chief executive of Duke Energy, one of the nation's largest coal-burning utilities, has said of global climate change, "From a personal perspective I can think of no more pressing global issue." He went on to say:

> *"From a business perspective, the need for mandatory federal policy in the United States to manage greenhouse gases is both urgent and real. In my view, voluntary actions will not get us where we need to be. Until business leaders know what the rules will be—which actions will be penalized and which will be rewarded—we will be unable to take the significant actions the issue requires."*[88]

Duke's website states, "Congress needs to establish a national, economy-wide greenhouse gas mandatory program as soon as possible."[89]

The head of Exelon has stated, "We accept that the science on global warming is overwhelming. There should be mandatory carbon constraints."[90] And the head of PNM

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[85] Ibid., 18.

[86] Ibid., 22. In the deepest carbon reduction scenario, approximately 103 GW of existing coal capacity (171 plants) is retired, and 17 GW of new integrated-gasification combined-cycle (IGCC) capacity with carbon capture and sequestration equipment is added.

[87] UCS does not consider all of EIA's assumptions and methods realistic, nor do we believe its scenarios achieve the lowest possible cost. EIA has typically underestimated the potential of energy efficiency, combined heat and power, and renewable energy to reduce emissions at lower costs (see UCS, *Clean Energy Blueprint*, 2001). However, EIA's modeling is still useful for demonstrating how changes in one variable (e.g., imposition of carbon reduction targets) affect the economics of another (e.g., building new conventional coal plants) under a consistent set of assumptions.

[88] Paul Anderson, "Being (and Staying in Business): Sustainability from a Corporate Leadership Perspective," speech to CERES Annual Conference, April 6, 2006. Online at *http://www.duke-energy.com/news/mediainfo/viewpoint/PAnderson_CERES.pdf*).

[89] "Climate Change: Duke Energy Position on U.S. Climate Change Policy." Online at *http://www.duke-energy.com/environment/policies/climate_change*.

Resources said at Senate hearings, "We believe now is the time for a healthy debate at the federal level on climate change, and we support the move to a mandatory program."[91]

Many other power companies have expressed their support for federal CO_2 limits through coalition statements. In 2003, for example, Calpine, Con Edison, Keyspan, Northeast Utilities, PG&E Corporation, PPL Corporation, Public Service Enterprise Group, and Wisconsin Energy signed onto the CERES Consensus Statement, which called on the federal government to "develop a national, mandatory, market-based program" limiting global warming emissions.[92] In April 2006, the Clean Energy Group's Clean Air Policy Initiative submitted comments to the Senate Committee on Energy and Natural Resources supporting the adoption of a cap-and-trade program for the electricity sector.[93] Entergy, Exelon, and Florida Power & Light thereby added their names to those publicly calling for such a law.[94]

In sum, five of the nation's 10 largest private power producers (Calpine, Duke, Entergy, Exelon, and Florida Power & Light), accounting for more than 15 percent of U.S. electricity generation,[95] now support mandatory limits on CO_2 from power plants. Another (Progress) acknowledged in a 2006 special report to shareholders that the evidence for climate change is sufficient to warrant "action" by the "public sector," which the company believes should cover all sectors of the economy.[96] Executives from three of the remaining companies in the top 10 (American Electric Power, Southern Company, and Xcel), accounting for another 12 percent of U.S. power generation, have acknowledged that federal limits on CO_2 are coming, even if they do not support them.[97]

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[90] John W. Rowe, August 16, 2004, quoted in *Business Week.* Online at *http://www.businessweek.com/print/magazine/content/04_33/b3896001_mz001.htm?gl.*

[91] Jeff Sterba, April 4, 2006, quoted in the *Albuquerque Tribune*. Online at *http://www.abqtrib.com/albq/nw_national_government/article/0,2564,ALBQ_19861_4594645,00.html.*

[92] CERES, "Electric Power, Investors and Climate Change: A Call to Action," September 2003. Online at *http://www.ceres.org/pub/docs/Ceres_electric_power_calltoaction_0603.pdf.*

[93] Michael J. Bradley, April 4, 2006. Online at *http://energy.senate.gov/public/_files/ExecutiveSummariesforwebsite.pdf.*

[94] In addition, three signatories of the CERES Consensus Statement (Calpine, PG&E, and Public Service Enterprise Group) are part of the Clean Energy Group Clean Air Policy Initiative.

[95] The nation's 10 largest private power producers in 2004, in order of megawatt hours produced, were American Electric Power, Southern Company, Exelon, FPL Group, Entergy, Dominion, Duke Energy, Progress Energy, Calpine, and Xcel Energy. (Duke Energy has since moved up in the rankings by merging with Cinergy). See CERES, NRDC, and PSEG, "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States—2004," April 2006. Online at *http://www.nrdc.org/air/pollution/benchmarking/default.asp.*

[96] Progress's vague statement on the need for action on global warming has been interpreted by the trade press as a call for carbon regulation. See "Progress Energy calls for US carbon regulation," March 31, 2006, *Carbon Finance Online* (online at *www.carbonfinanceonline.com*; subscription required); also see "2006: Progress Energy's Report to Shareholders: An Assessment of Global Climate Change and Air Quality Risks and Actions" (online at *http://www.progress-energy.com/environment/climatechange.asp*).

[97] See Dale E. Heydlauff (American Electric Power), quoted in "Global Warming," August 16, 2004, *Business Week* (online at *http://www.businessweek.com/print/magazine/content/04_33/b3896001_mz001.htm?gl*); David Ratcliffe (Southern Company), quoted in "U.S. Utilities Urge Congress to Establish CO_2 Limits," Bloomberg.com (online at *http://www.bloomberg.com/apps/news?pid=10000103&sid=a75A1ADJv8cs&refer=us*); and

This expectation is widely shared in the industry: a 2004 national survey of electricity generating companies found that 60 percent of respondents expected mandatory limits on CO_2 within 10 years, and about half expected such limits within five years.[98]

The industry leaders quoted above echo the rising call for CO_2 limits by companies in other industries, including some of the nation's largest corporations. Wal-Mart calls climate change "an urgent threat not only to our business but also to our customers, communities, and the life support systems that sustain our world."[99] Both Wal-Mart and GE expressed support for CO_2 limits in April 2006 Senate hearings,[100] and Ford Motor Company and Hewlett-Packard joined 22 other multinational corporations in a 2005 statement urging leaders of the G8 nations to adopt cap-and-trade or other market-based mechanisms to limit global warming emissions.[101]

When a significant share of industry speaks out in favor of environmental regulations, including several major companies in the industry sector likely to be most heavily regulated, it is a strong sign that such regulations are near at hand. It is quite possible that CO_2 limits will be in place and operational before the same could be said for a proposed coal plant currently in the regulatory approval process.

IV. The private financial community is pushing companies to disclose and reduce their exposure to future climate regulation.

Concern is undeniably growing among investors and lenders over the financial risks of future CO_2 constraints. For example, the Investor Network on Climate Risk (INCR) was launched in 2003 as a coalition of institutional investors managing $600 billion in assets; by early 2006, it included a much wider array of investors managing more than three trillion dollars in assets.[102] The Carbon Disclosure Project, an investor coalition undertaken on the international level to obtain global warming emission data from 1,900 multinational corporations, now represents investors managing $31 trillion in assets—three times more than in 2003.[103]

The INCR stresses the regulatory risk faced by U.S. companies with high global warming emissions, calling federal carbon constraints "only a matter of time."[104] It has

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Wayne Brunetti (Xcel), quoted in "Xcel Energy expects US carbon regulations," September 9, 2004, PointCarbon (online at *http://www.pointcarbon.com/article.php?articleID=4459&categoryID=147*).

[98] PA Consulting Group, "PA survey finds that US generating companies expect mandatory carbon dioxide regulations within 10 years," press release, October 22, 2004. Online at *http://www.paconsulting.com/news/press_release/2004/pr_carbon_dioxide_regulations.htm*.

[99] Wal-Mart website (*http://walmartstores.com/GlobalWMStoresWeb/navigate.do?catg=347*).

[100] Raymond Bracy (Wal-Mart) and David Slump (GE Energy), comments to Senate Energy and Natural Resources Committee, April 4, 2006. Online at *http://energy.senate.gov/public/_files/ExecutiveSummariesforwebsite.pdf*.

[101] "Statement of the G8 Climate Change Roundtable," World Economic Forum, June 9, 2005. Online at *http://www.weforum.org/pdf/g8_climatechange.pdf*.

[102] Investor Network on Climate Risk (INCR) website (*http://www.incr.com/index.php?page=2*).

[103] Carbon Disclosure Project website (*http://www.cdproject.net/aboutus.asp*).

[104] INCR website, "INCR Overview." Online at *http://www.incr.com/index.php?page=9*.

called on companies in the electricity sector to estimate how future heat-trapping emission limits will affect their businesses and to identify steps they are taking to reduce those effects.[105] In doing so, a board member of the nation's largest public pension fund said, "Ignoring the impact of carbon on the environment and on corporate bottom lines would be fiscally irresponsible and a disservice to investors, taxpayers and the environment."[106]

Investors are particularly concerned with the financial wisdom of building new coal plants in the United States given the growing momentum here for federal CO_2 limits. Several of the nation's largest institutional investors recently warned TXU that the "future cost of carbon could alter the prudence" of the utility's plan to invest in new coal plants, and that TXU was "potentially exposing itself to unprecedented compliance costs" given the long lifespan of coal plants. It urged TXU to disclose to shareholders "how it has accounted for the 'future cost of carbon' in its resource planning for these plants."[107]

Many of the nation's largest banks and investment firms have recently announced more aggressive climate policies. Bank of America, for example, has launched a formal effort to assess and limit its risk from financing emission-intensive industries, including a commitment to reduce emissions from its public energy and utility portfolio seven percent by 2008.[108] JP Morgan Chase sees climate change as a "critical issue" with "potentially very serious consequences for both ourselves as well as our clients." In a recent speech, its director of environmental affairs said, "for the new power projects we are beginning to quantify the financial costs of those greenhouse gas emissions and incorporating that into our financial analysis of the transaction," and went on to note that looking at those costs is "going to have a big impact."[109] The head of global projects for Lehman Brothers has also addressed a cap on global warming emissions by saying, "There's a consensus that something's coming," adding that, "people are very much focused on how that's going to affect economics."[110]

Wall Street is also beginning to assess the impact new laws would have on particular power companies. Bernstein Research recently released a report describing the growing momentum toward CO_2 regulation, concluding that, "Regardless of which party wins the 2008 presidential elections . . . it is probable that the next administration will favor mandatory national limits on CO_2 emissions."[111] The report went on to identify the

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[105] INCR website, "Ten Point Investor Action Plan." Online at *http://www.incr.com/index.php?page=20*.
[106] Phil Angelides, quoted in "Investors Call on Power Sector and Wall Street to Focus Attention on Financial Risks From Climate Change," CERES website, April 13, 2005. Online at *http://www.ceres.org/news/news_item.php?nid=108*.
[107] INCR website, "Investors Concerned About TXU's Aggressive Coal Strategy," May 16, 2006. Online at *http://www.incr.com/index.php?page=ia&nid=178*.
[108] Bank of America website, "Bank of America Climate Change Position." Online at *http://www.bankofamerica.com/newsroom/presskits/view.cfm?page=climateandforests*.
[109] Amy Davidson, "Financial Institutions: Challenges and Opportunities," speech to the Earth Institute, Columbia University, March 29, 2006. Online at *http://www.earthinstitute.columbia.edu/sop2006/transcripts/tr_davidsen.html*.
[110] John Veech, quoted in "Analysts View Energy Policy Act through Climate Change Lens," August 30, 2005, *SNL Generation Markets Week*.
[111] Wynne, 2006.

utilities facing the greatest financial risk: "unregulated coal-fired generators supplying markets where gas is the predominant price setting fuel,"[112] which cannot pass the added costs of an emission cap on to consumers. The assumption, of course, is that regulated utilities *will* be able to pass future compliance costs on to ratepayers—an assumption we challenge below (see part VI), but which does reflect current regulatory practice.

This attitude reveals why, at least for the moment, some sectors of the financial community are still willing to help regulated utilities build new coal plants even when they know that such plants will be substantially more expensive in the carbon-constrained world ahead. Wall Street is not concerned with protecting ratepayers—that will be a job for state regulators.

V. Future costs of CO_2 regulation must be part of any realistic estimate of a new coal plant's operating costs.

A. CO_2 costs are increasingly factored into risk planning by utilities, regulators, and regional planners.

Representatives of three utilities explained in a 2005 trade journal article the importance of assessing and managing CO_2 risk:

> *"The financial risk associated with likely future regulation of carbon dioxide emissions is becoming a focus of utilities' and regulators' risk management efforts, as they recognize the imprudence of assuming that carbon dioxide emissions will not cost anything over the 30-year or longer lifetime of new investments. Utilities can help protect their customers and shareholders from this financial risk by integrating an estimated cost of carbon dioxide emissions into their evaluation of resource options, and selecting the overall least-cost portfolio of resources. Utilities can learn from the experience that some utilities have gained at managing this risk to ensure that today's investments do not lock customers or shareholders into much higher costs tomorrow if greenhouse gases are regulated."*[113]

A recent Lawrence Berkeley National Laboratory analysis of western U.S. utilities' resource planning practices found the practice of quantifying CO_2 risk to be widespread: "Given the potential for future carbon regulations to dominate environmental compliance costs, seven of the twelve utilities in our sample . . . specifically analyzed the risk of future carbon regulations on portfolio selection."[114] State regulators have since ordered three additional utilities to include CO_2 costs in their planning, leaving only two

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[112] Ibid, 2.
[113] Karl Bokenkamp (Idaho Power), Hal LaFlash (Pacific Gas & Electric), Virinder Singh (Pacificorp), and Devra Bachrach Wang, "Hedging Carbon Risk: Protecting Customers and Shareholders from the Financial Risk Associated with Carbon Dioxide Emissions," July 2005, *The Electricity Journal* 18(6): 11–24.
[114] Mark Bolinger and Ryan Wiser, "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans," Lawrence Berkeley National Laboratory, August 2005. Online at http://eetd.lbl.gov/ea/EMS/reports/58450.pdf.

utilities (out of the 12 sampled) that continue to ignore CO_2 risks.[115] In its most recent resource plan, Northwestern Energy (formerly Montana Power) says it is "the mainstream practice of utility planners to factor a carbon tax into their models."[116]

California, Oregon, and Washington require utilities to factor CO_2 costs into their resource plans, and Montana ordered one utility, Northwestern Energy, to do so in its 2005 plan.[117] The California PUC actually chose a specific CO_2 value and requires the three investor-owned utilities in the state to use that value when evaluating bids (which has a direct, ongoing effect on resource selection outside the planning context).[118]

In 2005, the Northwest Power and Conservation Council (often referred to as the Northwest Council) issued a resource plan that incorporates estimates of future CO_2 values beginning in 2008.[119] This is worth noting not only because the 20-year plans developed by this federally created regional agency cover the entire Northwest, but also because most energy planning is conducted by utilities rather than independent planners who have no financial incentive to select one type of resource over another.

B. A useful range of CO_2 price forecasts is emerging from the literature.

Over the last few years, federal cap-and-trade proposals before Congress have spawned numerous analyses using computer models to simulate the market response to these regulations. For example, the EIA, the U.S. Environmental Protection Agency, the Massachusetts Institute of Technology (MIT), and the Tellus Institute have all modeled the effects of proposed legislation resulting in varying CO_2 cost projections.[120] The

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[115] Ibid., 62.

[116] Northwestern Energy, "2005 Electric Default Supply Resource Procurement Plan," Volume 2, Chapter 1, 25.

[117] See Bolinger and Wiser, 2005, 57 (note 75) and 60; Washington Administrative Code, section 480-100-238; and California PUC, "Interim Opinion on E3 Avoided Cost Methodology," April 22, 2004 (online at *http://www.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/45195.htm#TopOfPage*).

[118] California PUC, "Interim Opinion on E3 Avoided Cost Methodology," Decision 05-04-024, Proceeding 04-04-025, 29 and 89. Online at *http://www.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/45195.htm*. Also see UCS testimony submitted in this proceeding (online at *http://www.ucsusa.org/clean_energy/clean_energy_policies/testimony-on-accounting-for-californias-global-warming-gas-costs.html*).

[119] Northwest Power and Conservation Council, "The Fifth Northwest Electric Power and Conservation Plan," 2005, Volume 1, 19. Online at *http://www.nwcouncil.org/energy/powerplan/plan/Default.htm*.

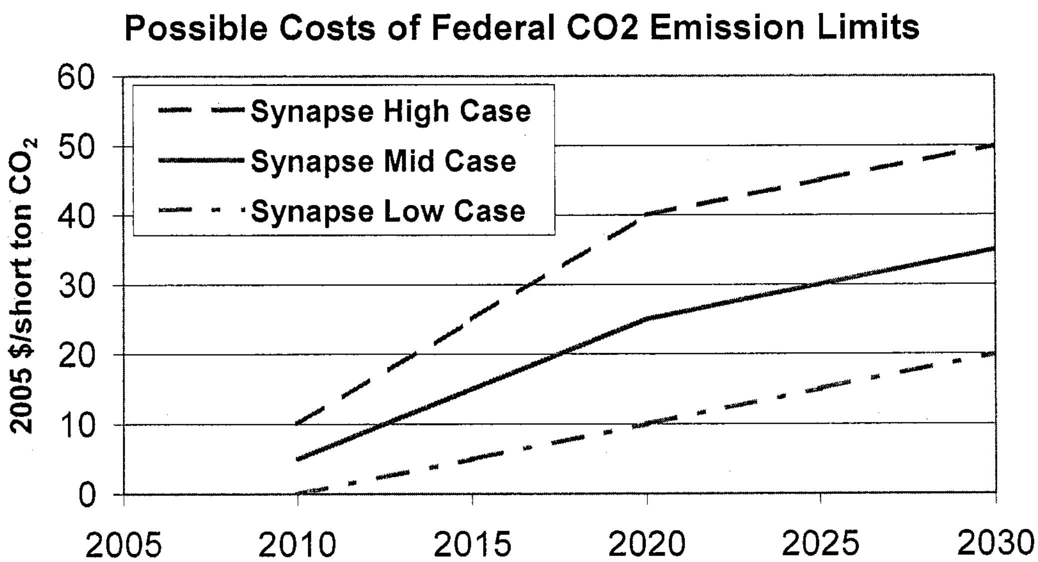
[120] See EIA, "Energy Market Impacts of Alternative Greenhouse Gas Intensity Targets," March 2006; "Impacts of Modeled Recommendations of the National Commission on Energy Policy," April 2005; "Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003," May 2004; "Analysis of S.139, the Climate Stewardship Act of 2003," June 2003;(online at *http://www.eia.doe.gov/oiaf/service_rpts.htm*); EPA, "Multi-Pollutant Legislative Analysis: The Clean Power Act," October 2005; and "Multi-Pollutant Legislative Analysis: The Clean Air Planning Act," October 2005 (online at *http://www.epa.gov/airmarkets/mp/index.html*); Massachusetts Institute of Technology Joint Program on the Science and Policy of Global Change, "Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal," June 2003 (online at *http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt97.pdf*); Tellus Institute, "Analysis of the Climate Stewardship Act Amendment," June 2004 (online at *http://www.tellus.org/energy/publications/McCainLieberman2004.pdf*).

domestic policy option that has been subjected to the most analysis is the Climate Stewardship Act proposed by Senators McCain and Lieberman.

Another more recent policy proposal analyzed by the EIA is one developed by the NCEP. This approach focuses on reducing emission "intensity" (emissions per dollar of gross domestic product) rather than total emissions, but like all cap-and-trade proposals it would still impose a cost on CO_2 emissions.

In May 2006, Synapse Energy Economics conducted a review of the cost projections of 10 such modeled analyses, as well as the emerging policy response to climate change and recent scientific and political developments.[121] This review resulted in the high, mid-range, and low CO_2 cost projections shown in Figure 4.

Figure 4



Source: Johnston et al., 2006.[122]

While Synapse warns that the real cost of CO_2 is unlikely to follow a smooth path, the company believes its projections "represent the most reasonable range to use for planning purposes, given all of the information we have been able to collect and analyze bearing on this important cost component of future electricity generation."[123] When

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[121] Lucy Johnston, Ezra Hausman, Anna Sommer, Bruce Biewald, Tim Woolf, David Schlissel, Amy Roschelle, and David White, "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning," Synapse Energy Economics, May 18, 2006. Online at *http://www.synapse-energy.com*.

[122] Ibid., p. 40.

[123] Ibid., 39.

Synapse's cost projections are levelized[124] over 30 years to 2005 dollars, the low CO_2 cost projection is $8.50/ton, the mid-range projection is $19.60/ton, and the high projection is $30.80/ton.[125]

Estimates of the price of future CO_2 allowances vary depending on a variety of factors, including the emission reduction target, the availability of offsets, whether international trading is allowed, the implementation timeline, and the existence of complementary policies such as energy efficiency programs and renewable electricity standards.[126] Two assumptions are particularly important and merit additional discussion here: the emission reduction target and the rate of technological progress.

First, all the analyses are based on relatively modest changes in U.S. emissions. The Climate Stewardship Act, for example, aims to return U.S. CO_2 emissions to 2000 levels over the period 2010 to 2015.[127] The NCEP proposal, which has been at the forefront of Senate hearings to design a cap-and-trade system, would slow the rate of emission growth but not reverse it.[128] None of the federal proposals that underlie these CO_2 cost estimates actually claim to deliver emission cuts sufficient to stabilize global CO_2 concentrations at a level that would avoid dangerous climate change.[129] Even the Kyoto Protocol, which would have required the United States to cut emissions seven percent below 1990 levels by the period 2008 to 2012, is only intended to be a first step leading to greater reductions later.[130]

As discussed in part I, section C, the science indicates that in order to prevent dangerous climate change, developed nations will need to reduce CO_2 emissions as much as 60 to 80 percent by 2050. Therefore, whatever federal policy to limit CO_2 emissions is initially adopted will have to be quickly followed with increasingly tighter caps if we are to put ourselves on a path toward climate stabilization in the decades ahead.

Much tighter national caps than those that have been analyzed would—all other things being equal—have the effect of driving CO_2 prices higher than the studies project. However, at some point, rising CO_2 prices would make low- or zero-carbon technologies competitive, leveling out the increase in CO_2 costs. How quickly that point is reached depends on a second important assumption: how quickly these technologies will develop. Most of the studies that provide the basis for the published cost projections (particularly

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[124] "Levelized" cost means "The present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation)." EIA Glossary, *http://www.eia.doe.gov/glossary/glossary_l.htm*.

[125] Johnston, et al., 2006,, 41.

[126] Ibid, 35–39.

[127] See Pew Center on Global Climate Change, "Summary of the 2003 Climate Stewardship Act." Online at *http://www.pewclimate.org/policy_center/analyses/s_139_summary.cfm*.

[128] Johnston et al., 2006, Figure 5.1.

[129] The newly introduced bills discussed in part II.C aiming for 80 percent reductions below 1990 levels by 2050 have not yet been the subject of analysis and are not reflected in cost projections.

[130] Climate Change Secretariat, "Caring for Climate: A Guide to the Climate Change Convention and the Kyoto Protocol," United Nations Framework Convention on Climate Change, 2003, 25. Online at *http://unfccc.int/resource/cfc_guide.pdf*.

those by the EIA) make very pessimistic assumptions about the cost and performance of renewables, efficiency, and other alternative technologies, both today and in the years ahead.[131] Moreover, they assume that there will be no new policies requiring or providing incentives for greater use of these technologies, despite growing support for such policies at both the state and federal level.

Using more optimistic assumptions about the costs, performance, and policy support for these clean energy technologies would have the effect of reducing CO_2 prices below projected levels (or keeping them from rising as much as they otherwise would in response to ever-tightening caps).[132] In this way, the rapid development of coal alternatives would have the paradoxical effect of reducing the future costs of coal power. Of course, if utilities and regulators use these more optimistic assumptions about the development of low-carbon energy in forecasting CO_2 prices, they must use the same assumptions when determining whether it would be cheaper in the long run to simply invest in low-carbon alternatives rather than building new coal plants. Optimism about alternative technologies to coal may reduce the estimated cost of coal plants by keeping future CO_2 allowance prices low, but that same optimism undermines the economic logic of building a new coal plant in the first place.

The CO_2 price projections by Synapse are roughly consistent with the range of projections being used by utilities and the Northwest Council in their resource plans, though without encompassing the highest and lowest of those values. Table 1 shows the range of numbers in use.[133] (In some cases, these values are discounted by the utility with a probability weighting when actually used in planning.)

Table 1: CO_2 Emission Trading Assumptions for Various Years (in 2005 dollars)

PG&E*	$0-9/ton (start year 2006)
Avista 2003*	$3/ton (start year 2004)
Avista 2005	$7 and $25/ton (2010) $15 and $62/ton (2026 and 2023)
Portland General Electric*	$0-55/ton (start year 2003)
Xcel-PSCCo	$9/ton (start year 2010) escalating at 2.5%/year
Idaho Power*	$0-61/ton (start year 2008)
Pacificorp 2004	$0-55/ton
Northwest Energy 2005	$15 and $41/ton
Northwest Power and Conservation Council	$0-15/ton between 2008 and 2016 $0-31/ton after 2016

Source: Johnston et al., 2006, Table 6.1.

[131] For example, see Steve Clemmer (Union of Concerned Scientists), "Renewable Energy Modeling Issues in the National Energy Modeling System," presentation at the National Renewable Energy Laboratory Energy Analysis Seminar, Washington, DC, December 9, 2004. Online at *http://www.nrel.gov/analysis/seminar/docs/2004/ea_seminar_december_9.ppt*.

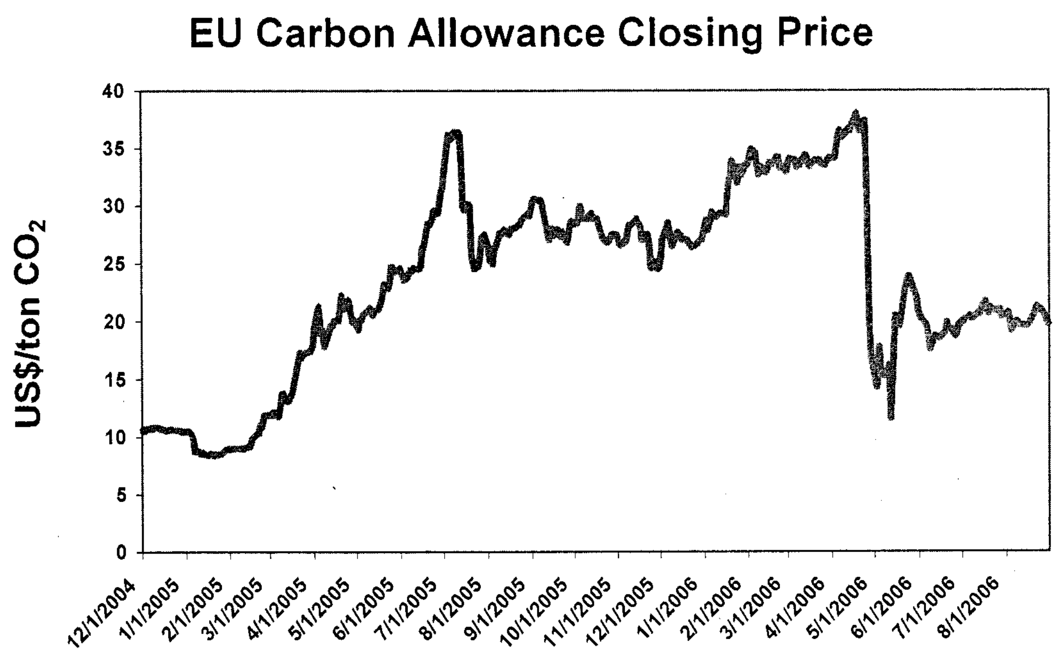
[132] The studies reviewed by the Tellus Institute used more optimistic assumptions and included complementary policies for energy efficiency and renewable energy technologies. The resulting CO_2 cost projections were closer to the Synapse mid-range projections and leveled off more in the later years of the forecast. See Tellus Institute, 2004.

[133] Ibid., 30.

Not included in Table 1 is the estimate of future CO_2 regulatory costs that California requires its utilities to assume in resource selection. At eight dollars per ton in 2004, rising by only five percent annually (less than the rate at which Synapse's projections rise), California's estimate begins near the high end of the Synapse analysis but move toward the low end in later years.[134]

Wall Street analysts Bernstein Research recently modeled the impact of a CO_2 allowance requirement on the earnings of several U.S. coal-fired generators, choosing nine dollars per ton of CO_2 as the price on which to base its analysis. It also considered a $28/ton CO_2 price based on the allowance prices recently prevalent under the European Union's cap-and-trade system, which reached levels as high as $35/ton during the past year.[135] As Figure 5 shows, CO_2 prices dropped sharply in May on news that many companies emitted less CO_2 than expected, suggesting that large emitters had been allocated too many allowances.[136] Prices have since partially rebounded.

Figure 5



Source: EU: PointCarbon.com using an average exchange rate for 2005 of 1.25 U.S. dollars per euro.

There are great uncertainties associated with predicting the future cost of CO_2 allowances, but this holds true for many other aspects of utility planning—especially

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[134] See Bolinger and Wiser, 2005, 60.
[135] Wynne, 2006, 11–17.
[136] Reuters, "EU undershoots emissions cap that critics call lax," May 12, 2006. Online at http://today.reuters.com/News/CrisesArticle.aspx?storyId=L12101022.

when considering the wisdom of investing in capital-intensive power plants that typically operate for a half-century or more in a rapidly changing world. The most prudent way to assess and minimize this risk is to consider the impact of a reasonable range of CO_2 cost projections (such as those described above) on a proposed coal plant. The one CO_2 price projection certain to be wrong is zero.

C. Reasonable projections of CO_2 prices would greatly increase the cost of coal power.

CO_2 allowance prices in the ranges discussed above would significantly increase the price of power from new coal plants. How much CO_2 allowance prices raise the cost of generating electricity from coal depends on the efficiency of the plant in question, but generally speaking, new coal plants emit roughly one ton of CO_2 per megawatt hour (MWh) of electricity produced.[137] This means, for example, that a CO_2 price of $10 per ton would increase a plant's costs by $10/MWh (or one cent per kilowatt-hour). Figure 6 shows how the cost of coal-fired electricity would rise in response to different CO_2 prices, starting with the EIA's estimated average base price of $47.50/MWh for new pulverized coal plants placed into service in the upper Midwest in 2015.[138]

Applying the Synapse levelized CO_2 cost projections to a coal plant increases the cost of energy from the EIA's average coal plant by the amounts and percentages shown in Table 2. For example, the cost of energy from an average coal plant would be 40 percent higher over its operating lifetime assuming mid-range CO_2 costs starting at five dollars per ton in 2010 and rising to $35 per ton by 2030.

Table 2: Increase in Energy Cost Based on Projected CO_2 Cost

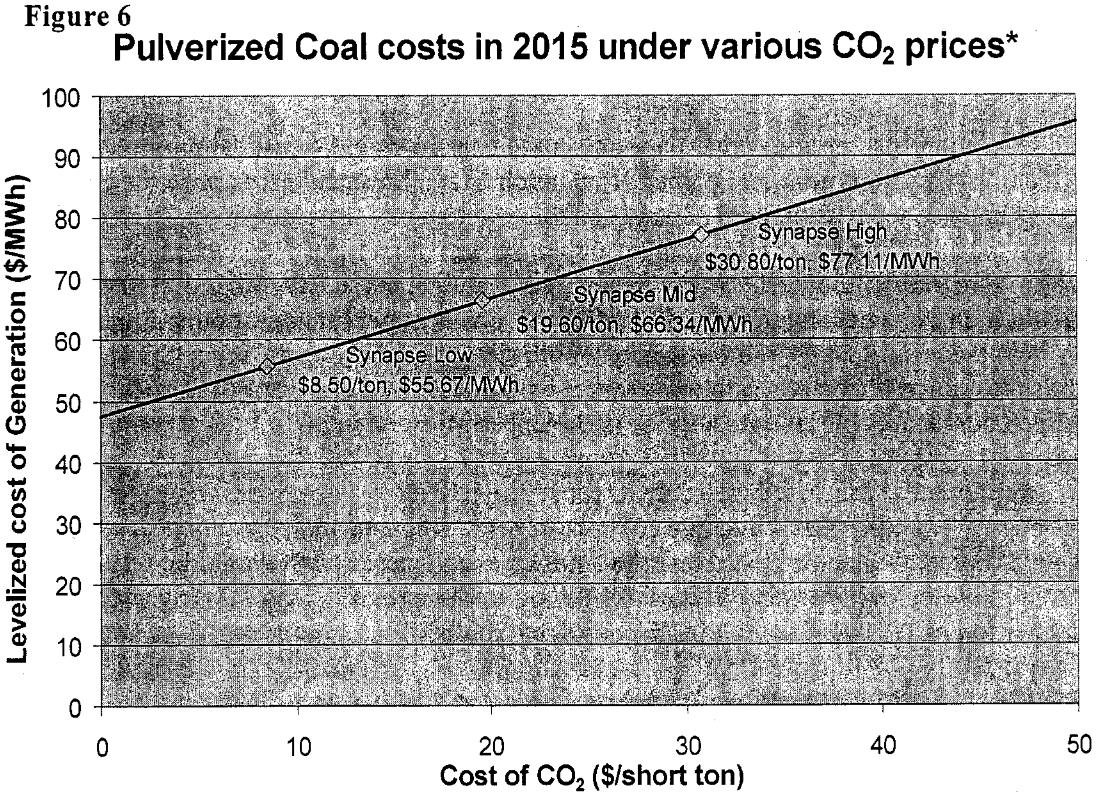
Price of CO_2 Allowance (levelized)	Cost of energy	Percent increase above base price
Base price (no CO_2 cost)	$47.50/MWh	–
Low projection: $8.50/ton	$55.67/MWh	17%
Mid-range projection: $19.60/ton	$66.34/MWh	40%
High projection: $30.80/ton	$77.11/MWh	62%

[137] Coal has a carbon intensity of 220 pounds per million British thermal units (Btu) and a new supercritical pulverized coal plant has a heat rate of 8,742 Btu per kilowatt-hour in 2005 (220 lbs/million Btu x 8,742 Btu/kWh/2,000 lbs/ton x 1,000 kWh/MWh/1,000,000 = 0.96 ton of CO_2 per MWh). See EIA, *Assumptions for Annual Energy Outlook 2006*, 2006.

[138] EIA, "NEMS EMM Factors for AEO06," spreadsheet, 2006. The costs are representative of a new coal plant built in the Midwest. Recent data indicates that EIA's base price for coal may be low. EIA's figure assumes overnight capital costs of $1,235/kW for a new plant. By comparison, the engineering firm Black and Veatch assumes overnight capital costs of $1,730/kW, based on the average cost of over 60 coal plant projects under construction or with air permits. (Source: Personal Communication with Ric O'Connell, Black and Veatch, August 20, 2006.) Using these capital costs, along with EIA's other assumptions, would raise the base cost of energy to $58/MWh.

Any utility proposing to build a coal plant would be reckless to make such a long-term investment without fully assessing a variable that could easily increase costs by $86 million per year on average, or $4.3 billion over a 50-year period, for a 600 MW coal plant.[139] The risk of future carbon constraints is far too great to ignore.

Figure 6



Source: EIA, "NEMS EMM Factors for AEO06," spreadsheet, 2006, and Johnston et al., 2006. The costs are representative of a new coal plant built in the Midwest.

D. Given the carbon-constrained world ahead, renewables and efficiency will generally be a much better investment than new coal plants.

In many cases, coal plants are already more expensive than cleaner options. This is particularly true with respect to investments in energy efficiency and wind turbines (in locations with favorable winds). With mid-range estimates of future CO_2 costs adding close to $20/MWh (or two cents per kilowatt-hour) to the cost of energy from a coal plant, cleaner options will cost less than coal in an even wider range of cases.

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[139] Based on an estimate by Synapse for the Big Stone II coal plant under a mid-range CO_2 cost projection. See David A. Schlissel and Anna Sommer, direct testimony to the South Dakota PUC, case no. EL05-022, May 19, 2006, 24. Online at *http://www.state.sd.us/puc/commission/dockets/electric/2005/el05-022/testimonyschlisselsommer.pdf*.

While the exact cost comparisons will vary by location, two recent analyses compare coal plants with cleaner options in a carbon-regulated world, and in these analyses new conventional coal plants cannot compete. The first such analysis is a massive exercise in regional resource planning recently conducted by the Northwest Council.[140] With no financial stake in the outcome to skew its planning judgment, the council's fifth 20-year plan (adopted in December 2004) is a useful contribution to resource planning.

Among other things, the plan ranks various supply- and demand-side options on a cents-per-kilowatt-hour scale. The Northwest Council identifies 25 different conservation and renewable options that cost less than the cheapest new coal plant (even in Montana, a coal-producing state).[141] The plan looks at many different scenarios and various price estimates for future CO_2 costs (though these estimates pre-date recent developments such as the Senate resolution calling for carbon regulation).[142]

The plan concludes that much more investment in conservation is warranted even though the Northwest has already made relatively high investments in conservation over the years.[143] Overall, the Northwest Council's approach of identifying options that are both low-cost and low-risk yielded a plan that greatly increases investment in conservation and wind and *does not include any new conventional coal plants* for the region throughout the 20-year planning period.[144] While the council's cost estimates may not directly apply to other regions, they provide a valuable example of how conventional coal plants become uncompetitive compared with energy efficiency and renewable energy when independent resource planners use realistic assumptions about the future and factor in carbon risk.

The second relevant analysis was conducted by Synapse Energy Economics, which in May 2006 submitted testimony critiquing a resource comparison that a coalition of utilities seeking to build a conventional coal plant submitted to South Dakota regulators.[145] The utilities did not compare the proposed 600 MW Big Stone II plant with a comparable investment in energy efficiency, nor did Synapse. However, the utilities did compare Big Stone II with the alternative of building 600 MW of wind power along with a 600 MW natural gas combined-cycle plant. Not surprisingly, the utilities' wind/gas alternative was more expensive than Big Stone II, since it assumed only 600 MW of wind power and unnecessarily assumed that the wind turbines required 100 percent backup from natural gas to compensate for the wind's intermittent nature.

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[140] Northwest Power and Conservation Council, 2005.
[141] Ibid., Table OV-2, 26–27.
[142] Ibid., 19. The Northwest Council assumes CO_2 costs of between zero and $15 per ton beginning in 2008, and between zero and $30 per ton beginning in 2016.
[143] Ibid., 4, 29–31.
[144] Ibid., 29.
[145] David A. Schlissel and Anna Sommer, direct testimony to the South Dakota PUC, case no. EL05-022, May 26, 2006. Online at *http://www.state.sd.us/puc/commission/dockets/electric/2005/el05-022/testimonyschissel052606.pdf*.

Synapse reworked the comparison by increasing the amount of wind power to 800 and 1200 MW, reducing the amount of natural gas to levels that would be needed to provide an equivalent amount of electric generation and capacity (300 to 480 MW) as the coal plant,[146] and factoring in its low, mid-range, and high CO_2 cost estimates (described in part V, section B). Synapse also completed a sensitivity analysis of a few key variables including the continued existence of the federal production tax credit for wind, a capacity value for wind (which affects the amount of natural gas capacity needed), and whether the utilities were investor-owned or publicly owned.

Under all of the CO_2 price forecasts, the analysis showed that all of the high-wind (1,200 MW) scenarios were approximately the same or less costly than the 600 MW coal plant, even without the federal production tax credit and using a very conservative capacity value for wind. Under the most likely mid-range CO_2 price forecast, Big Stone II cost 27 to 71 percent more than the high-wind scenarios, across the entire range of assumptions.[147]

The analysis also showed that all of the wind/gas alternatives had lower costs than the 600 MW coal plant under both the mid-range and high CO_2 price forecasts. Coal fared remarkably poorly in these comparisons even though Synapse did not correct all of the utilities' assumptions that underestimated the cost of coal and overestimated the cost of wind.[148] In addition, the Big Stone II co-owners recently announced that the capital costs for the project have increased by 50 percent—from \$1.2 billion to \$1.8 billion.[149] Using these new costs, and incorporating energy efficiency into the alternatives analysis, would make the alternatives even more economically viable than described above.

Both the Northwest Council and Synapse analyses show coal unable to compete financially with other options available today when future carbon constraints are considered. In the future, coal is likely to be even less competitive, because policies designed to combat global warming will not just make coal more expensive but will surely accelerate improvements in cleaner technologies. Unlike conventional coal plants, many energy efficiency and renewable energy technologies are still relatively new. As they break out of niche markets and achieve greater economies of scale, improvements in price and performance will follow. Utilities that invest heavily in coal today are therefore

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[146] Ibid., 14. Synapse explains in its testimony that, by accepting the utilities' assumption that any dedicated backup plants would be built to support wind power, its analysis overstates the cost of the wind options.
[147] Ibid., Tables 1 and 2, 17. (A corrected version of these tables with slight alterations to the originally-filed numbers is online at *http://www.state.sd.us/puc/commission/dockets/electric/2005/el05-022/corrected062306.pdf*.)
[148] Ibid., 13–16. Synapse explains in its testimony its decision not to correct several of the utilities' original assumptions that bias the analysis against wind. For example, while the tax and financing advantages of public utilities were reflected in the cost of Big Stone II, they were not reflected in the cost of wind. Synapse corrected the utilities' assumption that wind had zero capacity value, but it conservatively assumed that wind resources have a capacity value of only 15 or 25 percent (despite recent utility studies showing that wind in the region has a capacity value between 27 and 34 percent). Synapse also used the utilities' value of \$12/MWh for the production tax credit, despite data from the EIA showing a value of \$21/MWh.
[149] Associated Press, "Higher cost for SD power plant won't help ND chances, exec says," August 4, 2006. Online at *http://www.kxma.com/getARticle.asp?ArticleId=30517*.

not only running unnecessary financial risks, but also losing the flexibility to take full advantage of the technological opportunities ahead.

E. Retrofitting a pulverized coal plant to limit CO_2 emissions is feasible, but will be very expensive.

Coal plants emit far more CO_2 than any pollutant that is federally regulated today. By way of example, the Final Environmental Impact Statement for the Weston 4 coal plant in Wisconsin lists potential mercury emissions of 78 pounds per year, sulfur dioxide emissions of about 2,300 tons per year, and nitrogen oxide emissions of about 1,600 tons per year. CO_2 emissions, by comparison, are projected to be 4,100,000 tons per year.[150] Collecting and disposing of CO_2 emissions therefore pose much greater technological challenges than those faced by coal plants to date.

