BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	
Application of Duke Power Company LLC d/b/a Duke	)	
Energy Carolinas, LLC for Approval for an Electric	)	**Docket No. E-7,**
Generation Certificate of Public Convenience and	)	**Sub 790**
Necessity to Construct Two 800 MW State of the Art	)	
Coal Units for Cliffside Project	)	

Direct Testimony of

David A. Schlissel and Anna Sommer

Synapse Energy Economics, Inc.

On Behalf of

Southern Alliance for Clean Energy

Environmental Defense and

Southern Environmental Law Center

PUBLIC VERSION
PROTECTED MATERIALS REDACTED

September 6, 2006

1. Introduction and Qualifications

Q. Mr. Schlissel, please state your name, position and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. Ms. Sommer, please state your name position and business address.

A. My name is Anna Sommer. I am a Research Associate at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. We are testifying on behalf of the Southern Alliance for Clean Energy ("SACE"), Environmental Defense, and Southern Environmental Law Center.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal and state government agencies and utilities.

Q. Mr. Schlissel, please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.
Since 1983 I have been retained by governmental bodies, publicly-owned utilities,

and private organizations in 28 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My clients have included the Staff of the Arizona Corporation Commission, the General Staff of the Arkansas Public Service Commission, the Staff of the Kansas State Corporation Commission, municipal utility systems in Massachusetts, New York, Texas, and North Carolina, and the Attorney General of the Commonwealth of Massachusetts.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, South Dakota, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, and Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission. A copy of my current resume is attached as Exhibit Synapse-1.

Q. Have you previously submitted testimony before the North Carolina Utilities Commission?

A. Yes. I have testified before this Commission in Docket E-2, Sub 526, and Docket E-2, Sub 537.

Q. Ms. Sommer, please summarize your educational background and work experience.

A. I am a Research Associate with Synapse Energy Economics. I provide research and assist in writing testimony and reports on a wide range of issues from renewable energy policy to integrated resource planning. My recent work includes evaluating a proposal for a supercritical, pulverized coal plant in South Dakota, aiding a Florida utility in its integrated resource planning, evaluating the DSM programs of a Nevada utility, assessing the feasibility of carbon sequestration and reviewing the analyses of the air emissions compliance plans of two Indiana utilities and one Nova Scotia utility. I also have participated in studies of proposed renewable portfolio standards in the United States and Canada. In addition, I have evaluated the equity of utility renewable energy solicitations in

Nova Scotia and the feasibility and prudence of the sale and purchase of existing gas and nuclear capacity in Arkansas and Iowa.

Prior to joining Synapse, I worked at EFI and XENERGY (now KEMA Consulting) and Zilkha Renewable Energy (now Horizon Wind Energy). At XENERGY and Zilkha, I focused on policy and economic aspects of renewable energy. While at Zilkha, I authored a strategy and information plan for the development of wind farms in the western United States.

I hold a BS in Economics and Environmental Studies from Tufts University. A copy of my current resume is attached as Exhibit Synapse-2.

Q. Ms. Sommer, have you previously submitted testimony before this Commission?

A. No.

Q. What is the purpose of your testimony in this proceeding?

A. Synapse was asked to evaluate the need for and the economics of Duke Energy Carolinas' ("Duke" or "the Company") Cliffside Project consisting of two 800 MW coal-fired generating units. This testimony provides the results of our evaluation.

Q. Please summarize your conclusions:

A. The Commission should not grant a Certificate of Public Convenience and Necessity for the Cliffside Project for the following reasons:

1. The Commission should not rely on the results of Duke's capacity expansion modeling.

2. The economic analyses on which Duke bases the decision to add 1600 MW of new coal-fired capacity from the Cliffside Project do not adequately consider the potential impact of greenhouse gas regulations.

3. Duke's analyses do not adequately consider the potential for energy efficiency and renewable wind and biomass facilities as alternatives to the Cliffside Project.

4. Duke has not demonstrated a need for 1600 MW of new baseload capacity in 2011.

2. The Commission Should Not Rely on the Results of Duke's Capacity Expansion Modeling

Q. What is Duke's current projected cost for the two Cliffside units?

A. [Redacted][1]

Q. What coal capital costs did Duke assume in the 2005 Annual Plan studies discussed by Company witness Griffith?

A. [Redacted]

[2]

[Redacted]

[1] Duke's confidential response to SACE's First Data Request, Question No. 1.