It is considered technologically possible to capture 80 to 90 percent of the CO_2 from a conventional coal plant by scaling up methods currently in use to produce CO_2 for beverage and chemical applications.[151] However, the costs—in terms of energy consumed by the capture process and added capital and operating expenses—would be very high. The energy penalty of adding such technology to the plant would equal 24 to 40 percent of the energy produced by the plant.[152] A recent MIT study estimates that adding CO_2 capture technology to a conventional coal plant and disposing of the CO_2 in geological formations would increase the plant's levelized cost by nearly $30/MWh or 74 percent.[153]

Thus, there is no technological solution that can be reasonably expected to buffer a conventional coal plant from the financial risk associated with CO_2 regulation. Whether the plant operator ultimately pays for emission allowances or installs technology to capture and dispose of the CO_2, it runs a high risk of greatly increased costs.

VI. Regulators should protect ratepayers from future CO_2 costs by refusing to authorize new coal plants; alternatively, they should clearly place the risk of future CO_2 costs on utility shareholders rather than on ratepayers.

Currently, a utility's environmental compliance costs are routinely passed through to ratepayers as a cost of providing electricity. In particular, costs of buying pollution allowances (such as the sulfur dioxide allowances coal operators purchase today) are considered operating expenses recoverable through rates. This regulatory pattern of

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[150] Public Service Commission of Wisconsin, Weston Unit 4 Power Plant Final Environmental Impact Statement, Volume 1, July 2004, 134 and 145. Online at http://psc.wi.gov/utilityinfo/electric/cases/weston/document/Volume1/W4_FEIS.pdf.

[151] IPCC, "Carbon Dioxide Capture and Storage," 121. Current unit capacities would have to be increased by a factor of between 20 and 50 for deployment at a 500 MW coal plant.

[152] Ibid, Summary for Policymakers, 4.

[153] Ram C. Sekar, John E. Parsons, Howard J. Herzog, and Henry D. Jacoby, "Future Carbon Regulations and Current Investments in Alternative Coal-Fired Power Plant Designs," MIT Joint Program on the Science and Policy of Global Change, December 2005, 4.

treating pollution allowance costs as operating expenses means that utilities may feel confident that they can also recover any future CO_2 allowance costs through their rates.

Such confidence, however, means a utility operating in a regulated environment has little incentive to assess CO_2 allowance costs in a serious way, even when contemplating major new long-term investments. From a societal standpoint, this is a financial disaster waiting to happen; the financial risks of building a new coal plant are very high, but the party making the investment is not deterred because it does not feel at risk.

It is, of course, up to state regulators to make sure this financial disaster is avoided and that ratepayers are protected. By far the best way to do that is to deny approval of the proposed coal plant and encourage the utility to pursue less financially risky alternatives.

However, if regulators do approve construction of a proposed plant, they should ensure that the utility has an incentive to minimize this risk as it emerges by warning it that future CO_2 allowance costs will not be recoverable through rates. This is particularly important given how rapidly climate change policy is evolving and how long it takes to build a coal plant. Because utilities would for some time have the ability to cancel or downsize new plants in response to the growing risk of CO_2 costs, regulators should give them the incentive to monitor and respond to that risk. Shifting the risk of future CO_2 regulations onto utilities may be inconsistent with current rate treatment of pollution allowances, but it is fully consistent with underlying ratemaking principles and the case law related to investments in new baseload plants.

In the late 1960s and 1970s, many of the nation's utilities believed two things that turned out to be wrong: that electricity demand would keep growing at a fast rate and that nuclear power would be an inexpensive way to meet that demand. These mistaken beliefs resulted in substantial excess baseload capacity in the early 1980s (largely from unneeded coal plants), many abandoned nuclear plants, and disputes around the nation about whether the costs of these mistakes should be paid by utility shareholders or ratepayers.

The regulatory decisions made during this era typically allocated at least a share of excess costs to shareholders, and articulated standards intended to give utilities a stronger incentive to avoid such unwise investments in the future.[154] Now that utilities are again in the midst of a baseload power plant construction boom based on risky assumptions, these standards are again highly relevant.

Two complementary regulatory approaches emerge in these disputes: the "prudent investment approach" and the "shared costs approach." Both approaches are intended, in part, to create incentives for utilities to continually rethink their investment decisions in

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154 For overviews of these cases see Richard J. Pierce, Jr., "The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity," 132 *U. Pa. L. Rev.* 497 (1984); "Abandoned Nuclear Plant Recovery," 83 *ALR*4th 183 (1991); and Roger D. Colton, "Excess Capacity: Who Gets the Charge from the Power Plant?" 34 *Hastings L.J.* 1133 (1983).

light of emerging events (rather than sticking to a chosen path even when subsequent developments clearly make that path unwise).

Under the prudent investment approach all or part of a utility's investment can be excluded from rates if any decision made by the utility in relation to that investment is found to be imprudent. This could include the decision to build a power plant and the subsequent decision not to cancel it after changing circumstances show the project to be unwise.[155]

While this principle has often been invoked by utilities seeking to recover from unsuccessful investments that appeared to be prudent when they were initially made,[156] the principle is also intended to protect ratepayers from unwise utility decisions.[157] Over the years, regulators have denied rate recovery for some enormous investments judged to be imprudent, including costs related to abandoned nuclear power plant construction plans[158] and coal plants that were built but created excess capacity.[159]

To determine whether an investment was prudent, courts consider what a utility knew or should have known when the investment was made, and any alternative generating options that were available at the time. The inquiry not only focuses on the initial decision to build a plant, but also on the subsequent, ongoing decisions to continue pursuing construction even after events such as the adoption of a new regulatory approach greatly increased cost estimates beyond those originally projected. As parts I through V show, building a coal plant without reasonably factoring in the substantial financial risk associated with coming climate laws is clearly imprudent. On these grounds alone, regulators would be justified in disallowing rate recovery of CO_2 costs.

However, an investment need not be deemed imprudent for recovery to be disallowed. The U.S. Supreme Court has explicitly upheld the authority of state regulators to limit a utility's recovery for an investment that appeared prudent at the time it was made but ultimately proved unwise.[160] States have considerable discretion to set rates that appropriately balance the interests of shareholders and ratepayers, and some have adopted approaches that divide financial risks between these parties. State regulators have particularly used this shared costs approach in cases of excess capacity built as a result of inaccurate demand forecasts, because they concluded that placing all the risk on ratepayers is unfair and creates the wrong incentives for utility management. In 1982, for example, Iowa regulators refused to pass on to ratepayers all the costs a utility incurred in building what later proved to be excess generating capacity, even though the decision to build was reasonable when made. The Iowa commission explained its reasoning this way:

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155 See Pierce, supra, p. 7.
156 See Duquesne Light Co. v. Barasch, 488 U.S. 299, 109 S.Ct. 609 (1989).
157 Verizon Communications Inc. v. FCC, 535 U.S. 467, 122 S.Ct. 1646, 1659 (2002).
158 See e.g., Association of Businesses Advocating Tariff Equity v. Public Service Commission, 527 N.W.2d 533 (Mich. App. 1994); In Re Interstate Power Company, 416 NW2d 800 (Minn. App. 1987); Re Boston Edison Co., 46 PUR4th 431 (Mass DPU, 1982), aff'd 455 NE2d 414.
159 Gulf Power Company v. Florida Public Service Commission, 453 So.2d 799 (Fla. 1984);
160 Duquesne Light Co. v. Barasch, 488 U.S. 299, 109 S. Ct. 609 (1989).

"In the real world of competitive enterprise, management officials must continuously rethink prior decisions as new events unfold. Those who fail to stay on top of current events lose out to their competition. Iowa utilities should also maintain surveillance over costs associated with a particular decision, and in the absence of the kind of incentive provided by a competitor, the responsibility falls upon us to provide the requisite incentive."[161]

The Wisconsin Supreme Court agreed with Iowa's shared costs approach and recognized the authority of Wisconsin regulators to apply it in the same context.[162] Pennsylvania regulators applied similar reasoning in an excess capacity case, noting that while the investments were prudent and the excess capacity was no fault of the utility or its investors, "neither was it the fault of ratepayers. Under these circumstances there must be some sharing of the risk associated with bringing these large plants on line."[163]

North Dakota regulators took a similar approach in response to excess capacity created by a coal plant, refusing to allow all the costs to be passed on to ratepayers. Though they did not deem the utility's investment imprudent, regulators felt it was "unreasonable to expect ratepayers to completely absorb the risk" of excess capacity, and that "there must be some risk placed on the utility and there must be some incentive for the pool and the individual utility member to continuously strive for accurate and precise management" of investments in baseload capacity. [164]

Both the prudent investment approach and the shared costs approach recognize the importance of giving utilities a strong incentive to avoid making investment mistakes, especially when building expensive, long-lived baseload plants. And both lines of cases stress how important it is for utility management to keep track of changes that affect the wisdom of the utility's investment during the period after a plant receives regulatory approval but before construction is completed.

These cases grew out of an era (the 1970s) when utilities making large investments in baseload capacity were surprised by events beyond their control—primarily the OPEC embargo, which led to slower growth in energy demand, and the Three Mile Island accident, which resulted in stricter safety standards and higher construction costs. Once again, utilities are making huge investments in baseload power, but this time the global changes that threaten the economic viability of these investments are far more predictable than they were in the past. Indeed, they are looming, and they threaten to substantially increase the cost of energy from new coal plants. It is even more critical today that utilities be given a strong incentive to track regulatory developments and continually re-examine their construction decisions in light of those developments.

[161] Re Iowa Public Service Company, 46 PUR4th 339, 368-69 (IA Commerce Commission, 1982).
[162] Madison Gas and Electric Company v. Public Service Commission of Wisconsin, 325 N.W.2d 339 (Wis. 1982).
[163] Pennsylvania Public Utility Commission v. Philadelphia Electric Co., 37 PUR4th 381, 387 (Pa. Public Utility Commission, 1980).
[164] Re Montana-Dakota Utilities Co., 44 PUR4th 249, 255 (N.D. PSC 1981); see also Re Otter Tail Power Company, 44 PUR4th 219 (N.D. PSC 1981).

Regulators can create such an incentive by determining, as a condition of plant approval, that future CO_2 costs will be borne by utility shareholders rather than ratepayers.

VII. Conclusion

The fight against global warming will unquestionably change the laws, economics, and technology of power production and use. Many different groups have a role to play in helping ensure our society responds sensibly to these changes.

- Utilities should factor future CO_2 costs into their resource planning and procurement, aggressively pursue conservation, efficiency and renewable energy, and at the very least defer making major coal plant construction decisions until they have a clearer picture of the regulatory risks and technological opportunities ahead.

- Regulators should insist that utilities take the above steps. They should also protect ratepayers by refusing to authorize the construction of new conventional coal plants, which are premised on the regulatory conditions of the past, not those of the future. At the least, they should warn utility managers that shareholders will bear the risk that coal investments will result in excess carbon costs.

- Investors and shareholders should recognize the inevitability of CO_2 regulations and understand that utilities that behave imprudently by building coal plants despite these costs would, under existing regulatory principles, be prevented from recovering at least a portion of such costs in their rates. Shareholders should question utility management closely on how they are assessing and managing carbon risks, and require reporting and accountability. Long-term investors should favorably regard companies who are proactively considering and managing these risks effectively.

- Ratepayers and consumer groups should realize that the utilities building new coal plants will seek to recover all their costs, including CO_2 regulatory costs, from ratepayers. While legal principles support denying rate recovery of these costs, history shows that these cases are extremely contentious and expensive. A far better way for ratepayers and consumer groups to protect themselves from such financial risk is by resisting the construction of new conventional coal plants in the first place and by supporting investments in cleaner alternatives such as efficiency and renewable energy.

Building a major energy resource – especially one that costs as much and lasts as long as a coal plant -- is unavoidably an exercise in predicting the future. It cannot be prudently done without objectively analyzing the trends and potential risks that will shape the decades ahead. In the case of new coal plants, the critical trends are undeniable and moving with unstoppable momentum: CO_2 levels are rising to levels unseen on the planet in millions of years, global temperatures are setting new records, scientific evidence showing that our current energy path is leading to dangerous climate changes is mounting, and the policy response at every level of government is accelerating. To assume in the face of these trends that a new coal plant could be put into service and allowed to emit millions of tons of CO_2 for free for the next few decades is reckless, to say the least. New conventional coal plants in the age of global warming are not just bad policy – they are a bad investment, and one we cannot afford to make.

Current Carbon Emissions in Context:
Final Report to the National Commission on Energy Policy

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Executive Summary

The challenge of developing policy for the mitigation of greenhouse gas (GHG) emissions arises from several different factors. In particular, GHG mitigation is a long-term task and sustaining policy over a long time can be difficult. Next, the cost benefit of GHG mitigation is not consistent with the preferred policy approach of delivering immediate benefit, with costs deferred to a later time. GHG mitigation is in many ways like buying insurance for future generations. Further, the total cost of mitigation appears to be very large, primarily because the scale of the systems that need to be changed is massive. Finally, the United States is currently the largest national emitter of carbon dioxide. There is a real question of how the U.S. should view itself within the context of this global challenge, particularly in light of the growing emissions from the developing world.

The idea of a "carbon shadow" is a new concept that might help policy makers as they wrestle with the important issues outlined above. The key idea that underlies the concept is that the current capital stock of fossil fuel generating and consuming technology will continue to produce carbon emissions until they are retired. The properties of existing capital stock limit the policy options available, because the premature retirement of capital stock is one of the most important costs in an aggressive GHG mitigation strategy. The rate at which capital stock produces GHG emissions is a property of the technology itself, reflected in the efficiency of a fossil-fired fuel plant or of a motor vehicle. Therefore if one understands how long the technology will be in use it is possible to calculate how much carbon dioxide will be emitted by an individual plant or vehicle.

In order to demonstrate the power of this approach we have conducted an analysis of the carbon shadows for existing U.S. electricity and transportation capital stock. For reference:

- Electricity generation accounted for 39% of 2001 U.S. carbon emissions
- Highway transportation (cars and trucks) accounted for 23% of 2001 U.S. carbon emissions

Together, these two capital stocks represent 62% of U.S. emissions, about 15% of global carbon emissions in 2001.

The analysis does several things:

1. It examines the ways in which one might determine the lifetime of a particular piece of technology, drawing a distinction between approaches based on the capital cycle and actual retirement data.

2. It focuses on the use of a retirement model based on historical data and describes retirement rates for U.S. electricity generation and transportation capital based on these data. These retirement rates are then used to derive the carbon shadows for

the technologies based on their inferred retirement rate.

3. It then describes how the desire for stabilizing carbon dioxide concentrations at a particular level leads, because of the nature of the carbon cycle, to a global budget for carbon dioxide emissions.

4. The carbon budget is then used to calculate "carbon shadow indices" for existing U.S. capital stock in the electricity generating and ground transportation sectors, which reflect the fraction of the global carbon budget (550 ppmv stabilization) that will be consumed by this capital stock over the next 50 and 100 years. These indices give insight into if and when premature retirement of capital stock might be required to meet emission targets.

5. The analysis of the electricity generation and ground transportation sectors were then used to generalize the carbon shadows for the entire U.S. economy.

6. Finally, the analysis is extended to show how various factors such as carbon cycle uncertainties, choice of stabilization level, and specific technology characteristics affect the basic results.

The results of these analyses provide an interesting perspective on current emissions. Figure ES1 shows the carbon shadow of currently existing U.S. electricity generating capital stock. The total projected emissions, based on the retirement model, exceeds 25 gigatons of carbon over the next 100 years and is dominated by coal-fired steam turbines. Note that almost 20% of these emissions come after 2050, showing the potential impact of continuing historical retirement practices into the future.

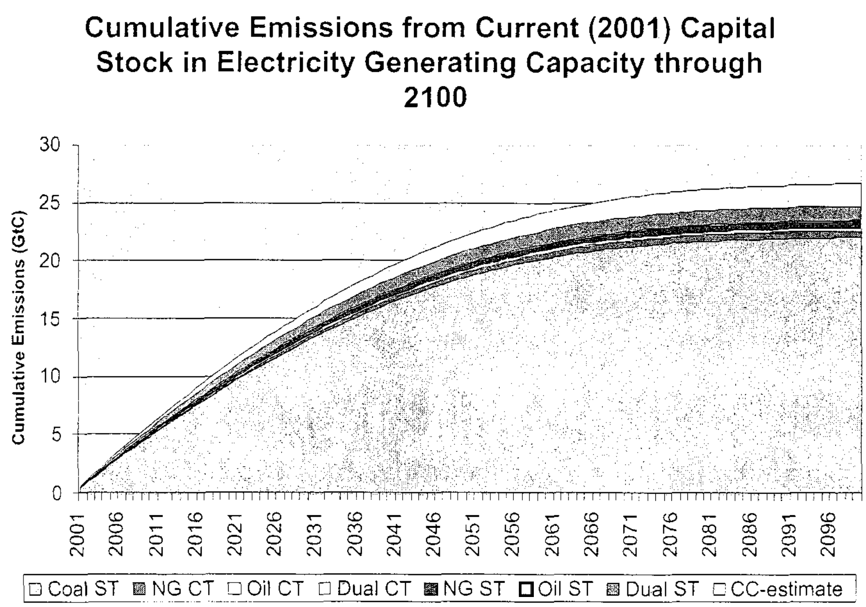

Figure ES1. Cumulative emissions (GtC) from electricity capacity technologies operating as of 2001 through 2100.

There is a contrast with the vehicle sector (Figure ES2) where most of the emissions that make up the carbon shadow come in the first 25 years of the century. Yet even with the shorter lifetime of vehicle stock the current U.S. vehicle fleet is projected to emit more than 4 gigatons of carbon. The bulk of the carbon shadow is equally divided among passenger vehicles, light duty trucks (including SUVs) and heavy-duty trucks.

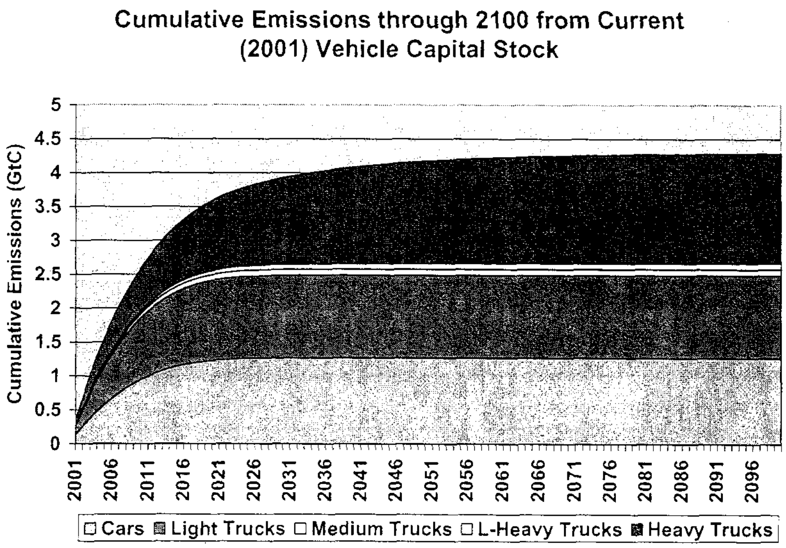

Figure ES 2. Cumulative emissions from current (2001) capital stock in vehicle capital stock through 2100.

Having analyzed electricity generation and ground transportation in detail, we have used those results to generalize the results to determine the carbon shadows for the entire U.S. capital stock. These results for the two analyzed sectors and the generalization to the rest of the U.S. capital stock are summarized in Table ES1. The definition of the carbon shadow as shown here is the amount of carbon that will be emitted by sector over the period from the present to dates indicated (2050 and 2100).

Sector	Carbon Shadow 2050 (GtC)	Carbon Shadow 2100 (GtC)
Electricity Generation	22.3	26.8
Ground Transportation	4.2	4.3
Other	13.4	16.1
Total Carbon Shadows	39.9	47.2

Table ES1. Total carbon shadows for the United States capital stock to 2050 and 2100 respectively.

Putting these carbon shadows in perspective requires the calculation of a budget for global carbon emissions under the constraint of some stabilization level. The level of 550 ppmv has been chosen as a reference case. The budget was calculated under some key assumptions. First, it used a reduced form carbon cycle model that has fairly standard assumptions about how the natural carbon cycle operates. Second stabilization was constrained to be completed by 2150 and the carbon reductions profile was constrained by a cost minimization approach of the type used by Wigley, Richels and Edmonds. Finally the base case for global emissions was a variant of the IPCC B2, scenario a moderate economic and population growth scenario. The resulting global carbon budgets are 460 GtC and 870 GtC to 2050 and 2100, respectively.

	2001 emissions	2050	2100
Emissions from Electricity Generation Capacity	0.6 GtC	22.0 GtC 4.8%	26.8 GtC 3.1%
Emissions from Ground Transportation	0.36 GtC	4.2 GtC 0.9%	4.3 GtC 0.5%
Emissions from other sources	0.6 GtC	13.4 GtC 2.9%	16.1 GtC 1.9%
Shadow in GtC As % of Global Carbon Budget		**39.9 GtC 8.7%**	**47.2 GtC 5.4%**

Table ES2. Global carbon budgets and their relationship to the carbon shadows of existing U.S. capital stock. The percentages of the global budgets are calculated on the basis a budget of 460 GtC to 2050 and 870 GtC to 2100.

The results are striking. The current U.S. capital stock in electricity generation alone is projected to consume 4.2% of the entire global carbon budget (550 stabilization) for the next 50 years and 3.1% of the 100-year budget. Currently installed coal fired steam turbines account for most of the carbon shadow of U.S. emissions, and are projected to consume 4.1% of the entire global carbon budget over the next 50 years and 2.6% over the next 100.

The situation is even more interesting when one considers what the situation will be in 2020, if the U.S. continues on a more or less "business as usual" path of the use of fossil fuels resources. A simple analysis suggests that by 2020 the combination of emissions from 2000 to 2020 with the carbon shadows of the capital stock existing in 2020 will lead to the U.S. having used or committed to use, 63.9 and 80.1 GtC, of the global carbon budget to 2050 and 2100, respectively. This corresponds to 13.9% and 9.2% of the global carbon budget (550 ppmv stabilization target), even if no further capital equipment utilizing fossil fuels were introduced into the U.S. economy after 2020.

It is useful to put the U.S. situation in a more specific context, by trying to estimate what might be an "appropriate" U.S. share of global emissions. We have taken five different approaches to such an estimate, which can be summarized as follows:

1. The U.S. share for the 21st century is based on maintaining an average emission of some benchmark year.

2. Estimating the U.S. share by claiming that the share of emissions in a given year would be the share in perpetuity of the global budget.

3. Indexing emissions to GDP and extrapolating the likely share of U.S. share of global GDP over the 21st century.

4. Using the current administration's goal of reducing carbon intensity by 18% per decade.

5. Having the relative shares of carbon emissions trend to a per capita distribution of shares by 2100.

Table ES3 summarizes these possible U.S. carbon budgets and provides a comparison with the various possible U.S. shares of the carbon budget noted above.

Basis of allocation		U.S. Budget to 2050 (GtC) with % of Global Budget	U.S. Carbon shadow to 2050 as a % of budget (550)	U.S. Budget to 2100 (GtC) with % of Global Budget	U.S. Carbon shadow to 2100 as a % of budget (550)
Maintain average emissions	Base Year 1990	66 14.3%	60.5%	132 15.2%	35.8%
	Base Year 2001	78 17.0%	51.2%	156 17.9%	30.3%
Maintain share of global emissions	Base Year 1990	99 21.5%	40.3%	187 21.5%	25.2%
	Base Year 2001	108 23.5%	36.9%	205 23.6%	23.0%
Share based on relative share of the global economy		126 27.4%	31.7%	213 24.5%	22.2%
18% per decade reduction in carbon intensity		76-117 16.5-25.4%	52.5-34.1%	122-182 14.0-20.9%	38.7-25.9%
Trend to share based on relative population in 2100		87 18.9%	45.9%	124 14.3%	38.1%

Table ES3. United States carbon budgets to 2050 and 2100 under the various assumptions described in the text. For perspective the U.S. budgets are also shown as a percentage of the global carbon budgets to 2050 and 2100, 460 and 870 GtC (550 stabilization) respectively. Also shown is the carbon shadow for the entire U.S. economy as a percentage of the U.S. budgets.

The various means of estimating U.S. shares give a wide range of possible U.S. budgets, yet the results are striking in any context. They suggest that existing capital stock has committed the U.S. to the use of 30-60% of a reasonable estimate of the allowance for a 550 ppmv stabilization to 2050 and 22-38% of the those allowances for the century. This analysis is extended in the main text of the report and further suggests that, if the U.S. continues a "business as usual" use of fossil fuels as described above, by 2020 it will have either consumed, or committed to consume (as carbon shadow) 50-95% of its share to 2050 and 35-65% of its share for the century.

Clearly if the U.S. continues on something that resembles its current emissions pathway, by 2020 it will be faced with the prospect of prematurely retiring some of its capital stock under some of these budget scenarios.

All analyses like the ones described above are subject to uncertainties and are sensitive to underlying assumptions. While other sensitivities and uncertainties need to be addressed, two deserve special mention because they have important policy implications. They are uncertainty in our understanding of the carbon cycle and sensitivity to the selection of a carbon stabilization goal. The calculation of a carbon budget helps put the carbon shadows in context. However our knowledge of the global carbon cycle is not perfect and one uncertainty in particular has a major impact on the stabilization budgets. This is the value for the long-term uptake of carbon dioxide by the oceans and terrestrial ecosystems. Similarly, while a reference analysis was done using a concentration of 550 ppmv for a CO_2 stabilization goal, this is not the only choice. 550 ppmv is a frequently used target value, simply because it represents a doubling of the pre-industrial concentration of carbon dioxide. Performing the analysis for other concentration targets, 450 and 650 ppmv shows the sensitivity of the results to the stabilization policy.

Table ES4 summarizes the impact of the carbon cycle and uncertainty and the stabilization level policy choice. The reference case is the amount of carbon that would be emitted under the base assumptions noted above, an IPCC B2-like scenario. Several points are worth noting. First, that for the 650 ppmv target, major reductions are not required until the second half of the century. For 450 ppmv stabilization there are not only severe reductions in allowable emissions in the next 50 years, the emissions allowed in the second half of the century are less than 200 gigatons. Next, it is important to note the impact of the uncertainty in the carbon cycle shown in the uncertainty range. While the large range of uncertainty is interesting, the policy ramifications of reducing the possibility of very much lower than expected budgets due to lower uptake of carbon dioxide is evident. The reduction of budgets would 10-20% through 2050 and 20-40% through 2100, which make them both much tougher targets.

	Stabilization at 650 ppmv	**Stabilization at 550 ppmv**	**Stabilization at 450 ppmv**	**Reference case**
Global carbon budget to **2050** (GtC)	505	460	373	500
Uncertainty range (GtC)	451 – 515	423 – 463	311 – 397	
Global carbon budget to **2100** (GtC)	1089	870	579	1345
Uncertainty range (GtC)	815 -1 176	663 – 973	331 - 655	

Table ES4. The global carbon budget, assumptions and uncertainties.

When we begin to compare the global budgets above to the U.S. carbon shadows and the analysis of U.S. likely future emissions, several key points emerge. As can be seen in Table ES5, current shares and likely near term emissions have greatest impact for concentration goals lower than 550 ppmv. Further, the impact is not linear, but skewed and 450 ppmv is far harder to reach relative to 550 ppmv than 550 ppmv is relative to 650 ppmv. It is important to note that for the lower target (450 ppmv), existing capital stock makes a significant impact even in the second half of the century.

		To 2050		To 2100	
Total U.S. Carbon Shadow in GtC		**39.9 GtC**		**47.2 GtC**	
As % of Global Carbon Budget			**Range**		**Range**
for 450 ppmv		**10.7%**	**10.1-12.8%**	**8.2%**	**7.2-14.2%**
for 550 ppmv		**8.7%**	**8.6-9.4%**	**5.4%**	**4.8-7.1%**
for 650 ppmv		**7.9%**	**7.7-8.8%**	**4.3%**	**4.0-5.8%**

Table ES5. The U.S. carbon shadows to 2050 and 2100 shown as a percentage of the corresponding global carbon budgets.

Finally, when we look at how current capital stock and near term emissions might impact the U.S. share of the budget, the difficulty with trying to meet lower targets is even more obvious. This is highlighted by looking at Table ES6, which looks at the impact U.S. near term emissions and likely future carbon shadows have on U.S. shares of the global carbon budget in 2020.

	U.S. share of total global budget (percentage of global budget)	U.S. budgets and carbon shadow as a percentage of the budget to 2050		
Assumptions about U.S. share of global carbon budget		450	550	650
Maintain share (2001)	23.5%	88	108	119
		72.9%	59.1%	53.8%
Maintain % of Global Economy	27.4%	102	126	138
		62.5%	50.7%	46.2%
Population Based	18.9%	70	87	95
		90.6%	73.5%	66.9%
		U.S. budgets and carbon shadow as a percentage of the budget to 2100		
		450	550	650
Maintain share (2001)	23.5%	136	204	256
		58.9%	39.2%	31.3%
Maintain % of Global Economy	24.5%	142	213	267
		56.5%	37.6%	30.0%
Population Based	14.3%	83	124	156
		96.7%	64.4%	51.4%

Table ES6. The consumption of and committed consumption (carbon shadow) of the U.S. share of the global carbon budget in 2020 under a range of target concentrations and for three U.S. policy options that are referenced to the emissions in the rest of the world and a continuation of business as usual use of fossil fuels by the U.S.

The results of these analyses lead to the following conclusion and observations:

- The concept of a global carbon budget associated with particular stabilization levels for atmospheric carbon dioxide is a useful method for putting future emissions in context.

- For the globe global carbon budgets to 2100 range from 579 GtC for 450 ppmv target to 1089 GtC for a 650 ppmv target. The uncertainties in these budgets due to knowledge of the carbon cycle are only 10-15% for the next 50 years and climb to 20-25% for the century

- It is possible to analyze the U.S. capital stock in transportation and electricity generation and estimate future emissions from these existing sources by estimating future retirement rates based on past experience. It is also possible to generalize the results for these two sectors to the entire U.S. capital stock. This analysis suggests that current capital stock will release approximately 39.9 GtC over the next 50 years and 47.2 GtC over the next century.

- An analysis of possible future emissions by the U.S. suggest that by 2020, on a business as usual trajectory, the U.S. will have consumed or committed to consume 63.9 and 80.1 GtC of the global budgets to 2050 and 2100 respectively.

- Based on an analysis of a wide variety of possible U.S. shares of global carbon budgets of between 14% and 28% of global emissions, we find that existing capital stock has committed the U.S. to the use of 30-60% of its possible allowance for a 550 ppmv stabilization to 2050 and 22-38% of the possible allowance for the century. If the U.S. continues a "business as usual" use of fossil by 2020 it will have either consumed, or committed to consume (carbon shadow) 50-95% of its share to 2050 and 35-65% of its share for the century.

- The impact of current U.S. capital stock on global carbon budgets, and the corresponding U.S. share of that budget, is greatest for lower desired carbon dioxide concentrations. Under some scenarios for these low concentrations targets, current capital stock has consumed a higher fraction of the 100 year budget than of the 50 year budget, suggesting future pressure for premature retirement of capital stock.

By 2020 the U.S. may be in a position that it has little if any option to create new capital stock that freely vents carbon dioxide to the atmosphere if a global goal of 450 ppmv is to be achieved. Further even if the concentration goals are higher there will be severe constraints on deploying such resources as well.

1. Introduction and Background

Developing policy for the mitigation of greenhouse gas (GHG) emissions is a major challenge. The challenge arises from several perspectives.

First, GHG mitigation is a long-term task. Whatever policy, or succession of policies are developed, they must be sustained over the period of time necessary to stabilize greenhouse gas concentrations. All analyses suggest that the time period is at least a century.

Second, every policy has both benefits and costs. Problematically, the cost benefit profile of GHG mitigation is contrary to the preferred policy approach. Policymakers prefer to provide immediate benefits, with costs deferred to a later time. For GHG mitigation however, even if the policy is effective, and the change in emissions is exactly what is desired, it may not be possible to see the impact of actions on total emissions for several decades. Further, GHG mitigation does not reverse climate change, it only stops the anthropogenic component of that change and climate stabilization will only be achieved after the end of the stabilization process. On the other hand, the costs are far more immediate – essentially, beginning now.

Third, the costs can appear to be very large. The total global costs of most mitigation scenarios are measured in trillions of dollars. If one puts these costs in perspective by either comparing them to global GDP or to total investment that will be made in energy generation and consumption technology over this century, the costs look relatively modest. However, the total cost is intimidating, particularly when advocating action now, while there remains some uncertainty in the science.

Fourth, the scale of the systems that need to be changed is massive. The goal is to make a dramatic change in the nature of global energy production and use. Currently, the annual global waste stream from fossil fuel combustion, measured in billions of tons of carbon emitted, is six times larger than the annual global production of iron and steel. It is not just the existing energy system that must be transformed. Concurrently, it will be necessary to provide an energy infrastructure for developing nations that both provides adequate energy for development and does not drive their technological infrastructure into a dependence on fossil fuels and the free venting of carbon dioxide to the atmosphere.

Finally, the United States must be a significant player in the eventual mitigation of GHG emissions. It is currently the largest national emitter of carbon dioxide. There is a real question of how the U.S. should view itself within the context of this global challenge, particularly in light of the growing emissions from the developing world.

In this paper we suggest that the key to near term actions is an understanding that there is not only the issue of current emissions, but also the issue of current capital stock that will continue emitting into the future. An important cost of future mitigation is the loss of economic value of existing capital stock through premature retirement. The current stock of energy generating and consuming technologies, for example in the transportation and electricity generating sectors, cast a carbon shadow into the future. When the shadow of the existing capital stock, as well as current construction and manufacture of fossil fuel dependent technologies, is calculated, one realizes the extent to which we have already committed to consuming this century's global budget of carbon dioxide emissions. This carbon shadow highlights the potential need for both an accelerated deployment of non-carbon emitting technologies and a policy approach that addresses the problem of current capital stock.

In what follows we will:

1. Describe how the desire for stabilizing carbon dioxide concentrations at a particular level leads, because of the nature of the carbon cycle, to a global budget for carbon dioxide emissions.

2. Discuss the variety of ways that a carbon shadow can be important, motivating the focus of this report on U.S. electricity generation and transportation vehicles.

3. Examine the ways in which one might determine the lifetime of a particular piece of technology, drawing a distinction between the capital cycle and actual retirement.

4. Describe the process for calculating the retirement rates for U.S. electricity generation and transportation capital and derive the carbon shadows for the technologies based on their inferred retirement rate.

5. Generalize the carbon shadows for the U.S. beyond electricity generation and ground transportation, and put these in the context of various assumptions about appropriate U.S. shares of the global carbon budget.

6. Describe how various factors such as carbon cycle uncertainties, choice of stabilization level, and specific technology characteristics affect the basic results.

2. Budgets and Shadows

2.1 Carbon Budgets

There are a variety of ways to think about the transition from the current situation of increasing concentrations of atmospheric greenhouse gases to a stabilization of those concentrations. For the current work we are putting that transition into perspective by looking at the amount of carbon that can be emitted between now and a future time along a particular projected emissions path that would achieve a stabilization of the atmospheric concentration of carbon dioxide. The cumulative carbon emissions leading to stabilization is what we will refer to as an "allowable carbon budget."

The allowable carbon budget for stabilization is largely a function of two considerations. The first is the concentration at which one might wish to achieve stabilization: the lower the stabilized concentration the lower the allowable budget. Second, it is a function of the behavior of the Earth's carbon-cycle. If terrestrial and oceanic carbon reservoirs take up carbon at a greater rate, then the allowable budget for anthropogenic emissions will be larger. The shape of the path toward stabilization and the exact time of stabilization have some effect on the size of the allowable carbon budget, but are much less important than the target value and carbon-cycle parameters. A detailed discussion of how these various factors determine the allowable carbon budget is contained in Appendix A.

In Appendix A the trajectory for stabilization is of a type that has become to be known as a WRE trajectory. This trajectory, first elucidated by Wigley, Richels and Edmonds in 1996 is determined by minimizing the cost of achieving a particular stabilization level. As noted above, the exact trajectory is not critical to the allowable budget. Table 1 presents the allowable carbon budget for fossil emissions (fossil fuels plus cement production) for a trajectory that would achieve a 550 ppmv concentration target by 2150. The allowable carbon budgets up to the years 2050 and 2100 are 460 and 870 GtC, respectively.

The results in this section will be presented for a concentration target of 550 ppmv. A discussion of the impact on the analysis of selecting alternate target concentration is discussed later in the paper and in Appendix A.

	Allowable cumulative emissions under a 550 ppmv atmospheric concentration target by 2150 (GtC)
2050	460
2100	870

Table 1 Allowable cumulative emissions, in gigatons of carbon (GtC), from 2000 to 2050 and 2100 along a trajectory that would achieve a 550-ppmv atmospheric concentration target by 2150.

With the "allowable" carbon budget established, we can now turn to the question of how much of budget is already "committed to" because of the existing capital stock.

2.2 Carbon Shadows

The idea of a "carbon shadow" is a concept that attempts to capture quantitatively the impact of the current capital stock of fossil fuel generating and consuming technology as they continue to produce carbon emissions until they are retired. Specifically, the concept can be used in conjunction with the "allowable" budgets, discussed previously, to indicate the extent to which current capital stocks limit future flexibility in carbon emissions. It is possible to compute these shadows because the rate at which capital stock produces carbon emissions is a property of the technology itself, reflected in the efficiency of a fossil-fired fuel plant or of a motor vehicle. Therefore, if one understands how long the technology will be in use and how much it will be used, it is possible to calculate how much carbon dioxide will be emitted by an individual plant or vehicle.

By itself the carbon shadow cast by existing capital stock is interesting but lacks context. The context comes when one understands that stabilization at any particular concentration of atmospheric carbon dioxide implies a global budget for emissions over the course of this century. Therefore, it is possible to understand what fraction of this global budget is "spoken for" by the existing capital stock. This fraction we will refer to as the carbon shadow index, or share committed to, of the current capital stock. The capital stock, and therefore the carbon shadow, can be disaggregated by sector, specific technology or by country, providing context at a variety of levels.

Current capital stock leads to future emissions in three ways, direct conversion, energy utilization technologies, and structural consumption. This report focuses on only the first class of technologies, but as one contemplates the problem of stabilizing the concentrations of greenhouse gases it is important to realize that there are other technological shadows that impact carbon emissions, largely through their consumption of energy.

1. Direct conversion technologies: These technologies directly convert fossil fuels into energy services. This report will focus on the two largest of these technologies, electricity generation and vehicle transport. There are other technologies that fall into this class, such as cement production, some forms of steel production, and the use of natural gas for home heating. The basic characteristic of these technologies is that the individual plant or vehicle is characterized by a direct relationship between the energy service and the consumption of fossil fuels. This relationship is a property of the capital stock itself and is not readily changed. An example is automotive efficiency measured in miles per gallon.

2. Energy utilization technologies: These technologies are characterized by a direct relationship between an energy service and the consumption of some energy

carrier. Examples include many end use technologies, such as refrigerator and air conditioners. Like the direct conversion technologies the relationship between the energy service and the consumption of, for example, electricity is a property of the technology and not easily changed over the lifetime of its usage. The degree to which these technologies create a carbon shadow is a function of the extent to which the energy carrier generates carbon emissions and the turnover rate of the technologies.

3. Structural consumption: Some demand for energy services is structural and embodied either in a capital infrastructure or other societal factors. These range from buildings to highways to zoning decisions. Each has a certain degree of mutability as a function of time, but the basic structure implies a demand for energy services. For example tall buildings require elevators, and housing and employment being separated by large distances creates a demand for surface transportation. The impact of these demands on carbon emissions can be modified through changing the technologies that provide the services. However, the structural demand places limits on the benefits that energy efficiency or carbon intensity improvements can achieve. These limits are in turn embodied in a long-lived capital stock.

The key point about all three of these sources of carbon shadows is their embodiment in capital stock. Further, the currently existing capital stock limits the possible alternatives for the future. Retiring capital stocks before their useful life has run out incurs costs on society by shifting resources from capital expansion to capital replacement, with a concomitant loss of the economic value of the prematurely retired asset. This cost therefore suggests that, absent any policy, existing capital stocks will still be used until their retirement.

3. Carbon Shadows of U.S. Transportation and Electricity Generation Sectors

3.1 Capital Cycles vs. Retirement

The calculation of a carbon shadow for a direct conversion technology is based on three factors. They are the rate of carbon emissions per unit of service provided (e.g. carbon emissions per kilowatt), the average rate utilization of the services provided (kilowatts produced per year) and the lifetime of the technology (years before retirement). There are a number of timescales that could be used, and have been used, to estimate time of retirement. Because we are discussing capital stock and the financial consequences of premature retirement, it is tempting to use financial measures to determine the age of the asset at retirement. Such measures include the time to pay off funds borrowed for construction of the asset, to the time to depreciate the capital stock for tax purposes. These two are some times referred to as capital cycles. Capital cycles analysis assumes that characteristics such as lifespan, time to retirement, of capital investments are a fixed characteristic of capital itself.

A recent report by Lempert, Popper, Resetar and Hart[1] has examined the question of capital cycles in the climate change context. They conclude, "Capital has no fixed cycle". That is to say that financial considerations alone do not determine when one piece of capital stock is replaced with another. They highlight this by also concluding "equipment lifetime and more efficient technologies are not significant drivers in the absence of policy or market drivers".

Clearly, the useful life of capital can be extended well beyond its "normal" financial lifespan; coal plants, in particular, are still economically viable for decades after all capital costs have been paid.

The depreciation approach assumes that the useful output of a capital stock is reduced by a constant percentage each year. The data, however, (see model description below) suggests that capital retirement proceeds more slowly in early years and most quickly in the middle years of capital life, not at the constant rate assumed by depreciation. The retirement of capital stock appears rather to be driven by a combination of engineering factors, such as efficiency, breakdown, and repair costs, which in turn are driven by age and non-age-related factors, such as economic conditions, fuel prices, and the prices and/or the availability of alternative technologies.

The following analysis is based on third approach, an historical analysis of the actual retirement (removal from service) of direct conversion technologies used for electricity and vehicle transportation.

[1] "Capital Cycles and the timing of climate change policy" Pew Center for Global Climate Change, October 2002.

Before beginning the historical analysis of retirement it is worth noting the reasons for selecting electricity production and highway transportation. The basic numbers are quite compelling:

- Electricity generation accounted for 39% of 2001 U.S. carbon emissions
- Highway transportation (cars and trucks) accounted for 23% of 2001 U.S. carbon emissions
- Together, these two capital stocks represent 62% of U.S. emissions, and roughly 15% of global carbon emissions for 2001.

These sources do have some important differences. The capital stock in electricity production sector has a long life (30-70 years) and a correspondingly longer carbon shadow. The sector is composed of a small number of large emitters and some units (especially steam turbines) can be used almost indefinitely. On the other hand ground transportation is characterized by a relatively short life (10-15 years) and thus, a shorter carbon shadow. It is composed of a large number of small-scale emitters and vehicles are used more intensively when younger than when older, leading to a more rapid drop-off in the carbon shadow as the stock ages.

Once we have completed the analysis for these two sectors we will generalize the results in order to estimate the entire U.S. carbon emissions shadow.