Q. Does the 20 percent coal capital cost sensitivity prepared by Duke, on its own, show that the addition of the two units of the Cliffside Project is more economic that other possible alternatives?

A. No. First, Duke did not consider the 20 percent higher coal capital cost scenario in its busbar comparisons of alternative generation options. Second, the only sensitivity scenario that Duke has presented combined the 20 percent higher coal capital cost with higher coal and natural gas prices.[3] This distorted the analysis and masked the impact of the higher coal capital cost by including the mostly unrelated higher natural gas prices.

Q. Is Duke's current projected cost for the Cliffside Project based on a detailed engineering design?

A. [Redacted]

[4]

Q. Has Duke signed any contracts for the provision of labor or major equipment components for the Cliffside Project?

A. [Redacted]

[5] Duke has not signed any contracts for the boilers, labor or air pollution control equipment for the Cliffside Project. It anticipates entering into such contracts in approximately the first quarter of 2007.

Q. Are there any factors which suggest that Duke's current projected capital cost estimate for the Cliffside Project may be too low?

A. Yes. There are several factors which suggest that Duke's current projected capital cost estimate for the Cliffside Project may be need to be raised.

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2 Duke's confidential response to SACE's First Data Request, Question No. 6.

3 Duke's 2005 Annual Plan filing, at page 49.

4 Duke's confidential response to SACE's First Data Request, Question No. 1.b.

5 Duke's confidential response to SACE's First Data Request, Question No. 1.b.

First, Duke assumes that it will achieve [Redacted] from building two 800 MW coal units at Cliffside. But it is very speculative to assume such [Redacted] due to the very preliminary nature of the Cliffside Project cost estimate

Second, we are aware from other work that the estimated capital costs of other proposed supercritical coal units are substantially higher than the capital cost Duke is projecting for the Cliffside Project. For example, the originally estimated cost for the 600 MW Big Stone II supercritical coal facility in South Dakota was approximately $1.0 billion, or about 1,700$/kW.

Third, we also are aware that projected power plant capital costs have risen dramatically during the past year or so due to the intense competition for labor, basic materials such as steel, and plant equipment. For example, the projected capital cost of the proposed Big Stone II plant was increased by about 30 percent[6] in early July of this year due, in significant part, to such higher costs. Given that the Big Stone II project was much further along in design and contracting status than the Cliffside Project, it is reasonable to expect that Duke's proposed facilities may experience similar increases.

Q. Do you have any concerns about Duke's planning methodology?

A. Yes. We have several significant concerns about what appears to be Duke's planning methodology. First, Duke performs a screening analysis which eliminates all but the coal, natural gas and nuclear alternatives. Then, Duke performs what it terms a quantitative analysis using Global Energy's Capital Expansion Module. In that quantitative analysis, however, the model is constrained to only two coal options – one 800 MW unit or two 800 MW units.

Thus, it is not a surprise that the two unit Cliffside Project is "selected." In fact, by eliminating the non-fossil and non-nuclear options and by limiting the coal-

[6] Minnesota Public Utilities Commission Order in Docket No. E-017/RP-05-968, August 9, 2006.

fired choices to large units, the Company is essentially picking the plan, not the model.

At the same time, Global Energy notes that one of the advantages of using its Capital Expansion Module is as a [Redacted] :

[Redacted]

[7]

Consequently, we are confused as to why Duke has undertaken its preliminary screening analysis that eliminates all but the fossil, nuclear and gas options instead of examining those alternatives with the Capacity Expansion Module.

Moreover, it is unclear whether Duke has performed the final screening with the [Redacted] . If so, Duke has ignored [Redacted] .

Finally, Duke has not fully considered all potential renewable alternatives to the Cliffside Project.

Q. What other technologies should Duke have considered as part of evaluation of the relative economics of building the Cliffside Project?

A. As we will discuss later in this testimony, Duke should have considered the potential for biomass generated power and should have more fully considered wind power as alternatives to a coal-fired facility.

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[7] Global Energy Decisions, January 2006 Capacity Expansion User Guide, at page 2. Provided in Duke's confidential response to SACE's First Data Request, Question No. 4.

3. Duke's Consideration of the Potential Regulation of Greenhouse Gas Emissions Was Inadequate.

Q. Is it prudent to expect that a policy to address climate change will be implemented in the U.S. in a way that should be of concern to coal-dependent utilities like Duke?

A. Yes. The prospect of global warming and the resultant widespread climate changes have 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 ("UNFCCC"), a treaty that the U.S. ratified in 1992, along with almost every other country in the world. The Kyoto Protocol, a supplement to the UNFCCC, establishes legally binding limits on the greenhouse gas emissions of industrialized nations and economies in transition.

Despite being the single largest contributor to global emissions of greenhouse gases, the United States remains one of a very few industrialized nations that have not ratified the Kyoto Protocol. Nevertheless, individual states, regional groups of states, shareholders and corporations are making serious efforts and taking significant steps towards reducing greenhouse gas emissions in the United States. Efforts to pass federal legislation addressing carbon, though not yet successful, have gained ground in recent years. These developments, combined with the growing scientific understanding of, and evidence of, 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. 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 regulating large point sources.

There are, of course, important uncertainties with regard to the timing, the emission limits, and many other details of what a carbon policy in the United States will look like.

Q. Has Duke prepared any assessments of the potential for CO_2 taxes or regulations being adopted at any point within the next twenty years?

A. Apparently not. SACE asked Duke to provide any such assessments. Its response was that Duke Energy Carolinas does not have any responsive documents.[8]

Q. Does Duke adequately consider the potential for carbon regulation in deciding whether to build the Cliffside Units?

A. No. Duke did consider a carbon tax sensitivity in the 2005 Annual Plan on which it bases the decision to undertake the Cliffside units. However, that consideration was extremely inadequate.

Q. Please explain why you have concluded that Duke's evaluation of the potential for carbon regulation was extremely inadequate.

A. Duke has said that the 2005 Annual Plan contained a carbon tax sensitivity of $7 per ton of CO_2 beginning in 2015 and escalating at 5% per year.[9] This CO_2 price sensitivity was modeled after draft legislation prepared by U.S. Senator Jeff Bingaman of New Mexico. The draft legislation proposed a national mandatory greenhouse gas cap and trade program to begin in 2010 and included a "safety valve" allowance price that would act as a cap on the price that would have to be paid for an allowance.

We have concluded that the carbon tax sensitivity considered by Duke was inadequate for a number of reasons. First, we believe that the figures used by Duke represent the very low end of the reasonable ranges of carbon taxes or allowance prices. Second, we believe that pushing the starting date for such a carbon tax out as far as 2015 understates the possible impact of earlier carbon regulations on the relative impacts of building new coal units. Third, we believe that it is not appropriate to base an estimate of future carbon prices on any single piece of legislation or let alone proposed legislation or draft legislation that was

[8] Duke's response to SACE's First Data Request, Question No. 12.

[9] Duke's Response to SACE's First Data Request, Question No. 5.

never introduced in either House of Congress. Finally, the carbon tax sensitivity was not incorporated into Duke's evaluation of all alternatives to coal-fired generation including, for example, wind, biomass and energy efficiency. Indeed, the expected carbon tax was not even put into Duke's base case in the Annual Plan. Instead, it was only considered in a sensitivity analysis and the timing of when that sensitivity was performed means that it was essentially a very comparison between limited coal, natural gas and nuclear alternatives.

Although the draft proposed legislation on which Duke bases its carbon tax sensitivity certainly did have a "safety valve" price, it would be misleading to conclude that that price is the highest price CO_2 allowances will ever reach. Any conclusion to this effect would be made in a scientific and political vacuum since it assumes that any one piece of legislation is the best indication of what Congress might pass in the future and that politics and the desire of the American people to see more aggressive action against climate change won't increase even as the impacts of climate change become more apparent.

Atmospheric concentrations of carbon dioxide are going up, emissions of carbon dioxide are going up and temperatures continue to rise. The debate on climate change and how to deal with the issue is evolving and gaining more attention. For example, the number of climate change related proposals introduced in the U.S. Congress have risen from seven in the 105th Congress (1997-1998) to 25 in the 106th Congress (1999-2000) to over 80 in the 107th Congress (2001-2002) to nearly 100 proposals in the 108th Congress (2003-2004) according to the Pew Center on Global Climate Change.

Q. Have recent polls indicated that the American people are increasingly in favor of government action to address global warming concerns?

A. Yes. A summer 2006 poll by Zogby International showed that an overwhelming majority of Americans are more convinced that global warming is happening than they were even two years ago, and they are also connecting intense weather events like Hurricane Katrina and heat waves to global warming.[10] Indeed, the poll found that 87% of Democrats, 56% of Republicans and 82% of Independents believe that we are experiencing the effects of global warming.