3.2 Electricity Generation

Three fossil fuels —coal, natural gas, and oil— are used in four different electricity production technologies —steam turbine, combustion turbine, internal combustion, and combined-cycle— to produce most of the electricity consumed in the United States.[2] Appendix B contains a more detailed description of nature of each of these electrical generation technologies. Appendix B also contains the details of the methodology used to calculate the carbon shadows.

Briefly, the base methodology employed for the analysis proceeds in three steps. First is the calculation of a retirement rate. The methodology for this is adopted from a Federal Reserve analysis due to Greenspan and Cohen. Their approach[3] considers two factors in retirement, age and a collection of financial terms cyclical scrappage.

The second step is to assess the capacity factor for the plants – how much the plant runs in a given year. Both the retirement rate and the capacity factor were estimated from historical data. The capacity factor is also a function of the age of the plant with older plants having a lower capacity factor. The final term in the analysis is the heat rate term,

[2] Other fuels include biomass and wastes, while other technologies include renewable energy sources such as wind turbines, hydro turbines, and geothermal steam turbines. As these fuels and technologies are either carbon neutral or at least very low carbon emitters, they are ignored in this study.

[3] http://www.federalreserve.gov/Pubs/FEDS/1996/199640/199640pap.pdf

which is used to calculate how much carbon dioxide is emitted by the plant when operating.

Since each electrical generating technology has a slightly different history, separate calculations were carried out for each technology-fuel combination. As shown in Figures 1 and 2, coal-fired generators dominate the carbon shadow of the electricity-generating sector. By 2050, the cumulative total coming from non-coal generators is 3.6 GtC, as compared to coal's 18.6 GtC, giving non-coal technologies approximately 16% of the sector's cumulative emissions. By 2100, this total increases to 4.7 GtC, compared to coal's 22.1 GtC, increasing non-coal technologies' share of cumulative emissions to 17.5%. This reflects the youth of the combined cycle generator stock, which continues to churn out carbon well into the 21st century, even after most of today's coal plants have been retired.

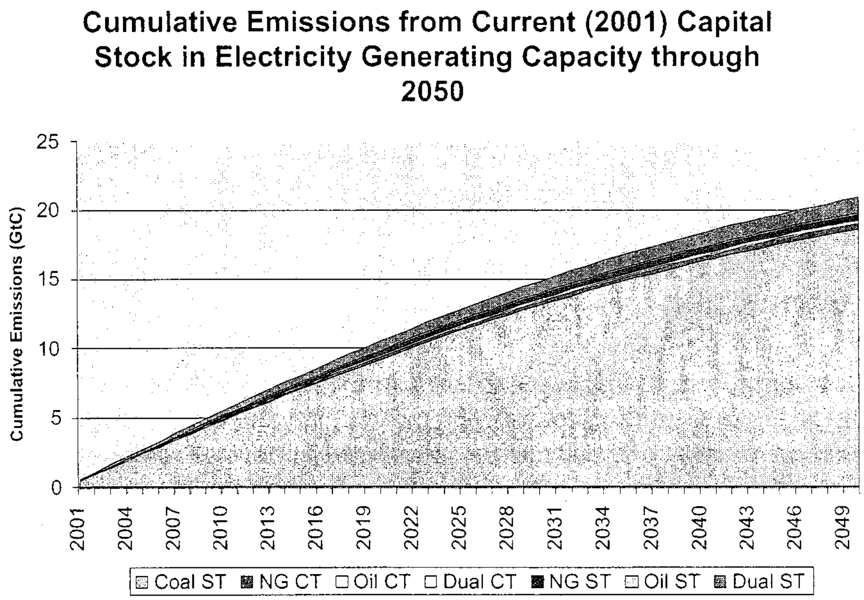

Figure 1. Cumulative emissions (GtC) from electricity capacity technologies operating as of 2001 through 2050. In the legend ST=steam turbines; CT=combustion turbines; NG=natural gas; and, dual refers to Steam turbines capable of being fired by either oil or natural gas.

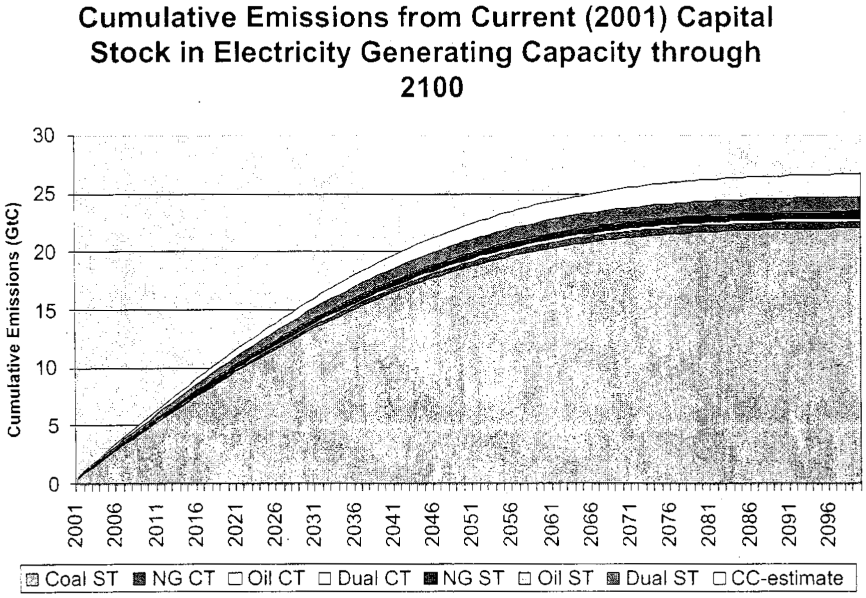

Figure 2. Cumulative emissions (GtC) from electricity capacity technologies operating as of 2001 through 2100. In the legend ST=steam turbines; CT=combustion turbines; NG=natural gas; and, dual refers to Steam turbines capable of being fired by either oil or natural gas.

The relatively long life of electricity generating capital stocks is highlighted in Table 2. In this table we show what the emissions would be if there were no retirements of capital stock as well as the projected emissions with retirement. Over the next 50 years there will a less than 25% reduction in cumulative emissions if the historical retirement rate of electrical generating capacity is maintained. Alternatively, existing capital stock is not very much of a factor after 2050.

While the carbon shadow diminishes for electrical generation, it should be noted that new fossil generation capacity will have an impact over much of the coming century and decisions how to replace retiring units will be critical to managing future commitments to carbon emissions.

Emissions from Electricity Capacity in year:	Cumulative emissions without retirement but with 2001 capital stock emissions constant for 50 or 100 years (GtC)	Cumulative emissions under expected retirement of 2001 capital stock (GtC)
2001	0.6	0.6
2050	30.1	22.3
2100	60.2	26.8

Table 2. Cumulative Emissions from electricity capacity under expected retirement of 2001 capital stock and with 2001 level emissions kept constant for 50 or 100 years.

3.3 Ground Transportation

The U.S. transportation sector accounted for 33% of national annual carbon emissions in 2001[4] , a significant source of emissions and potentially major contributor to U.S. carbon shadow. However, unlike power plants, data concerning vehicles is much harder to come by—the sheer number of vehicles makes reliable data difficult to find or expensive to obtain. For this reason, our model of transportation carbon shadows has been restricted to highway vehicles: cars, medium (GVW 10,001-16,000), light-heavy (GVW 16,001-26,000) and heavy-heavy (GVW 26,001+).light trucks, and heavy trucks.[5] Contributing approximately 76% of total transportation emissions, roughly a quarter of U.S. carbon emissions were attributable to these vehicles. This means that our more restricted model captures the lion's share of transportation-related carbon emissions. We will discuss other emissions associated with for example air transport as part of our generalization of the U.S. carbon shadow in the next section of the paper.

The detailed calculation of the ground transportation carbon shadow is contained in Appendix C. The model for this sector, like the electricity generator models, has three components. First, a retirement model calculates the total number of vehicles of each age group surviving into the next year. Second, a usage model determines how many vehicle miles are driven for each age cohort. The third component assigns the appropriate efficiency (measured in miles per gallon (mpg)) to each vehicle type and age group to obtain a total amount of fuel consumed and the associated carbon emissions.

Figures 3and 4 show the results of the calculations of the carbon shadow for the existing U.S. ground transportation fleet. There are several key features of these figures. First, unlike electricity generation where one technology dominates the carbon shadow, for ground transportation, passenger cars, light trucks and heavy trucks represent almost identical portions of the carbon shadow. Second, heavy trucks dominate the long-term component of the ground transportation shadow. Finally, practically all of the existing fleet will be retired before 2050.

[4] Information on total 2001 carbon emissions from EIA's 2001 AEO. http://www.eia.doe.gov/oiaf/aeo/results.html
[5] Polk, a data collection company, has extensive (but expensive) data on these classes of vehicles. There are some data available on publicly-owned transportation (buses and rail systems) and some information on the number of planes, but the historical data and usage data necessary to create a reliable vintage capital model is lacking.

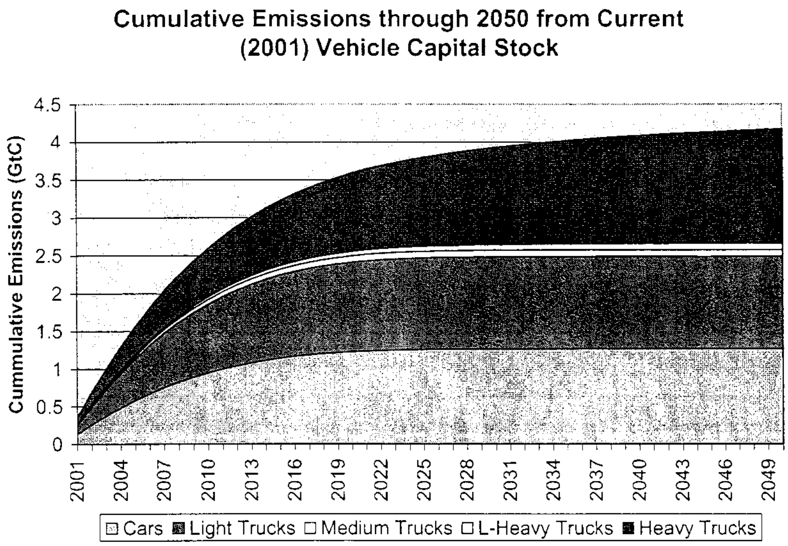

Figure 3. Cumulative emissions from current (2001) capital stock in vehicle capital stock through 2050.

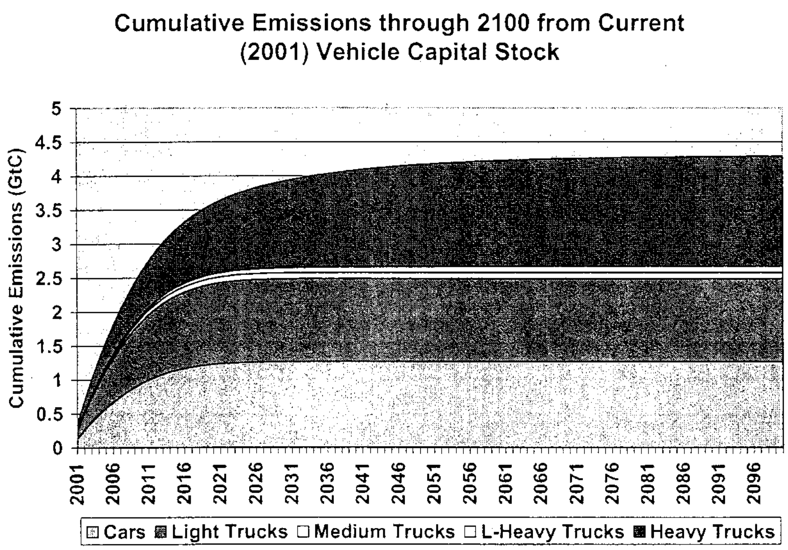

Figure 4. Cumulative emissions from current (2001) capital stock in vehicle capital stock through 2100.

This latter point is highlighted in Table 3. This table is the ground transportation equivalent of Table 2. Unlike electricity generation, the ground transportation stock only accounts for less than 25% of the emissions that would come from a constantly emitting fleet of surface transportation vehicles with comparable carbon emissions to the current U.S. fleet. Further, less than 3% of the carbon shadow of the current fleet will be emitted after 2050, in contrast to almost 17% of the shadow of the electrical generation sector coming from post 2050 emissions.

The results in Tables 2 and 3 highlight an important point about technological change. Specifically, a technology with relatively rapid turnover, like ground transportation, can see the effect of the introduction of new technology fairly quickly. As a result, the rapid turnover technology is not likely to be driven to early, uneconomic retirement by carbon emission policies. For longer-lived technologies, such as those found in electricity generation, premature retirement, and/or retrofit technologies maybe required to meet carbon emission targets.

Emissions from ground transportation in year:	**Cumulative emissions without retirement but with 2001 capital stock emissions constant for 50 or 100 years (GtC)**	**Cumulative emissions under expected retirement of 2001 capital stock (GtC)**
2001	0.36	0.36
2050	18.11	4.17
2100	36.23	4.29

Table 3. Cumulative emissions from U.S. ground transportation under expected retirement of 2001 capital stock and with 2001 level emissions kept constant for 50 or 100 years.

3.4 Projecting balance of the U.S. emissions shadow

The combined carbon shadows of the electrical generation and ground transportation technologies considered above are 26.4 and 31.0 GtC, for 2050 and 2100 respectively. However, as noted at the outset of the discussion, these sources, while making up most of the U.S. emissions, are not all of the emissions. The two sectors that we have analyzed make up approximately 62% of the total emissions. Table 4 summarizes the other sources of the other 38% of carbon emissions in the U.S.

Source	MtC (% of U.S) 2001	Nature of emissions (primary energy services)
Other transportation	447 (7.8%)	Aircraft, shipping, rail, buses
Industrial	1048 (18.2%)	Process and boiler heat
Commercial	227.2 (4.0%)	Space conditioning
Residential	366.2 (6.4%)	Space and water heating; cooking
Other	112.8 (2.0%)	Cement; gas production; waste combustion

Table 4. Carbon emissions in MtC in 2001 from sectors other than electricity generation and the ground transportation discussed earlier. Source AEO 2004 (DOE/EIA-383(2004)) and Emissions of Greenhouse Gases in the United States (DOE/EIA-0573(2002)).

An approach to estimating the rest of the U.S. carbon shadow is to use these numbers and the very different retirement characteristics of the two detailed analyses already completed as the basis of the estimate. Specifically, the ratio of the current annual emissions to the carbon shadow for a particular technology could be a measure of an "effective lifetime" of the technology. By this we mean if all of the emissions in a period were to be released to the atmosphere at a constant rate and all of the sources were to retire at the same time how long would they emit? Table 5 gives the effective lifetime for the electricity generation and ground transportation sectors calculated from the data in Tables 2 and 3.

	Effective Lifetime in Years
Electricity Generation – 2050	37.1
Electricity Generation – 2100	44.6
Ground Transportation - 2050	11.6
Ground Transportation - 2100	11.9

Table 5. Effective lifetimes of the capital stock in the electricity generation and ground transportation sectors based on the data in Tables 2 and 3.

End-use sector		Transport	Electricity		Transport	Electricity	
	2001	2050			2100		
Transportation	0.12	1.4	4.4	1.8	1.4	5.3	1.8
Industry	0.29	3.4	10.8	8.1	3.5	12.9	9.7
Commercial	.062	0.7	2.3	0.9	0.7	2.8	1.0
Residential	0.10	1.2	3.7	1.4	1.2	4.5	1.5
Other	.031	0.4	1.1	1.2	0.4	1.4	2.1
Total	0.60			13.4			16.1

Table 6. Estimating the carbon shadows for the rest of the U.S. economy. This table shows the 2001 emission in GtC for the end-use sectors not previously analyzed and summarized in Table 4. In the third and fourth columns the carbon shadow to 2050 is shown if the carbon emitting capital stock in each end-use sector had the same effective lifetime. The "other" end-use sector data comes from Table 7.

Considering each of these end-uses in turn we can use the data in Table 6 to estimate their carbon shadows.

<u>Other transportation</u>: From Table 4 we can see that the previously not considered elements of the transportation sector are largely aircraft, rail and shipping. The base technologies probably have a longer lifetime than the average for ground transportation, which is dominated by passenger cars and light duty trucks. If we look at the carbon shadow for heavy trucks alone, we can calculate an effective lifetime to 2050 and 2100, of 17.6 an 18.9 years[6]. In Table 6 we have adopted an intermediate value for the balance of the transportation sector that is the average of the ground transportation and the heavy truck effective lifetime of 14.6 and 15.4 years giving carbon shadows of 1.4 and 1.8 GtC.

<u>Industry</u>: The mix of end-uses associated with the industrial sector appear to be more durable than that associated with the transportation sector, but may not be as durable as the electricity generation sector. For present purposes we are estimating that these end-uses have a similar retirement profile to the electricity sector, but with a shorter effective lifetime. For present purposes we are estimating that this sector will have an effective lifetime 75% of the electricity generation sector.

[6] For U.S. heavy trucks the 2001 carbon emissions were 85.8 MtC and the retirement analysis in Appendix C gives a carbon shadow of 1.51 and 1.62 GtC for 2050 and 2100 respectively.

Commercial: We expect the commercial sectors carbon emissions to be greater than ground transportation and to be more in keeping with the balance of the transportation sector described above. While buildings themselves are relatively durable the heating infrastructure is replaced more often than the shell is raised and we estimate the durability of this capital to be comparable to that of the "Other Transportation" sector and will adopt its effective lifetimes for this calculation.

Residential: Space and water heating are the dominant end-uses and we are estimating that these systems have retirement rates comparable to their commercial counterparts.

Other U.S. Carbon Emissions: These emissions are difficult to estimate for several reasons. Looking at the five major sources in turn, we note that:

Cement production: The emissions from cement production are a function of the process not the capital stock. The emissions are therefore a product of the production of cement, which is in fact growing.

Natural Gas Flaring: This is a practice that is in heavy decline, having dropped nearly by a factor of 2 in the last decade. As a rapidly disappearing practice one cannot expect much of a shadow.

CO_2 in Natural Gas: The emissions here are a product of the natural gas being recovered and the demand for the CO_2 for other purposes that might sequester it. This source has increased with time.

Waste Incineration: These emissions are tied to a capital stock that likely has an industrial retirement schedule.

Other industrial: These include emissions from smelting and the use of limestone in desulphurization. The associated capital stock will have a characteristic industrial time scale.

Source	2001	Assumption	ELT 2050	ELT 2100	Shadow 2050 (GtC)	Shadow 2100 (GtC)
Cement	11.3	Constant	50	100	0.56	1.13
NG Flaring	1.4	Zero	0	0	0	0
CO2 in NG	5.1	Constant	50	100	0.25	0.52
Waste	5.4	Industrial	27.8	33.4	0.15	0.18
Other	7.6	Industrial	27.8	33.4	0.21	0.25
Total	30.8				1.18	2.07

Table 7: Estimates of the Carbon Shadow for other industrial sources. Column 3 contains the assumption made to estimate the effective lifetime (ELT) for the associated capital stock. Constant implies that the source is a product of the process not the capital equipment and the assumption is that there is constant use of the resource. Industrial means that the industrial effective lifetime (75% of the electricity sector has been used. Zero has been assumed for natural gas flaring which is a sharply diminishing practice.

We can now estimate the total carbon shadow for the United States, which is summarized in Table 8.

Sector	Carbon Shadow 2050 (GtC)	Carbon Shadow 2100 (GtC)
Electricity Generation	22.3	26.8
Ground Transportation	4.2	4.3
Other	13.4	16.1
Total	39.9	47.2

Table 8: Total carbon shadows for the United States to 2050 and 2100 respectively.

4.0 U.S. Emissions in Perspective

The key question now is, "what are the ramifications of capital lifetimes on future options for carbon dioxide emissions mitigation strategies in the United States?" Specifically, this can be looked at from four perspectives:

1. If the U.S. were to continue its emissions at present levels over the next century, how much of the global budget of emissions would it consume?

2. How much of the global carbon budget does the existing U.S. capital stock of carbon emitting facilities consume of the global budget?

3. If we estimate a range of values for the "share " of the century's global carbon budget that could be assigned to the U.S. how much of those budgets will the existing capital stock consume?

4. Since it takes time to make a transition to new energy systems, can we estimate the U.S. situation with respect to possible carbon budgets 20 years hence?

Many policy proposals start with stabilizing emissions as an interim goal on the path to carbon emissions reduction. Table 9 summarizes what the U.S. emission would be if they average 2001 emissions for the next 50 and 100 years respectively. There are several points worth noting in the context of Table 9:

- Maintaining average 2001 emissions over the next 50 and 100 means that the U.S. would use less than its current annual percentage of global emissions (Currently the U.S. is 24% of global carbon emissions.). This reflects the impact of the projected growth of carbon emissions in the rest of the world, most notably developing countries.

- For reference, it should be noted that the U.S. emissions in 2001 (1.56 GtC) have grown from 1990 levels (1.32 GtC). If the U.S. were to average 1990 emission levels for the next 50 and 100 years, those emissions would constitute 14.3% and 15.2% respectively of the global budget.

- Finally, Table 9 illustrates the impact of the stabilization trajectory that calls for less emissions in the second half of the 21st century than in the first, a reduction of 50 GtC.

	2001 U.S. Annual Emissions (GtC)	U.S. Emissions to 2050 and percent of the Global Carbon budget	U.S. Emissions to 2100 as a percent of the Global Carbon budget
Electricity Generation	0.60 GtC	30.1 GtC (6.5%)	60.2 GtC (6.9%)
Ground Transportation	0.36 GtC	18.1 GtC (3.9%)	36.2 GtC (4.1%)
Other Carbon Emissions	0.60 GtC	30.0 GtC (6.5%)	60.0 GtC (6.9%)
Total	1.56 GtC	17.0%	17.9%
Global Carbon Budget (GtC) for 550 ppmv stabilization		460 GtC	870 GtC
Global Carbon Emissions in 2000	6.61		

Table 9: Projection of U.S. emissions to 2050 and 2100 under the assumption of constant U.S. emissions. The results are shown both as total emissions in GtC and as a percentage of the Global Carbon Budget. The calculations of the percentages are based on budgets to 2050 and 2100, for a 550 ppmv target concentration.

The second question is, in essence, "how significant is the U.S. carbon shadow in the context of a global carbon budget?" The bottom line (Table 10) is that the carbon shadow of the current U.S. carbon emitting capital stock represents 8.7% and 5.4% of the global carbon budget to years 2050 and 2100 respectively. For context, from Table 9 we note that the if U.S. emissions remained constant over the century that they would represent 17.0% and 17.9% of the 2050 and 2100 global budgets respectively. Table 10 shows further that in the electric utility sector, existing capital has committed the U.S. to almost 75% of the emissions it would have it continued to emit at a constant level over the next 50 years.

<table>
<tr><th colspan="2"></th><th colspan="2">2050</th><th colspan="2">2100</th></tr>
<tr><th colspan="2"></th><th>Cumulative emissions without retirement but with 2001 capital stock emissions constant</th><th>Carbon Shadow (Carbon Shadow as a percent of constant emissions)</th><th>Cumulative emissions without retirement but with 2001 capital stock emissions constant</th><th>Carbon Shadow (Carbon Shadow as a percent of constant emissions)</th></tr>
<tr><td colspan="2">Cumulative U.S. Emissions from Electricity Capacity</td><td>30.1 GtC</td><td>22.0 GtC (73.1%)</td><td>60.2 GtC</td><td>26.8 GtC (44.5%)</td></tr>
<tr><td colspan="2">Cumulative U.S. Emissions from Ground Transportation</td><td>18.1 GtC</td><td>4.2 GtC (23.2%)</td><td>36.2 GtC</td><td>4.3 GtC (11.9%)</td></tr>
<tr><td colspan="2">Cumulative U.S. Emissions from other sources</td><td>30.0 GtC</td><td>13.4 GtC (44.7%)</td><td>60.0 GtC</td><td>16.1 GtC (26.8%)</td></tr>
<tr><td rowspan="2">Total U.S Carbon Shadow</td><td>Shadow in GtC</td><td colspan="2">39.9 GtC</td><td colspan="2">47.2 GtC</td></tr>
<tr><td>As % of Global Carbon Budget</td><td colspan="2">8.7%</td><td colspan="2">5.4%</td></tr>
</table>

Table 10: A summary of U.S emissions from tables 8 and 9 showing the relationship between carbon shadows of various sectors and the global carbon budget and emissions associate with a flat emissions profile. Global carbon emissions budgets are based on target of 550 ppmv atmospheric concentration by 2150 and are 460 GtC (to 2050) and 870 GtC (to 2100).

While the percentage of the global budget is instructive, it is also worthwhile to consider what impact the carbon shadow of the U.S. current capital stock may have on future carbon emissions mitigations options. One way to do this is to consider what range of global emissions might apply to the United States. The purpose of this is not to enter into a discussion of what might be the "fair share" of global emissions that might be allocated to the U.S., but rather to see the extent to which current "committed" emissions might constrain future U.S. policy. In order to estimate what plausible range of U.S. emissions budgets might be, we have hypothesized five "bases of allocation" of global emissions. Again, none of these are recommendations as the basis of allocation; they are simply heuristics for understanding U.S. policy options. The five used here are:

1. Set the U.S. budget for the 21st century based on maintaining an average emission of some benchmark year. Table 10 does this for a benchmark year of 2001, but one could imagine using 1990, the year of the signing of the UN Framework Convention on Climate Change. If the benchmark year is 2001 the cumulative U.S. budget to 2050 is 78 GtC and to 2100 156 GtC. If the benchmark year were

1990 the U.S. budgets would be 66 and 132 GtC to 2050 and 2100, respectively.

2. Another means of estimating a budget would to say that the budget for any given year would be the same fraction, in perpetuity, of the global budget. Again there is the question of establishing the benchmark year for the budget. In 2001 the U.S. accounted for 23.6% of global emissions and 1990 21.5%. Therefore with 2001 base year the cumulative U.S. budgets would be 108 and 205 GtC to 2050 and 2100 respectively. If the base year were 1990 the U.S. budgets would be 99 and 187 GtC.

3. Since emissions are tied to economic activity it may be useful to consider indexing emissions budgets to GDP. In 2000 the U.S. economy was about 31% of global GDP. Using the IPCC Special Report on Emission Scenarios and assuming that the current relative rates of growth of the global economy and the advanced economies persist, on average, over the next century, the U.S. economy would be about 18% of the global economy, that is a $40-95T economy for the U.S. in 2100. By assuming a linear transition to this share of GDP we get U.S. carbon budgets of 126 and 213 GtC to 2050 and 2100, respectively.

4. Another approach might be to set the share in terms of a policy aspiration. One example is the idea of using the current administration's goal of reducing carbon intensity by 18% per decade. Currently the U.S. emits about .16 tons of carbon per dollar of GDP. If the goal of reducing the U.S. carbon emissions by 18% per decade could be sustained over this century that number would reach .022 tons of carbon per $ of GDP in 2100. Using the 2100 U.S. GDP numbers above ($40-95T) and an assumption of linear GDP growth over the century, the U.S. emissions budgets would be in the range of 76-117 GtC to 2050 and 122-182 GtC to 2100.

5. Finally, there has been some discussion of having the relative shares of carbon emissions trend to a per capita distribution of shares. For the U.S this would be a 5% share of annual emissions in 2100. Presuming a linear transition from the current 23.6% share of annual emissions this would imply 87 and 124 GtC U.S. budgets to 2050 and 2100.

Table 11 summarizes these possible U.S. carbon budgets and provides a comparison with the various possible U.S. shares of the carbon budget noted above.

Basis of allocation		U.S. Budget to 2050 (GtC) with % of Global Budget	U.S. Carbon shadow to 2050 as a % of budget (550)	U.S. Budget to 2100 (GtC) with % of Global Budget	U.S. Carbon shadow to 2100 as a % of budget (550)
Maintain average emissions	Base Year 1990	66 14.3%	60.5%	132 15.2%	35.8%
	Base Year 2001	78 17.0%	51.2%	156 17.9%	30.3%
Maintain share of global emissions	Base Year 1990	99 21.5%	40.3%	187 21.5%	25.2%
	Base Year 2001	108 23.5%	36.9%	205 23.6%	23.0%
Share based on relative share of the global economy		126 27.4%	31.7%	213 24.5%	22.2%
18% per decade reduction in carbon intensity		76-117 16.5-25.4%	52.5-34.1%	122-182 14.0-20.9%	38.7-25.9%
Trend to share based on relative population in 2100		87 18.9%	45.9%	124 14.3%	38.1%

Table 11: United States carbon budgets to 2050 and 2100 under the various assumptions described in the text. For perspective the U.S. budgets are also shown as a percentage of the global carbon budgets to 2050 and 2100 (460 and 870 GtC respectively for a 550 ppmv stabilization target). Also shown is the carbon shadow for the entire U.S. economy as a percentage of the U.S. budgets.

It is important not to be caught up in the details of Table 11. The range of U.S. carbon budgets described above are 66-126 GtC to 2050 and 124-213 GtC to 2100. Thee are to be compared to the U.S. carbon shadows of 39.9 GtC and 47.2 GtC to 2050 and 2100 respectively. Even from this simple perspective, the results are fairly dramatic.

The biggest impact of carbon shadows is clearly in the next 50 years. Under the assumptions described in the text above the current U.S. capital stock, if retired at historical rates represents a commitment to consume between 30 and 60% of possible U.S. shares of the global carbon budget. Recall that this commitment is without the construction of another fossil fuel fired power plant or the construction of a single petroleum fueled vehicle. Perhaps just as striking is that the current U.S. capital stock represents a commitment to emitting an amount equal to 22-38% of possible U.S. budgets for the next 100 years. Clearly the carbon shadow of current U.S. capital stock is quite long.

The final task in our attempt to put U.S. carbon emissions in perspective is to estimate what might happen over the next twenty years if the U.S. does not make a significant transition to a much lower carbon intensity path. There are two parts to the question. First what will happen to the U.S. carbon shadow as various elements of the carbon emitting capital stock are retired and replaced? Second how what will the emissions over the next 20 years look like and how much of the U.S. carbon budget will those emissions consume?

Two factors control estimate of what happens to the shadow over the next 20 years.

- What kind of capital stock replaces retired capital stock?
- What capital stock is added over and above replacement?

The answers to these two questions probably have an opposite impact on the carbon shadow of the resulting capital stock. We would expect that new capacity would produce energy services at higher efficiency and therefore lower carbon intensity. Alternatively, the addition of capacity would simply increase the carbon shadow. New capital equipment may have a longer lifetime than the equipment it replaces (the tendency for motor vehicles), which would add to the carbon shadow. Similarly, if the replacement capital equipment has a shorter lifetime, e.g. a combustion turbine versus a pulverized coal plant, the shadow would be smaller. For present purposes, we will take a conservative (lower carbon shadow assumption that the carbon shadow in 2020 would be equal to the current carbon shadows, 39.9 and 47.2 GtC to 2070 and 2120 respectively. Following the previous analyses, we estimate the carbon shadow to be 29.9 GtC from 2020 to 2050 and 46.1 GtC to 2100.

The next question is what might the expected emission for the U.S. over the next 20 years. Over the past decade the annual U.S. carbon emissions have increased at about 1.7% per year. For present purposes we estimate U.S. increases at half this rate for the next 20 years. Under this assumption, the U.S. would emit approximately 34 GtC over the 20-year period. Therefore by 2020 the U.S. has emitted and committed to emit 63.9 GtC and 80.1 GtC to 2050 and 2100, respectively.

Table 12 summarizes the impact of these assumptions on the various U.S. shares of the global carbon budget as described in Table 11 and the associated text. There are several key points. First, even for the most generous U.S. share of the global carbon budget, one based on GDP, by 2020 the U.S. has either emitted or committed to emit, in the form of its carbon shadow more than 50% of its budget to 2050 and almost 38% of the budget to 2100.

Basis of allocation		U.S. Carbon shadow in 2020, plus 2001-2020 emissions (63.9GtC) to 2050 as a % of budget (550)	U.S. Carbon shadow in 2020, plus 2001-2020 emissions (80.1GtC) to 2100 as a % of budget (550)
Maintain average emissions	Base Year 1990	96.8%	60.7%
	Base Year 2001	81.9%	51.3%
Maintain share of global emissions	Base Year 1990	64.5%	42.8%
	Base Year 2001	59.2%	39.0%
Share based on relative share of the global economy		50.7%	37.6%
18% per decade reduction in carbon intensity		84.1-54.6%	65.7-44.0%
Trend to share based on relative population in 2100		73.4%	64.6%

Table 12: Use and committed use of the United States carbon budgets to 2050 and 2100 by 2020 following the assumptions in the text. The basis for determining the U.S. budgets is the same as for Table 11.

As above rather than focusing on the detailed results in the table we can consider the ranges consumption of the possible U.S. carbon budgets. Doing that we note that to 2050, the combination of twenty years of "business as usual" consumption, and the carbon shadow of the evolved capital stock implies consumption of 51-97% of the possible U.S. budgets to 2050. To 2100, we may have consumed and committed to consume 38-65% of the range of U.S. budgets considered here.

What does it mean to have emitted or committed to emit 100% of the nation's budget? If we were speaking to the entire period, from a given time forward to the stabilization date of 2150, it would imply that the nation in question could not build any more carbon emitting technologies, even to replace those that have retired. In the current context using 100% of the budget to an intermediate point in time, implies that the changing emissions profile will not stay on a cost minimization WRE-like trajectory and that future emissions reductions may require premature retirement of capital stock in order to meet the final budget.

4.1 Impacts of policy goals

The previous results and discussion are even more powerful when put in the context of the policy options related to managing the concentration of atmospheric carbon dioxide. The analysis in Appendix A, which discusses both the budget for different levels but also the impacts on those budgets of uncertainties in our understanding of the carbon cycle, gave the following budgets (Table 13) for global carbon dioxide emissions over the next century.

	Stabilization at 650 ppmv	**Stabilization at 550 ppmv**	**Stabilization at 450 ppmv**	**Reference case**
Global carbon budget to **2050** (GtC)	505	460	373	500
Uncertainty range (GtC)	451 – 515	423 – 463	311 – 397	
Global carbon budget to **2100** (GtC)	1089	870	579	1345
Uncertainty range (GtC)	815 -1176	663 – 973	331 - 655	

Table 13: The carbon budget, assumptions and uncertainties (from Appendix A). As described in the appendix, the uncertainty range is due to our current uncertainty in the carbon cycle, largely related to the long-term uptake of carbon in the oceans.

The values in Table 13 have been used to calculate the consumption of global carbon budgets by current U.S. capital stock (Table 14). There are two points to be noted from Table 14. First, the impact of a 450 ppmv target on the fraction of the global budget consumed by existing U.S. capital stock is greater than for the 650 ppmv policy case. This reflects the fact that as one lowers the target concentration and future emissions are more severely constrained, the impact of existing capital stock is correspondingly greater. The second point is that carbon cycle uncertainties are important, but primarily for the 450 policy case on the 100 year time scale. For the 450 case, in the long term, the existing capital stock could have an even greater impact on global budgets in the second half of the 21st century than in the first half.

		To 2050		To 2100	
Total U.S. Carbon Shadow in GtC		**39.9 GtC**		**47.2 GtC**	
As % of Global Carbon Budget			**Range**		**Range**
for 450 ppmv		**10.7%**	**10.1-12.8%**	**8.2%**	**7.2-14.2%**
for 550 ppmv		**8.7%**	**8.6-9.4%**	**5.4%**	**4.8-7.1%**
for 650 ppmv		**7.9%**	**7.7-8.8%**	**4.3%**	**4.0-5.8%**

Table 14. The U.S. carbon shadows to 2050 and 2100 expressed as a percentage of the corresponding global carbon budgets. These are the shadow calculated from 2000 and correspond to the values in Table 10.

What do the 450 and 650 ppmv cases imply for the U.S. with respect to possible allocations of shares of the global carbon to U.S. and the corresponding consumption of those budgets by existing capital stock? Because of the differing ways in which the U.S. shares were determined, there are two different impacts.

For two cases, previously discussed, we have assumed a U.S. share based on policy targets that are not indexed to anything else going on in the world. In these two cases, holding U.S. emissions to an average of the emissions in some reference year and setting a targeted reduction in the intensity of carbon emissions, the absolute carbon budget, and therefore the percentage of the U.S. budget consumed by current capital stock does not change. However, the U.S. share of the global budgets changes. These results are shown in Table 15 and they raise two issues. First, note that for both of these options existing capital stock already consumes a significant fraction of these budgets. Second it is clear again that targets as low as 450 will make it increasingly difficult for the U.S. to maintain these budgets in view of global competition for emissions budgets. It is also instructive to refer back to Table 12, where we note that the continuation of U.S. emission patterns suggests that for these cases the U.S. carbon shadow in 2020 will have consumed 60-80% of the U.S. budget to 2050 and nearly half of the U.S. budget to 2100.

Global Budget to 2050	Maintain U.S. average at 2001 emission levels with Carbon Shadow (%) of U.S. budget	U.S. Budget as a Percentage of Global Budget	Reduce carbon intensity 18% per decade with Carbon Shadow (%) of U.S. budget	U.S. Budget as a Percentage of Global Budget
U.S. Budget	78 (51.2%)		76-117 (52.5-34.1%)	
450		20.9%		20.4-31.4%
550		17.0%		16.5-25.4%
650		15.4%		15.0-23.2%
Global Budget to 2100				
U.S. Budget	156 (30.3%)		122-178 (38.7-25.9%)	
450		26.9%		21.1-30.7%
550		17.9%		14.0-20.5%
650		14.3%		11.2-16.3%

Table 15. The U.S. share of the global carbon budget under a range of target concentrations and for two U.S. policy options that represent unilateral U.S. policies, without reference to the rest of the world's emissions.

The other possible U.S. budgets are more closely tied to the rest of the world, indexed to (1) shares of global emissions, (2) shares based on global GDP and (3) shares based on population. For these three estimates changing the stabilization goal will change the proportion of the U.S. share consumed by current capital stock. The results are shown in Table 16. Again, the results are striking. Several points emerge, the most prominent of which is that for lower stabilization targets (450 ppmv) current capital stock consumes a substantial fraction of the U.S. share both in the first half of the 21st century and for the second half of the century as well.

	U.S. share of total global budget (percentage of global budget)	U.S. budgets and carbon shadow as a percentage of the budget to 2050		
Assumptions about U.S. share of global carbon budget		450	550	650
Maintain share (2001)	23.5%	88	108	119
		45.5%	36.9%	33.6%
Maintain % of Global Economy	27.4%	102	126	138
		39.0%	31.7%	28.8%
Population Based	18.9%	70	87	95
		56.6%	45.9%	41.8%
		U.S. budgets and carbon shadow as a percentage of the budget to 2100		
		450	550	650
Maintain share (2001)	23.5%	136	204	256
		34.7%	23.1%	18.4%
Maintain % of Global Economy	24.5%	142	213	267
		33.3%	22.1%	17.7%
Population Based	14.3%	83	124	156
		57.0%	37.9%	30.3%

Table 16. The U.S. share of the global carbon budget under a range of target concentrations and for three U.S. policy options that are referenced to the emissions in the rest of the world.

The results in Table 16 are amplified in Table 17 where we have taken the previous analysis of what the consumption over the next 20 years might be and estimated the carbon shadow in 2020 (Table 11) and looked at the corresponding consumption of the carbon budget as of 2020. In this case, a business as usual use of fossil fuels by the U.S. for the next 20 years has dramatically limited options. Specifically with respect to the 450 ppmv stabilization goal the U.S. has either consumed or committed to consume 60-90% of its "share" of global emissions not only to 2050 but also to 2100. For higher stabilization levels, the picture is similar but not as severe. For 550 ppmv, consumed plus committed emissions represents 50-75% of possible budgets to 2050 and 40-65% of budgets to 2100. Even for a 650 ppmv goal, consumed plus committed emissions have consumed 45-65% of the 2050 budget and 30-50% of the budget to 2100. These shadows are profound and are cast well into the second half of the 21st century. The implications are just as compelling when one considers that these correspond to consuming 17.1%, 13.9% and 12.7% of global budgets to 2050 and 13.8%, 9.2% and 7.4% to 2100, for targets of 450, 550 and 650 ppmv, respectively.

	U.S. share of total global budget (percentage of global budget)	U.S. budgets and carbon shadow as a percentage of the budget to 2050		
Assumptions about U.S. share of global carbon budget		450	550	650
Maintain share (2001)	23.5%	88	108	119
		72.9%	59.1%	53.8%
Maintain % of Global Economy	27.4%	102	126	138
		62.5%	50.7%	46.2%
Population Based	18.9%	70	87	95
		90.6%	73.5%	66.9%
		U.S. budgets and carbon shadow as a percentage of the budget to 2100		
		450	550	650
Maintain share (2001)	23.5%	136	204	256
		58.9%	39.2%	31.3%
Maintain % of Global Economy	24.5%	142	213	267
		56.5%	37.6%	30.0%
Population Based	14.3%	83	124	156
		96.7%	64.4%	51.4%

Table 17. The consumption of and committed consumption (carbon shadow) of the U.S. share of the global carbon budget in 2020 under a range of target concentrations and for three U.S. policy options that are referenced to the emissions in the rest of the world and a continuation of business as usual use of fossil fuels by the U.S.

Highlighting a point made earlier, for some of these approaches to determining a U.S. share, these results suggest that by 2020 the U.S. may be in a position that it has little if any option to create new capital stock that vents carbon dioxide to the atmosphere if a global goal of 450 ppmv is to be achieved. Further even if the concentration goals are higher there will be severe constraints on deploying such resources in those cases as well.

5.0 Conclusions

This report has examined both current emissions from the United States and the likely persistence of some of those emissions into the future. These emissions are put in the context of a global budget for carbon dioxide for a variety of stabilization levels. The primary results and observations are as follows:

- The concept of a global carbon budget associated with particular stabilization levels for atmospheric carbon dioxide is a useful method for putting future emissions in context.

- For the globe global carbon budgets to 2100 range from 579 GtC for 450 ppmv target to 1089 GtC for a 650 ppmv target. The uncertainties in these budgets due to knowledge of the carbon cycle are only 10-15% for the next 50 years and climb to 20-25% for the century

- It is possible to analyze the U.S. capital stock in transportation and electricity generation and estimate future emissions from these existing sources by estimating future retirement rates based on past experience. It is also possible to generalize the results for these two sectors to the entire U.S. capital stock. This analysis suggests that current capital stock will release approximately 39.9 GtC over the next 50 years and 47.2 GtC over the next century.

- An analysis of possible future emissions by the U.S. suggest that by 2020, on a business as usual trajectory, the U.S. will have consumed or committed to consume 63.9 and 80.1 GtC of the global budgets to 2050 and 2100 respectively.

- Based on an analysis of a wide variety of possible U.S. shares of global carbon budgets of between 14% and 28% of global emissions, we find that existing capital stock has committed the U.S. to the use of 30-60% of its possible allowance for a 550 ppmv stabilization to 2050 and 22-38% of the possible allowance for the century. If the U.S. continues a "business as usual" use of fossil by 2020 it will have either consumed, or committed to consume (carbon shadow) 50-95% of its share to 2050 and 35-65% of its share for the century.