The poll also indicated that there is strong support for measures to require major industries to reduce their greenhouse gas emissions to improve the environment without harming the economy – 72% of likely voters agreed such measures should be taken.[11]

Polls taken earlier in 2006 reached similar conclusions. For example, a Time/ABC/Stanford University poll issued in the spring found 68 percent of Americans are in favor of more government action.[12]

Q. Is the $7/ton "safety valve" price used by Duke in its carbon tax sensitivity an appropriate estimate of what federal regulation of greenhouse gases will cost?

A. The value itself may be appropriate to assume for a limited number of years; it is the fact that this is the only value used by Duke and the period over which it is used that we disagree with. In contrast to the Company's CO_2 sensitivity, our forecast of future CO_2 prices is not a single number, but a range and $7/ton falls within what is the expected CO_2 price in 2010 of $0 to $10/ton. Also, unlike Duke's CO2 sensitivity, our forecast does not rely on only one piece of draft legislation.

It also is important to keep in context all the climate related bills, including the draft legislation upon which Duke's CO_2 sensitivity is based. None of the current legislative proposals require emissions reductions sufficient to stabilize atmospheric concentrations of CO_2. However, our forecast, unlike Duke's, does

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10 "Americans Link Hurricane Katrina and Heat Wave to Global Warming," Zogby International, August 21, 2006, available at www.zogby.com/news.

11 Ibid.

12 "Polls find groundswell of belief in, concern about global warming." Greenwire, April 21, 2006, Vol. 10 No. 9.

assume that although the legislation controlling greenhouse gas emissions that will be implemented by the early part of the next decade won't be significantly different from the bills introduced to date, the stringency of carbon regulation *will* increase over time.

Q. Are there any significant differences between the assumptions in Duke's carbon tax sensitivity and the draft legislation on which Duke says it relied for that sensitivity?

A. Yes. Duke assumes in its sensitivity analysis that the carbon tax would not be implemented until 2015 while the draft Climate and Economy Insurance Act of 2005, the draft legislation on which the Company says it based the sensitivity, had a proposed starting date of 2010. By pushing the starting date for the CO_2 tax five years out into the future in its carbon tax sensitivity, Duke reduced the effect of that tax on the costs of fossil-fired alternatives.

Q. Have any of Duke's senior management expressed opinions about whether and when greenhouse gas regulation will come?

A. Yes. 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.[13]

James Rogers, CEO of Duke Energy, also has publicly said "[I]n private, 80-85% of my peers think carbon regulation is coming within ten years, but most sure don't want it now."[14] Mr. Rogers also was quoted in a recent *Business Week*

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[13] 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

[14] "The Greening of General Electric: A Lean, Clean Electric Machine," *The Economist*, December 10, 2005, at page 79.

article, as saying to his utility colleagues, “If we stonewall this thing [carbon dioxide regulation] to five years out, all of a sudden the cost to us and ultimately to our consumers can be gigantic.”[15]

In addition, in 2001, Mr. Rogers testified before the Senate Committee on Environment and Public Works[16] that “Congress needs to address the climate change issue [and f]urther, I know from personal experience that it’s impossible to build new coal baseload power plants since the economics cannot be determined without knowing what requirements the plant will face on carbon.”

Moreover, before the merger, when Mr. Rogers was CEO of Cinergy, that Company made a number of frank public statements about global warming including:[17]

> Global climate change is perhaps the greatest environmental challenge for Cinergy as a coal-burning energy company. There is growing consensus among scientists that our planet’s climate is warming as a result of human actions. While there is neither consensus on the rate of this warming nor the ultimate impact on Earth, global climate change has become one of the most important scientific and political issues of our time.
>
> The impact of climate change on Cinergy’s 13,300 megawatts of coal-fired generation is obvious. We burn nearly 30 million tons of coal in our facilities, emitting 66.5 million tons of carbon dioxide (CO_2) a year. CO_2 is the most common of the “greenhouse gases,” so labeled because, when in the atmosphere, they can prevent the sun’s heat from escaping back into space. The balance between the heat from the sun and the heat escaping from the earth helps our planet remain habitable. But an atmosphere overloaded with green-house gases could result in a warm planet drastically different from what we now know.
>
> Cinergy is the sixth largest utility emitter of CO_2 in the United States, simply because we burn large quantities of coal. We burn coal

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15 “The Race Against Climate Change,” *Business Week*, December 12, 2005, online at http://businessweek.com/magazine/content/05_50/b3963401.htm.