- The impact of current U.S. capital stock on global carbon budgets, and the corresponding U.S. share of that budget, is greatest for lower desired carbon dioxide concentrations. Under some scenarios for these low concentrations targets, current capital stock has consumed a higher fraction of the 100 year budget than of the 50 year budget, suggesting future pressure for premature retirement of capital stock.

- By 2020 the U.S. may be in a position that it has little if any option to create new capital stock that freely vents carbon dioxide to the atmosphere if a global goal of 450 ppmv is to be achieved. Further even if the concentration goals are higher there will be severe constraints on deploying such resources as well.

In conclusion, the concepts of global carbon budgets and carbon shadows provide two insights. First it shows the extent to which current practices and technologies are not only responsible for current but for future emissions. Second, it shows how existing capital stock may restrict the ability to cost effectively achieve low carbon dioxide stabilization levels. With these broad insights, we can see the challenge ahead for the U.S. Not only do we need to be concerned about reducing emissions, but we need to be mindful of the fact that decisions made today will cast shadows into the future, just as past decisions are affecting our flexibility now.

Appendix A: Carbon Cycle and Carbon Budgets

The concentration of carbon dioxide in the Earth's atmosphere is a consequence of the flows of carbon among a variety of different stocks of carbon. The movement among these stocks is controlled by a variety of geophysical process, each of which has a different characteristic time scale associated with it.

The time scales associated with the key processes affecting carbon dioxide concentrations can be ordered from fast to slow. There are two important fast processes. The first is the annual cycle of growth of plants associated with the change of the seasons. This cycle is driven in temperate climates mainly by spring and summer uptake of carbon dioxide due to net photosynthesis and release of carbon back to the atmosphere in the fall and winter when decay processes break down plant material. This process is large enough to be seen in the annual global variation of carbon dioxide concentration, such as that observed at Mauna Loa. The second fast process is the equilibrium that is established between the atmosphere and the mixed layer of the ocean.

The intermediate time scale is tied to these first two processes. In the case of the terrestrial component, there is a gradual net addition of carbon to standing biomass, perennial organisms like trees, and the soil. Second, in the ocean, the waters in the mixed layer, the top few hundred meters of the ocean, are gradually mixed by ocean circulation into the deep ocean, which is out of contact with the atmosphere. These two processes operate on timescales of decades to centuries. Finally, there is a geologic scale, operating over periods with characteristic times of millennia to millions of years where carbon is incorporated in geologic formations such as fossil fuels. It is the intermediate timescale processes, which are most relevant to the removal of carbon dioxide in the timeframe, that this project is concerned with (50-100 years).

When society mines the geologic repositories of carbon to generate energy through combustion or to make cement, an excess of carbon dioxide is emitted into the atmosphere. The ability of plants and the the ocean to absorb these emissions is limited, and, on an annual basis, this results in only about half of the carbon dioxide emitted being removed annually. The remaining carbon dioxide, in excess of the natural removal processes, leads to an increment in the atmospheric carbon dioxide concentration.

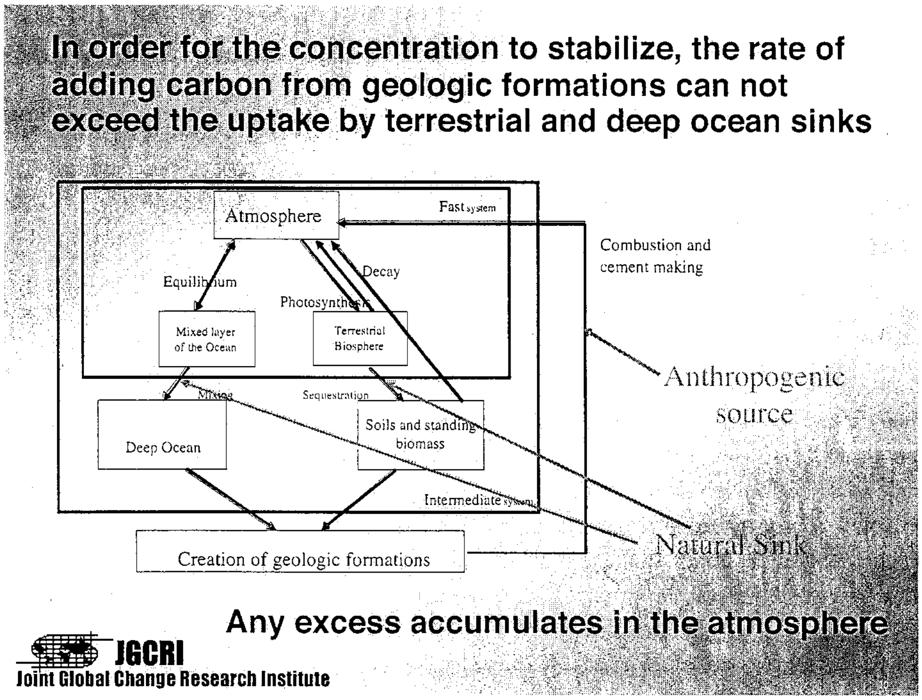

Figure A1. Overview of the carbon cycle

To be in equilibrium, the carbon fluxes, emissions and sink processes, must balance one another. For that to occur, each year we could only emit an amount of carbon equal to the amount of uptake by the deep-ocean and terrestrial systems without causing an increase in the atmospheric carbon dioxide concentration. Alternatively, we can budget an amount of emissions beyond this level by accepting a given increment in the atmospheric concentration of carbon dioxide. Thus, if we choose a given concentration as our target for stabilization, we can determine future annual carbon budgets that exceed annual uptake and increment the concentration towards the target. Once the stabilization level is reached, however, in order to be maintained, our emissions budget is limited to the equilibrium budget, meaning that the annual release of geologic carbon cannot exceed the rate at which the deep ocean and the terrestrial carbon pools are taking up the carbon dioxide.

When we speak of "allowable" emissions, we are referring to this type of future annual carbon budgets. The difference between current concentrations and stabilization target concentrations tells us what the total incremental increase in concentration can be. This total is distributed over time by constraining carbon emissions to an "economically efficient" path, in the sense of the work of Wigley, Richels and Edmonds – the WRE curves. That is, the amount of incremental increase allocated to each annual budget between now and the target year is determined by a least cost path to reach stabilization concentration in that year.

The results presented for allowable emissions are the integrated results from three JGCRI models: the Second Generation Model (SGM), the Mini-Climate Assessment Model

(MiniCAM), and a new global optimization model. Additionally, the optimization model uses the Model for the Assessment of Greenhouse gas Induced Climate Change (MAGICC), developed by Tom Wigley and collaborators.

The MiniCAM and the SGM are extensively described in model documentation (Brenkert *et al.* 2003a,b). These models were used to provide cost curves that were input into the global optimization model. The SGM contains an explicit representation of energy producing capital stock with vintaging in a computable general equilibrium framework. These features make the SGM the appropriate model to provide estimates of the cost of near-term reductions in global carbon dioxide emissions. The SGM has been used for this purpose in numerous national and international studies.

The MiniCAM is a flexible model with numerous technological options that runs on a global scale with a resolution of 14 world regions. The MiniCAM incorporates socio-economic changes over a century time scale such as improvements in energy technologies, demographic changes, economic development, and fossil resource depletion. These characteristics make the MiniCAM the appropriate tool for examining the costs of carbon policies over a century time scale. The MiniCAM was used to provide estimates of the cost of emissions reductions from 2050 onward. The cost curves from these two models were extrapolated for intermediate periods.

The global optimization model used here is a new model developed at JGCRI. This model uses a genetic optimization algorithm to produce globally optimized, cost-minimizing pathway to a specified climate target. The key input parameters are the value of the climate target (for example, stabilization at 550 ppmv) and the cost of emissions reductions. Cost curves from the two models above were used to determine emissions reduction costs. The program finds an emissions pathway that meets the specified target with the lowest total discounted cost. The discount rate used in the present calculations is 8%. Both the cost of emissions reductions and the constraints imposed by the carbon-cycle in order to achieve stabilization affect the shape of the resulting emissions curve. Because costs are discounted over time, emissions reduction costs are the most important factor for the early portion of the curve and the behavior of the carbon-cycle is more important at later times. Ultimately, however, it is the behavior of the carbon-cycle that largely determines the emissions budget allowed for a given stabilization level. This will be discussed at greater length in the section on sensitivity analysis.

The global optimization model uses MAGICC to translate carbon dioxide emissions into concentrations. MAGICC is a widely used "simple climate model" (Harvey et al. 1997) that includes the effects of all the major greenhouse gases (CO_2, CH_4, N_2O, halocarbons, ozone) and the effects of aerosol compounds (sulfur dioxide and black carbon). The carbon-cycle used in MAGICC is represented on a global scale as a terrestrial and an ocean component. The ocean component of the carbon cycle is an expanded version of the Maier-Reimer and Hasselmann (1987) model. The terrestrial carbon-cycle represents carbon flows between living biomass, liter, and soil carbon stock taking into account anthropogenic deforestation (Wigley 1991).

Figure A2 presents the allowable carbon budget for fossil emissions (fossil fuels plus cement production) for a 550 ppmv concentration target by 2150. The carbon budgets for the years 2050 and 2100 amount to 460 and 870 GtC, respectively.

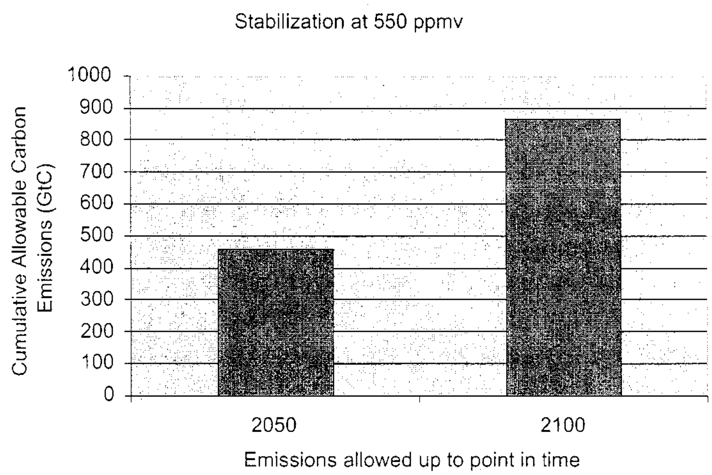

Figure A2. Carbon budgets for stabilization of carbon dioxide concentrations at 550 ppmv cumulative to the years 2050 (460 GtC) and 2100 (870 GtC). Budget figures are relative to the year 2000. Figures are shown for the central reference case of the carbon cycle model.

Appendix B: Retirement Models for Electricity Generations

Three fossil fuels —coal, natural gas, and oil— are used in four different electricity production technologies —steam turbine, combustion turbine, internal combustion, and combined-cycle— to produce most of the electricity consumed in the United States.[7] In order to understand the carbon shadow model at the core of this paper, it is necessary to outline the characteristics of these technologies and corresponding fuels that are relevant to the model.

B.1 Characteristics of electricity conversion systems

B.1.1 Steam Turbines

A steam turbine generator consists of three main parts. A boiler system burns one of the fossil fuels, using the generated heat to boil a large supply of water. This water is then moved, under great pressure, into the steam turbine itself, where it is allowed to expand. This expansion of gases pushes against rotor blades in the turbine, turning a drive shaft. This drive shaft is connected to the third part, the generator, where a large magnet spins inside a coil of wires, producing an electric current. This current is the output of the electrical plant. In the U.S. these units use primarily coal as a fuel, though there are a number of such generators that burn either oil or natural gas. The efficiency of steam generation is largely determined by the size of the unit, so these plants tend to be very large (many of the coal burning units built in the 70s and 80s are over 1000 MW capacity).

Two characteristics of these units are important for modeling purposes. First, the large amount of water that needs to be heated in the generation process means that these units take a large amount of energy and a long time to get going from a cold start. For this reason, steam turbines tend to be used as what are known as baseload units, meaning that they provide the constant minimum level of electricity that is demanded on the grid. Although very expensive in terms of capital to build, these units can be run on cheap fuel (such as coal) and are run almost continuously. Second, the parts of steam turbine units are very durable, and with proper maintenance can last several decades beyond their rated lifespan. This means that retirement decisions will likely be dominated by considerations other than serviceability.

B.1.2 Combustion Turbines

A combustion turbine has only two primary components. First, inside the turbine itself, natural gas and/or petroleum products are burned to create very high temperatures and pressures. The high pressure of the gases created pushes the turbine blades inside the turbine, turning a drive shaft that drives the generator.

[7] Other fuels include biomass and wastes, while other technologies include renewables such as wind turbines, hydro turbines, and geothermal steam turbines. As these fuels and technologies are either carbon neutral or at least very low carbon emitters, they are ignored in this study.

These units are the opposite of steam turbines for modeling purposes. First, unlike steam generators, these units have very low startup times and costs. Thus, instead of being run continuously, these units are brought online during periods of high demand to provided electricity for the higher cost "peak" periods. This allows them to use higher cost fuel than steam turbines (piped-in natural gas and petroleum), as owners are able to sell the generated electricity at a much higher price. Their role as "peaking" units means that these units are usually operational less than 10% of the time. Secondly, the significantly higher temperatures and pressures inside the turbine, relative to a steam turbine, means that the moving parts are exposed to much harsher conditions. Thus, these units tend to have a shorter lifespan.

B.1.3 Internal Combustion Generators

Internal combustion (IC) generators burn either natural gas or petroleum products inside a large engine (not unlike a truck engine), where the explosion of the fuel pushes pistons that turn a drive shaft. This drive shaft in turn rotates a generator that produces an electrical current in the same way as the above units.

For the purposes of modeling, IC generators are fairly analogous to combustion turbines. On the one hand, they have very low capital costs and startup costs, and thus make excellent peaking units. On the other hand, the internal explosions that drive the IC engine also put it under considerable strain, meaning that these units have a short, relatively constrained useful lifetime.

B.1.4 The Combined Cycle

Combined cycle plants are a fairly recently introduced hybrid of steam and combustion turbine units that produce electricity in two stages. In the first stage, a group of combustion turbines each turn a generator unit, creating electricity in the same process as normal combustion turbines. The exhaust heat from these units is then applied to a boiler unit, heating up water, which is then used to run a large steam turbine. This turbine turns a different generator, producing more electricity. By capturing and using the "waste" heat from the combustion turbines, these units are able to achieve much higher efficiencies than steam turbine or combustion turbines alone.

By combining the features of combustion and steam turbines, these units are not only difficult to model, but also difficult to keep accurate data on.[8] First, the inclusion of a steam turbine and boiler units does make the whole process difficult to start up, and thus these units are expected to play a role as baseload units. Secondly, however, it is difficult to say how the retirement aspects of these units will play out. On the one hand, the steam components will last near indefinitely, while on the other hand the combustion turbine components will experience shorter lifespan. This may result in combustion components

[8] The EIA has yet to introduce a standardized system of recording information about combined-cycle units, resulting in data that is very hard to make use of. Since data is recorded by individual generator and combined cycle "units" typically consists of 3-14 generators, how they get recorded, and how power production is divided among them is not clear at all. Thus, some combined-cycle units are listed as normal combustion turbines, while others appear as "combustion turbine components of combined cycle units," while still others are labeled "combined cycle" units.

being replaced regularly throughout the life of the steam turbine and thus giving these units a projected lifespan more akin to steam turbines. On the contrary, retirement decisions may be dominated by the combustion turbine components, meaning that combined-cycle units would have shorter service lives. Although the higher costs of steam units relative to combustion units seems to speak towards the first of these hypotheses, no data yet exists on the retirement decisions of combined-cycle owners as no combined-cycle plants have been retired.

B.2 Coal Generators

Projecting the currently existing coal power generators forward 50 and 100 years to obtain estimates of committed carbon emissions required a three step process. First, we developed a retirement model based on historic data to be able to project the amount of coal generation capacity remaining in use in each future year (see Figures B1 and B2). Second, a capacity factor model that ties usage to generator age was developed to adjust for the fact that older generators are generally used less intensively than newer units. Finally, generator usage had to be translated into a level of emissions for each future year. This necessitated, first, an efficiency (heat rate) model that could determine the amount of coal necessary to produce the electricity generated, and secondly, a carbon coefficient that could convert coal burned into carbon emitted. The following sections outline each of these model components and the results, in the form of emissions predicted by the model.

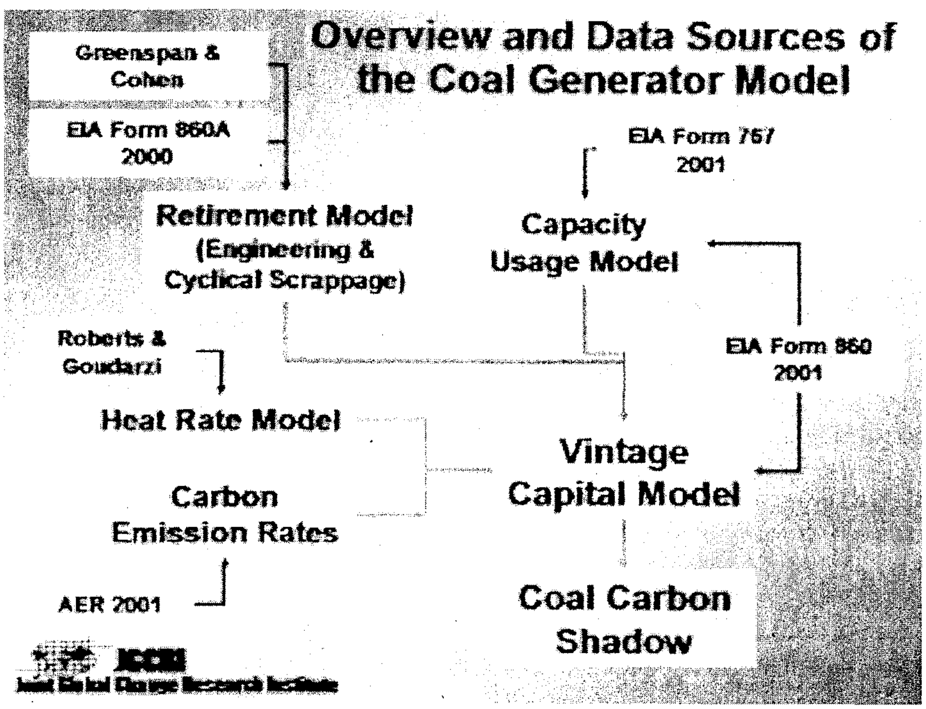

Figure B1 Overview and data sources of the coal generator model

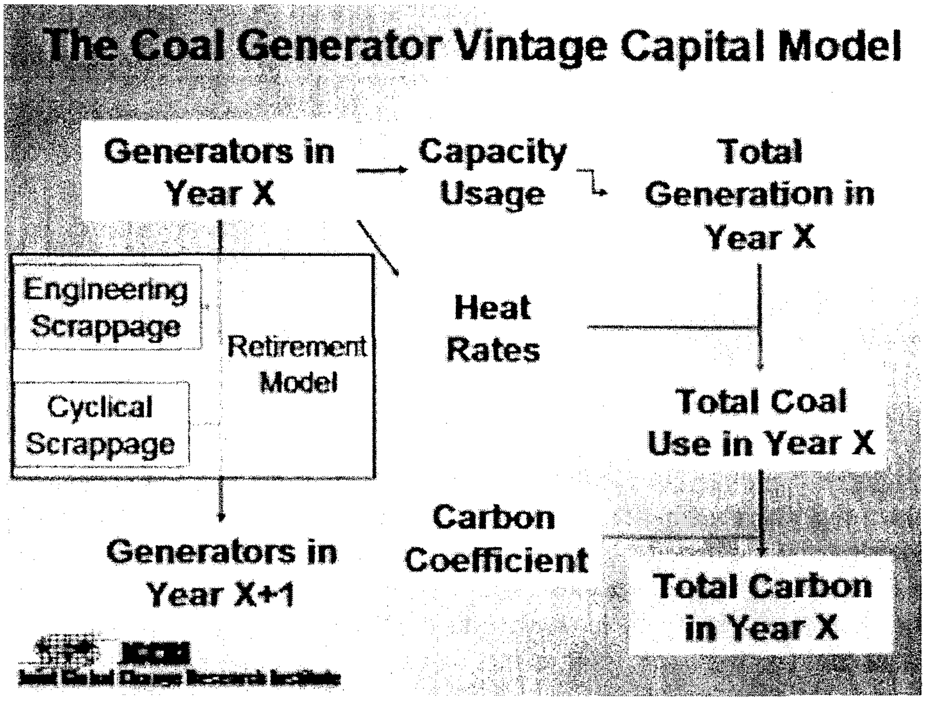

Figure B2. Overview of the coal generator vintage capital model

B.2.1 The Coal Generator Retirement Model

B.2.1.1 The data

The dataset used for determining the retirement model for coal power generators is the Energy Information Administration (EIA) Form 860a for the year 2000.[9,10] This database contains information on every utility-owned electric generator operated in the United States since 1970, including the rated summer capacity (the maximum producible electricity under average summer ambient conditions, in MW), year of initial operation, operation status, and year of retirement that was used in constructing the retirement model. Unfortunately, there is not a corresponding EIA database that contains information on non-utility generator retirements over the past 30 years. As such, we are forced to work under the assumption that all power generators face similar retirement patterns regardless of whether they are utility-owned.[11]

[9] Generators are the basic unit of this model, rather than plants, due to the fact that generators have a single build year associated with them allowing for calculations of the age of the generator. Plants, insomuch as they often contain multiple generating units cannot readily have a single age applied to them.
[10] http://www.eia.doe.gov/cneaf/electricity/page/eia860.html.
[11] This assumption is not likely to be all that influential in terms of the model's findings given that most of the large coal power units are owned and operated by utility companies. Furthermore, it should be mentioned that although the derivation of the retirement model relies on the utility database, the application of the model to the data uses a dataset that contains non-utility generators as well.

From this dataset, we extracted those power generators whose primary fuel is coal, waste coal, or synthetic coal derivatives and that have a rated summer capacity of 10 Megawatts (MW) or greater.[12] Using the "first-service" (the year the generator came on line) and retirement years, the total number of coal generators existing in the years 1970-2000 was extrapolated and divided up by age of the generators. This allowed us to compute a figure for the total fraction of generators of a given age that survive another year. Looking at every year from 1970-2000, the total the number of generators of age X was determined and how many of these survived to age X+1 was computed. This technique yielded an aggregated survival rate for each generator age (1 through 60). This was transformed into the data needed for regression by assuming an initial 100% stock level at age zero and then applying the derived survival rate for each year of age through 60 to find the fraction of the stock remaining at each age.

B.2.1.2 The Regression Model

The regression model itself is based on a model for the retirement of automobiles developed by Greenspan and Cohen.[13] They assumed two different types of scrappage, termed "engineering scrappage" and "cyclical scrappage," which refer, respectively, to age-motivated scrapping decisions and economically-motivated capital scrappage.[14] They assumed that a certain fraction of the capital stock, the engineering scrappage rate, is retired in any given year due to age considerations alone. The model we use for coal generators reproduces in part their methodology for the derivation of this engineering scrappage rate. It is important to note that this assumes homogeneity within the capital stock, meaning in our case that power generators are treated the same regardless of their geographic location, ownership, or profitability. This limits the model from being an accurate gauge of *which* generators will be scrapped in any given year. However, insomuch as the model builds up from aggregated data, it should still be a reliable guide to *average aggregate* retirements, which is all that is required to measure the aggregate committed carbon emissions of the stock of generators as a whole.

In the Greenspan/Cohen model, a shorter capital lifespan and a much larger data set (almost 200 million vehicles as compared to roughly 1600 coal generators) allow for separate curves to be derived for each model year of vehicles. In our model, coal generator lifetime characteristics are assumed to be homogenous across vintage classes, meaning that power generators built in 1950 will have the same age-related retirement rates as those built in 1970. Little research exists that explicitly supports this assumption, but there is also little evidence that it is wrong either.[15]

[12] Generators smaller than 10 MW represent roughly 16.6% of coal steam generators, but are an almost insignificant .4% of total capacity.
[13] http://www.federalreserve.gov/Pubs/FEDS/1996/199640/199640pap.pdf
[14] "Scrappage" is used here interchangeably with "retirement." Both are taken to refer to discontinuing the use of a particular unit of fixed capital.
[15] Since the generators built prior to 1950 are the only ones that can give us information on the retirement of units older than 50 years of age, leaving them out would force us to extrapolate the late-lifetime characteristics of generators from a much shorter pool of data. If, however, generator lives have been extended due to technological improvements in their design during the 60s and 70s, then this model will

The retirement model uses aggregate capacity, instead of individual generators, as the unit of analysis. This stems from the fact that the number of generators is fairly inconsequential from an aggregate point of view. For instance, knowing that 5% of generators are retired in a given year means less than knowing 5% of capacity is retired when the focus is on the need to provide a certain total capacity of electricity. Thus, the retirement model focuses on fractions of capacity rather than number of generators. Accordingly, survival of capacity follows an S-shaped curve through time such that little capacity is retired in the first several years after a vintage is built, more rapid retirement occurs in the middle range of generator lifetimes, and the fraction of capacity remaining levels off at a low level in the later years of the lifetime. Also, we assume that no capacity is retired in the first 10 years of operation.[16] In this coal generator retirement model, the curve is functionally approximated by the following regression:

$$\ln(Y) = \text{constant} + \beta * t^3 \qquad (1)$$

where Y is the fraction of originally built generator capacity remaining after 10 + t years.[17] Using the extracted data described above, the regression results of (1) were:

$$Y = \exp(.00863 - .00000273 * t^3) \qquad (2)$$

$$\text{(t-statistic)} \quad (3.34) \quad (-45.8) \qquad \text{Adj. } R^2 = .9785$$

Figure B3 shows how this model compares to the original data. As the graph shows, the log-cubic model fits the data extremely well for the first 60 years of generator lifetime. It should be noted that beyond sixty years of generator life, the data is very thin (there weren't many generators greater than 10 MW built before 1935 and even fewer survived to be reported in this dataset). This means that there is very little information on the structure of the tail of the lifetime curve—a thinner tail (like a logistic estimation) would mean that more generators retire sooner, while a thicker curve (the log-squared result mentioned in note 8) would mean generators were around even longer. The log-cubic functional form was chosen both because of its superior fit to the data we have and because it is between the other two forms in terms of tail thickness.

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understate the amount of generation coming from existing coal generators in the distant future. As such, these findings would constitute a lower bound for such predictions.

[16] In reality .1% of generators are shut down within 10 years of operation, but ignoring this allows for a model that fits the data better by exhibiting a longer flat section with very minor scrappage.

[17] The Greenspan/Cohen model has both a t^2 and t^3 term; in our results the t^3 term dominated the t^2 results, however, leading to the eventual dropping of the t^2 term from the model.

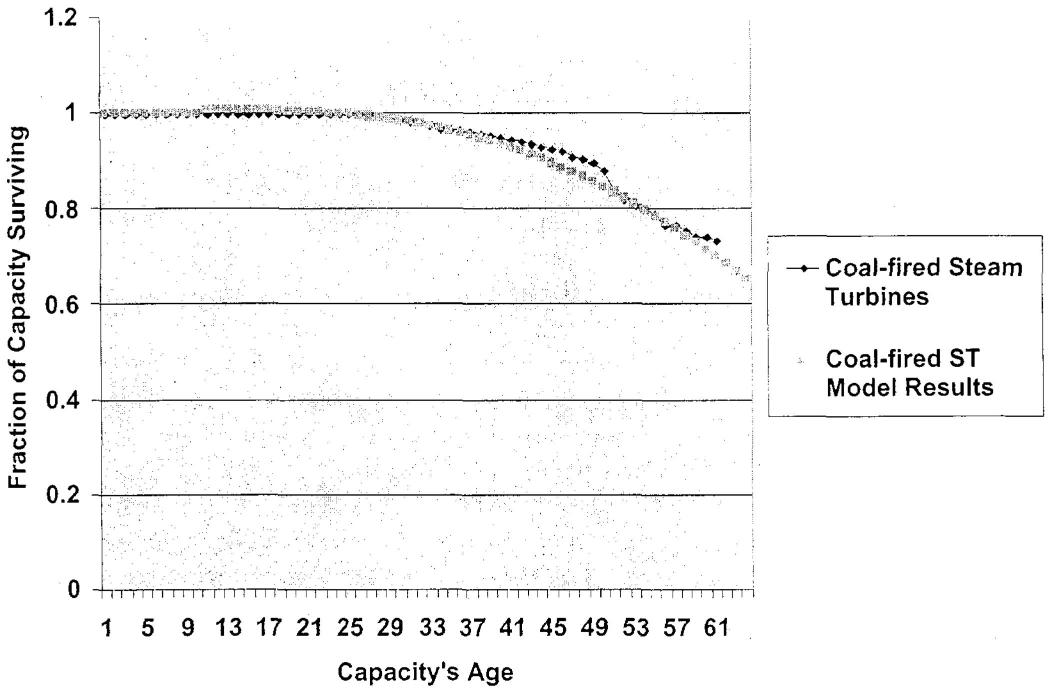

Figure B3 Coal-fired steam turbine electricity generating capacity surviving by age

Cyclical scrappage was then computed for each year 1970-2000 by subtracting the estimated engineering scrappage for each year (determined by the model described above) from the actual observed retirements in that year. This difference was then divided by the total capacity to yield the cyclical scrappage fraction. This change in actual scrappage above or below scrappage due to generator age was assumed to be dependent on the price of coal.[18] An initial model using just the logged price of coal, however, failed to explain a handful of years where retirement of coal generators was significantly above the retirements predicted by the engineering scrapping model and coal prices alone. It was discovered that these years (1981, 1985, and 1987) corresponded with years in which larger than average numbers of nuclear generators came on line.[19] Adding this information to the model yielded the following model of cyclical retirement as a fraction of total active capacity at a point in time:[20]

[18] Different regressions also compared cyclical scrappage to the price of natural gas, petroleum, and the ratio of coal prices to each of these fuels. None of them proved significant, however. An attempt to include the historic price of electricity as an indicator of excess demand/supply also failed to yield significant results.
[19] Data on the number of nuclear reactors online used to compute the change in the number of reactors each year was obtained from: http://www.eia.doe.gov/emeu/aer/txt/ptb0901.html
[20] The price of coal is drawn from http://www.eia.doe.gov/emeu/aer/txt/ptb0708.html, and is in 1996 chain-weighted dollars per short ton.

$$\text{CycFrac} = -0.009863 + .0027388 * \ln(\text{coalprice}) + .0001709 * \text{deltanukes} \quad (3)$$
$$(-4.67) \qquad (4.24) \qquad (3.00) \qquad \text{Adj } R^2 = .642$$

B.2.1.3 Capacity Factor[21] Model

Information on generator usage was drawn from EIA Form 767[22], the steam generator report, from 2001. Using plant and generator ID codes, these data were matched up with generator summer capacities and first-service years from the EIA Form 860 from the same year. The resulting dataset was 1116 coal generators that were online in 2001. Capacity factor figures were calculated by dividing annual generation by summer capacity times 8760 hours (number of hours in a year). Figure B4 shows these fractions plotted against summer capacity for all 1116 units. Clearly, there is much wider variation of capacity factors among generators with summer capacity ratings less than 100MW than for those above 100MW. For this reason, generators rated at more than 100MW were treated separately from those less than 100MW in determining the relationship between capacity factor and age. Figure B5 plots capacity factors against age for generators over 100 MW summer capacity. There is clearly a linear trend downward through the data, which was estimated in an ordinary least square (OLS) regression as:

$$\text{CapFact} = 0.8343 - 0.004426 * \text{Age} \quad (4)$$
$$(\text{t-statistic}) \quad (54.79) \qquad (-9.90) \qquad \text{Adj } R^2 = .1100$$

where CapFact is the fraction of total possible output (summer capacity times 8760 hours) that is actually produced annually. The generators smaller than 100MW also exhibit a downward trend, though it is steeper than the larger units (Figure B6). The OLS result for the smaller units was:

$$\text{CapFact} = 0.8107 - 0.00755 * \text{Age} \quad (5)$$
$$(\text{t-statistic}) \quad (16.22) \qquad (-6.60) \qquad \text{Adj } R^2 = .1144$$

[21] "Capacity factor" is a measurement of usage intensity, and is equal to the actual annual generation (in kWh) divided by the total possible annual generation (8760 times the capacity of the generator; kW capacity times the maximum 8760 hours operations → kWh).
[22] http://www.eia.doe.gov/cneaf/electricity/forms/eia767/eia767.pdf

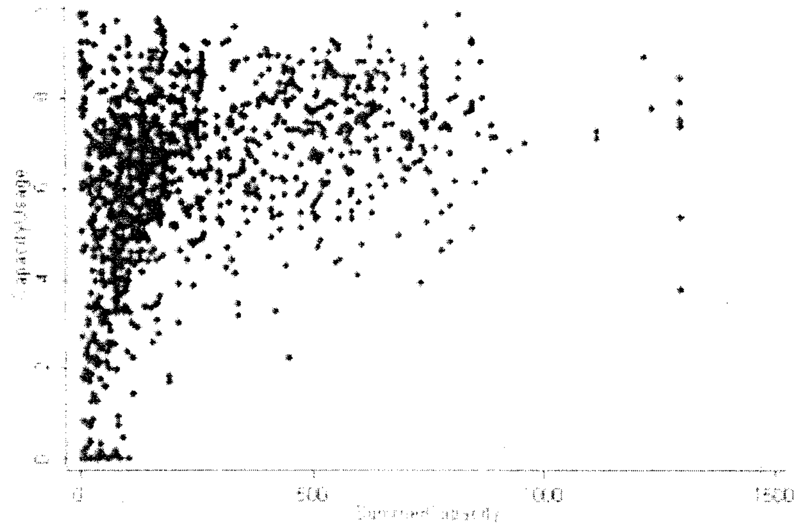

Figure B4. Capacity factors plotted against summer capacity for all 1116 coal-fired electric units operating in 2001

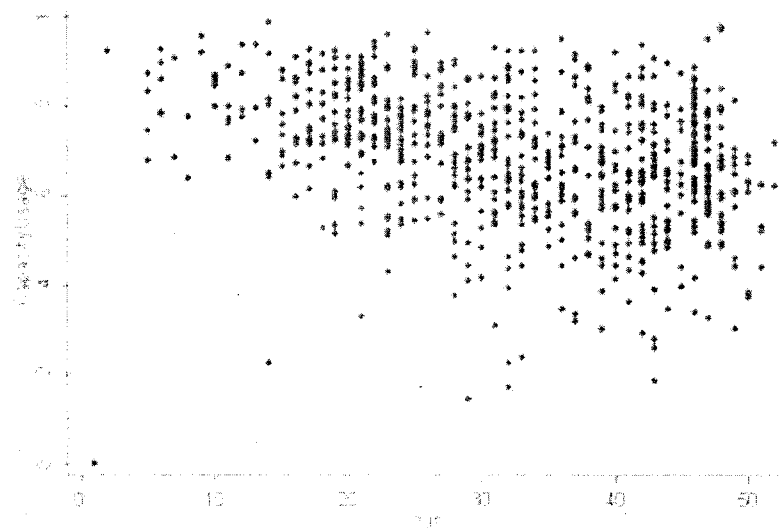

Figure B5. Capacity factors of coal-fired electric generators over 100 MW summer capacity operating in 2001 plotted against the generators' ages

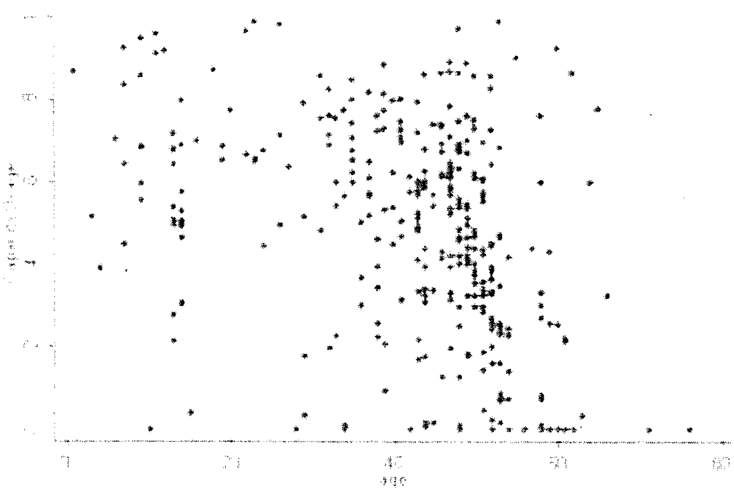

Figure B6 Capacity factors of generators smaller than 100 MW also exhibit a downward trend, though it is sharper than the larger units.

B.2.1.4 The Vintage Capital Model

EIA Form 860 from 2001 was used to find the total number of coal generators of each age that existed in 2001 and their associated rated summer capacity. The newest generators were built in 2000, while the oldest date from 1921. A separate age category is used for ages 0-80, with all generators older than 81 lumped together in an 82nd category. Every generator in a given age category is assumed to have the same summer capacity as that age group's average summer capacity. This average capacity rating moves with the age group as the model advances through the years 2001-2100. A weighted average of the 80 and 81+ capacities in year X provide the average capacity of the 81+ category in year X+1.

Each year, the model computes engineering scrappage by applying model (2) to each age cohort and totaling the capacity that is projected not to survive. Cyclical scrappage is then computed according to (3) multiplied by the total capacity at the beginning of the year These two figures are totaled to yield the total capacity retired during that year:

$$\text{Total Scrappage} = \Sigma_{(\text{age}=0\text{-}81+)} (\text{Capacity(age)} * (1 - \text{SurvFrac(age)})) + \text{CycFrac} * \text{Total Capacity} \quad (6)$$

where

$$\text{SurvFrac} = \text{Y(age+1)} / \text{Y(age)} \quad (7)$$

where Y is the calculated survival rate from (2). Retirements are then assigned, with the least efficient generators (as determined by the heat rate equation, (8), discussed below) being retired in turn until the total projected capacity retirement is met.[23]

[23] This approach is informed by the desire to produce a lower bound estimate for carbon emissions. Although geographic and economic considerations may not always lead to the least efficient generators

Next, the capacity factor models described above ((4) and (5)) are used to calculate capacity factors for each age group of generators in the model. Multiplying the capacities for each group by 8760 times the estimated capacity factor, total output in GWh by vintage cohort is estimated. These are then totaled to yield a total GWh output for each year.

B.2.1.5 Generator Heat Rates and CO_2 Emissions

The conversion of GWh electrical output to CO_2 emitted is a two-step process in this model. First, GWh must be converted to Btu of coal burned by means of heat rates in units of Btu/kWh. The number used for this conversion is dependent on the efficiency of the generator in question, expressed as heat rates, which ranges from 9500 Btu/kWh to 12500 Btu/kWh or more. Roberts and Goudarzi developed a model of coal generator efficiency based on the age, size, fuel, and abatement technology of the generator.[24] We draw on this model in determining the heat rate of the generators in our coal carbon shadow model. The heat rate of each vintage year of generators is determined, based on the age of the cohort and the average summer capacity of the generators as follows:

$$\text{Heat rate} = 13763.2 * (\text{age}^{.07325025}) * (\text{capacity}^{-.0932101}) \qquad (8)$$

This equation is used for the "average" case. It is increased by 9.548% in the "high" emissions case and decreased by 4.459% in the "low" emissions case. These adjustments are drawn from the original model, and represent lignite fuel with scrubbers in the "high" case and bituminous fuel with no scrubbing in the "low" case. The average case represents subituminous (or a mix of the three) fuel with no scrubbers.

The second conversion brings the model from Btu of coal burned to tons of CO_2 emitted. Carbon emissions from coal vary from 56 lbs/MBtu for Bituminous coal to 58.7 lbs/MBtu for Lignite coal (anthracite has a higher carbon value, but is not typically used for electricity production).[25] An average value (taken from the AER 2001) of 57.2 lbs/MBtu is used in the model for the average case, with the other values used in the low and high cases respectively.[26]

These two conversion factors are applied to the total generation values for each year to obtain an estimate of the total CO_2 emissions from coal generators for that year. In turn, a cumulative total of these emissions measures how much the generators existing in 2001 have emitted over the course of the model.

being retired first, doing so in the model keeps us from over estimating emissions, and gives the benefit of the doubt to a "best-case scenario."

[24] The paper with this model is on http://www.econsci.com/euar9801.html.

[25] These conversion values are from http://www.eia.doe.gov/cneaf/coal/quarterly/co2_article/co2.html.

[26] AER, http://www.eia.doe.gov/emeu/aer/pdf/pages/sec13.pdf.

B.2.1.6 Cumulative Emissions of Coal-fired Electricity Generation and its Uncertainties due to the Quality of Coal used and Scrubbing Levels

Figure B7 shows the Low, Average, and High case paths of cumulative CO_2 emissions up to the year 2050 assuming no change in the number of large nuclear plants, and the coal price predictions published in the AEO (adjusted to 1996 dollars, with the 2025 prediction extended through to 2100).[27] Table B1 summarizes the results for 2050 and 2000. All three cases have begun leveling off by 2050, as the retirement of existing generators slows, given that most of the year-2001-generators have retired by that time. In the average case, the year 2001 coal generators have emitted 18.7 gigatons (Gt) of carbon by 2050. The high and low cases yield results of 20.9 Gt and 17.4 Gt of carbon respectively. By 2100, the emissions have leveled off at cumulative 20.6, 22.2, and 24.8 GtC for the low, average, and high cases respectively.

Emissions (Cumulative Giga ton Carbon) from Coal-Fired Electricity Generators Operating as of 2001 (GtC)			
Year	2001	2050	2100
Low carbon coefficient & high generation efficiency	0.47	17.4	20.6
Average case: average carbon coefficient and average generation efficiency	0.50	18.7	22.2
High carbon coefficient & low generation efficiency	0.56	20.9	24.8

Table B1 Cumulative emissions (GtC) from coal-fired electricity capacity operating as of 2001 through 2050 and 2100.