16 Statement of Mr. James E. Rogers, Chairman, President and Chief Executive Officer of Cinergy Corp. before the Committee on Environment and Public Works, United States Senate, May 2, 2001.

17 “Cinergy Sustainability Report.” www.cinergy.com/pdfs/sustainability_report.pdf, page 8.

> because it's the most abundant and, therefore, the most economical way to produce electricity. Our customers want, and our country's economy needs, reasonably priced energy. Our challenge is to meet these needs in a more environmentally benign way.
>
> As yet, there is no technology that removes CO_2 from exhaust gases; there is no scrubber, no selective catalytic reduction (SCR) unit, and no "carbon collector." The short-term answers lie in energy-efficiency and carbon sequestration projects to offset our emissions. The long-term answers beg for technology, both to lighten the environmental footprint of coal and to provide us with other methods of energy generation.

Q. Is Duke's request for a Certificate of Public Convenience and Necessity to build two 800 MW coal units at the Cliffside Project consistent with these statements by Mr. Anderson and Mr. Rogers?

A. No. Duke's senior officers advocate for CO_2 regulation but the Company does not reflect such regulation in its base case in the Annual Plan and apparently expects that regulation to do very little, if anything at all, to actually reduce carbon dioxide emissions.

Q. But is Duke an outlier, one of a few companies that believe that mandatory greenhouse gas regulation is on the way?

A. Duke is not alone in believing that carbon regulation is inevitable and, indeed, some utilities are advocating for mandatory greenhouse gas reductions. In a May 6, 2005, statement to the Climate Leaders Partners (a voluntary EPA-industry partnership), John Rowe, Chair and CEO of Exelon stated, "At Exelon, we accept that the science of global warming is overwhelming. We accept that limitations on greenhouse gases emissions [sic] will prove necessary. Until those limitations are adopted, we believe that business should take voluntary action to begin the transition to a lower carbon future."

In fact, several electric utilities and electric generation companies have incorporated assumptions about carbon regulation and costs into their long term planning, and have set specific agendas to mitigate shareholder risks associated with future U.S. 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 U.S. electric sector's 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."[18]

Even those in the electric industry who oppose mandatory limits on greenhouse gas regulation believe that regulation is inevitable. David Ratcliffe, CEO of Southern Company, a predominantly coal-fired utility that opposes mandatory limits, said at a March 29, 2006, press briefing that "There certainly is enough public pressure and enough Congressional discussion that it is likely we will see some form of regulation, some sort of legislation around carbon."[19]

Q. Do companies outside of electric utilities support greenhouse gas regulation?

A. Yes. Support for the passage of greenhouse gas regulation has been expressed by senior executives in companies such as Wal-Mart, General Electric, BP, Shell, and Goldman Sachs.[20]

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18 Northwest Energy 2005 Electric Default Supply Resource Procurement Plan, December 20, 2005; Volume 1, p. 4.

19 Quoted in "U.S. Utilities Urge Congress to Establish CO2 Limits," Bloomberg.com, http://www.bloomberg.com/apps/news?pid=10000103&sid=a75A1ADJv8cs&refer=us

20 Exhibit Synapse-3, at pages 23-26.

Q. Why would so many electric utilities, in particular, be concerned about future carbon regulation?

A. Electricity generation is very carbon-intensive. Electric utilities are likely to be one of the first, if not the first, industries subject to carbon regulation because of the relative ease in regulating stationary sources as opposed to mobile sources (automobiles) and because electricity generation represents a significant portion of total U.S. greenhouse gas emissions. A new generating facility may have a book life of twenty to forty years, but in practice, the utility may expect that that asset will have an operating life of 50 years or more. By adding new plants, especially new coal plants, a utility is essentially locking-in a large quantity of carbon dioxide emissions for decades to come. In general, electric utilities are increasingly aware that the fact that we do not currently have federal greenhouse gas regulation is irrelevant to the issue of whether we will in the future, and that new plant investment decisions are extremely sensitive to the expected cost of greenhouse gas regulation throughout the life of the facility.

Q. Have mandatory greenhouse gas emissions reductions programs begun to be examined and debated in the U.S. federal government?

A. To date, the U.S. government has not required greenhouse gas emission reductions. However, legislative initiatives for a mandatory market-based greenhouse gas cap and trade program are under consideration.[21]

Several mandatory emissions reduction proposals have been introduced in Congress. These proposals establish carbon dioxide 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

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[21] Exhibit Synapse-3, at pages 11-16.

different policy approaches, and they are laying the groundwork for a national mandatory program. The federal proposals that would require greenhouse gas emission reductions that had been submitted through April 2006 are summarized in Table 5.1 in Exhibit Synapse-3.

In addition, Senators McCain and Lieberman have resubmitted their Climate Stewardship Act in the current Congress. Two new bills also have been introduced in Congress since April.

For example, Senators Carper (D-Del) and a bi-partisan group of senators, including Republican Senators Lamar Alexander (R-Tennessee), Lindsey Graham (R-South Carolina), Lincoln Chafee (R-Rhode Island) and Judd Gregg (R-New Hampshire), have introduced the Clean Air Planning Act of 2006. This measure would cap carbon dioxide emissions from power plants at 2006 levels by 2010 and reduce these emissions to 2001 levels by 2015. The sponsorship of legislation by these Republican Senators shows that capping greenhouse gas emissions because of concerns over global warming is not a partisan issue.

It is significant that the U.S. Congress is examining and debating these emissions reduction proposals. However, as shown in Figure 5.2 in Exhibit Synapse-3, the emissions trajectories contained in the proposed federal legislation are in fact quite modest compared with the emissions reductions that are anticipated to be necessary to achieve stabilization of atmospheric concentrations of greenhouse gases. Figure 5.2 in Exhibit Synapse-3 compares various emission reduction trajectories and goals in relation to a 1990 baseline. U.S. federal proposals, and even Kyoto Protocol reduction targets, are small compared with the current E.U. emissions reduction target for 2020, and the emissions reductions that scientists have said will ultimately be necessary to avoid the most dangerous impacts of global warming.

Q. Are any states developing and implementing climate change policies that will have a bearing on resource choices in the electric sector?

A. Yes. A growing number of states are developing and implementing the following types of policies that will affect greenhouse gas emissions in the electric sector:

(1) direct policies that require specific emissions reductions from electric generation sources; (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.[22]

Direct policies include the New Hampshire and Massachusetts laws imposing caps on carbon dioxide emissions from power plants in those states.

Indirect policies include the requirements by various states to either consider future carbon dioxide regulation or use specific "adders" for carbon dioxide in resource planning. It also includes policies and incentives to increase energy efficiency and renewable energy use, such as renewable portfolio standards. Some of these requirements are at the direction of state public utilities commissions, others are statutory requirements.

Lawsuits make up the majority of the third category. For example, several states are suing the U.S. Environmental Protection Agency (EPA) to have carbon dioxide regulated as a pollutant under the Clean Air Act.

Among the voluntary programs undertaken at the state level are the climate change action plans developed by 28 states.

But states are not just acting individually; there are a number of 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 ("RGGI"). The objective of the RGGI is the 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. These regional activities are summarized in Table 5.5 in Exhibit Synapse-3.

[22] Exhibit Synapse-3, at pages 16 through 21.

Q. Have any states adopted direct policies that require specific emissions reductions from electric sources?

A. Yes. The states of Massachusetts, New Hampshire, Oregon and California have adopted policies requiring greenhouse gas emission reductions from power plants.[23]

In particular, California has just passed legislation, supported by the largest utility in the state, that will require an estimated 25 percent reduction in the state's CO_2 emissions by 2020. California Governor Schwarzenegger has said that he will sign the bill.[24]

Q. Do any states require that utilities or default service suppliers evaluate costs or risks associated with greenhouse gas emissions in long-range planning or resource procurement?

A. Yes. As shown in Table 1 below, several states require companies under their jurisdiction to account for the emission of greenhouse gases in resource planning.

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23 Exhibit Synapse-3, Table 5.3 on page 18.

24 Young, Samantha. "Assembly send global warming bill to Schwarzenegger." *San Jose Mercury News*, 31 August 2006, available at http://www.mercurynews.com/mld/mercurynews/news/breaking_news/15410954.htm.

1 **Table 1. Requirements for Consideration of Greenhouse Gas Emissions in Electric**
2 **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)

Q. What carbon dioxide values are being used by utilities in electric resource planning?

A. Table 2 below presents the carbon dioxide costs, in \$/ton CO_2, that are presently being used in the industry for both resource planning and modeling of carbon regulation policies.