[27] Coal price predictions taken from the AEO: http://www.eia.doe.gov/oiaf/aeo/aeotab_3.htm

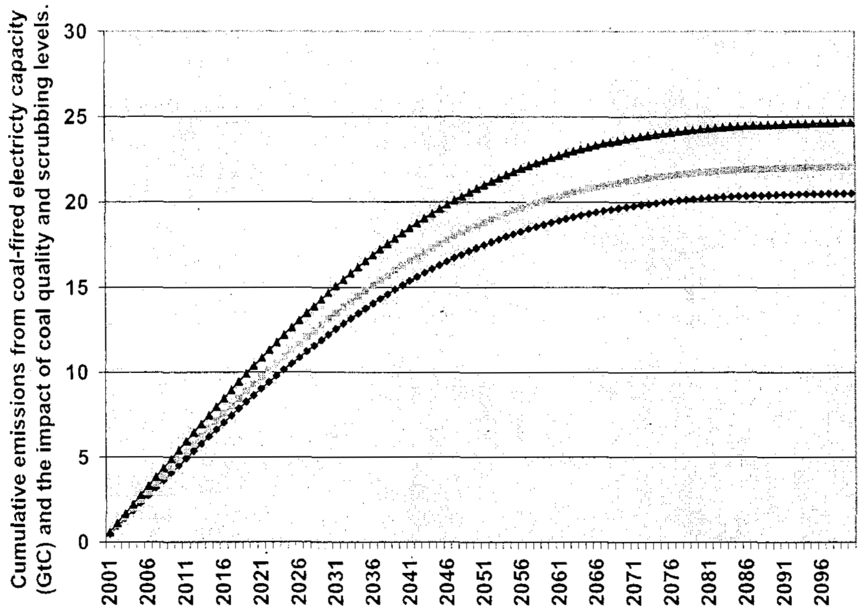

Figure B7. Cumulative emissions (GtC) from coal-fired electricity capacity operating as of 2001 through 2100 with high and low estimates due to the quality of coal used and scrubbing levels

B.3 Other than Coal-fired Electricity Generating Technologies

At 87% of carbon emissions from electricity production, coal comprises the lion's share of the U.S. electricity sector's emissions. Furthermore, as discussed above, coal generators are used for extremely long periods of time, causing coal to be the dominant contributor to that sector's carbon shadow. However, investigating the shadows of the other production technologies, despite their small share, would not only make our overview more complete, but also provide tools of analysis necessary for looking at futures that move away from the dominance of coal. Unfortunately, as these technologies are a much smaller share than coal in terms of generation and emissions, they receive less attention and thus the data on them is thinner. Although we use the same model framework developed for the coal steam turbines, the lack of data in some cases results in a number of limiting assumptions.

The following overview looks at, in turn,

- other steam turbines, with "other" referring to petroleum and natural gas steam generators, in contrast to coal steam generators discussed before,
- gas turbines,
- internal combustion generators, and
- combined-cycle generators.

Each section outlines the models used for each of these technologies, highlighting the differences between them and the coal model, and listing the regression equations for each fuel-technology combination. The data used for the retirement models are from the same sources as for coal, that is, from EIA Form 860 while the capacity factor and heat rate models draw from a different source in these models.[28] Within these models, the carbon coefficients for oil and gas are 47.4 and 31.9 lbs C/MBtu respectively, and are drawn from the 2001 AER. These sections are followed by a summary of the carbon shadow results of each of these models, and their comparison to the coal results above.

B.3.1 Other Steam Turbines[29]

B.3.1.1 Other Steam Turbine Retirement Components

Three types of steam turbines were looked at in this study:

- Oil only[30],
- Natural gas, and
- Dual oil-gas.

To account for the possibility of different usage characteristics based on type of fuel, these three were treated separately from one another, with a separate model developed for each. Engineering scrappage was computed for each in the same manner as for the coal steam turbines, identifying the percentage of generators reaching age X to pass on to age X+1 over the 30 years (1970-2000) of data contained in the EIA Form 860 data set. As with the coal, the functional form most closely approximating the retirement data was a log-cubic. The regression results for each fuel type are listed below.

Oil only:

$$Y = \exp(-.0038902 - .00000710 * t^3)$$

(t-statistic) (-.69) (-48.22) Adj. $R^2 = .981$

Gas only:

$$Y = \exp(.0124994 - .00000319 * t^3)$$

(t-statistic) (3.29) (-28.14) Adj. $R^2 = .948$

Dual Gas-Oil:

$$Y = \exp(-.0040379 - .00000574 * t^3)$$

(t-statistic) (.94) (-57.98) Adj. $R^2 = .986$

where Y is the fraction of originally built generator capacity remaining after 10 + t years.

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[28] The total generation (used to calculate the capacity factor) and fuel usage (used to calculate the heat rate) are draw from EIA Form 759 from 2000. These data were matched up by generator ID to the capacity and age figures from EIA Form 860 from 2000, much in the same way that Form 767 and Form 860 were used for the coal model.

[29] "Other" here refers to petroleum and natural gas steam generators. Biomass and waste generators are ignored in this study as arguments can be made that they are carbon neutral or at least have lower *net* carbon emissions. Focus remains on the fossil fuel generators in the U.S.

[30] Oil-based generators are those that use residual fuel oil, distillate fuel oil, kerosene, waste oil, or jet fuel.

We have not been able to develop a cyclical model that fits with the data. Therefore, for the purposes of these models, cyclical scrappage is ignored for non-coal steam units, and engineering scrappage is assumed to dominate retirement decisions.

B.3.1.2 Other Steam Turbine Capacity Factors

The capacity factor for non-coal steam turbines was estimated using the age and size of the plants. As the regression results below show, capacity usage of non-coal steam generators is dominated by the size of the unit. Unlike coal, where age was the predominant variable, the capacity factor is linked most closely to summer capacity, with larger units seeing more usage than their smaller counterparts.[31] As with coal units, older generators are assumed to be used less intensively than younger ones, but the difference between older and younger ones' use is much smaller.

Oil Only:

CF =	.7196922	-.0004186*summcap	- .0085659*age
	(4.51)	(-2.36)	(-2.47)
			Adj. $R^2 = .0793$

Gas Only:

CF =	.1391057	+.0007092*summcap	- .0000206*age
	(1.87)	(5.37)	(-0.01)
			Adj. $R^2 = .1866$

Dual Gas-Oil:

CF =	.3117907	+.0002554*summcap	- .0030909*age
	(6.38)	(4.57)	(-2.87)
			Adj. $R^2 = .1312$

B.3.1.3 Other Steam Turbine Heat Rates

Non-coal steam turbine heat rates were initially regressed against age and summer capacity. However, unlike coal turbines, age was not a statistically significant factor in determining heat rates. On the one hand, this is most likely related to similar findings for the capacity factors (if, for instance, heat rate is not dependent on age for these units, usage decisions could be explained as also not dependent on age). On the other hand, at this point, we have no explanation for this result, as we would expect these generators to physically behave like coal generators in terms of lifetime efficiency. The heat rate regression results are:

Oil Only:

$$\text{Heat rate} = 14358 * \text{age}^{(.0309015)} * \text{capacity}^{(-.0694145)}$$

(t-statistic)	(20.81)	(0.29)	(-2.51)	Adj. $R^2 = .111$

[31] The oil-only generators, however, exhibit considerably different statistical results. Capacity is negatively related to CF for them, and the regression on a whole has a much lower R-squared. This is possibly due to a low sample size (66) relative to the others.

Gas Only:

$$\text{Heat rate} = 14827 * \text{capacity}^{(-.0510657)}$$

(t-statistic) (164.53) (-3.75) Adj. $R^2 = .107$

Dual Oil-Gas:

$$\text{Heat rate} = 15360 * \text{age}^{(.0437232)} * \text{capacity}^{(-.0896352)}$$

(t-statistic) (47.78) (0.91) (-8.74) Adj. $R^2 = .233$

B.3.1.4 The Vintage Capital Models of Other Steam Turbines

The vintage capital model equations are combined in a similar fashion as for coal plants to yield annual carbon emissions for non-coal steam generators. An additional calculation, however, is required for determining how much oil and gas are used at dual-fueled plants. The lack of historical information on this share limits us to a static model (rather than one built on relative oil and gas prices) that uses the fuel ratio in dual-fired generators from 2000: 18.1% oil and 71.9% gas.[32] This fuel ratio is then used to determine the amount oil and gas respectively, which are then transformed into an amount of carbon emissions, using the appropriate carbon coefficient.

Figure B8 shows how the model results compare to the original data for "other" steam turbines.

[32] This ratio is express in terms of percent of total BTUs burned, and is drawn from the EIA Form 759 2000 database.

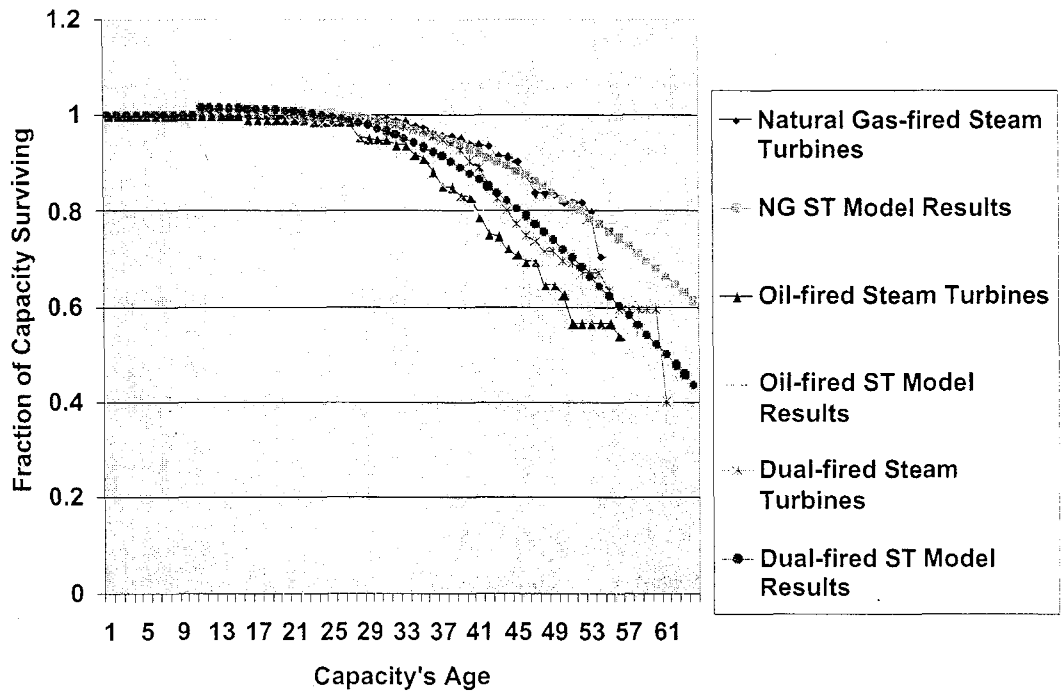

Figure B8. Other steam turbine capacity survival

B.3.2 Combustion Turbines

Gas turbines differ significantly from steam turbines (STs) in terms of both physical structure and use. In steam turbines, the movable turbine blades are exposed to high pressures and temperatures just over 100 degrees Celsius. In combustion turbines (CTs), however, as the burning occurs in the turbine, the same moving parts must be able to withstand significantly higher pressures and temperatures. As such, they have a shorter lifespan than steam turbines. Also, the facts that they are cheaper per kW to build and can be cold started much more quickly than steam turbines (as there is no water that must be heated up) lead combustion turbines to serve as peaking units rather than baseload. This means that while steam generators run most of the time to provide the constant, or baseload, supply of electricity used 24-7 by the power grid, combustion turbines tend to be brought online only during the few hours of highest, or peak, demand, during the day. Thus, while steam turbines might see usage 50-70% of the time, capacity factors for combustion turbines are routinely in the single digits.

Another feature of combustion turbines should be mentioned, as it significantly limits the results of this sub-model. Most baseload units are owned by utility companies, and thus are included in the EIA 860 2000 dataset used for determining the retirement figures and the EIA 759 2000 database used for determining heat rates and capacity factors. However, peaking units, such as combustion turbines, are often owned by non-utilities, and neither of these datasets contains information on non-utility generators.[33] Thus, all of the figures calculated for the combustion turbine models are rough approximations based on the behavior of the utility-owned share of generators.

B.3.2.1 Combustion Turbine Retirement Models

The log-cubic model used for engineering scrappage for steam turbines did not fit the combustion turbine data well, as it did not drop off quite as steeply as the data suggests is the norm for combustion turbines. Thus, for these units, a logistic model was fit to the data, yielding a survival curve that moves through the period of rapid retirement much more quickly than the log-cubic model. Again, combustion turbines are treated separately depending on fuel type. The regression results for the engineering scrappage models are listed below:

Oil only:

	Y =	1/(exp(-4.903729 + .1330449*t) + 1)	
(t-statistic)		(-18.26) (8.22)	Adj. R^2 = .712

Gas only:

	Y =	1/(exp(-6.17968 + .1098589*t) + 1)	
(t-statistic)		(-49.5) (26.3)	Adj. R^2 = .933

Dual Gas-Oil:

	Y =	1/(exp(-5.800948+ .1239683*t) + 1)	
(t-statistic)		(-73.71) (42.51)	Adj. R^2 = .976

where Y is the fraction of originally built generator capacity remaining after 10 + t years.

As with steam turbines, all attempts to link a cyclical retirement figure to the data proved fruitless. With natural gas turbines, for example, utility-owned generators have only been retired in six separate years, meaning that retirement was zero for the other 24 years. This limits the ability of the cyclical model to produce meaningful results. Thus, for the purposes of this model, the engineering scrappage figure for combustion turbines represents all of the projected scrappage. That is, for combustion turbines, no cyclical figure is included. The inclusion on non-utility power plant retirements might allow such a regression to be successfully reported, but the unavailability of such a dataset limits us to the engineering figure.

B.3.2.2 Combustion Turbine Capacity Factors

As mentioned above, the capacity factor for combustion turbines tends to be rather low. Investigation of the data found that, additionally, there is very little systematic variation

[33] When the vintage capital model is run, it uses the EIA 860 2001 dataset, which has both utility and non-utility generators in it, so all existing generators are included in the model. However, the 2000 dataset is the only one with comprehensive retirement figures, although it only contains information on utility-owned generators.

in the capacity factor along the lines of age or capacity. That is, the intensity of use of these generators does not appear to be based on either age or generator size. This may make sense given that, as peaking units, their usage will be determined more by demand than by supply-side characteristics such as age. To get around this fact, the mean capacity factor for each fuel type was used (the standard deviation of each mean appears in parentheses):

Oil Only:	.0165215	(.0680926)
Gas Only:	.0911429	(.2212842)
Dual Gas-Oil:	.0339475	(.0672977)

B.3.2.3 Combustion Turbine Heat Rates

The heat rates for the combustion turbines were determined using an age and summer capacity based regression model, yielding results similar to the coal steam turbines:

Oil Only:

$$\text{Heat rate} = 29476 * \text{age}^{(.1079179)} * \text{capacity}^{(-.009151)}$$

(t-statistic) (32.7) (1.93) (-3.83) Adj. $R^2 = .041$

Gas Only:

$$\text{Heat rate} = 15907 * \text{age}^{(.0927727)} * \text{capacity}^{(-.023813)}$$

(t-statistic) (22.1) (3.35) (-.63) Adj. $R^2 = .145$

Dual Gas-Oil:

$$\text{Heat rate} = 22606 * \text{age}^{(.0896531)} * \text{capacity}^{(-.0593075)}$$

(t-statistic) (43.16) (4.61) (-3.11) Adj. $R^2 = .097$

B.3.2.4 The Vintage Capital Models for Combustion Turbine

The vintage capital model equations are combined in a similar fashion as for coal plants to yield annual carbon emissions for non-coal steam generators. An additional calculation, however, is required for determining how much oil and gas are used at dual-fueled plants. The lack of historical information on this share limits us to a static model (rather than one built on relative oil and gas prices) that uses the fuel ratio in dual-fired generators from 2000: 22.2% oil and 67.8% gas.[34] This fuel ratio is then used to determine the amount of from oil and gas respectively, which are then transformed into carbon emissions using the appropriate carbon coefficient.

[34] This ratio is express in terms of percent of total BTUs burned, and is drawn from the EIA Form 759 2000 database.

B.3.3 Combined-Cycle Generators

Natural gas combined-cycle (NGCC) generators, insomuch as they are a hybrid between gas turbines and steam turbines propose a number of model methodological issues from the outset. Additionally, the limited data available on these units, combined with the recentness of their introduction (such that no units have had to be retired from service, as of yet) makes modeling their carbon shadows an uncertain task at best.

B.3.3.1 Combined Cycle Retirement Model

As with the models for the other power generators, the NGCC retirement model draws its historical data from the EIA Form 860A database for 2000 and its capital stock data from the same database from 2001. This dataset, however, provided a number of limitations. First, some units are listed with their gas turbine and steam turbine components separated into each individual generator unit, while other plants have these units aggregated into one combined-cycle generator. This makes pinning down the exact composition of the capital stock nearly impossible. Secondly, although combined-cycle technology has only been used in the last decade and a half, the historical database lists NGCC plants with startup years as far back as 1912. In fact, only 50% of the NGCC generating capacity listed have startup dates after 1990. Due to these discrepancies, we therefore decided not to use the age figures from the Form 860 dataset in our model.

Since no NGCC generators have been retired in the U.S., we were not able to derive a historically-based retirement model as we did with the other technologies. Furthermore, the dual-nature of NGCC units makes it hard to determine what the dominant retirement characteristic would be. On the one hand, the gas turbine components, which are used at approximately 10 times the intensity as normal GT generators, will wear out rather quickly (although not 10 times quicker than GTs, as the avoidance of destructive cold-start cycles reduces wear considerably). On the other hand, the much more expensive steam turbine components (steam turbines cost $1200-$1500 per kW, whereas combustion turbines costs as low as $400 per kW) last a very long time (there are still steam turbines in operation that were built more than 80 years ago).

In our model, we assume that the steam turbine component dominates the retirement decision (which is to say that the less expensive gas turbine components will be replaced throughout the service life of the steam turbine components), and we therefore use the same engineering scrappage model developed for natural gas steam turbines. Thus:

$$Y = \exp(.0124994 - .00000319 * t^3)$$

where Y is the fraction of originally built generator capacity remaining after 10 + t years. No cyclical scrappage component was derived for NGCC generators.

B.3.3.2 Combined Cycle Capacity Factor

The inconsistent aggregation among the data discussed above limited our ability to develop a model of capacity factors based on age and size as with other generator types. Instead, an average capacity factor was computed as follows. The capacity factor was derived using the "total capacity" figures from the Form 860, 2001 database with estimations of generation derived from the other models. From the NG gas turbine, NG steam turbine, dual-fired steam and dual-fired gas turbine models, we were able to produce an estimate of the amount of natural-gas-fueled electricity (in GWh) that was produced by these generators in 2001, that is, 329,000 GWh. We subtracted this from the EIA figure for total electricity produced from natural gas in 2001 — 629,100 GWh — to get 310,000 GWh as an estimate for the amount of generation from NGCC units in 2001.[35] Dividing this figure by 8760 hours and the NGCC capacity in 2001 (which comes from the Form 860 database for that year) of 66.6 GW, we obtain a capacity factor of 53.1%.

B.3.3.3 Combined Cycle Heat Rates

Again, the data limitations kept us from deriving an age and size dependent model of generator efficiency. Instead, heat rate information for NGCC plants was drawn from David and Herzog (2000)'s paper on generation technologies, and a heat rate of 6201 Btu/kWh is used for all generators.[36,37]

B.3.3.4 The Vintage Capital Model for Combined Cycle

Since we decided to ignore the first-service data, the age structure of the existing capital stock had to be derived instead from the Form 860 2001 dataset. To do this, we used the "total capacity" figures from the EIA Annual Energy Outlooks (AEOs) of 1995 through 2003 to see how much NGCC capacity had been built in each year.[38] The number built in 2001 (and thus starting at age zero in the model) is equal to the capacity existing in the Form 860 dataset from 2001 minus the year 2000 capacity reported in the 2003 AEO. All capacity built before 1993 was assumed to have been built in 1992.[39]

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[35] http://www.eia.doe.gov/emeu/aer/txt/ptb0802a.html

[36] David, J. and H. Herzog. 2000. The cost of carbon capture. Fifth International Conference on GHGCT. Cairns, Australia

[37] This means that the decrease in efficiency normally observed as generators age is not included in the model. This is partially offset (at least in terms of project emissions) by the fact that, by not having capacity factor determined by age, generator use does not decrease later in the lifecycle.

[38] Ideally, we would have used the Annual Energy Review (AER), which has historical data, to get these numbers. However, the AER does not have breakdowns by generation technology, whereas the AEO does. However, each year's AEO only has 1-2 years worth of historical data, thus it was necessary to use multiple years (1995-2003) to get accurate figures for number built each year.

[39] It should be noted that this means that age cohorts in this model consist only of a total capacity, and not individual generators. Thus, while in other models we were able to drop generators based on their efficiency, in this model we are limited to just reducing the total capacity of each age cohort based as determined by the retirement model.

After that, the model is analogous to the others, previously described. Each year, emissions are calculated by first multiplying total capacity by 8760 and by the capacity factor to determine the total GWh of electricity produced. Then, the heat rate is used to convert this to a total Btu of natural gas consumed in NGCC generators. Finally, the carbon coefficient of 37.1 lbs CO_2/Btu converts energy to total amount of carbon emitted.

At the end of each year, the retirement model is applied to each age cohort to determine the percentage of capacity progressing to the next age cohort in the following year. Since we were not able to get age information for individual generators, the selective removal system used in the previous models is not employed here. Instead, each age cohort simply loses the amount of capacity dictated by the retirement model. The process is repeated for each year, 2001-2100.

Figure B9 shows how the model results compare to the original data for combustion turbines

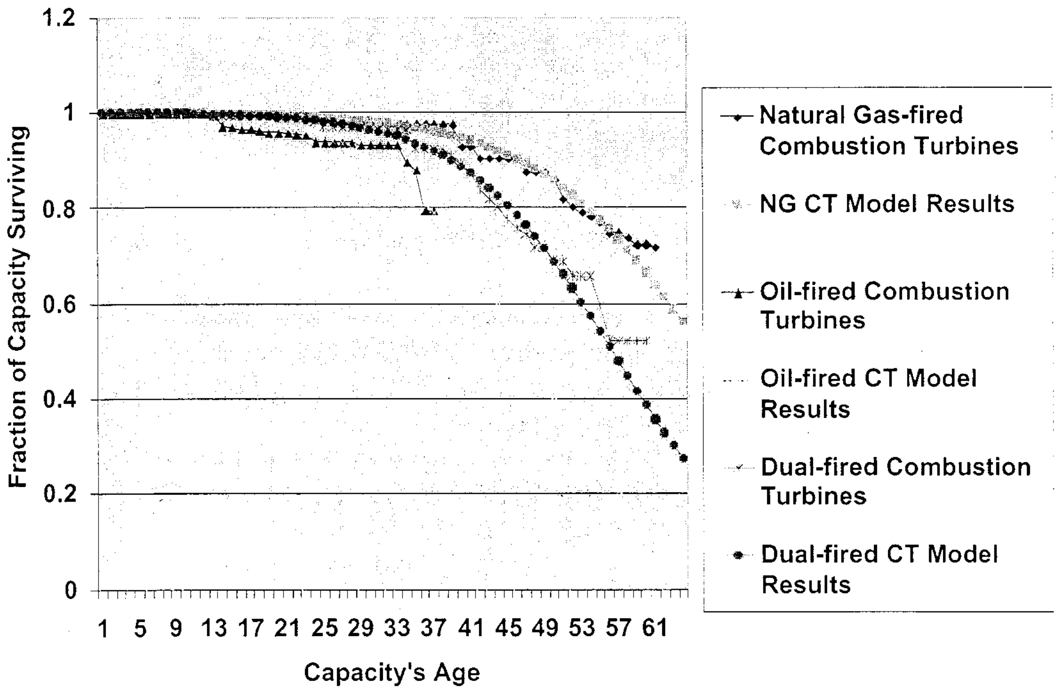

Figure B9. Combustion turbine capacity survival

Appendix C: Retirement Models for transportation

The model, like the generator models, works in three components. First, a retirement model calculates the total number of vehicles of each age group surviving into the next year. Second, a usage model determines how many vehicle miles are driven by each age group. The third component assigns the appropriate efficiency (measured in miles per gallon (mpg)) to each vehicle type and age group to obtain a total amount of fuel consumed. This is transformed into a total carbon emissions figure by means of a carbon coefficient. Each model component is discussed in turn below.

C.1 Transportation Sector Retirement Model

C.1.1 The Data

Polk Automotive Corporation produces the only existing dataset on retirements of cars and trucks in the United States. While we were not able to use this dataset directly, our retirement model was drawn from a report that did have access to it. An unpublished paper of Richard L. Schmoyer's is referenced in edition 23 of the Department of Energy's Transportation Energy Data Book as the source of three engineering scrappage models—for cars, light trucks, and heavy trucks.[40] Schmoyer used the Polk data set and the scrappage model developed by Greenspan and Cohen to produce nine engineering scrappage models: a separate one for model years 1970, 1980 and 1990 for each class of vehicle (cars, light trucks, heavy trucks).[41] These models assign a scrappage rate (percent of existing vehicles retired in a given year) for each vehicle age. That is, for each model year, it specifies the percent of vehicles that will be retired at age 1, the percent of those remaining that will be retired at age 2, and so on.

Data on the existing vehicle stock and its age structure is drawn from two smaller (and more affordable) Polk datasets. Data on cars and light trucks comes from Polk's 2001 National Vehicle Population Profile. The 2001 stock of trucks had to be estimated from Polk's 2003 Vehicles in Operation report (Polk apparently does not keep truck data that is more than a year old), using the Schmoyer retirement model to extrapolate back to the 2001 levels. Cars were treated as their own category in our modeling, as were light trucks (defined as trucks with gross vehicle weight (GVW) under 10,000 lbs). The other trucks were divided into three categories: medium (GVW 10,001-16,000), light-heavy (GVW 16,001-26,000) and heavy-heavy (GVW 26,001+). In 2001, the first period of the model, the vehicular capital stock was comprised of 128.7 million cars, 79 million light trucks 1.7 million medium trucks, 640 thousand light-heavy trucks, and 3.7 million heavy-heavy trucks.

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[40] The scrappage models can be found in the tables for chapter 3: http://www-cta.ornl.gov/data/chapter3.html

[41] http://www.federalreserve.gov/Pubs/FEDS/1996/199640/199640pap.pdf

C.1.2 Determining Retirements

Each of the five categories of vehicles is divided up into age cohorts, which are determined by model year. The Schmoyer model only has figures for scrappage of vehicles of model years 1970, 1980, and 1990, and thus we needed to derive figures for the other model years. For vehicles with model years between 1970 and 1990, scrappage rates are determined for each age level by assuming a linear change in scrappage rates between 1970 and 1980 and between 1980 and 1990. Vehicles with model years after 1990 are assumed to be retired at the same rate as those with model year 1990.

Also, scrappage numbers from the Schmoyer model are listed only for light and heavy trucks—medium and light-heavy trucks do not have their own figures. However, when estimating the 2001 numbers from the 2003 numbers for these two groups, it was observed that the estimates for the 2001 totals were considerably off if we used the heavy truck scrappage figures for medium trucks (in which case the 2001 estimates were much too low) or if we used the light truck scrappage rates for light-heavy trucks (in which case the 2001 estimates for the youngest 15 cohorts alone was larger than what the entire 2001 should have been). Thus, we decided to use the light-truck rates for medium trucks and the heavy truck rates for light-heavies.[42]

Each year, total retirements are determined by calculating the scrappage rate (percent of vehicles to be retired) for each model year and finding the rate associated with the appropriate age (i.e. the age that cars of that model year will be in the year under calculation in the model). These scrappage rates are applied to their appropriate age/vehicle cohorts, and the model outputs the vehicles surviving into the next year.

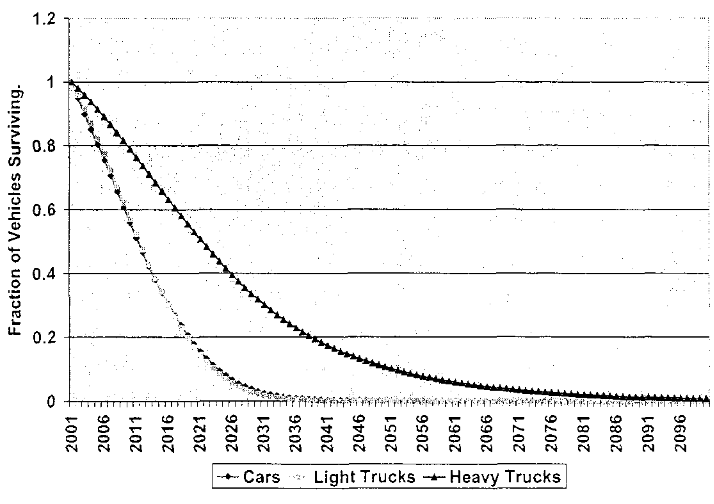

Figure C1. Fraction of vehicle capital stock Surviving

[42] Insomuch as the reference to Schmoyer's paper does not specify what exactly is meant by light and heavy trucks, it is possible that medium trucks were included in "light" and light-heavies were included in "heavy" in the first place.

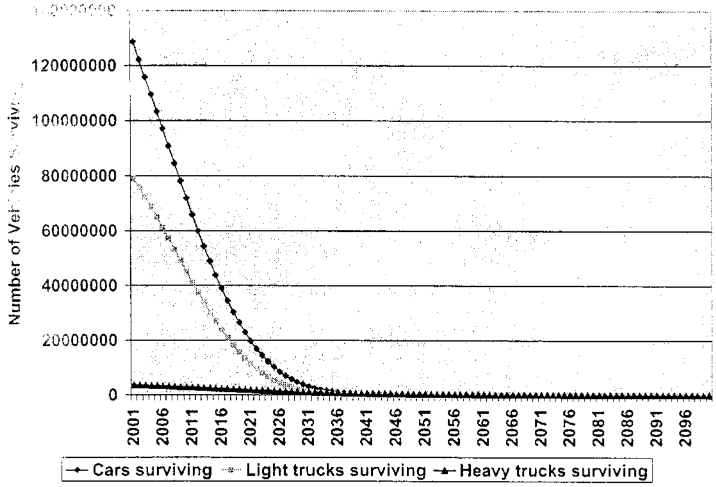

Figure C2. Number of vehicles surviving

C.2 The Transportation Usage Model

C.2.1 The Data

The usage models are derived from two surveys. Car and light truck usage information comes from the vehicle-level portion of the National Household Travel Survey of 2001, a survey of vehicle ownership and usage characteristics.[43] From this dataset, we extracted data on the type of vehicle (car or light truck/van), its age, and the total annual miles driven. The data on trucks comes from the vehicle-level version of the 1997 Vehicle Inventory and Use Survey, survey of truck ownership and travel characteristics conducted by the U.S. census bureau.[44] This dataset provided information on truck size, truck age (approximated by model year), and annual miles driven.

C.2.2 The Regression Models

A brief glimpse at the data shows that there is a negative relationship between age and the number of miles driven in a year—older vehicles are driven less distance than newer vehicles, on average. This relationship tends to level off in later years, however, with the difference in driving distance between a 30-year old and 31-yar old vehicle being considerably smaller than the difference between younger vehicles one year apart. For each of the five vehicle types, we used data from the appropriate data set to regress the number of miles driven against the age of the vehicle for all vehicles under 30 years old.

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[43] http://nhts.ornl.gov/2001/index.shtml

[44] http://www.census.gov/svsd/www/97vehinv.html

The data was weighted using the weight figure included in the two datasets. The regression results are listed below.

Cars:

	Miles = 13878.8	- 422.2 * age	
(t-stat)	(100.23)	(-28.4)	Adj. $R^2 = .0334$

Light Trucks:

	Miles = 15974.9	- 508.9 * age	
(t-stat)	(110.53)	(-33.17)	Adj. $R^2 = .0595$

Medium Trucks

	Miles = 26874.5	- 1123.8 * age	
(t-stat)	(50.0)	(-12.9)	Adj. $R^2 = .0329$

Light-Heavy Trucks:

	Miles = 34204.9	- 1386.8 * age	
(t-stat)	(32.0)	(-8.12)	Adj. $R^2 = .0272$

Heavy-Heavy Trucks:

	Miles = 91714.3	- 5167.7 * age	
(t-stat)	(168.9)	(-55.4)	Adj. $R^2 = .1061$

As vehicle size increases, the number of miles driven by age 0 vehicles also increases. However, the steepness of the age-related drop-off in driving also increases, so that while new heavy trucks are driven over 6 times the distance of new cars, the driving drops off 13 times faster with age. It should also be mentioned that, although these regressions have low R-squares, they are still useful average indicators. Since we're dealing with vehicle stocks in the aggregate, the individual variation among vehicles is not as important as the general relationships—such as the generally observed relationship between age and usage.

In the model, these five usage models are applied to each age/size cohort to yield the average number of miles driven by each cohort. This, in turn, is multiplied by the total vehicles in each cohort to give the total vehicle-miles per cohort. Totaling these cohort totals yields the total vehicle miles driven in each year.

C.2.3 Fuel Use and Carbon Emissions

For cars and light trucks, vehicle efficiency is determined using model-year fleet averages published by the EPA.[45] Each cohort (model year) is assigned the appropriate mpg figure provided by the EPA, and is assumed to maintain this efficiency throughout its useful life.[46] For trucks, limited EPA data led us to turn back to the 1997 VIUS, which

[45] http://www.epa.gov/otaq/cert/mpg/fetrends/r03006-a.pdf

[46] While this may or may not be a realistic assumption, we are limited to it by the data available. There is, to our knowledge, however, no published research that shows that efficiency declines with age for vehicles.

also contains user-reported mpg figures for most trucks in the survey. We took the average of each model year for each truck weight class. Unfortunately, the dataset only demarcates model years 1988 through 1997, so we were forced to assume that all trucks built before 1988 have the 1988 model year efficiency for their weight class and that all trucks built after 1997 have the 1997 level of efficiency appropriated to their weight class.

Each year, the total vehicle-miles driven by each age/size cohort is divided by these mpg figures to yield the gallons of fuel consumed. For cars, all fuel is assumed to be gasoline and for heavy-heavy trucks, all fuel is assumed to be diesel. For the other three classes, the VIUS was again used to determine the average fuel share between diesel and gasoline for these weight classes. It was found that for light trucks, 3.2% of miles driven were diesel-fueled, 35% for medium trucks, and 12% for light-heavy trucks. Using these figures, the total number of gallons of gasoline and diesel consumed by each weight class could be determined for each year of the model.

These fuel totals were then converted into carbon emission totals. Each gallon of fuel contains .125 MBtu and each MBtu of fuel burned emits 42.8 pounds of carbon for gasoline and 44 pounds of carbon for diesel fuel. A cumulative total of these carbon emission numbers provides the carbon shadow estimate of the model.

Appendix D: Uncertainty and Sensitivity

All analyses like the ones described in the preceding sections are subject to uncertainties and are sensitive to underlying assumptions. The current analysis faces one major uncertainty associated with the carbon cycle and two major sensitivities to the underlying assumptions. There are of course other uncertainties and sensitivities, but these three have been set aside in the baseline analysis to clarify the basic story. While other sensitivities and uncertainties need to be addressed, these three deserve special mention because they have important policy implications. The three are:

1. Uncertainty in our understanding of the carbon cycle. The calculation of a carbon budget helps put the carbon shadows in context. However our knowledge is of the global carbon cycle is not perfect and one uncertainty in particular has a major impact on the stabilization budgets. This is the value for the long-term uptake of carbon dioxide by the oceans.

2. Sensitivity to the carbon stabilization goal. The reference analysis was done using a concentration of 550 ppmv for a CO_2 stabilization goal. This is a frequently used target value, simply because it represents a doubling of the pre-industrial concentration of carbon dioxide. Performing the analysis for other concentration targets shows the sensitivity of the results to the stabilization policy.

3. Sensitivity of coal analyses to the type of coal used to compute carbon emissions. Coal is a very non-uniform fuel and assumptions were made about the quality of coal that might be burned as part of projecting future emissions. While this is a relatively smaller effect than the previous two, it does affect the largest single source of the U.S. capital stock carbon shadow.

D.1 Carbon cycle uncertainties and sensitivity to stabilization level

Recall that allowable carbon dioxide emissions were calculated based atmospheric stabilization targets and assumptions with regard to the behavior of the Earth's carbon cycle. Least cost pathways to reach stabilization targets were obtained through an optimization algorithm with cost curve inputs and the widely used "simple climate model" MAGICC which translates carbon dioxide emission inputs into atmospheric concentrations over time.

There are a number of uncertainties associated with our understanding of the natural carbon cycle. One of the most important, for long-term stabilization trajectories, is the one associated with the projected rate of uptake of carbon dioxide by the Earth's oceans. In order to illustrate the impact of these uncertainties on our projected carbon budgets we have repeated our calculations using 10%-90% percentile bounds on carbon-cycle uptake (Dr. Tom Wigley personal communication; see also Wigley and Raper 2001).

We have also calculated the carbon budgets not only for the 550 ppmv concentration target used in the earlier analysis, but also for a much more constrained atmospheric concentration target of 450 ppmv and for a more relaxed target of 650 ppmv.

Cumulative carbon emissions in the WRE reference case amount to 500 GtC by 2050 and 1345 GtC by 2100. These represent the cumulative carbon emissions to the given year if no climate policies are in place. In reality, future emissions are not known and could be higher or lower than the value given here (IPCC Special Report on Emissions Scenarios, Nakicenovic and Swart 2000).

The impact of uncertainty associated with the carbon cycle and the sensitivity to stabilization goals on carbon budgets to 2050 and 2100 are summarized in Table D1 and figures D1 and D2. Examination of this material suggests two important conclusions.

1. The uncertainty in the carbon cycle budgets has a larger impact on the carbon budgets associated with the lower target concentration (450 ppmv) than the corresponding values for 550 and 650 ppmv.

2. From the perspective of science impacting policy, eliminating the possibility that the ocean uptake is lower than the current best estimate in carbon cycle models has a great impact on the flexibility policy makes may have in meeting any particular stabilization target.

	Stabilization at 650 ppmv	**Stabilization at 550 ppmv**	**Stabilization at 450 ppmv**	**Reference case**
Global carbon budget to **2050** (GtC)	505	460	373	500
Uncertainty range (GtC)	451 – 515	423 – 463	311 – 397	
Global carbon budget to **2100** (GtC)	1089	870	579	1345
Uncertainty range (GtC)	815 -1 176	663 – 973	331 - 655	

Table D1. The carbon budget, assumptions and uncertainties

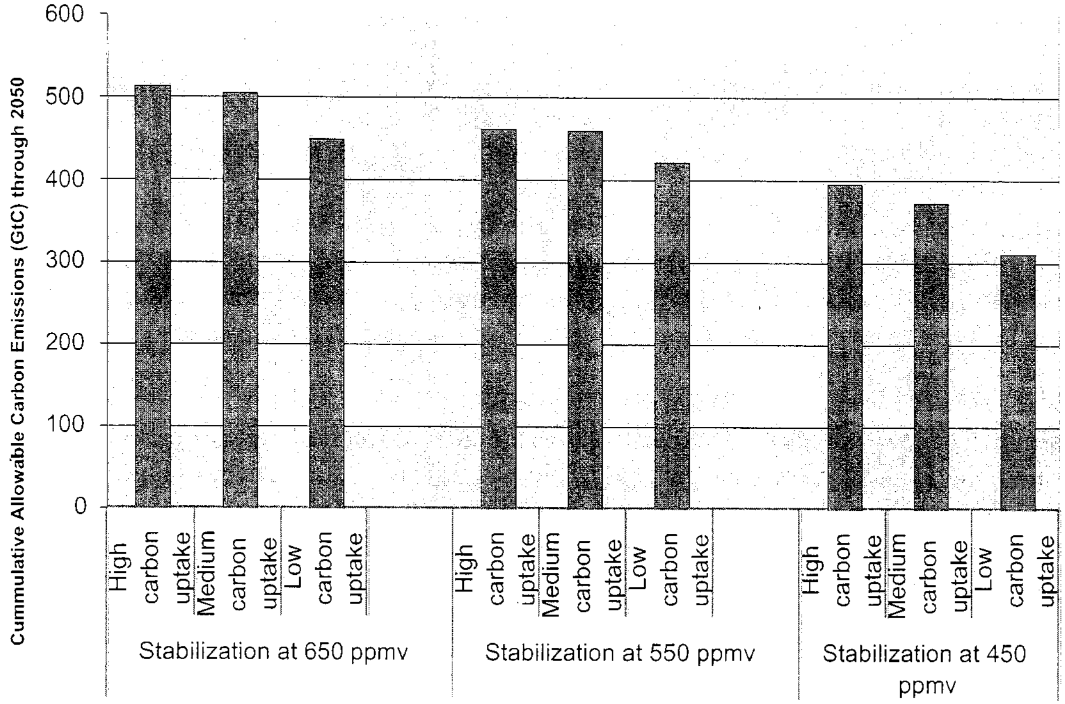

Figure D1. The global carbon budgets of cumulatively allowable carbon emissions (GtC) through 2050 and their uncertainties due to various assumptions on carbon uptake by carbon cycling calculated based on least cost emission trajectories.

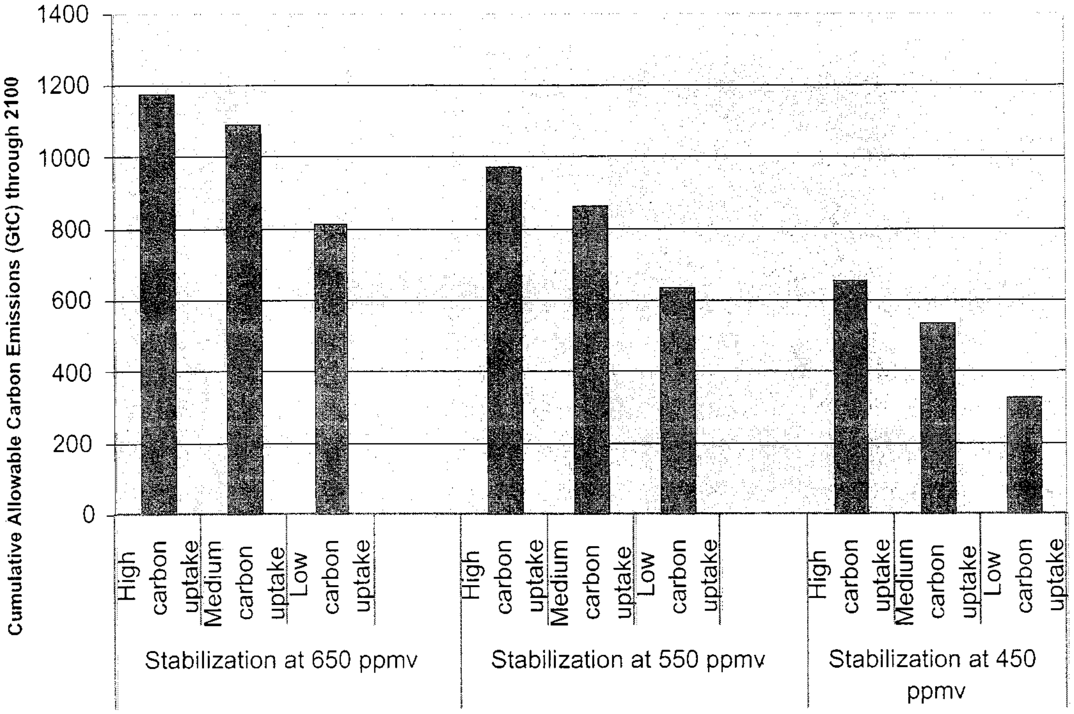

Figure D2. The global carbon budgets of cumulatively allowable carbon emissions (GtC) through 2100 and their uncertainties due to various assumptions on carbon uptake by carbon cycling calculated based on least cost emission trajectories.