Table 2. Carbon Dioxide Costs Used by Utilities

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.

Q. How should utilities plan for and mitigate the risk of greenhouse gas regulation?

A. The key part of that question is "plan for the risk of greenhouse gas regulation." Mitigating risk begins with the resource planning process and the decision as to the demand-side and supply-side options that should be pursued. A utility that chooses to go forward with a new, carbon intensive energy resource without proper consideration of carbon regulation is imprudent. To give an analogy it would be like choosing to build a gas-fired power plant without consideration of the cost of gas because one believes that building the plant is "worth it" regardless of what gas might cost.

A utility that desires to be prudent about the risk of carbon regulation would, at a minimum, consider carbon regulation by developing an expected carbon price forecast for its base case analysis as well as reasonable sensitivities around that case.

Q. Has Synapse developed a carbon price forecast that would assist the Commission in determining whether Duke has adequately considered carbon risk?

A. Yes. Our forecast is described in more detail in Exhibit Synapse-3, starting on page 39.

During the decade from 2010 to 2020, we anticipate that a reasonable range of carbon emissions prices will reflect 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). We expect that the widest uncertainty in our forecasts will begin at the end of this decade, that is, from $10 to $40 per ton of CO_2 in 2020, depending on the relative strength of these factors.

After 2020, we expect the price of carbon emissions allowances to trend upward toward a marginal mitigation cost. This number will depend on currently uncertain factors such as technological innovation and the stringency of carbon caps, but it is likely that, by this time, the least expensive mitigation options (such as simple energy efficiency and fuel switching) will have been exhausted. Our projection for greenhouse gas emissions costs at the end of this decade ranges from $20 to $50 per ton of CO_2 emissions.

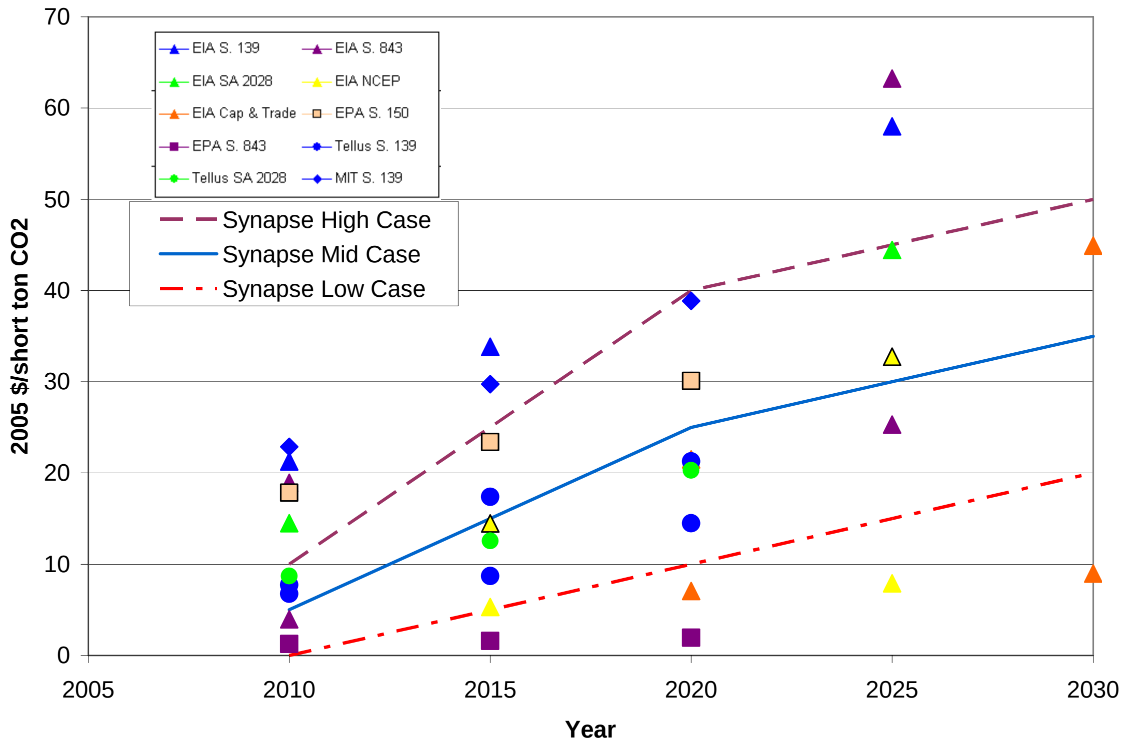
We currently believe that the most likely scenario is that as policymakers commit to taking serious action to reduce carbon emissions, they will choose to enact both cap and trade regimes and a range of complementary energy policies that lead to lower cost scenarios, and that technology innovation will 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. We expect that the probability of taking this path will increase 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 will increase due to the interplay of factors such as the level of carbon constraints required and technological innovation. As discussed in Exhibit Synapse-3, 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 will 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 we have not quantified the cost of such deeper cuts on a per ton basis.