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Energy Economics, Inc.

Climate Change and Power:

Carbon Dioxide Emissions Costs and Electricity Resource Planning

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May 18, 2006

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Executive Summary

The fact of human-induced global climate change as a consequence of our greenhouse gas emissions is now well established, and the only remaining questions among mainstream scientists concern the nature and timing of future disruptions and dislocations and the magnitude of the socio-economic impacts. It is also generally agreed that different CO_2 emissions trajectories will lead to varying levels of environmental, economic, and social costs – which means that the more sharply and the sooner we can reduce emissions, the greater the avoided costs will be.

This report is designed to assist utilities, regulators, consumer advocates and others in projecting the future cost of complying with carbon dioxide regulations in the United States.[1] These cost forecasts are necessary for use in long-term electricity resource planning, in electricity resource economics, and in utility risk management.

We recognize that there is considerable uncertainty inherent in projecting long-term carbon emissions costs, not least of which concerns the timing and form of future emissions regulations in the United States. However, this uncertainty is no reason to ignore this very real component of future production cost. In fact, this type of uncertainty is similar to that of other critical electricity cost drivers such as fossil-fuel prices.

Accounting for Climate Change Regulations in Electricity Planning

The United States contributes more than any other nation, by far, to global greenhouse gas emissions on both a total and a per capita basis. The United States contributes 24 percent of the world CO_2 emissions, but has only 4.6 percent of the population.

Within the United States, the electricity sector is responsible for roughly 39% of CO_2 emissions. Within the electricity industry, roughly 82% of CO_2 emissions come from coal-fired plants, roughly 13% come from gas-fired plants, and roughly 5% come from oil-fired plants.

Because of its contribution to US and worldwide CO_2 emissions, the US electricity industry will clearly need to play a critical role in reducing greenhouse gas (GHG) emissions. In addition, the electricity industry is composed of large point sources of emissions, and it is often easier and more cost-effective to control emissions from large sources than multiple small sources. Analyses by the US Energy Information Administration indicate that 60% to 90% of all domestic greenhouse gas reductions are likely to come from the electric sector under a wide range of economy-wide federal policy scenarios.

In this context, the failure of entities in the electric sector to anticipate the future costs associated with carbon dioxide regulations is short-sighted, economically unjustifiable,

[1] This paper does not address the determination of an "externality value" associated with greenhouse gas emissions. The externality value would include societal costs beyond those internalized into market costs through regulation. While this report refers to the ecological and socio-economic impacts of climate change, estimation of the external costs of greenhouse gas emissions is beyond the scope of this analysis.

and ultimately self-defeating. Long-term resource planning and investment decisions that do not quantify the likely future cost of CO_2 regulations will understate the true cost of future resources, and thus will result in uneconomic, imprudent decisions. Generating companies will naturally attempt to pass these unnecessarily high costs on to electricity ratepayers. Thus, properly accounting for future CO_2 regulations is as much a consumer issue as it is an issue of prudent resource selection.

Some utility planners argue that the cost of complying with future CO_2 regulations involves too much uncertainty, and thus they leave the cost out of the planning process altogether. This approach results in making an implicit assumption that the cost of complying with future CO_2 regulations will be zero. This assumption of zero cost will apply to new generation facilities that may operate for 50 or more years into the future. In this report, we demonstrate that under all reasonable forecasts of the near- to mid-term future, the cost of complying with CO_2 regulations will certainly be greater than zero.

Federal Initiatives to Regulate Greenhouse Gases

The scientific consensus on climate change has spurred efforts around the world to reduce greenhouse gas emissions, many of which are grounded in the United Nations Framework Convention on Climate Change (UNFCCC). The United States is a signatory to this convention, which means that it has agreed to a goal of "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." However, the United States has not yet agreed to the legally binding limits on greenhouse gas emissions contained in the Kyoto Protocol, a supplement to the UNFCCC.

Table ES-1. Summary of Federal Mandatory Emission Reduction Legislation

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
McCain Lieberman S.139	Climate Stewardship Act	2003	Cap at 2000 levels 2010-2015. Cap at 1990 levels beyond 2015.	Economy-wide, large emitting sources
McCain Lieberman SA 2028	Climate Stewardship Act	2005	Cap at 2000 levels	Economy-wide, large emitting sources
Bingaman-Domenici (NCEP)	Greenhouse Gas Intensity Reduction Goals	2004	Reduce GHG intensity by 2.4%/yr 2010-2019 and by 2.8%/yr 2020-2025. Safety-valve on allowance price	Economy-wide, large emitting sources
Sen. Feinstein	Strong Economy and Climate Protection Act	2006	Stabilize emissions through 2010; 0.5% cut per year from 2011-15; 1% cut per year from 2016-2020. Total reduction is 7.25% below current levels.	Economy-wide, large emitting sources
Jeffords S. 150	Multi-pollutant legislation	2005	2.050 billion tons beginning 2010	Existing and new fossil-fuel fired electric generating plants > 15 MW
Carper S. 843	Clean Air Planning Act	2005	2006 levels (2.655 billion tons CO2) starting in 2009, 2001 levels (2.454 billion tons CO2) starting in 2013.	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants > 25 MW
Rep. Udall - Rep. Petri	Keep America Competitive Global Warming Policy Act	2006	Establishes prospective baseline for greenhouse gas emissions, with safety valve.	Not available

Nonetheless, there have been several important attempts at the federal level to limit the emissions of greenhouse gases in the United States. Table ES-1 presents a summary of federal legislation that has been introduced in recent years. Most of this legislation includes some form of mandatory national limits on the emissions of greenhouse gases, as well as market-based cap and trade mechanisms to assist in meeting those limits.

State and Regional Initiatives to Regulate Greenhouse Gases

Many states across the country have not waited for federal policies, and are developing and implementing climate change-related policies that have a direct bearing on electric resource planning. States, acting individually and through regional coordination, have been the leaders on climate change policies in the United States.

State policies generally fall into the following categories: (a) direct policies that require specific emission reductions from electric generation sources; (b) indirect policies that affect electric sector resource mix such as through promoting low-emission electric sources; (c) legal proceedings; or (d) voluntary programs including educational efforts and energy planning. Table ES-2 presents a summary of types of policies with recent state policies on climate change listed on the right side of the table.

Table ES-2. Summary of Individual State Climate Change Policies

Type of Policy	State Examples
Direct	
• Power plant emission restrictions (e.g. cap or emission rate)	• MA, NH
• New plant emission restrictions	• OR, WA
• State GHG reduction targets	• CT, NJ, ME, MA, CA, NM, NY, OR, WA
• Fuel/generation efficiency	• CA vehicle emissions standards to be adopted by CT, NY, ME, MA, NJ, OR, PA, RI, VT, WA
Indirect (clean energy)	
• Load-based GHG cap	• CA
• GHG in resource planning	• CA, WA, OR, MT, KY
• Renewable portfolio standards	• 22 states and D.C.
• Energy efficiency/renewable charges and funding; energy efficiency programs	• More than half the states
• Net metering, tax incentives	• 41 states
Lawsuits	
• States, environmental groups sue EPA to determine whether greenhouse gases can be regulated under the Clean Air Act	• States include CA, CT, ME, MA, NM, NY, OR, RI, VT, and WI
• States sue individual companies to reduce GHG emissions	• NY, CT, CA, IA, NJ, RI, VT, WI
Climate change action plans	• 28 states, with NC and AZ in progress

Several states require that regulated utilities evaluate costs or risks associated with greenhouse gas emissions regulations in long-range planning or resource procurement. Some of the states require that companies use a specific value, while other states require that companies consider the risk of future regulation in their planning process. Table ES-3 summarizes state requirements for considering greenhouse gas emissions in electricity resource planning.

Table ES-3. Requirements for Consideration of GHG Emissions in Electric Resource Decisions

Program type	State	Description	Date	Source
GHG value in resource planning	CA	PUC requires that regulated utility IRPs include carbon adder of $8/ton CO_2, escalating at 5% per year.	April 1, 2005	CPUC Decision 05-04-024
GHG value in resource planning	WA	Law requiring that cost of risks associated with carbon emissions be included in Integrated Resource Planning for electric and gas utilities	January, 2006	WAC 480-100-238 and 480-90-238
GHG value in resource planning	OR	PUC requires that regulated utility IRPs include analysis of a range of carbon costs	Year 1993	Order 93-695
GHG value in resource planning	NWPCC	Inclusion of carbon tax scenarios in Fifth Power Plan	May, 2006	NWPCC Fifth Energy Plan
GHG value in resource planning	MN	Law requires utilities to use PUC established environmental externalities values in resource planning	January 3, 1997	Order in Docket No. E-999/CI-93-583
GHG in resource planning	MT	IRP statute includes an "Environmental Externality Adjustment Factor" which includes risk due to greenhouse gases. PSC required Northwestern to account for financial risk of carbon dioxide emissions in 2005 IRP.	August 17, 2004	Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229; Sec. 38.5.8219, A.R.M.
GHG in resource planning	KY	KY staff reports on IRP require IRPs to demonstrate that planning adequately reflects impact of future CO_2 restrictions	2003 and 2006	Staff Report On the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company - Case 2005-00162, February 2006
GHG in resource planning	UT	Commission directs Pacificorp to consider financial risk associated with potential future regulations, including carbon regulation	June 18, 1992	Docket 90-2035-01, and subsequent IRP reviews
GHG in resource planning	MN	Commission directs Xcel to "provide an expansion of CO2 contingency planning to check the extent to which resource mix changes can lower the cost of meeting customer demand under different forms of regulation."	August 29, 2001	Order in Docket No. RP00-787
GHG in CON	MN	Law requires that proposed non-renewable generating facilities consider the risk of environmental regulation over expected useful life of the facility	2005	Minn. Stat. §216B.243 subd. 3(12)

States are not just acting individually; there are several examples of innovative regional policy initiatives. To date, there are regional initiatives including Northeastern and Mid-Atlantic states (CT, DE, MD, ME, NH, NJ, NY, and VT), West Coast states (CA, OR, WA), Southwestern states (NM, AZ), and Midwestern states (IL, IA, MI, MN, OH, WI).

The Northeastern and Mid-Atlantic states recently reached agreement on the creation of the Regional Greenhouse Gas Initiative (RGGI); a multi-year cooperative effort to design a regional cap and trade program covering CO_2 emissions from power plants in the region. The RGGI states have agreed to the following:

- Stabilization of CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019.
- Allocation of a minimum of 25 percent of allowances for consumer benefit and strategic energy purposes.
- Certain offset provisions that increase flexibility to moderate price impacts.
- Development of complimentary energy policies to improve energy efficiency, decrease the use of higher polluting electricity generation and to maintain economic growth.

Electric Industry Actions to Address Greenhouse Gases

Some CEOs in the electric industry have determined that inaction on climate change issues is not good corporate strategy, and individual electric companies have begun to evaluate the risks associated with future greenhouse gas regulation and take steps to reduce greenhouse gas emissions. Their actions represent increasing initiative in the electric industry to address the threat of climate change and manage risk associated with future carbon constraints.

Recently, eight US-based utility companies have joined forces to create the "Clean Energy Group." This group's mission is to seek "national four-pollutant legislation that would, among other things... stabilize carbon emissions at 2001 levels by 2013."

In addition, leaders of electric companies such as Duke and Exelon have vocalized support for mandatory national carbon regulation. These companies urge a mandatory federal policy, stating that climate change is a pressing issue that must be resolved, that voluntary action is not sufficient, and that companies need regulatory certainty to make appropriate decisions. Even companies that do not advocate federal requirements, anticipate their adoption and urge regulatory certainty. Several companies have established greenhouse gas reduction goals for their company.

Several electric utilities and electric generation companies have incorporated specific forecasts of carbon regulation and costs into their long term planning practices. Table ES-4 illustrates the range of carbon cost values, in \$/ton CO_2, that are currently being used in the industry for both resource planning and modeling of carbon regulation policies.

Table ES-4. CO_2 Cost Estimates Used in Electricity Resource Plans

Company	CO2 emissions trading assumptions for various years ($2005)
PG&E*	$0-9/ton (start year 2006)
Avista 2003*	$3/ton (start year 2004)
Avista 2005	$7 and $25/ton (2010) $15 and $62/ton (2026 and 2023)
Portland General Electric*	$0-55/ton (start year 2003)
Xcel-PSCCo	$9/ton (start year 2010) escalating at 2.5%/year
Idaho Power*	$0-61/ton (start year 2008)
Pacificorp 2004	$0-55/ton
Northwest Energy 2005	$15 and $41/ton
Northwest Power and Conservation Council	$0-15/ton between 2008 and 2016 $0-31/ton after 2016

**Values for these utilities from Wiser, Ryan, and Bolinger, Mark. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." Lawrence Berkeley National Laboratories. August 2005. LBNL-58450. Table 7.*
Other values: PacifiCorp, Integrated Resource Plan 2004, pages 62-63; and Idaho Power Company, 2004 Integrated Resource Plan Draft, July 2004, page 59; Avista Integrated Resource Plan 2005, Section 6.3; Northwestern Energy Integrated Resource Plan 2005, Volume 1 p. 62; Northwest Power and Conservation Council, Fifth Power Plan pp. 6-7. Xcel-PSCCo, Comprehensive Settlement submitted to the CO PUC in dockets 04A-214E, 215E and 216E, December 3, 2004. Converted to $2005 using GDP implicit price deflator.

Synapse Forecast of Carbon Dioxide Allowance Prices

This report presents our current forecast of the most likely costs of compliance with future climate change regulations. In making this forecast we review a range of current estimates from a variety of different sources. We review the results of several analyses of federal policy proposals, and a few analyses of the Kyoto Protocol. We also look briefly at carbon markets in the European Union to demonstrate the levels at which carbon dioxide emissions are valued in an active market.

Figure ES-1 presents CO_2 allowance price forecasts from the range of recent studies that we reviewed. All of the studies here are based on the costs associated with complying with potential CO_2 regulations in the United States. The range of these price forecasts reflects the range of policy initiatives that have been proposed in the United States, as well as the diversity of economic models and methodologies used to estimate their price impacts.

Figure ES-1 superimposes the Synapse long term forecasts of CO_2 allowance prices upon the other forecasts gleaned from the literature. In order to help address the uncertainty involved in forecasting CO_2 prices, we present a "base case" forecast as well as a "low case" and a "high case." All three forecasts are based on our review of both regulatory trends and economic models, as outlined in this document.

As with any forecast, our forecast is likely to be revised over time as the form and timing of carbon emission regulations come increasingly into focus. It is our judgment that this range represents a reasonable quantification of what is known today about future carbon emissions costs in the United States. As such, it is appropriate for use in long range resource planning purposes until better information or more clarity become available.

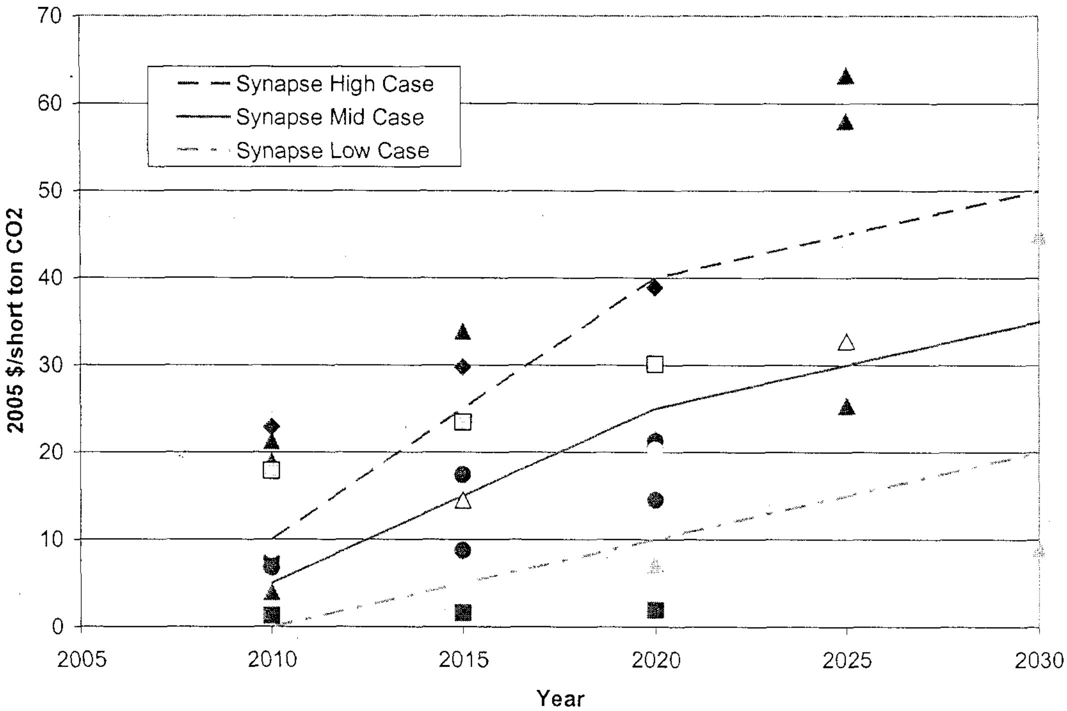

Figure ES-1. Synapse Forecast of Carbon Dioxide Allowance Prices

High, mid and low-case Synapse carbon emissions price forecasts superimposed on policy model forecasts as presented in Figure 6.3.

Additional Costs Associated with Greenhouse Gases

This report summarizes current policy initiatives and costs associated with greenhouse gas emissions from the electric sector. It is important to note that the greenhouse gas emission reduction requirements contained in federal legislation proposed to date, and even the targets in the Kyoto Protocol, are relatively modest compared with the range of emissions reductions that are anticipated to be necessary for keeping global warming at a manageable level. Further, we do not attempt to calculate the full cost to society (or to electric utilities) associated with anticipated future climate changes. Even if electric utilities comply with some of the most aggressive regulatory requirements underlying our CO_2 price forecasts presented above, climate change will continue to occur, albeit at a slower pace, and more stringent emissions reductions will be necessary to avoid dangerous changes to the climate system.

The consensus from the international scientific community clearly indicates that in order to stabilize the concentration of greenhouse gases in the atmosphere and to try to keep further global warming trends manageable, greenhouse gas emissions will have to be reduced significantly below those limits underlying our CO_2 price forecasts. The scientific consensus expressed in the Intergovernmental Panel on Climate Change Report from 2001 is that greenhouse gas emissions would have to decline to a very small fraction of current emissions in order to stabilize greenhouse gas concentrations, and keep global warming in the vicinity of a 2-3 degree centigrade temperature increase. Simply complying with the regulations underlying our CO_2 price forecasts does not eliminate the ecological and socio-economic threat created by CO_2 emissions – it merely mitigates that threat.

In keeping with these findings, the European Union has adopted an objective of keeping global surface temperature increases to 2 degrees centigrade above pre-industrial levels. The EU Environment Council concluded in 2005 that this goal is likely to require emissions reductions of 15-30% below 1990 levels by 2020, and 60-80% below 1990 levels by 2050.

In other words, incorporating a reasonable CO_2 price forecast into electricity resource planning will help address electricity consumer concerns about prudent economic decision-making and direct impacts on future electricity rates, but it does not address all the ecological and socio-economic concerns posed by greenhouse gas emissions. Regulators should consider other policy mechanisms to account for the remaining pervasive impacts associated with greenhouse gas emissions.

1. Introduction

Climate change is not only an "environmental" issue. It is at the confluence of energy and environmental policy, posing challenges to national security, economic prosperity, and national infrastructure. Many states do not require greenhouse gas reductions, nor do we yet have a federal policy requiring greenhouse gas reductions in the United States; thus many policy makers and corporate decision-makers in the electric sector may be tempted to consider climate change policy a hazy future possibility rather than a current factor in resource decisions. However, such a "wait and see" approach is imprudent for resource decisions with horizons of more than a few years. Scientific developments, policy initiatives at the local, state, and federal level, and actions of corporate leaders, all indicate that climate change policy will affect the electric sector – the question is not "whether" but "when," and in what magnitude.

Attention to global warming and its potential environmental, economic, and social impacts has rapidly increased over the past few years, adding to the pressure for comprehensive climate change policy in the United States The April 3, 2006 edition of TIME Magazine reports the results of a new survey conducted by TIME, ABC News and Stanford University which reveals that more than 80 percent of Americans believe global warming is occurring, while nearly 90 percent are worried that warming presents a serious problem for future generations. The poll reveals that 75 percent would like the US government, US businesses, and the American people to take further action on global warming in the next year.[2]

In the past several years, climate change has emerged as a significant financial risk for companies. A 2002 report from the investment community identifies climate change as representing a potential multi-billion dollar risk to a variety of US businesses and industries.[3] Addressing climate change presents particular risk and opportunity to the electric sector. Because the electric sector (and associated emissions) continue to grow, and because controlling emissions from large point sources (such as power plants) is easier, and often cheaper, than small disparate sources (like automobiles), the electric sector is likely to be a prime component of future greenhouse gas regulatory scenarios. The report states that "climate change clearly represents a major strategic issue for the electric utilities industry and is of relevance to the long-term evolution of the industry and possibly the survival of individual companies." Risks to electric companies include the following:

- Cost of reducing greenhouse gas emissions and cost of investment in new, cleaner power production technologies and methods;
- Higher maintenance and repair costs and reliability concerns due to more frequent weather extremes and climatic disturbance; and

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[2] TIME/ABC News/Stanford University Poll, appearing in April 3, 2006 issue of Time Magazine.

[3] Innovest Strategic Value Advisors; "Value at Risk: Climate Change and the Future of Governance;" The Coalition for Environmentally Responsible Economies; April 2002.

- Growing pressure from customers and shareholders to address emissions contributing to climate change.[4]

A subsequent report, "Electric Power, Investors, and Climate Change: A Call to Action," presents the findings of a diverse group of experts from the power sector, environmental and consumer groups, and the investment community.[5] Participants in this dialogue found that greenhouse gas emissions, including carbon dioxide emissions, will be regulated in the United States; the only remaining issue is when and how. Participants also agreed that regulation of greenhouse gases poses financial risks and opportunities for the electric sector. Managing the uncertain policy environment on climate change is identified as "one of a number of significant environmental challenges facing electric company executives and investors in the next few years as well as the decades to come."[6] One of the report's four recommendations is that investors and electric companies come together to quantify and assess the financial risks and opportunities of climate change.

In a 2003 report for the World Wildlife Fund, Innovest Strategic Advisors determined that climate policy is likely to have important consequences for power generation costs, fuel choices, wholesale power prices and the profitability of utilities and other power plant owners.[7] The report found that, even under conservative scenarios, additional costs could exceed 10 percent of 2002 earnings, though there are also significant opportunities. While utilities and non-utility generation owners have many options to deal with the impact of increasing prices on CO_2 emissions, doing nothing is the worst option. The report concludes that a company's profits could even increase with astute resource decisions (including fuel switching or power plant replacement).

Increased CO_2 emissions from fossil-fired power plants will not only increase environmental damages and challenges to socio-economic systems; on an individual company level they will also increase the costs of complying with future regulations – costs that are likely to be passed on to all customers. Power plants built today can generate electricity for as long as 50 years or more into the future.[8]

As illustrated in the table below, factoring costs associated with future regulations of carbon dioxide has an impact on the costs of resources. Resources with higher CO_2 emissions have a higher CO_2 cost per megawatt-hour than those with lower emissions.

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[4] Ibid., pages 45-48.

[5] CERES; "Electric Power, Investors, and Climate Change: A Call to Action;" September 2003.

[6] Ibid., p. 6

[7] Innovest Strategic Value Advisors; "Power Switch: Impacts of Climate Change on the Global Power Sector;" WWF International; November 2003

[8] Biewald et. al.; "A Responsible Electricity Future: An Efficient, Cleaner and Balanced Scenario for the US Electricity System;" prepared for the National Association of State PIRGs; June 11, 2004.

Table I.1. Comparison of CO_2 costs per MWh for Various Resources

Resource	Scrubbed Coal (Bit)	Scrubbed Coal (Sub)	IGCC	Combined Cycle	Source Notes
Size	600	600	550	400	1
CO_2 (lb/MMBtu)	205.45	212.58	205.45	116.97	2, 3
Heat Rate (Btu/kWh)	8844	8844	8309	7196	1
CO_2 Price (2005$/ton)	19.63	19.63	19.63	19.63	4
CO_2 Cost per MWh	$17.83	$18.45	$16.75	$8.26	

1 - From AEO 2006
2 - From EIA's Electric Power Annual 2004, page 76
3 - IGCC emission rate assumed to be the same as the bituminous scrubbed coal rate
4 - From Synapse's carbon emissions price forecast levelized from 2010-2040 at a 7.32% real discount rate

Many trends in this country show increasing pressure for a federal policy requiring greenhouse gas emissions reductions. Given the strong likelihood of future carbon regulation in the United States, the contributions of the power sector to our nation's greenhouse gas emissions, and the long lives of power plants, utilities and non-utility generation owners should include carbon cost in all resource evaluation and planning.

The purpose of this report is to identify a reasonable basis for anticipating the likely cost of future mandated carbon emissions reductions for use in long-term resource planning decisions.[9] Section 2 presents information on US carbon emissions. Section 3 describes recent scientific findings on climate change. Section 4 describes international efforts to address the threat of climate change. Section 5 summarizes various initiatives at the state, regional, and corporate level to address climate change. Finally, section 6 summarizes information that can form the basis for forecasts of carbon allowance prices; and provides a reasonable carbon allowance price forecast for use in resource planning and investment decisions in the electric sector.

2. Growing scientific evidence of climate change

In 2001 the Intergovernmental Panel on Climate Change issued its Third Assessment Report.[10] The report, prepared by hundreds of scientists worldwide, concluded that the earth is warming, that most of the warming over the past fifty years is attributable to human activities, and that average surface temperature of the earth is likely to increase

[9] This paper focuses on anticipating the cost of future emission reduction requirements. This paper does not address the determination of an "externality value" associated with greenhouse gas emissions. The externality value would include societal costs beyond those internalized into market costs through regulation. While this report refers to the ecological and socio-economic impacts of climate change, estimation of the external costs of greenhouse gas emissions is beyond the scope of this analysis.

[10] Intergovernmental Panel on Climate Change, *Third Assessment Report*, 2001.

between 1.4 and 5.8 degrees Centigrade during this century, with a wide range of impacts on the natural world and human societies.

Scientists continue to explore the possible impacts associated with temperature increase of different magnitudes. In addition, they are examining a variety of possible scenarios to determine how much the temperature is likely to rise if atmospheric greenhouse gas concentrations are stabilized at certain levels. The consensus in the international scientific community is that greenhouse gas emissions will have to be reduced significantly below current levels. This would correspond to levels much lower than those limits underlying our CO_2 price forecasts. In 2001 the Intergovernmental Panel on Climate Change reported that greenhouse gas emissions would have to decline to a very small fraction of current emissions in order to keep global warming in the vicinity of a 2-3 degree centigrade temperature increase.[11]

Since 2001 the evidence of climate change, and human contribution to climate change, is even more compelling. In June 2005 the National Science Academies from eleven major nations, including the United States, issued a Joint Statement on a Global Response to Climate Change.[12] Among the conclusions in the statement were that

- Significant global warming is occurring;
- It is likely that most of the warming in recent decades can be attributed to human activities;
- The scientific understanding of climate change is now sufficiently clear to justify nations taking prompt action;
- Action taken now to reduce significantly the build-up of greenhouse gases in the atmosphere will lessen the magnitude and rate of climate change;
- The Joint Academies urge all nations to take prompt action to reduce the causes of climate change, adapt to its impacts and ensure that the issue is included in all relevant national and international strategies.

There is increasing concern in the scientific community that the earth may be more sensitive to global warming than previously thought. Increasing attention is focused on understanding and avoiding dangerous levels of climate change. A 2005 Scientific Symposium on Stabilization of Greenhouse Gases reached the following conclusions:[13]

[11] IPCC, *Climate Change 2001: Synthesis Report*, Fourth Volume of the IPCC Third Assessment Report. IPCC 2001. Question 6.

[12] *Joint Science Academies' Statement: Global Response to Climate Change*, National Academies of Brazil, Canada, China, France, Germany, India, Italy, Japan, Russia, United Kingdom, and United States, June 7, 2005.

[13] UK Department of Environment, Food, and Rural Affairs, *Avoiding Dangerous Climate Change – Scientific Symposium on Stabilization of Greenhouse Gases, February 1-3, 2005 Exeter, U.K. Report of the International Scientific Steering Committee,* May 2005. http://www.stabilisation2005.com/Steering_Commitee_Report.pdf

- There is greater clarity and reduced uncertainty about the impacts of climate change across a wide range of systems, sectors and societies. In many cases the risks are more serious than previously thought.
- Surveys of the literature suggest increasing damage if the globe warms about 1 to 3^0C above current levels. Serious risk of large scale, irreversible system disruption, such as reversal of the land carbon sink and possible de-stabilisation of the Antarctic ice sheets is more likely above 3^0C.
- Many climate impacts, particularly the most damaging ones, will be associated with an increased frequency or intensity of extreme events (such as heat waves, storms, and droughts).
- Different models suggest that delaying action would require greater action later for the same temperature target and that even a delay of 5 years could be significant. If action to reduce emissions is delayed by 20 years, rates of emission reduction may need to be 3 to 7 times greater to meet the same temperature target.

As scientific evidence of climate change continues to emerge, including unusually high temperatures, increased storm intensity, melting of the polar icecaps and glaciers worldwide, coral bleaching, and sea level rise, pressure will continue to mount for concerted governmental action on climate change.[14]

3. US carbon emissions

The United States contributes more than any other nation, by far, to global greenhouse gas emissions on both a total and a per capita basis. The United States contributes 24 percent of the world CO_2 emissions from fossil fuel consumption, but has only 4.6 percent of the population. According to the International Energy Agency, 80 percent of 2002 global energy-related CO_2 emissions were emitted by 22 countries – from all world regions, 12 of which are OECD countries. These 22 countries also produced 80 percent of the world's 2002 economic output (GDP) and represented 78 percent of the world's Total Primary Energy Supply.[15] Figure 3.1 shows the top twenty carbon dioxide emitters in the world.

[14] Several websites provide summary information on climate change science including www.ipcc.org www.nrdc.org, www.ucsusa.org, and www.climateark.org.

[15] International Energy Agency, "CO_2 from Fuel Combustion – Fact Sheet," 2005

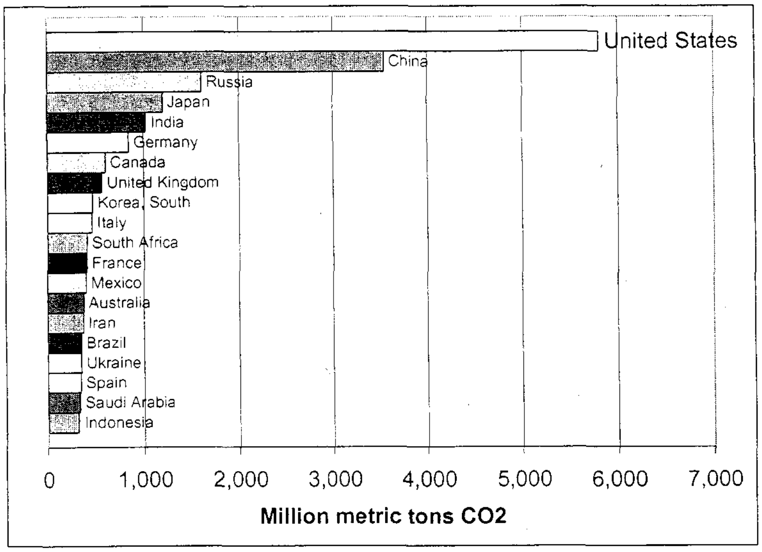

Figure 3.1. Top Worldwide Emitters of Carbon Dioxide in 2003

Source: Data from EIA Table H.1co2 World Carbon Dioxide Emissions from the Consumption and Flaring of Fossil Fuels, 1980-2003, July 11, 2005

Emissions in this country in 2004 were roughly divided among three sectors: transportation (1,934 million metric tons CO_2), electric generation (2,299 million metric tons CO_2), and other (which includes commercial and industrial heat and process applications – 1,673 million metric tons CO_2). These emissions, largely attributable to the burning of fossil fuels, came from combustion of oil (44%), coal (35.4%), and natural gas (20.4%). Figure 3.2 shows emissions from the different sectors, with the electric sector broken out by fuel source.

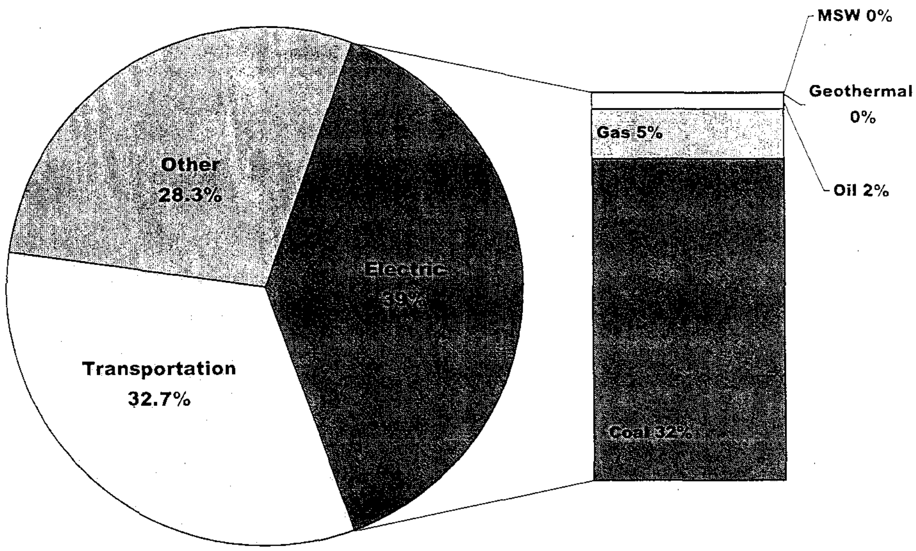

Figure 3.2. US CO_2 Emissions by Sector in 2004

Source: Data from EIA Emissions of Greenhouse Gases in the United States 2004, December 2005

Recent analysis has shown that in 2004, power plant CO_2 emissions were 27 percent higher than they were in 1990. [16] US greenhouse gas emissions per unit of Gross Domestic Product (GDP) fell from 677 metric tons per million 2000 constant dollars of GDP (MTCO2e/$Million GDP) in 2003 to 662 MTCO2e /$Million GDP in 2004, a decline of 2.1 percent.[17] However, while the carbon intensity of the US economy (carbon emissions per unit of GDP) fell by 12 percent between 1991 and 2002, the carbon intensity of the electric power sector held steady. [18] This is because the carbon efficiency gains from the construction of efficient and relatively clean new natural gas plants have been offset by increasing reliance on existing coal plants. Since federal acid rain legislation was enacted in 1990, the average rate at which existing coal plants are operated increased from 61 percent to 72 percent. Power plant CO_2 emissions are concentrated in states along the Ohio River Valley and in the South. Five states – Indiana, Ohio, Pennsylvania, Texas, and West Virginia – are the source of 30 percent of the electric power industry's NO_x and CO_2 emissions, and nearly 40 percent of its SO_2 and mercury emissions.

[16] EIA, "Emissions of Greenhouse Gases in the United Sates, 2004;" Energy Information Administration; December 2005, xiii

[17] EIA *Emissions of Greenhouse Gases in the United States 2004,* December 2005.

[18] Goodman, Sandra; "Benchmarking Air Emissions of the 100 Largest Electric Generation Owners in the US - 2002;" CERES, Natural Resources Defense Council (NRDC), and Public Service Enterprise Group Incorporated (PSEG); April 2004. An updated "Benchmarking Study" has been released: Goodman, Sandra and Walker, Michael. "Benchmarking Air Emissions of the 100 Largest Electric Generation Owners in the US - 2004." CERES, Natural Resources Defense Council (NRDC), and Public Service Enterprise Group Incorporated (PSEG). April 2006.

4. Governments worldwide have agreed to respond to climate change by reducing greenhouse gas emissions

The prospect of global warming and associated climate change has spurred one of the most comprehensive international treaties on environmental issues.[19] The 1992 United Nations Framework Convention on Climate Change has almost worldwide membership; and, as such, is one of the most widely supported of all international environmental agreements.[20] President George H.W. Bush signed the Convention in 1992, and it was ratified by Congress in the same year. In so doing, the United States joined other nations in agreeing that "The Parties should protect the climate system for the benefit of present and future generations of humankind, on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities."[21] Industrialized nations, such as the United States, and Economies in Transition, known as Annex I countries in the UNFCCC, agree to adopt climate change policies to reduce their greenhouse gas emissions.[22] Industrialized countries that were members of the Organization for Economic Cooperation and Development (OECD) in 1992, called Annex II countries, have the further obligation to assist developing countries with emissions mitigation and climate change adaptation.

Following this historic agreement, most Parties to the UNFCCC adopted the Kyoto Protocol on December 11, 1997. The Kyoto Protocol supplements and strengthens the Convention; the Convention continues as the main focus for intergovernmental action to combat climate change. The Protocol establishes legally-binding targets to limit or reduce greenhouse gas emissions.[23] The Protocol also includes various mechanisms to cut emissions reduction costs. Specific rules have been developed on emissions sinks, joint implementation projects, and clean development mechanisms. The Protocol envisions a long-term process of five-year commitment periods. Negotiations on targets for the second commitment period (2013-2017) are beginning.

The Kyoto targets are shown below, in Table 4.1. Only Parties to the Convention that have also become Parties to the Protocol (i.e. by ratifying, accepting, approving, or acceding to it), are bound by the Protocol's commitments, following its entry into force in

[19] For comprehensive information on the UNFCC and the Kyoto Protocol, see UNFCC, "Caring for Climate: a guide to the climate change convention and the Kyoto Protocol," issued by the Climate Change Secretariat (UNFCC) Bonn, Germany. 2003. This and other publications are available at the UNFCCC's website: http://unfccc.int/.

[20] The First World Climate Conference was held in 1979. In 1988, the World Meteorological Society and the United Nations Environment Programme created the Intergovernmental Panel on Climate Change to evaluate scientific information on climate change. Subsequently, in 1992 countries around the world, including the United States, adopted the United Nations Framework Convention on Climate Change.

[21] From Article 3 of the United Nations Framework Convention on Climate Change, 1992.

[22] One of obligations of the United States and other industrialized nations is to a National Report describing actions it is taking to implement the Convention

[23] Greenhouse gases covered by the Protocol are CO_2, CH_4, N_2O, HFCs, PFCs and SF_6.

February 2005.[24] The individual targets for Annex I Parties add up to a total cut in greenhouse-gas emissions of at least 5 percent from 1990 levels in the commitment period 2008-2012.

Only a few industrialized countries have not signed the Kyoto Protocol; these countries include the United States, Australia, and Monaco. Of these, the United States is by far the largest emitter with 36.1 percent of Annex I emissions in 1990; Australia and Monaco were responsible for 2.1 percent and less than 0.1 percent of Annex I emissions, respectively. The United States did not sign the Kyoto protocol, stating concerns over impacts on the US economy and absence of binding emissions targets for countries such as India and China. Many developing countries, including India, China and Brazil have signed the Protocol, but do not yet have emission reduction targets.

In December 2005, the Parties agreed to final adoption of a Kyoto "rulebook" and a two-track approach to consider next steps. These next steps will include negotiation of new binding commitments for Kyoto's developed country parties, and, a nonbinding "dialogue on long-term cooperative action" under the Framework Convention.

Table 4.1. Emission Reduction Targets Under the Kyoto Protocol[25]

Country	**Target**: change in emissions from 1990** levels by 2008/2012
EU-15*, Bulgaria, Czech Republic, Estonia, Latvia, Liechtenstein, Lithuania, Monaco, Romania, Slovakia, Slovenia, Switzerland	-8%
United States***	-7%
Canada, Hungary, Japan, Poland	-6%
Croatia	-5%
New Zealand, Russian Federation, Ukraine	0
Norway	+1%
Australia***	+8%
Iceland	+10%

** The EU's 15 member States will redistribute their targets among themselves, as allowed under the Protocol. The EU has already reached agreement on how its targets will be redistributed.*
*** Some Economies In Transition have a baseline other than 1990.*
**** The United States and Australia have indicated their intention not to ratify the Kyoto Protocol.*

As the largest single emitter of greenhouse gas emissions, and as one of the only industrialized nations not to sign the Kyoto Protocol, the United States is under significant international scrutiny; and pressure is building for the United States to take more initiative in addressing the emerging problem of climate change. In 2005 climate change was a priority at the G8 Summit in Gleneagles, with the G8 leaders agreeing to "act with resolve and urgency now" on the issue of climate change.[26] The leaders

[24] Entry into force required 55 Parties to the Convention to ratify the Protocol, including Annex I Parties accounting for 55 percent of that group's carbon dioxide emissions in 1990. This threshold was reached when Russia ratified the Protocol in November 2004. The Protocol entered into force February 16, 2005.

[25] Background information at: http://unfccc.int/essential_background/kyoto_protocol/items/3145.php

[26] G8 Leaders, *Climate Change, Clean Energy, and Sustainable Development*, Political Statement and Action Plan from the G8 Leaders' Communiqué at the G8 Summit in Gleneagles U.K., 2005. Available

reached agreement that greenhouse gas emissions should slow, peak and reverse, and that the G8 nations must make "substantial cuts" in greenhouse gas emissions. They also reaffirmed their commitment to the UNFCCC and its objective of stabilizing greenhouse gas concentrations in the atmosphere at a level that prevents dangerous anthropogenic interference with the climate system.

The EU has already adopted goals for emissions reductions beyond the Kyoto Protocol. The EU has stated its commitment to limiting global surface temperature increases to 2 degrees centigrade above pre-industrial levels.[27] The EU Environment Council concluded in 2005 that to meet this objective in an equitable manner, developed countries should reduce emissions 15-30% below 1990 levels by 2020, and 60-80% below 1990 levels by 2050. A 2005 report from the European Environment Agency concluded that a 2 degree centigrade temperature increase was likely to require that global emissions increases be limited at 35% above 1990 levels by 2020, with a reduction by 2050 of between 15 and 50% below 1990 levels.[28] The EU has committed to emission reductions of 20-30% below 1990 levels by 2020, and reduction targets for 2050 are still under discussion.[29]

5. Legislators, state governmental agencies, shareholders, and corporations are working to reduce greenhouse gas emissions from the United States

There is currently no mandatory federal program requiring greenhouse gas emission reductions. Nevertheless, various federal legislative proposals are under consideration, and President Bush has acknowledged that humans are contributing to global warming. Meanwhile, state and municipal governments (individually and in cooperation), are leading the development and design of climate policy in the United States. Simultaneously, companies in the electric sector, acting on their own initiative or in compliance with state requirements, are beginning to incorporate future climate change policy as a factor in resource planning and investment decisions.

at: http://www.g8.gov.uk/servlet/Front?pagename=OpenMarket/Xcelerate/ShowPage&c=Page&cid=1094235520309

[27] Council of the European Union, *Information Note – Brussels March 10, 2005.* http://ue.eu.int/uedocs/cmsUpload/st07242.en05.pdf

[28] European Environment Agency, *Climate Change and a European Low Carbon Energy System,* 2005. EEA Report No 1/2005. ISSN 1725-9177. http://reports.eea.europa.eu/eea_report_2005_1/en/Climate_change-FINAL-web.pdf

[29] Ibid; and European Parliament Press Release "Winning the Battle Against Climate Change" November 17, 2005. http://www.europarl.europa.eu/news/expert/infopress_page/064-2439-320-11-46-911-20051117IPR02438-16-11-2005-2005-false/default_en.htm

5.1 Federal initiatives

With ratification of the United Nations Framework Convention on Climate Change in 1992, the United States agreed to a goal of "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."[30] To date, the Federal Government in the United States has not required greenhouse gas emission reductions, and the question of what constitutes a dangerous level of human interference with the climate system remains unresolved. However, legislative initiatives for a mandatory market-based greenhouse gas cap and trade program are under consideration.

To date, the Bush Administration has relied on voluntary action. In July 2005, President Bush changed his public position on causation, acknowledging that the earth is warming and that human actions are contributing to global warming.[31] That summer, the Administration launched a new climate change pact between the United States and five Asian and Pacific nations aimed at stimulating technology development and inducing private investments in low-carbon and carbon-free technologies. The Asia-Pacific Partnership on Clean Development and Climate – signed by Australia, China, India, Japan, South Korea and the United States – brings some of the largest greenhouse gas emitters together; however its reliance on voluntary measures reduces its effectiveness.

The legislative branch has been more active in exploring mandatory greenhouse gas reduction policies. In June 2005, the Senate passed a sense of the Senate resolution recognizing the need to enact a US cap and trade program to slow, stop and reverse the growth of greenhouse gases.[32]

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[30] The UNFCC was signed by President George H. Bush in 1992 and ratified by the Senate in the same year.

[31] "Bush acknowledges human contribution to global warming; calls for post-Kyoto strategy." Greenwire, July 6, 2005.

[32] US Senate, *Sense of the Senate Resolution on Climate Change,* US Senate Resolution 866; June 22, 2005. Available at: http://energy.senate.gov/public/index.cfm?FuseAction=PressReleases.Detail&PressRelease_id=234715&Month=6&Year=2005&Party=0

Sense of the Senate Resolution – June 2005

> It is the sense of the Senate that, before the end of the 109th Congress, Congress should enact a comprehensive and effective national program of mandatory, market-based limits on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions at a rate and in a manner that
>
> (1) will not significantly harm the United States economy; and
>
> (2) will encourage complementary action by other nations that are major trading partners and key contributors to global emissions.

This Resolution built upon previous areas of agreement in the Senate, and provides a foundation for future agreement on a cap and trade program. On May 10, 2006 the House Appropriations Committee adopted very similar language supporting a mandatory cap on greenhouse gas emissions in a non-binding amendment to a 2007 spending bill.[33]

Several mandatory emissions reduction proposals have been introduced in Congress. These proposals establish emission trajectories below the projected business-as-usual emission trajectories, and they generally rely on market-based mechanisms (such as cap and trade programs) for achieving the targets. The proposals also include various provisions to spur technology innovation, as well as details pertaining to offsets, allowance allocation, restrictions on allowance prices and other issues. Through their consideration of these proposals, legislators are increasingly educated on the complex details of different policy approaches, and they are laying the groundwork for a national mandatory program. Federal proposals that would require greenhouse gas emission reductions are summarized in Table 5.1, below.

[33] "House appropriators OK resolution on need to cap emissions," Greenwire, May 10, 2005.

Table 5.1. Summary of Federal Mandatory Emission Reduction Proposals

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
McCain Lieberman S.139	Climate Stewardship Act	2003	Cap at 2000 levels 2010-2015. Cap at 1990 levels beyond 2015.	Economy-wide, large emitting sources
McCain Lieberman SA 2028	Climate Stewardship Act	2005	Cap at 2000 levels	Economy-wide, large emitting sources
Bingaman-Domenici (NCEP)	Greenhouse Gas Intensity Reduction Goals	2004	Reduce GHG intensity by 2.4%/yr 2010-2019 and by 2.8%/yr 2020-2025. Safety-valve on allowance price	Economy-wide, large emitting sources
Sen. Feinstein	Strong Economy and Climate Protection Act	2006	Stabilize emissions through 2010; 0.5% cut per year from 2011-15; 1% cut per year from 2016-2020. Total reduction is 7.25% below current levels.	Economy-wide, large emitting sources
Jeffords S. 150	Multi-pollutant legislation	2005	2.050 billion tons beginning 2010	Existing and new fossil-fuel fired electric generating plants >15 MW
Carper S. 843	Clean Air Planning Act	2005	2006 levels (2.655 billion tons CO2) starting in 2009, 2001 levels (2.454 billion tons CO2) starting in 2013.	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants >25 MW
Rep. Udall - Rep. Petri	Keep America Competitive Global Warming Policy Act	2006	Establishes prospective baseline for greenhouse gas emissions, with safety valve.	Not available

Landmark legislation that would regulate carbon, the Climate Stewardship Act (S.139), was introduced by Senators McCain and Lieberman in 2003, and received 43 votes in the Senate. A companion bill was introduced in the House by Congressmen Olver and Gilchrest. As initially proposed, the bill created an economy-wide two-step cap on greenhouse gas emissions. The bill was reintroduced in the 109th Congress on February 10, 2005; the revised Climate Stewardship Act, SA 2028, would create a national cap and trade program to reduce CO_2 to year 2000 emission levels over the period 2010 to 2015. Other legislative initiatives on climate change were also under consideration in the spring of 2005, including a proposal by Senator Jeffords (D-VT) to cap greenhouse gas emissions from the electric sector (S. 150), and an electric sector four-pollutant bill from Senator Carper (D-DE) (S. 843).

In 2006, the Senate appears to be moving beyond the question of whether to regulate greenhouse gas emissions, to working out the details of how to regulate greenhouse gas emissions. Senators Domenici (R-NM) and Bingaman (D-NM) are working on bi-partisan legislation based on the recommendations of the National Commission on Energy Policy (NCEP). The NCEP – a bipartisan group of energy experts from industry, government, labor, academia, and environmental and consumer groups – released a consensus strategy in December 2004 to address major long-term US energy challenges. Their report recommends a mandatory economy-wide tradable permits program to limit GHG. Costs would be capped at $7/metric ton of CO_2 equivalent in 2010 with the cap rising 5 percent annually.[34] The Senators are investigating the details of creating a mandatory economy-wide cap and trade system based on mandatory reductions in greenhouse gas intensity (measured in tons of emissions per dollar of GDP). In the spring of 2006, the Senate Energy and Natural Resources Committee held hearings to develop the details of a proposal.[35] During these hearings many companies in the electric power sector, such as Exelon, Duke Energy, and PNM Resources, expressed support for a mandatory national greenhouse gas cap and trade program.[36]

Two other proposals in early 2006 have added to the detail of the increasingly lively discussion of federal climate change strategies. Senator Feinstein (D-CA) issued a proposal for an economy-wide cap and trade system in order to further spur debate on the issue.[37] Senator Feinstein's proposal would cap emissions and seek reductions at levels largely consistent with the original McCain-Lieberman proposal. The most recent proposal to be added to the discussion is one by Reps. Tom Udall (D-NM) and Tom Petri (R-WI). The proposal includes a market-based trading system with an emissions cap to be established by the EPA about three years after the bill becomes law. The bill includes provisions to spur new research and development by setting aside 25 percent of the trading system's allocations for a new Energy Department technology program, and 10 percent of the plan's emission allowances to the State Department for spending on zero-carbon and low-carbon projects in developing nations. The bill would regulate greenhouse gas emissions at "upstream" sources such as coal mines and oil imports. Also,

[34] National Commission on Energy Policy, *Ending the Energy Stalemate*, December 2004, pages 19-29.

[35] The Senators have issued a white paper, inviting comments on various aspects of a greenhouse gas regulatory system. See, Senator Pete V. Domenici and Senator Jeff Bingaman, "Design Elements of a Mandatory Market-based Greenhouse Gas Regulatory System," issued February 2, 2006.

[36] All of the comments submitted to the Senate Energy and Natural Resources Committee are available at: http://energy.senate.gov/public/index.cfm?FuseAction=IssueItems.View&IssueItem_ID=38

[37] Letter of Senator Feinstein announcing "Strong Economy and Climate Protection Act of 2006," March 20, 2006.

it would establish a "safety valve" initially limiting the price of a ton of carbon dioxide emission to $25.[38]

Figure 5.1 illustrates the anticipated emissions trajectories from the economy-wide proposals - though the most recent proposal in the House is not included due to its lack of a specified emissions cap.

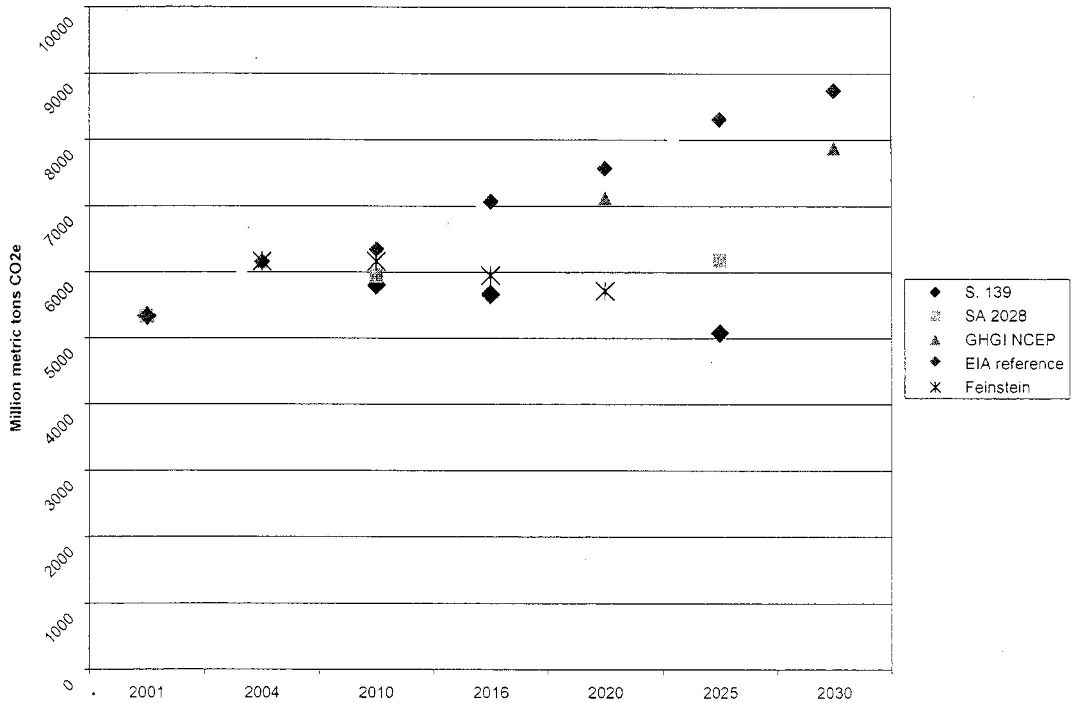

Figure 5.1. Emission Trajectories of Proposed Federal Legislation

Anticipated emissions trajectories from federal proposals for economy-wide greenhouse gas cap and trade proposals (McCain Lieberman S.139 Climate Stewardship Act 2003, McCain-Lieberman SA 2028 Climate Stewardship Act 2005, National Commission on Energy Policy greenhouse gas emissions intensity cap, and Senator Feinstein's Strong Economy and Climate Protection Act). EIA Reference trajectory is a composite of Reference cases in EIA analyses of the above policy proposals.

The emissions trajectories contained in the proposed federal legislation are in fact quite modest compared with emissions reductions that are anticipated to be necessary to achieve stabilization of atmospheric concentrations of greenhouse gases at levels that correspond to temperature increase of about 2 degrees centigrade. Figure 5.2 compares various emission reduction trajectories and goals in relation to a 1990 baseline. US federal proposals, and even Kyoto Protocol reduction targets, are small compared with the current EU emissions reduction target for 2020, and emissions reductions that will ultimately be necessary to cope with global warming.

[38] Press release, "Udall and Petri introduce legislation to curb global warming," March 29, 2006.

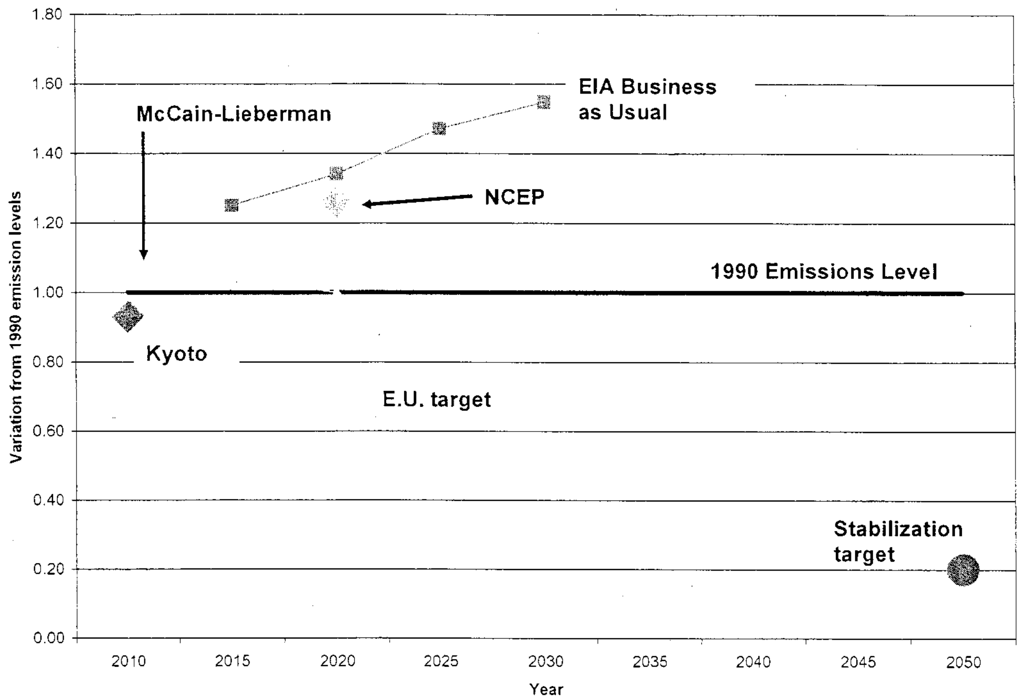

Figure 5.2 Comparison of Emission Reduction Goals

Figure compares emission reduction goals with 1990 as the baseline. Kyoto Protocol target for the United States would have been 7% below 1990 emissions levels. EU target is 20-30% below 1990 emissions levels. Stabilization target represents a reduction of 80% below 1990 levels. While there is no international agreement on the level at which emissions concentrations should be stabilized, and the emissions trajectory to achieve a stabilization target is not determined, reductions of 80% below 1990 levels indicates the magnitude of emissions reductions that are currently anticipated to be necessary.

As illustrated in the above figure, long term emission reduction goals are likely to be much more aggressive than those contained in federal policy proposals to date. Thus it is likely that cost projections will increase as targets become more stringent.

While efforts continue at the federal level, some individual states and regions are adopting their own greenhouse gas mitigation policies. Many corporations are also taking steps, on their own initiative, pursuant to state requirements, or under pressure from shareholder resolutions, in anticipation of mandates to reduce emissions of greenhouse gases. These efforts are described below.

5.2 State and regional policies

Many states across the country have not waited for federal policies and are developing and implementing climate change-related policies that have a direct bearing on resource choices in the electric sector. States, acting individually, and through regional coordination, have been the leaders on climate change policies in the United States. Generally, policies that individual states adopt fall into the following categories: (1) Direct policies that require specific emission reductions from electric generation sources; and (2) Indirect policies that affect electric sector resource mix such as through promoting low-emission electric sources; (3) Legal proceedings; or (4) Voluntary programs including educational efforts and energy planning.

Table 5.2. Summary of Individual State Climate Change Policies

Type of Policy	Examples
Direct	
• Power plant emission restrictions (e.g. cap or emission rate)	• MA, NH
• New plant emission restrictions	• OR, WA
• State GHG reduction targets	• CT, NJ, ME, MA, CA, NM, NY, OR, WA
• Fuel/generation efficiency	• CA vehicle emissions standards to be adopted by CT, NY, ME, MA, NJ, OR, PA, RI, VT, WA
Indirect (clean energy)	
• Load-based GHG cap	• CA
• GHG in resource planning	• CA, WA, OR, MT, KY
• Renewable portfolio standards	• 22 states and D.C.
• Energy efficiency/renewable charges and funding; energy efficiency programs	• More than half the states
• Net metering, tax incentives	• 41 states
Lawsuits	
• States, environmental groups sue EPA to determine whether greenhouse gases can be regulated under the Clean Air Act	• States include CA, CT, ME, MA, NM, NY, OR, RI, VT, and WI
• States sue individual companies to reduce GHG emissions	• NY, CT, CA, IA, NJ, RI, VT, WI
Climate change action plans	• 28 states, with NC and AZ in progress

Several states have adopted direct policies that require specific emission reductions from specific electric sources. Some states have capped carbon dioxide emissions from sources in the state (through rulemaking or legislation), and some restrict emissions from new sources through offset requirements. The California Public Utilities Commission recently stated that it will develop a load-based cap on greenhouse gas emissions in the electric sector. Table 5.3 summarizes these direct policies.

Table 5.3. State Policies Requiring GHG Emission Reductions From Power Plants

Program type	State	Description	Date	Source
Emissions limit	MA	Department of Environmental Protection decision capping GHG emissions, requiring 10 percent reduction from historic baseline	April 1, 2001	310 C.M.R. 7.29
Emissions limit	NH	NH Clean Power Act	May 1, 2002	HB 284
Emissions limit on new plants	OR	Standard for CO_2 emissions from new electricity generating facilities (base-load gas, and non-base load generation)	Updated September 2003	OR Admin. Rules, Ch. 345, Div 24
Emissions limit on new plants	WA	Law requiring new power plants to mitigate emissions or pay for a portion of emissions	March 1, 2004	RCW 80.70.020
Load-based emissions limit	CA	Public Utilities Commission decision stating intent to establish load-based cap on GHG emissions	February 17, 2006	D. 06-02-032 in docket R. 04-04-003

Several states require that integrated utilities or default service suppliers evaluate costs or risks associated with greenhouse gas emissions in long-range planning or resource procurement. Some of the states such as California require that companies use a specific value, while other states require generally that companies consider the risk of future regulation in their planning process. Table 5.4 summarizes state requirements for consideration of greenhouse gas emissions in the planning process.

Table 5.4. Requirements for Consideration of GHG Emissions in Electric Resource Decisions

Program type	State	Description	Date	Source
GHG value in resource planning	CA	PUC requires that regulated utility IRPs include carbon adder of $8/ton CO_2, escalating at 5% per year.	April 1, 2005	CPUC Decision 05-04-024
GHG value in resource planning	WA	Law requiring that cost of risks associated with carbon emissions be included in Integrated Resource Planning for electric and gas utilities	January, 2006	WAC 480-100-238 and 480-90-238
GHG value in resource planning	OR	PUC requires that regulated utility IRPs include analysis of a range of carbon costs	Year 1993	Order 93-695
GHG value in resource planning	NWPCC	Inclusion of carbon tax scenarios in Fifth Power Plan	May, 2006	NWPCC Fifth Energy Plan
GHG value in resource planning	MN	Law requires utilities to use PUC established environmental externalities values in resource planning	January 3, 1997	Order in Docket No. E-999/CI-93-583
GHG in resource planning	MT	IRP statute includes an "Environmental Externality Adjustment Factor" which includes risk due to greenhouse gases. PSC required Northwestern to account for financial risk of carbon dioxide emissions in 2005 IRP.	August 17, 2004	Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229; Sec. 38.5.8219, A.R.M.
GHG in resource planning	KY	KY staff reports on IRP require IRPs to demonstrate that planning adequately reflects impact of future CO_2 restrictions	2003 and 2006	Staff Report On the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company - Case 2005-00162, February 2006
GHG in resource planning	UT	Commission directs Pacificorp to consider financial risk associated with potential future regulations, including carbon regulation	June 18, 1992	Docket 90-2035-01, and subsequent IRP reviews
GHG in resource planning	MN	Commission directs Xcel to "provide an expansion of CO2 contingency planning to check the extent to which resource mix changes can lower the cost of meeting customer demand under different forms of regulation."	August 29, 2001	Order in Docket No. RP00-787
GHG in CON	MN	Law requires that proposed non-renewable generating facilities consider the risk of environmental regulation over expected useful life of the facility	2005	Minn. Stat. §216B.243 subd. 3(12)

In June 2005 both California and New Mexico adopted ambitious greenhouse gas emission reduction targets that are consistent with current scientific understanding of the emissions reductions that are likely to be necessary to avoid dangerous human interference with the climate system. In California, an Executive Order directs the state to reduce GHG emissions to 2000 levels by 2010, 1990 levels by 2020, and 80 percent below 1990 levels by 2050. In New Mexico, an Executive Order established statewide goals to reduce New Mexico's total greenhouse gas emissions to 2000 levels by 2012, 10 percent below those levels by 2020, and 75 percent below 2000 levels by 2050. In September 2005 New Mexico also adopted a legally binding agreement to lower emissions through the Chicago Climate Exchange. More broadly, to date at least twenty-eight states have developed Climate Action Plans that include statewide plans for addressing climate change issues. Arizona and North Carolina are in the process of developing such plans.

States are also pursuing other approaches. For example, in November 2005, the governor of Pennsylvania announced a new program to modernize energy infrastructure through replacement of traditional coal technology with advanced coal gasification technology. Energy Deployment for a Growing Economy allows coal plant owners a limited time to continue to operate without updated emissions technology as long as they make a commitment by 2007 to replace older plants with IGCC by 2013.[39] In September of 2005 the North Carolina legislature formed a commission to study and make recommendations on voluntary GHG emissions controls. In October 2005, New Jersey designated carbon dioxide as a pollutant, a necessary step for the state's participation in the Regional Greenhouse Gas Initiative (described below).[40]

Finally, states are pursuing legal proceedings addressing greenhouse gas emissions. Many states have participated in one or several legal proceedings to seek greenhouse gas emission reductions from some of the largest polluting power plants. Some states have also sought a legal determination regarding regulation of greenhouse gases under the Clean Air Act. The most recent case involves 10 states and two cities suing the Environmental Protection Agency to determine whether greenhouse gases can be regulated under the Clean Air Act.[41] The states argue that EPA's recent emissions standards for new sources should include carbon dioxide since carbon dioxide, as a major contributor to global warming, harms public health and welfare, and thus falls within the scope of the Clean Air Act.

While much of the focus to date has been on the electric sector, states are also beginning to address greenhouse gas emissions in other sectors. For example, California has

[39] Press release, "Governor Rendell's New Initiative, 'The Pennsylvania EDGE,' Will Put Commonwealth's Energy Resources to Work to Grow Economy, Clean Environment," November 28, 2005.

[40] Press release, "Codey Takes Crucial Step to Combat Global Warming," October 18, 2005.

[41] The states are CA, CT, ME, MA, NM, NY, OR, RI, VT, and WI. New York City and Washington D.C., as well as the Natural Resources Defense Council, the Sierra Club, and Environmental Defense. New York State Attorney General Eliot Spitzer, "States Sue EPA for Violating Clean Air Act and Failing to Act on Global Warming," press release, April 27, 2006.

adopted emissions standards for vehicles that would restrict carbon dioxide emissions. Ten other states have decided to adopt California's vehicle emissions standards.

States are not just acting individually; there are several examples of innovative regional policy initiatives that range from agreeing to coordinate information (e.g. Southwest governors, and Midwestern legislators) to development of a regional cap and trade program through the Regional Greenhouse Gas Initiative in the Northeast. These regional activities are summarized in Table 5.5, below.

Table 5.5. Regional Climate Change Policy Initiatives

Program type	State	Description	Date	Source
Regional GHG reduction Plan	CT, DE, MD, ME, NH, NJ, NY, VT	Regional Greenhouse Gas Initiative capping GHG emissions in the region and establishing trading program	MOU December 20, 2005, Model Rule February 2006	Memorandum of Understanding and Model Rule
Regional GHG reduction Plan	CA, OR, WA	West Coast Governors' Climate Change Initiative	September 2003, Staff report November 2004	Staff Report to the Governors
Regional GHG coordination	NM, AZ	Southwest Climate Change Initiative	February 28, 2006	Press release
Regional legislative coordination	IL, IA, MI, MN, OH, WI	Legislators from multiple states agree to coordinate regional initiatives limiting global warming pollution	February 7, 2006	Press release
Regional Climate Change Action Plan	New England, Eastern Canada	New England Governors and Eastern Canadian Premiers agreement for comprehensive regional Climate Change Action Plan. Targets are to reduce regional GHG emissions to 1990 levels by 2010, at least 10 percent below 1990 levels by 2020, and long-term reduction consistent with elimination of dangerous threat to climate (75-85 percent below current levels).	August, 2001	Memorandum of Understanding

Seven Northeastern and Mid-Atlantic states (CT, DE, ME, NH, NJ, NY, and VT) reached agreement in December 2005 on the creation of a regional greenhouse gas cap and trade program. The Regional Greenhouse Gas Initiative (RGGI) is a multi-year cooperative effort to design a regional cap and trade program initially covering CO_2 emissions from power plants in the region. Massachusetts and Rhode Island have actively participated in RGGI, but have not yet signed the agreement. Collectively, these states and Massachusetts and Rhode Island (which participated in RGGI negotiations) contribute 9.3 percent of total US CO_2 emissions and together rank as the fifth highest CO_2 emitter in the world. Maryland passed a law in April 2006 requiring participation in RGGI.[42] Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process.[43]

The RGGI states have agreed to the following:

- Stabilization of CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019.
- Allocation of a minimum of 25 percent of allowances for consumer benefit and strategic energy purposes
- Certain offset provisions that increase flexibility to moderate price impacts
- Development of complimentary energy policies to improve energy efficiency, decrease the use of higher polluting electricity generation and to maintain economic growth.[44]

The states released a Model Rule in February 2006. The states must next consider adoption of rules consistent with the Model Rule through their regular legislative and regulatory policies and procedures.

Many cities and towns are also adopting climate change policies. Over 150 cities in the United States have adopted plans and initiatives to reduce emissions of greenhouse gases, setting emissions reduction targets and taking measures within municipal government operations. Climate change was a major issue at the annual US Conference of Mayors convention in June 2005, when the Conference voted unanimously to support a climate protection agreement, which commits cities to the goal of reducing emissions seven percent below 1990 levels by 2012.[45] World-wide, the Cities for Climate Protection Campaign (CCP), begun in 1993, is a global campaign to reduce emissions that cause climate change and air pollution. By 1999, the campaign had engaged more than 350 local governments in this effort, who jointly accounted for approximately seven percent of global greenhouse gas emissions.[46]All of these recent activities contribute to growing pressure within the United States to adopt regulations at a national level to reduce the emissions of greenhouse gases, particularly CO_2. This pressure is likely to increase over time as climate change issues and measures for addressing them become better

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[42] Maryland Senate Bill 154 *Healthy Air Act*, signed April 6, 2006.

[43] Information on this effort is available at www.rggi.org

[44] The MOU states "Each state will maintain and, where feasible, expand energy policies to decrease the use of less efficient or relatively higher polluting generation while maintaining economic growth. These may include such measures as: end-use efficiency programs, demand response programs, distributed generation policies, electricity rate designs, appliance efficiency standards and building codes. Also, each state will maintain and, where feasible, expand programs that encourage development of non-carbon emitting electric generation and related technologies." RGGI MOU, Section 7, December 20, 2005.

[45] the US Mayors Climate Protection Agreement, 2005. Information available at http://www.ci.seattle.wa.us/mayor/climate

[46] Information on the Cities for Climate Protection Campaign, including links to over 150 cities that have adopted greenhouse gas reduction measures, is available at http://www.iclei.org/projserv.htm#ccp

understood by the scientific community, by the public, the private sector, and particularly by elected officials.

5.3 Investor and corporate action

Several electric companies and other corporate leaders have supported the concept of a mandatory greenhouse gas emissions program in the United States. For example, in April 2006, the Chairman of Duke Energy, Paul Anderson, stated:

> From a business perspective, the need for mandatory federal policy in the United States to manage greenhouse gases is both urgent and real. In my view, voluntary actions will not get us where we need to be. Until business leaders know what the rules will be – which actions will be penalized and which will be rewarded – we will be unable to take the significant actions the issue requires.[47]

Similarly, in comments to the Senate Energy and Natural Resources Committee, the vice president of Exelon reiterated the company's support for a federal mandatory carbon policy, stating that "It is critical that we start now. We need the economic and regulatory certainty to invest in a low-carbon energy future."[48] Corporate leaders from other sectors are also increasingly recognizing climate change as a significant policy issue that will affect the economy and individual corporations. For example, leaders from Wal-Mart, GE, Shell, and BP, have all taken public positions supporting the development of mandatory climate change policies.[49]

In a 2004 national survey of electric generating companies in the United States, conducted by PA Consulting Group, about half the respondents believe that Congress will enact mandatory limits on CO_2 emissions within five years, while nearly 60 percent anticipate mandatory limits within the next 10 years. Respondents represented companies that generate roughly 30 percent of US electricity.[50] Similarly, in a 2005 survey of the North American electricity industry, 93% of respondents anticipate increased pressure to take action on global climate change.[51]

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[47] Paul Anderson, Chairman, Duke Energy, "Being (and Staying in Business): Sustainability from a Corporate Leadership Perspective," April 6, 2006 speech to CERES Annual Conference, at: http://www.duke-energy.com/news/mediainfo/viewpoint/PAnderson_CERES.pdf

[48] Elizabeth Moler, Exelon V.P., to the Senate Energy and Natural Resources Committee, April 4, 2006, quoted in Grist, http://www.grist.org/news/muck/2006/04/14/griscom-little/

[49] See, e.g., Raymond Bracy, V.P. for Corporate Affairs, Wal-Mart, Comments to Senate Energy and Natural Resources Committee hearings on the design of CO2 cap-and-trade system, April 4, 2006; David Slump, GE Energy, General Manager, Global Marketing, Comments to Senate Energy and Natural Resources Committee hearings on the design of CO2 cap-and-trade system, April 4, 2006; John Browne, CEO of BP, "Beyond Kyoto," Foreign Affairs, July/August 2004; Shell company website at www.shell.com.

[50] PA Consulting Group, "Environmental Survey 2004" Press release, October 22, 2004.

[51] GF Energy, "GF Energy 2005 Electricity Outlook" January 2005. However, it is interesting to note that climate ranked 11th among issues deemed important to individual companies.

Some investors and corporate leaders have taken steps to manage risk associated with climate change and carbon policy. Investors are gradually becoming aware of the financial risks associated with climate change, and there is a growing body of literature regarding the financial risks to electric companies and others associated with climate change. Many investors are now demanding that companies take seriously the risks associated with carbon emissions. Shareholders have filed a record number of global warming resolutions for 2005 for oil and gas companies, electric power producers, real estate firms, manufacturers, financial institutions, and auto makers.[52] The resolutions request financial risk disclosure and plans to reduce greenhouse gas emissions. Four electric utilities – AEP, Cinergy, TXU and Southern – have all released reports on climate risk following shareholder requests in 2004. In February 2006, four more US electric power companies in Missouri and Wisconsin also agreed to prepare climate risk reports.[53]

State and city treasurers, labor pension fund officials, and foundation leaders have formed the Investor Network on Climate Risk (INCR) which now includes investors controlling $3 trillion in assets. In 2005, the INCR issued "A New Call for Action: Managing Climate Risk and Capturing the Opportunities," which discusses efforts to address climate risk since 2003 and identifies areas for further action. It urges institutional investors, fund managers, companies, and government policymakers to increase their oversight and scrutiny of the investment implications of climate change.[54] A 2004 report cites analysis indicating that carbon constraints affect market value – with modest greenhouse gas controls reducing the market capitalization of many coal-dependent US electric utilities by 5 to 10 percent, while a more stringent reduction target could reduce their market value 10 to 35 percent. [55] The report recommends, as one of the steps that company CEOs should pursue, integrating climate policy in strategic business planning to maximize opportunities and minimize risks.

Institutional investors have formed The Carbon Disclosure Project (CDP), which is a forum for institutional investors to collaborate on climate change issues. Its mission is to inform investors regarding the significant risks and opportunities presented by climate change; and to inform company management regarding the serious concerns of shareholders regarding the impact of these issues on company value. Involvement with the CDP tripled in about two and a half years, from $10 trillion under managements in

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[52] "US Companies Face Record Number of Global Warming Shareholder Resolutions on Wider Range of Business Sectors," CERES press release, February 17, 2005.

[53] "Four Electric Power Companies in Midwest Agree to Disclose Climate Risk," CERES press release February 21, 2006. Companies are Great Plains Energy Inc. in Kansas City, MO, Alliant Energy in Madison, WI, WPS Resources in Green Bay, WI and MGE Energy in Madison, WI.

[54] 2005 Institutional Investor Summit, "A New Call for Action: Managing Climate Risk and Capturing the Opportunities," May 10, 2005. The Final Report from the 2003 Institutional Investors Summit on Climate Risk, November 21, 2003 contains good summary information on risk associated with climate change.

[55] Cogan, Douglas G.; "Investor Guide to Climate Risk: Action Plan and Resource for Plan Sponsors, Fund Managers, and Corporations;" Investor Responsibility Research Center; July 2004 citing Frank Dixon and Martin Whittaker, "Valuing Corporate Environmental Performance: Innovest's Evaluation of the Electric Utilities Industry," New York, 1999.

Nov. 2003 to $31 trillion under management today.[56] The CDP released its third report in September 2005. This report continued the trend in the previous reports of increased participation in the survey, and demonstrated increasing awareness of climate change and of the business risks posed by climate change. CDP traces the escalation in scope and awareness – on behalf of both signatories and respondents – to an increased sense of urgency with respect to climate risk and carbon finance in the global business and investment community.[57]

Findings in the third CDP report included:

- More than 70% of FT500 companies responded to the CDP information request, a jump from 59% in CDP2 and 47% in CDP1.[58]
- More than 90% of the 354 responding FT500 companies flagged climate change as posing commercial risks and/or opportunities to their business.
- 86% reported allocating management responsibility for climate change.
- 80% disclosed emissions data.
- 63% of FT500 companies are taking steps to assess their climate risk and institute strategies to reduce greenhouse gas emissions.[59]

The fourth CDP information request (CDP4) was sent on behalf of 211 institutional investors with significant assets under management to the Chairmen of more than 1900 companies on February 1, 2006, including 300 of the largest electric utilities globally.

The California Public Employees' Retirement System (CalPERS) announced that it will use the influence made possible by its $183 billion portfolio to try to convince companies it invests in to release information on how they address climate change. The CalPERS board of trustees voted unanimously for the environmental initiative, which focuses on the auto and utility sectors in addition to promoting investment in firms with good environmental practices.[60]

Major financial institutions have also begun to incorporate climate change into their corporate policy. For example, Goldman Sachs and JP Morgan support mandatory market-based greenhouse gas reduction policies, and take greenhouse gas emissions into account in their financial analyses. Goldman Sachs was the first global investment bank to adopt a comprehensive environmental policy establishing company greenhouse gas

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[56] See: http://www.cdproject.net/aboutus.asp

[57] Innovest Strategic Value Advisors; "Climate Change and Shareholder Value In 2004," second report of the Carbon Disclosure Project; Innovest Strategic Value Advisors and the Carbon Disclosure Project; May 2004.

[58] FT 500 is the Financial Times' ranking of the top 500 companies ranked globally and by sector based on market capital.

[59] CDP press release, September 14, 2005. Information on the Carbon Disclosure Project, including reports, are available at: http://www.cdproject.net/index.asp.

[60] *Greenwire*, February 16, 2005

reduction targets and supporting a national policy to limit greenhouse gas emissions.[61] JP Morgan, Citigroup, and Bank of America have all adopted lending policies that cover a variety of project impacts including climate change.

Some CEOs in the electric industry have determined that inaction on climate change issues is not good corporate strategy, and individual electric companies have taken steps to reduce greenhouse gas emissions. Their actions represent increasing initiative in the electric industry to address the threat of climate change and manage risk associated with future carbon constraints. Recently, eight US-based utility companies have joined forces to create the "Clean Energy Group." This group's mission is to seek "national four-pollutant legislation that would, among other things… stabilize carbon emissions at 2001 levels by 2013."[62] The President of Duke Energy urges a federal carbon tax, and states that Duke should be a leader on climate change policy.[63] Prior to its merger with Duke, Cinergy Corporation was vocal on its support of mandatory national carbon regulation. Cinergy established a target is to produce 5 percent below 2000 levels by 2010 – 2012. AEP adopted a similar target. FPL Group and PSEG are both aiming to reduce total emissions by 18 percent between 2000 and 2008.[64] A fundamental impediment to action on the part of electric generating companies is the lack of clear, consistent, national guidelines so that companies could pursue emissions reductions without sacrificing competitiveness.

While statements such as these are an important first step, they are only a starting point, and do not, in and of themselves, cause reductions in carbon emissions. It is important to keep in mind the distinction between policy statements and actions consistent with those statements.

6. Anticipating the cost of reducing carbon emissions in the electric sector

Uncertainty about the form of future greenhouse gas reduction policies poses a planning challenge for generation-owning entities in the electric sector, including utilities and non-utility generators. Nevertheless, it is not reasonable or prudent to assume in resource planning that there is no cost or financial risk associated with carbon dioxide emissions, or with other greenhouse gas emissions. There is clear evidence of climate change, federal legislation has been under discussion for the past few years, state and regional regulatory efforts are currently underway, investors are increasingly pushing for companies to address climate change, and the electric sector is likely to constitute one of

[61] Goldman Sachs Environmental Policy Framework, http://www.gs.com/our_firm/our_culture/corporate_citizenship/environmental_policy_framework/docs/EnvironmentalPolicyFramework.pdf

[62] Jacobson, Sanne, Neil Numark and Paloma Sarria, "Greenhouse Gas Emissions: A Changing US Climate," *Public Utilities Fortnightly*, February 2005.

[63] Paul M. Anderson Letter to Shareholders, March 15, 2005.

[64] Ibid.

the primary elements of any future regulatory plan. Analyses of various economy-wide policies indicate that a majority of emissions reductions will come from the electric sector. In this context and policy climate, utilities and non-utility generators must develop a reasoned assessment of the costs associated with expected emissions reductions requirements. Including this assessment in the evaluation of resource options enables companies to judge the robustness of a plan under a variety of potential circumstances.

This is particularly important in an industry where new capital stock usually has a lifetime of 50 or more years. An analysis of capital cycles in the electric sector finds that "external market conditions are the most significant influence on a firm's decision to invest in or decommission large pieces of physical capital stock.[65] Failure to adequately assess market conditions, including the potential cost increases associated with likely regulation, poses a significant investment risk for utilities. It would be imprudent for any company investing in plants in the electric sector, where capital costs are high and assets are long-lived, to ignore policies that are inevitable in the next five to twenty years. Likewise, it would be short-sighted for a regulatory entity to accept the valuation of carbon emissions at no cost.

Evidence suggests that a utility's overall compliance decisions will be more efficient if based on consideration of several pollutants at once, rather than addressing pollutants separately. For example, in a 1999 study EPA found that pollution control strategies to reduce emissions of nitrogen oxides, sulfur dioxide, carbon dioxide, and mercury are highly inter-related, and that the costs of control strategies are highly interdependent.[66] The study found that the total costs of a coordinated set of actions is less than that of a piecemeal approach, that plant owners will adopt different control strategies if they are aware of multiple pollutant requirements, and that combined SO_2 and carbon emissions reduction options lead to further emissions reductions.[67] Similarly, in one of several studies on multi-pollutant strategies, the Energy Information Administration (EIA) found that using an integrated approach to NO_x, SO_2, and CO_2, is likely to lead to lower total costs than addressing pollutants one at a time.[68] While these studies clearly indicate that federal emissions policies should be comprehensive and address multiple pollutants, they also demonstrate the value of including future carbon costs in current resource planning activities.

There are a variety of sources of information that form a basis for developing a reasonable estimate of the cost of carbon emissions for utility planning purposes. Useful sources include recent market transactions in carbon markets, values that are currently being used in utility planning, and costs estimates based on scenario modeling of proposed federal legislation and the Regional Greenhouse Gas Initiative.

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[65] Lempert, Popper, Resitar and Hart, "Capital Cycles and the Timing of Climate Change Policy." Pew Center on Global Climate Change, October 2002. page

[66] US EPA, *Analysis of Emissions Reduction Options for the Electric Power Industry,* March 1999.

[67] US EPA, *Briefing Report*, March 1999.

[68] EIA, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide.* December 2000.

6.1 International market transactions

Implementation of the Kyoto Protocol has moved forward with great progress in recent years. Countries in the European Union (EU) are now trading carbon in the first international emissions market, the EU Emissions Trading Scheme (ETS), which officially launched on January 1, 2005. This market, however, was operating before that time – Shell and Nuon entered the first trade on the ETS in February 2003. Trading volumes increased steadily throughout 2004 and totaled approximately 8 million tons CO_2 in that year. [69]

Prices for current- and near-term EU allowances (2006-2007) escalated sharply in 2005, rising from roughly \$11/ton CO_2 (9 euros/ton-CO_2) in the second half of 2004 and leveling off at about \$36/ton CO_2 (28 euros/ton- CO_2) early in 2006. In March 2006, the market price for 2008 allowances hovered at around \$32/ton CO_2 (25 euros/ton- CO_2).[70] Lower prices in late April resulted from several countries' announcements that their emissions were lower than anticipated. The EU member states will submit their carbon emission allocation plans for the period 2008-2012 in June. Market activity to date in the EU Emissions trading system illustrates the difficulty of predicting carbon emissions costs, and the financial risk potentially associated with carbon emissions.

With the US decision not to ratify the Kyoto Protocol, US businesses are unable to participate in the international markets, and emissions reductions in the United States have no value in international markets. When the United States does adopt a mandatory greenhouse gas policy, the ability of US businesses and companies to participate in international carbon markets will be affected by the design of the mandatory program. For example, if the mandatory program in the United States includes a safety valve price, it may restrict participation in international markets.[71]

6.2 Values used in electric resource planning

Several companies in the electric sector evaluate the costs and risks associated with carbon emissions in resource planning. Some of them do so at their own initiative, as part of prudent business management, others do so in compliance with state law or regulation.

Some states require companies under their jurisdiction to account for costs and/or risks associated with regulation of greenhouse gas emissions in resource planning. These states include California, Oregon, Washington, Montana, Kentucky (through staff reports), and Utah. Other states, such as Vermont, require that companies take into account environmental costs generally. The Northwest Power and Conservation Council

[69] "What determines the Price of Carbon," Carbon Market Analyst, *Point Carbon*, October 14, 2004.

[70] These prices are from Evolution Express trade data, http://www.evomarkets.com/, accessed on 3/31/06.

[71] See, e.g. Pershing, Jonathan, Comments in Response to Bingaman-Domenici Climate Change White Paper, March 13, 2006. Sandalow, David, Comments in Response to Bingaman-Domenici Climate Change White Paper, The Brookings Institution, March 13, 2006.

includes various carbon scenarios in its Fifth Power Plan. For more information on these requirements, see the section above on state policies.[72]

California has one of the most specific requirements for valuation of carbon in integrated resource planning. The California Public Utilities Commission (PUC) requires companies to include a carbon adder in long-term resource procurement plans. The Commission's decision requires the state's largest electric utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) to factor the financial risk associated with greenhouse gas emissions into new long-term power plant investments, and long-term resource plans. The Commission initially directed utilities to include a value between \$8–25/ton CO_2 in their submissions, and to justify their selection of a number.[73] In April 2005, the Commission adopted, for use in resource planning and bid evaluation, a CO_2 adder of \$8 per ton of CO_2 in 2004, escalating at 5% per year.[74] The Montana Public Service Commission specifically directed Northwest Energy to evaluate the risks associated with greenhouse gas emissions in its 2005 Integrated Resource Plan (IRP).[75] In 2006 the Oregon Public Utilities Commission (PUC) will be investigating its long-range planning requirements, and will consider whether a specific carbon adder should be required in the base case (Docket UM 1056).

Several electric utilities and electric generation companies have incorporated assumptions about carbon regulation and costs in their long term planning, and have set specific agendas to mitigate shareholder risks associated with future US carbon regulation policy. These utilities cite a variety of reasons for incorporating risk of future carbon regulation as a risk factor in their resource planning and evaluation, including scientific evidence of human-induced climate change, the US electric sector emissions contribution to emissions, and the magnitude of the financial risk of future greenhouse gas regulation.

Some of the companies believe that there is a high likelihood of federal regulation of greenhouse gas emissions within their planning period. For example, Pacificorp states a 50% probability of a CO_2 limit starting in 2010 and a 75% probability starting in 2011. The Northwest Power and Conservation Council models a 67% probability of federal regulation in the twenty-year planning period ending 2025 in its resource plan. Northwest Energy states that CO_2 taxes "are no longer a remote possibility."[76] Table 6.1 illustrates the range of carbon cost values, in \$/ton CO_2, that are currently being used in the industry for both resource planning and modeling of carbon regulation policies.

[72] For a discussion of the use of carbon values in integrated resource planning see, Wiser, Ryan, and Bolinger, Mark; *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans;* Lawrence Berkeley National Laboratories; August 2005. LBNL-58450

[73] California Public Utilities Commission, Decision 04-12-048, December 16, 2004

[74] California Public Utilities Commission, Decision 05-04-024, April 2005.

[75] Montana Public Service Commission, "Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229," August 17, 2004.

[76] Northwest Energy 2005 Electric Default Supply Resource Procurement Plan, December 20, 2005; Volume 1, p. 4.

Table 6.1 CO_2 Costs in Long Term Resource Plans

Company	CO2 emissions trading assumptions for various years ($2005)
PG&E*	$0-9/ton (start year 2006)
Avista 2003*	$3/ton (start year 2004)
Avista 2005	$7 and $25/ton (2010) $15 and $62/ton (2026 and 2023)
Portland General Electric*	$0-55/ton (start year 2003)
Xcel-PSCCo	$9/ton (start year 2010) escalating at 2.5%/year
Idaho Power*	$0-61/ton (start year 2008)
Pacificorp 2004	$0-55/ton
Northwest Energy 2005	$15 and $41/ton
Northwest Power and Conservation Council	$0-15/ton between 2008 and 2016 $0-31/ton after 2016

**Values for these utilities from Wiser, Ryan, and Bolinger, Mark. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." Lawrence Berkeley National Laboratories. August 2005. LBNL-58450. Table 7.*
Other values: PacifiCorp, Integrated Resource Plan 2003, pages 45-46; and Idaho Power Company, 2004 Integrated Resource Plan Draft, July 2004, page 59; Avista Integrated Resource Plan 2005, Section 6.3; Northwestern Energy Integrated Resource Plan 2005, Volume 1 p. 62; Northwest Power and Conservation Council, Fifth Power Plan pp. 6-7. Xcel-PSCCo, Comprehensive Settlement submitted to the CO PUC in dockets 04A-214E, 215E and 216E, December 3, 2004. Converted to $2005 using GDP implicit price deflator.

These early efforts by utilities have brought consideration of the risks associated with future carbon regulations into the mainstream in resource planning the electric sector.

6.3 Analyses of carbon emissions reduction costs

With the emergence of federal policy proposals in the United States in the past several years, there have been several policy analyses that project the cost of carbon-dioxide equivalent emission allowances under different policy designs. These studies reveal a range of cost estimates. While it is not possible to pinpoint emissions reduction costs given current uncertainties about the goal and design of carbon regulation as well as the inherent uncertainties in any forecast, the studies provide a useful source of information for inclusion in resource decisions. In addition to establishing ranges of cost estimates, the studies give a sense of which factors affect future costs of reducing carbon emissions.

There have been several studies of proposed federal cap and trade programs in the United States. Table 6.2 identifies some of the major recent studies of economy-wide carbon policy proposals.

Table 6.2. Analyses of US Carbon Policy Proposals

Policy proposal	Analysis
McCain Lieberman – S. 139	EIA 2003, MIT 2003, Tellus 2003
McCain Lieberman – SA 2028	EIA 2004, MIT 2003, Tellus 2004
Greenhouse Gas Intensity Targets	EIA 2005, EIA 2006
Jeffords – S. 150	EPA 2005
Carper 4-P – S. 843	EIA 2003, EPA 2005

Both versions of the McCain and Lieberman proposal (also known as the Climate Stewardship Act) were the subject of analyses by EIA, MIT, and the Tellus Institute. As originally proposed, the McCain Lieberman legislation capped 2010 emissions at 2000 levels, with a reduction in 2016 to 1990 levels. As revised, McCain Lieberman just included the initial cap at 2000 levels without a further restriction. In its analyses, EIA ran several sensitivity cases exploring the impact of technological innovation, gas prices, allowance auction, and flexibility mechanisms (banking and international offsets). [77]

In 2003 researchers at the Massachusetts Institute of Technology also analyzed potential costs of the McCain Lieberman legislation.[78] MIT held emissions for 2010 and beyond at 2000 levels (not modeling the second step of the proposed legislation). Due to constraints of the model, the MIT group studied an economy-wide emissions limit rather than a limit on the energy sector. A first set of scenarios considers the cap tightening in Phase II and banking. A second set of scenarios examines the possible effects of outside credits. And a final set examines the effects of different assumptions about baseline gross domestic product (GDP) and emissions growth.

The Tellus Institute conducted two studies for the Natural Resources Defense Council of the McCain Lieberman proposals (July 2003 and June 2004).[79] In its analysis of the first proposal (S. 139), Tellus relied on a modified version of the National Energy Modeling System that used more optimistic assumptions for energy efficiency and renewable energy technologies based on expert input from colleagues at the ACEEE, the Union of Concerned Scientists, the National Laboratories and elsewhere. Tellus then modeled two policy cases. The "Policy Case" scenario included the provisions of the Climate Stewardship Act (S.139) as well as oil savings measures, a national renewable transportation fuel standard, a national RPS, and emissions standards contained in the Clean Air Planning Act. The "Advanced Policy Case" included the same complimentary energy policies as the "Policy Case" and assumed additional oil savings in the

[77] Energy Information Administration, *Analysis of S. 139, the Climate Stewardship Act of 2003*, EIA June 2003, SR/OIAF/2003-02; Energy Information Administration, *Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003*, EIA May 2004, SR/OIAF/2004-06

[78] Paltsev, Sergei; Reilly, John M.; Jacoby, Henry D.; Ellerman, A. Denny; Tay, Kok Hou; *Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: the McCain-Lieberman Proposal.* MIT Joint Program on the Science and Policy of Global Change; Report No. 97; June 2003.

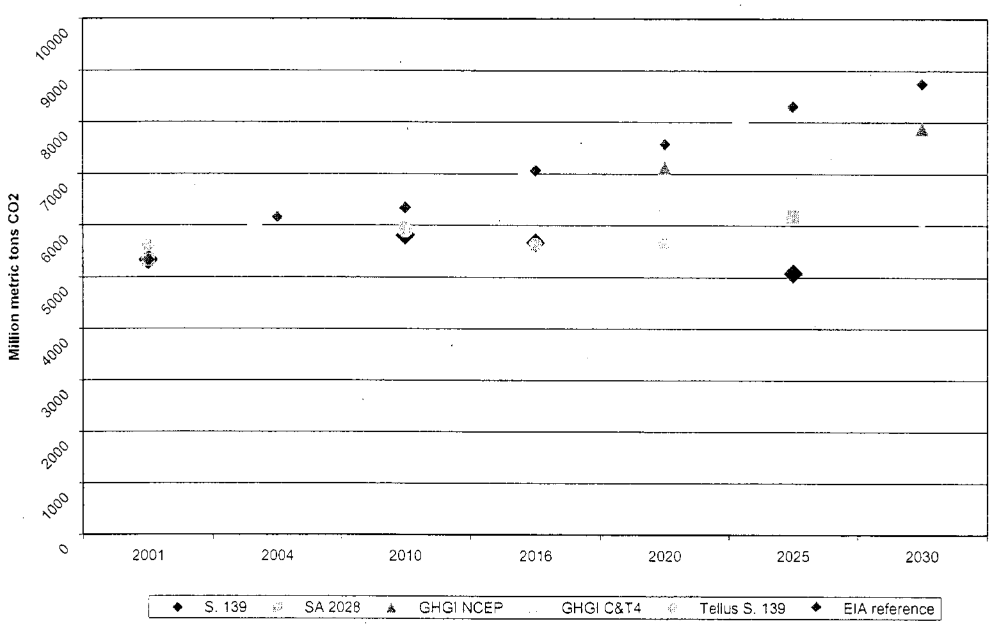
[79] Bailie et al., *Analysis of the Climate Stewardship Act,* July 2003; Bailie and Dougherty, *Analysis of the Climate Stewardship Act Amendment*, Tellus Institute, June, 2004. Available at http://www.tellus.org/energy/publications/McCainLieberman2004.pdf

transportation sector from increase the fuel efficiency of light-duty vehicles (CAFÉ) (25 mpg in 2005, increasing to 45 mpg in 2025).

EIA has also analyzed the effect and cost of greenhouse gas intensity targets as proposed by Senator Bingaman based on the National Commission on Energy Policy, as well as more stringent intensity targets.[80] Some of the scenarios included safety valve prices, and some did not.

In addition to the analysis of economy-wide policy proposals, proposals for GHG emissions restrictions have also been analyzed. Both EIA and the U.S. Environmental Protection Agency (EPA) analyzed the four-pollutant policy proposed by Senator Carper (S. 843).[81] EPA also analyzed the power sector proposal from Senator Jeffords (S. 150).[82]

Figure 6.1 shows the emissions trajectories that the analyses of economy-wide policies projected for specific policy proposals. The graph does not include projections for policies that would just apply to the electric sector since those are not directly comparable to economy-wide emissions trajectories.



[80] EIA, *Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals,* March 2006. SR/OIAF/2006-01.

[81] EIA. Analysis of S. 485, the Clear Skies Act of 2003, and S. 843, the Clean Air Planning Act of 2003. EIA Office of Integrated Analysis and Forecasting. SR/OIAF/2003-03. September 2003. US EPA, *Multi-pollutant Legislative Analysis: The Clean Power Act (Jeffords, S. 150 in the 109th).* US EPA Office of Air and Radiation, October 2005.

[82] US Environmental Protection Agency, *Multi-pollutant Legislative Analysis: The Clean Air Planning Act (Carper, S. 843 in the 108th).* US EPA Office of Air and Radiation, October 2005.

Figure 6.1. Projected Emissions Trajectories for US Economy-wide Carbon Policy Proposals.

Projected emissions trajectories from EIA and Tellus Institute Analyses of US economy-wide carbon policies. Emissions projections are for "affected sources" under proposed legislation. S. 139 is the EIA analysis of McCain Lieberman Climate Stewardship Act from 2003, SA 2028 is the EIA analysis of McCain Lieberman Climate Stewardship Act as amended in 2005. GHGI NCEP is the EIA analysis of greenhouse gas intensity targets recommended by the National Commission on Energy Policy and endorsed by Senators Bingaman and Domenici, GHGIC&T4 is the most stringent emission reduction target modeled by EIA in its 2006 analysis of greenhouse gas intensity targets, and Tellus S.139 is from the Tellus Institute analysis of S. 139.

Figure 6.2 presents projected carbon allowance costs from the economy-wide and electric sector studies in constant 2004 dollars per metric ton of carbon dioxide.

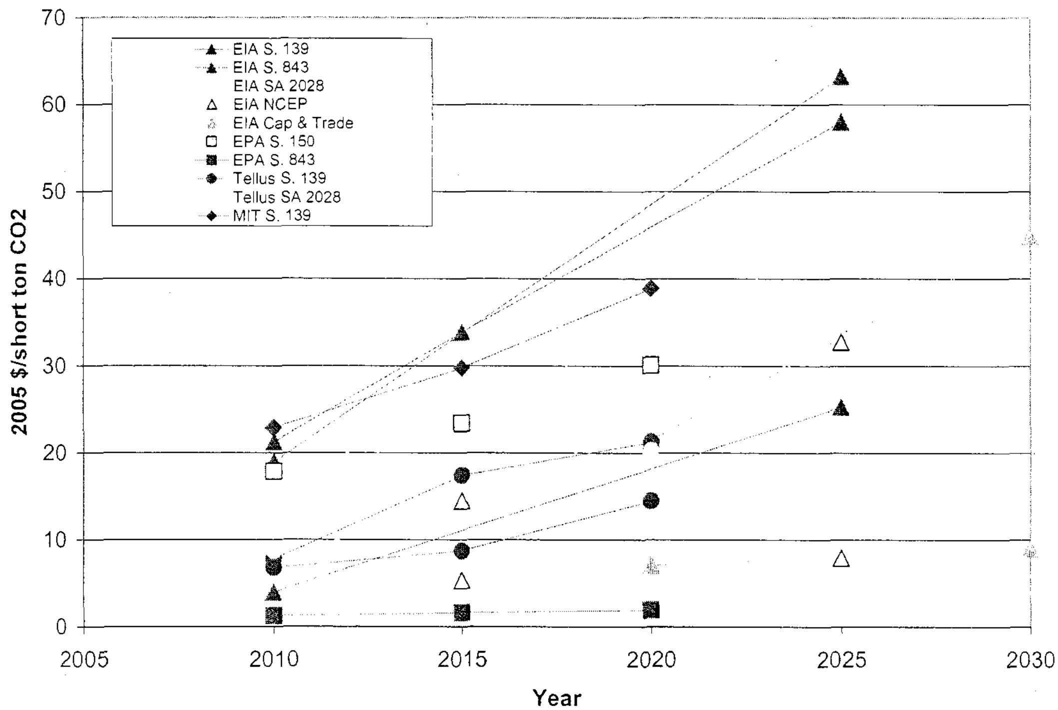


Figure 6.2. Allowance Cost Estimates From Studies of Economy-wide and Electric Sector US Policy Proposals

Carbon emissions price forecasts based on a range of proposed federal carbon regulations. Sources of data include: Triangles – US Energy Information Agency (EIA); Square – US EPA; Circles – Tellus Institute; Diamond – MIT. All values shown have been converted into 2005 dollars per short ton CO2 equivalent. Color-coded policies evaluated include:

***Blue:** S. 139, the McCain-Lieberman Climate Stewardship Act of January 2003. MIT Scenario includes banking and zero-cost credits (effectively relaxing the cap by 15% and 10% in phase I and II, respectively.) The Tellus scenarios are the "Policy" case (higher values) and the "Advanced" case (lower values). Both Tellus cases include complimentary emission reduction policies, with "advance" policy case assuming additional oil savings in the transportation sector from increase the fuel efficiency of light-duty vehicles (CAFÉ).*

***Tan:** S.150, the Clean Power Act of 2005*

***Violet:** S. 843, the Clean Air Planning Act of 2003. Includes international trading of offsets. EIA data include "High Offsets"(lower prices) and "Mid Offsets" (higher prices) cases. EPA data shows effect of tremendous offset flexibility.*

***Bright Green:** SA 2028, the McCain-Lieberman Climate Stewardship Act Amendment of October 2003. This version sets the emissions cap at constant 2000 levels and allows for 15% of the carbon reductions to be met through offsets from non-covered sectors, carbon sequestration and qualified international sources.*

***Yellow:** EIA analysis of the National Commission on Energy Policy (NCEP) policy option recommendations. Lower series has a safety-valve maximum permit price of $6.10 per metric ton CO2 in 2010 rising to $8.50 per metric ton CO2 in 2025, in 2003 dollars. Higher series has no safety value price. Both include a range of complementary policies recommended by NCEP.*

***Orange:** EIA analysis of cap and trade policies based on NCEP, but varying the carbon intensity reduction goals. Lower-priced series (Cap and trade 1) has an intensity reduction of 2.4%/yr from 2010 to 2020 and 2.8%/yr from 2020 to 2030; safety-valve prices are $6.16 in 2010, rising to $9.86 in 2030, in 2004 dollars. Higher-priced series (Cap and trade 4) has intensity reductions of 3% per year and 4% per year for 2010-2020 and 2020-2030, respectively, and safety-valve prices of $30.92 in 2010 rising to $49.47 in 2030, in 2004 dollars.*

The lowest allowance cost results (EPA S. 843, EIA NCEP, and EIA Cap & Trade) correspond to the EPA analysis of a power sector program with very extensive offset use, and to EIA analyses of greenhouse gas intensity targets with allowance safety valve prices. In these analyses, the identified emission reduction target is not achieved because the safety valve is triggered. In EIA GHGI C&T 4, the price is higher because the greenhouse gas intensity target is more stringent, and there is no safety valve. The EIA analysis of S. 843 shows higher cost projections because of the treatment of offsets, which clearly cause a huge range in the projections for this policy. In the EPA analysis, virtually all compliance is from offsets from sources outside of the power sector.

In addition to its recent modeling of US policy proposals, EIA has performed several studies projecting costs associated with compliance with the Kyoto Protocol. In 1998, EIA performed a study analyzing allowance costs associated with six scenarios ranging from emissions in 2010 at 24 percent above 1990 emissions levels, to emissions in 2010 at 7 percent below 1990 emissions levels.[83] In 1999 EIA performed a very similar study, but looked at phasing in carbon prices beginning in 2000 instead of 2005 as in the

[83] EIA, "Impacts of the Kyoto Protocol on US Energy Markets and Economic Activity," October 1998. SR/OIAD/98-03

original study.[84] Carbon dioxide costs projected in these EIA studies of Kyoto targets were generally higher than those projected in the studies of economy-wide legislative proposals due in part to the more stringent emission reduction requirements of the Kyoto Protocol. For example, carbon dioxide allowances for 2010 were projected at $91 per short ton CO_2 ($2005) and $100 per short ton CO_2 ($2005) respectively for targets of seven percent below 1990 emissions levels. While the United States has not ratified the Kyoto Protocol, these studies are informative since they evaluate more stringent emission reduction requirements than those contained in current federal policy proposals. Scientists anticipate that avoiding dangerous climate change will require even steeper reductions than those in the Kyoto Protocol.

The State Working Group of the RGGI in the Northeast engaged ICF Consulting to analyze the impacts of implementing a CO2 cap on the electric sector in the northeastern states. ICF used the IPM model to analyze the program package that the RGGI states ultimately agreed to. ICF's analysis results (in $2004) range from $1-$5/ton CO_2 in 2009 to about $2.50-$12/ton CO_2 in 2024.[85] The lowest CO2 allowance prices are associated with the RGGI program package under the expected emission growth scenario. The costs increase significantly under a high emissions scenario, and increase even more when the high emissions scenario is combined with a national cap and trade program due to the greater demand for allowances in a national program. ICF performed some analysis that included aggressive energy efficiency scenarios and found that those energy efficiency components would reduce the costs of the RGGI program significantly.

In 2003 ICF was retained by the state of Connecticut to model a carbon cap across the 10 northeastern states. The cap is set at 1990 levels in 2010, 5 percent below 1990 levels in 2015, and 10 percent below 1990 levels in 2020. The use of offsets is phased in with entities able to offset 5 percent or their emissions in 2015 and 10 percent in 2020. The CO_2 allowance price, in $US2004, for the 10-state region increases over the forecast period in the policy case, rising from $7/ton in 2010 to $11/ton in 2020.[86]

6.4 Factors that affect projections of carbon cost

Results from a range of studies highlight certain factors that affect projections of future carbon emissions prices. In particular, the studies provide insight into whether the factors increase or decrease expected costs, and to the relationships among different factors. A number of the key assumptions that affect policy cost projections (and indeed policy costs) are discussed in this section, and summarized in Table 6.3.

[84] EIA, "Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol," July 1999. SR/OIAF/99-02.

[85] ICF Consulting presentation of "RGGI Electricity Sector Modeling Results," September 21, 2005. Results of the ICF analysis are available at www.rggi.org

[86] Center for Clean Air Policy, *Connecticut Climate Change Stakeholder Dialogue: Recommendations to the Governors' Steering Committee*, January 2004, p. 3.3-27.

Here we only consider these factors in a qualitative sense, although quantitative meta-analyses do exist.[87] It is important to keep these factors in mind when attempting to compare and survey the range of cost/benefit studies for carbon emissions policies so the varying forecasts can be kept in the proper perspective.

Base case emissions forecast

Developing a business-as-usual case (in the absence of federal carbon emission regulations) is a complex modeling exercise in itself, requiring a wide range of assumptions and projections which are themselves subject to uncertainty. In addition to the question of future economic growth, assumptions must be made about the emissions intensity of that growth. Will growth be primarily in the service sector or in industry? Will technological improvements throughout the economy decrease the carbon emissions per unit of output?

In addition, a significant open question is the future generation mix in the United States. Throughout the 1990s most new generating investments were in natural gas-fired units, which emit much less carbon per unit of output than other fossil fuel sources. Today many utilities are looking at baseload coal due to the increased cost of natural gas, implying much higher emissions per MWh output. Some analysts predict a comeback for nuclear energy, which despite its high cost and unsolved waste disposal and safety issues has extremely low carbon emissions.

A business-as-usual case which included several decades of conventional base load coal, combined with rapid economic expansion, would present an extremely high emissions baseline. This would lead to an elevated projected cost of emissions reduction regardless of the assumed policy mechanism.

Complimentary policies

Complimentary energy policies, such as direct investments in energy efficiency, are a very effective way to reduce the demand for emissions allowances and thereby to lower their market price. A policy scenario which includes aggressive energy efficiency along with carbon emissions limits will result in lower allowances prices than one in which energy efficiency is not directly addressed.[88]

Policy implementation timeline and reduction target

Most "policy" scenarios are structured according to a goal such as achieving "1990 emissions by 2010" meaning that emissions should be decreased to a level in 2010 which

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[87] See, *e.g.*, Carolyn Fischer and Richard D. Morgenstern, *Carbon Abatement Costs: Why the Wide Range of Estimates?* Resources for the Future, September, 2003. http://www.rff.org/Documents/RFF-DP-03-42.pdf

[88] A recent analysis by ACEEE demonstrates the effect of energy efficiency investments in reducing the projected costs of the Regional Greenhouse Gas Initiative. Prindle, Shipley, and Elliott; *Energy Efficiency's Role in a Carbon Cap-and-Trade System: Modeling Results from the Regional Greenhouse Gas Initiative*; American Council for an Energy Efficient Economy, May 2006. Report Number E064.

is no higher than they were in 1990. Both of these policy parameters have strong implications for policy costs, although not necessarily in the intuitive sense. A later implementation date means that there is more time for the electric generating industry to develop and install mitigation technology, but it also means that if they wait to act, they will have to make much more drastic cuts in a short period of time. Models which assume phased-in targets, forcing industry to take early action, may stimulate technological innovations so that later, more aggressive targets can be reached at lower cost.

Program flexibility

The philosophy behind cap and trade regulation is that the rules should specify an overall emissions goal, but the market should find the most efficient way of meeting that goal. For emissions with broad impacts (as opposed to local health impacts) this approach will work best at minimizing cost if maximum flexibility is built into the system. For example, trading should be allowed across as broad as possible a geographical region, so that regions with lower mitigation cost will maximize their mitigation and sell their emission allowances. This need not be restricted to CO_2 but can include other GHGs on an equivalent basis, and indeed can potentially include trading for offsets which reduce atmospheric CO_2 such as reforestation projects. Another form of flexibility is to allow utilities to put emissions allowances "in the bank" to be used at a time when they hold higher value, or to allow international trading as is done in Europe through the Kyoto protocol.

One drawback to programs with higher flexibility is that they are much more complex to administer, monitor, and verify.[89] Emissions reductions must be credited only once, and offsets and trades must be associated with verifiable actions to reduce atmospheric CO_2. A generally accepted standard is the "five-point" test: "at a minimum, eligible offsets shall consist of actions that are real, surplus, verifiable, permanent and enforceable."[90] Still, there is a clear benefit in terms of overall mitigation costs to aim for as much flexibility as possible, especially as it is impossible to predict with certainty what the most cost-effective mitigation strategies will be in the future. Models which assume higher flexibility in all of these areas are likely to predict lower compliance costs for reaching any specified goal.

Technological progress

The rate of improvement in mitigation technology is a crucial assumption in predicting future emissions control costs. This has been an important factor in every major air emissions law, and has resulted, for example, in the pronounced downward trend in allowance prices for SO_2 and NO_x in the years since regulations of those two pollutants were enacted. For CO_2, looming questions include the future feasibility and cost of carbon capture and sequestration, and cost improvements in carbon-free generation

[89] An additional consideration is that greater geographic flexibility reduces potential local co-benefits, discussed below, that can derive from efforts to reduce greenhouse gas emissions.

[90] Massachusetts 310 CMR 7.29.

technologies. Improvements in the efficiency of coal burning technology or in the cost of nuclear power plants may also be a factor.

Reduced emissions co-benefits

Most technologies which reduce carbon emissions also reduce emissions of other criteria pollutants, such as NO_X, SO_2 and mercury. This results in cost savings not only to the generators who no longer need these permits, but also to broader economic benefits in the form of reduced permit costs and consequently lower priced electricity. In addition, there are a number of co-benefits such as improved public health, reduced premature mortality, and cleaner air associated with overall reductions in power plant emissions which have a high economic value to society. Models which include these co-benefits will predict a lower overall cost impact from carbon regulations, as the cost of reducing carbon emissions will be offset by savings in these other areas.

Table 6.3. Factors That Affect Future Carbon Emissions Policy Costs

Assumption	Increases Prices if…	Decreases Prices if…
• **"Base case" emissions forecast**	Assumes high rates of growth in the absence of a policy, strong and sustained economic growth	Lower forecast of business-as-usual" emissions
• **Complimentary policies**	No investments in programs to reduce carbon emissions	Aggressive investments in energy efficiency and renewable energy independent of emissions allowance market
• **Policy implementation timeline**	Delayed and/or sudden program implementation	Early action, phased-in emissions limits.
• **Reduction targets**	Aggressive reduction target, requiring high-cost marginal mitigation strategies	Minimal reduction target, within range of least-cost mitigation strategies
• **Program flexibility**	Minimal flexibility, limited use of trading, banking and offsets	High flexibility, broad trading geographically and among emissions types including various GHGs, allowance banking, inclusion of offsets perhaps including international projects.
• **Technological progress**	Assume only today's technology at today's costs	Assume rapid improvements in mitigation technology and cost reductions

Assumption	Increases Prices if...	Decreases Prices if...
• **Emissions co-benefits**	Ignore emissions co-benefits	Includes savings in reduced emissions of criteria pollutants.

Because of the uncertainties and interrelationships surrounding these factors, forecasting long-range carbon emissions price trajectories is quite complicated and involves significant uncertainty. Of course, this uncertainty is no greater than the uncertainty surrounding other key variables underlying future electricity costs, such as fuel prices, although there are certain characteristics that make carbon emissions price forecasting unique.

One of these is that the forecaster must predict the future political climate. As documented throughout this paper, recent years have seen a dramatic increase in both the documented effects of and the public awareness of global climate change. As these trends continue, it is likely that more aggressive and more expensive emissions policies will be politically feasible. Political events in other areas of the world may be another factor, in that it will be easier to justify aggressive policies in the United States if other nations such as China are also limiting emissions.

Another important consideration is the relationship between early investments and later emissions costs. It is likely that policies which produce high prices early will greatly accelerate technological innovation, which could lead to prices in the following decades which are lower than they would otherwise be. This effect has clearly played a role in NO_x and SO_2 allowance trading prices. However, the effect would be offset to some degree by the tendency for emissions limits to become more restrictive over time, especially if mitigation becomes less costly and the effects of global climate change become increasingly obvious.

6.5 Synapse forecast of carbon dioxide allowance prices

Below we offer an emissions price forecast which the authors judge to represent a reasonable range of likely future CO_2 allowance prices. Because of the factors discussed above and others, it is likely that the actual cost of emissions will not follow a smooth path like those shown here but will exhibit swings between and even outside of our "low" and "high" cases in response to political, technological, market and other factors. Nonetheless, we believe that these represent the most reasonable range to use for planning purposes, given all of the information we have been able to collect and analyze bearing on this important cost component of future electricity generation.

Figure 6.3 shows our price forecasts for the period 2010 through 2030, superimposed upon projections collected from other studies mentioned in this paper.

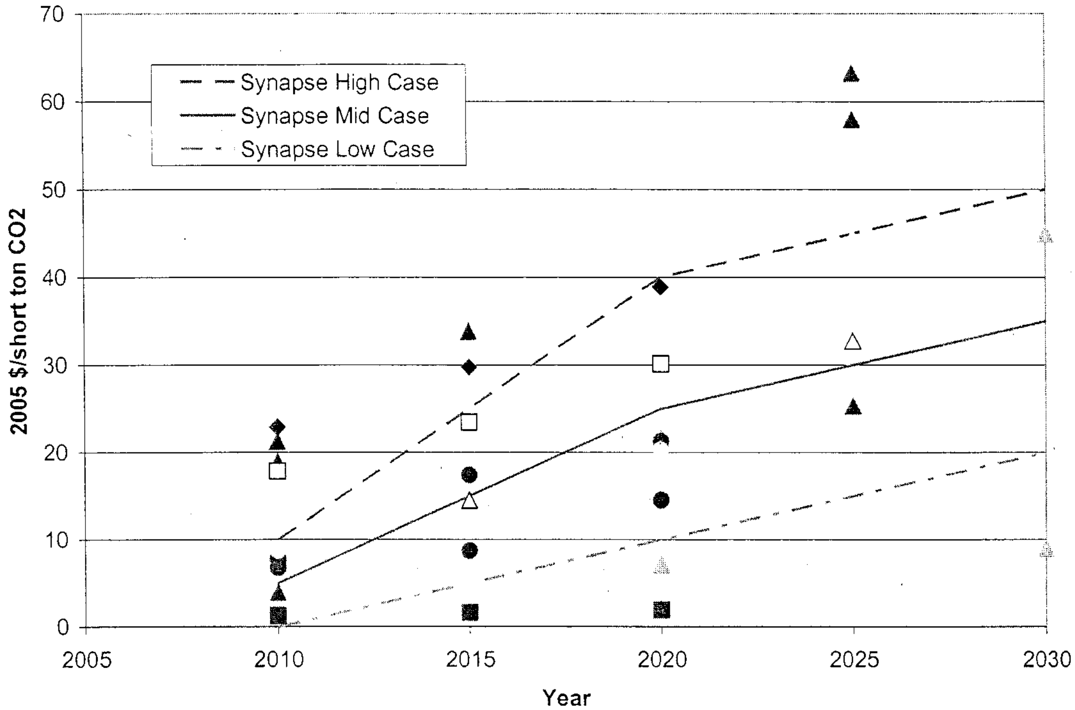

Figure 6.3. Synapse Forecast of Carbon Dioxide Allowance Prices

High, mid and low-case Synapse carbon dioxide emissions price forecasts superimposed on policy model forecasts as presented in Figure 6.2.

In developing our forecast we have reviewed the cost analyses of federal proposals, the Kyoto Protocol, and current electric company use of carbon values in IRP processes, as described earlier in this paper. The highest cost projections from studies of U.S. policy proposals generally reflect a combination of factors including more aggressive emissions reductions, conservative assumptions about complimentary energy policies, and limited or no offsets. For example, some of the highest results come from EIA analysis of the most aggressive emission reductions proposed -- the Climate Stewardship Act, as originally proposed by Senators McCain and Lieberman in 2003. Similarly, the highest cost projection for 2025 is from the EPA analysis of the Carper 4-P bill, S. 843, in a scenario with fairly restricted offset use. The lowest cost projections are from the analysis of the greenhouse gas intensity goal with a safety valve, as proposed by the National Commission on Energy Policy, as well as from an EPA analysis of the Carper 4-P bill, S. 843, with no restrictions on offset use. These highest and lowest cost estimates illustrate the effect of the factors that affect projections of CO_2 emissions costs, as discussed in the previous section.

We believe that the U.S. policies that have been modeled can reasonably be considered to represent the range of U.S. policies that could be adopted in the next several years. However, we do not anticipate the adoption of either the most aggressive or restrictive, or the most lenient and flexible policies illustrated in the range of projections from recent analyses. Thus we consider both the highest and the lowest cost projections from those studies to be outside of our reasonable forecast.

We note that EIA projections of costs to comply with Kyoto Protocol targets were much higher, in the range of \$100/ton CO_2. The higher cost projections associated with the Kyoto Protocol targets, which are somewhat more aggressive than U.S. policy proposals, are consistent with the anticipated effect of a more carbon-constrained future. The EIA analysis also has pessimistic assumptions regarding carbon emission-reducing technologies and complementary policies. The range of values that certain electric companies currently use in their resource planning and evaluation processes largely fall within the high and low cost projections from policy studies. Our forecast of carbon dioxide allowance prices is presented in Table 6.4.

Table 6.4. Synapse forecast of carbon dioxide allowance prices (\$2005/ton CO_2).

	2010	2020	2030	Levelized Value 2010-2040
Synapse Low Case	0	10	20	8.5
Synapse Mid Case	5	25	35	19.6
Synapse High Case	10	40	50	30.8

As illustrated in the table, we have identified what we believe to be a reasonable high, low, and mid case for three time periods: 2010, 2020, and 2030. These high, low, and mid case values for the years in question represent a range of values that are reasonably plausible for use in resource planning. Certainly other price trajectories are possible, indeed likely depending on factors such as level of reduction target, and year of implementation of a policy. We have much greater confidence in the levelized values over the period than we do in any particular annual values or in the specific shape of the price projections.

Using these value ranges, we have plotted cost lines in Figure 6.3 for use in resource analysis. In selecting these values, we have taken into account a variety of factors for the three time periods. While some regions and states may impose carbon emissions costs sooner, or federal legislation may be adopted sooner, our assumption conservatively assumes that implementation of any federal legislative requirements is unlikely before 2010. We project a cost in 2010 of between zero and \$10 per ton of CO_2.

During the decade from 2010 to 2020, we anticipate that a reasonable range of carbon emissions prices reflects the effects of increasing public concern over climate change (this public concern is likely to support increasingly stringent emission reduction requirements) and the reluctance of policymakers to take steps that would increase the cost of compliance (this reluctance could lead to increased emphasis on energy efficiency, modest emission reduction targets, or increased use of offsets). Thus we find the widest uncertainty in our forecasts begins at the end of this decade from \$10 to \$40 per ton of CO_2, depending on the relative strength of these factors.

After 2020, we expect the price of carbon emissions allowances to trend upward toward the marginal mitigation cost of carbon emissions. This number still depends on uncertain factors such as technological innovation and the stringency of carbon caps, but it is likely that the least expensive mitigation options (such as simple energy efficiency and fuel switching) will be exhausted. Our projection for the end of this decade ranges from $20 to $50 per ton of CO_2 emissions.

We think the most likely scenario is that as policymakers commit to taking serious action to reduce carbon emissions, they will choose to enact both cap and trade regimes and a range of complementary energy policies that lead to lower cost scenarios, and that technology innovation will reduce the price of low-carbon technologies, making the most likely scenario closer to (though not equal to) low case scenarios than the high case scenario. The probability of taking this path increases over time, as society learns more about optimal carbon reduction policies.

After 2030, and possibly even earlier, the uncertainty surrounding a forecast of carbon emission prices increases due to interplay of factors such as the level of carbon constraints required, and technological innovation. As discussed in previous sections, scientists anticipate that very significant emission reductions will be necessary, in the range of 80 percent below 1990 emission levels, to achieve stabilization targets that keep global temperature increases to a somewhat manageable level. As such, we believe there is a substantial likelihood that response to climate change impacts will require much more aggressive emission reductions than those contained in U.S. policy proposals, and in the Kyoto Protocol, to date. If the severity and certainty of climate change are such that emissions levels 70-80% below current rates are mandated, this could result in very high marginal emissions reduction costs, though the cost of such deeper cuts has not been quantified on a per ton basis.

On the other hand, we also anticipate a reasonable likelihood that increasing concern over climate change impacts, and the accompanying push for more aggressive emission reductions, will drive technological innovation, which may be anticipated to prevent unlimited cost escalation. For example, with continued technology improvement, coupled with attainment of economies of scale, significant price declines in distributed generation, grid management, and storage technologies, are likely to occur. The combination of such price declines and carbon prices could enable tapping very large supplies of distributed resources, such as solar, low-speed wind and bioenergy resources, as well as the development of new energy efficiency options. The potential development of carbon sequestration strategies, and/or the transition to a renewable energy-based economy may also mitigate continued carbon price escalation.

7. Conclusion

The earth's climate is strongly influenced by concentrations of greenhouse gases in the atmosphere. International scientific consensus, expressed in the Third Assessment Report of the Intergovernmental Panel on Climate Change and in countless peer-reviewed scientific studies and reports, is that the climate system is already being – and will continue to be – disrupted due to anthropogenic emissions of greenhouse gases. Scientists expect increasing atmospheric concentrations of greenhouse gases to cause temperature increases of 1.4 – 5.8 degrees centigrade by 2100, the fastest rate of change since end of the last ice age. Such global warming is expected to cause a wide range of climate impacts including changes in precipitation patterns, increased climate variability, melting of glaciers, ice shelves and permafrost, and rising sea levels. Some of these changes have already been observed and documented in a growing body of scientific literature. All countries will experience social and economic consequences, with disproportionate negative impacts on those countries least able to adapt.

The prospect of global warming and changing climate has spurred international efforts to work towards a sustainable level of greenhouse gas emissions. These international efforts are embodied in the United Nations Framework Convention on Climate Change. The Kyoto Protocol, a supplement to the UNFCCC, establishes legally binding limits on the greenhouse gas emissions by industrialized nations and by economies in transition.

The United States, which is the single largest contributor to global emissions of greenhouse gases, remains one of a very few industrialized nations that have not signed onto the Kyoto Protocol. Nevertheless, federal legislation seems likely in the next few years, and individual states, regional organizations, corporate shareholders and corporations themselves are making serious efforts and taking significant steps towards reducing greenhouse gas emissions in the United States. Efforts to pass federal legislation addressing carbon emissions, though not yet successful, have gained ground in recent years. And climate change issues have seen an unprecedented level of attention in the United States at all levels of government in the past few years.

These developments, combined with the growing scientific certainty related to climate change, mean that establishing federal policy requiring greenhouse gas emission reductions is just a matter of time. The question is not whether the United States will develop a national policy addressing climate change, but when and how, and how much additional damage will have been incurred by the process of delay. The electric sector will be a key component of any regulatory or legislative approach to reducing greenhouse gas emissions both because of this sector's contribution to national emissions and the comparative ease of controlling emissions from large point sources. While the future costs of compliance are subject to uncertainty, they are real and will be mandatory within the lifetime of electric industry capital stock being planned for and built today.

In this scientific, policy and economic context, it is imprudent for decision-makers in the electric sector to ignore the cost of future carbon emissions reductions or to treat future carbon emissions reductions merely as a sensitivity case. Failure to consider the potential future costs of greenhouse gas emissions under future mandatory emission reductions will result in investments that prove quite uneconomic in the future. Long term resource planning by utility and non-utility owners of electric generation must account for the cost of mitigating greenhouse gas emissions, particularly carbon dioxide. For example, decisions about a company's resource portfolio, including building new power plants, reducing other pollutants or installing pollution controls, avoided costs for efficiency or renewables, and retirement of existing power plants all can be more sophisticated and more efficient with appropriate consideration of future costs of carbon emissions mitigation.

Regulatory uncertainty associated with climate change clearly presents a planning challenge, but this does not justify proceeding as if no costs will be associated with carbon emissions in the future. The challenge, as with any unknown future cost driver, is to forecast a reasonable range of costs based on analysis of the information available. This report identifies many sources of information that can form the basis of reasonable assumptions about the likely costs of meeting future carbon emissions reduction requirements.

Additional Costs Associated with Greenhouse Gases

It is important to note that the greenhouse gas emission reduction requirements contained in federal legislation proposed to date, and even the targets in the Kyoto Protocol, are relatively modest compared with the range of emissions reductions that are anticipated to be necessary for keeping global warming at a manageable level. Further, we do not attempt to calculate the full cost to society (or to electric utilities) associated with anticipated future climate changes. Even if electric utilities comply with some of the most aggressive regulatory requirements underlying our CO_2 price forecasts presented above, climate change will continue to occur, albeit at a slower pace, and more stringent emissions reductions will be necessary to avoid dangerous changes to the climate system.

The consensus from the international scientific community clearly indicates that in order to stabilize the concentration of greenhouse gases in the atmosphere and to try to keep further global warming trends manageable, greenhouse gas emissions will have to be reduced significantly below those limits underlying our CO_2 price forecasts. The scientific consensus expressed in the Intergovernmental Panel on Climate Change Report from 2001 is that greenhouse gas emissions would have to decline to a very small fraction of current emissions in order to stabilize greenhouse gas concentrations, and keep global warming in the vicinity of a 2-3 degree centigrade temperature increase. Simply complying with the regulations underlying our CO_2 price forecasts does not eliminate the ecological and socio-economic threat created by CO_2 emissions – it merely mitigates that threat.

Incorporating a reasonable CO_2 price forecast into electricity resource planning will help address electricity consumer concerns about prudent economic decision-making and direct impacts on future electricity rates. However, current policy proposals are just a first step in the direction of emissions reductions that are likely to ultimately be necessary. Consequently, electric sector participants should anticipate increasingly stringent regulatory requirements. In addition, anticipating the financial risks associated with greenhouse gas regulation does not address all the ecological and socio-economic concerns posed by greenhouse gas emissions. Regulators should consider other policy mechanisms to account for the remaining pervasive impacts associated with greenhouse gas emissions.

This report updates and expands upon previous versions Synapse Energy Economics reports on climate change and carbon prices.

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