Q. What is Synapse's forecast of carbon dioxide emissions prices?

A. Synapse's forecast of future carbon dioxide emissions prices are presented in Figure 1 below. This figure superimposes Synapse's forecast on the results of other cost analyses of proposed federal policies:

Figure 1. Synapse Carbon Dioxide Prices



Q. What is Synapse's levelized carbon price forecast?

A. Synapse's forecast, levelized over 20 years, 2011 – 2030, is provided in Table 3 below.

Table 3. Synapse's Levelized Carbon Price Forecast (2005$/ton)

Low Case	Mid Case	High Case
$7.8	$19.1	$30.5

Q. Is Duke already heavily dependent upon coal-fired generation?

A. Yes. According to information provided in Duke's 2005 Annual Plan filing, the Company already owns approximately 7,900 MW of coal-fired generating capacity. This represents approximately 39 percent of its total generation capability. In 2004, coal-fired generating units provided 52.2% of system load requirements.[25]

Q. How much additional CO_2 will the Cliffside coal units emit into the atmosphere?

A. At an average 85 percent annual capacity factor (i.e., 11,914 GWH), the Cliffside Units would emit approximately 11.5 million tons of CO_2 each year for approximately 60 years.

4. Duke's Consideration of Alternatives to the Cliffside Project was Inadequate

Energy Efficiency

Q. Has Duke adequately addressed the potential for energy efficiency and maximized its demand-side resources?

A. No. The efficiency programs outlined in the 2005 Annual Plan are woefully inadequate compared to leading energy efficiency programs across the nation. The 2005 Annual Plan does not contemplate remedying this situation. Duke Witness Hager briefly mentions in her testimony a demand-side management (DSM) analysis that was conducted as part of the Company's planning, but offers no details, results, inputs or otherwise from it. Within the body of the Annual Plan there is no mention of this analysis. Page 76 of Appendix J suggests that there is a "DSM strategy analysis underway." That same page also suggests that some sort of energy efficiency potential analysis was undertaken saying that this analysis was "intended to be indicative of the level of opportunity available to Duke Power, rather than as a precise estimate of program costs and benefits." On the page following is a small table, replicated here.

[25] Duke's Annual Plan filing at page 9.

Projected New DSM Energy Efficiency Program Details

Category (all customer types)	Expected Total Annual MWh Reduction
EE	715,927 MWh

Despite having the word "details" in its title, this table gives no indication of whether this MWh reduction is cumulative, annual, or in what year it can be expected. It does not appear to have been factored in any way into the 2005 Annual Plan and there is no indication of how the Company might actually use this information in the future, if at all.

Through discovery, we obtained the July 21, 2005 DSM potential study prepared by Quantec on behalf of Duke which appears to be the indicative report the 2005 Annual Plan is referring to.

Q. Does the Quantec study identify the potential for cost-effective energy efficiency on the Duke system?

A. No. At four pages, the Quantec study is only a very rough start of an investigation of the potential for cost-effective energy efficiency on Duke's system. As Quantec itself points out "the results of this study, particularly those pertaining to energy efficiency potentials, are to be viewed as preliminary and indicative, rather than conclusive." Without a more complete study and the incorporation of that study into a proper planning analysis, this Commission does not have the information to determine how reasonable, cost-effective energy efficiency will affect the Company's need for new baseload capacity. Key questions such as will the implementation of cost-effective energy efficiency reduce the amount of new generating capacity required or defer the need for new capacity further out into the future simply cannot be answered without more information than Duke has provided.

Q. Do you have any other comments on the Company's testimony concerning its DSM efforts?

A. Yes, we do. Ms. Hager indicates in her testimony that her analysis revealed that "implementation of the [energy efficiency] programs considered would result in cross-subsidization between participating customers and non-participating customers."[26] We understand Ms. Hager to be saying that the energy efficiency programs analyzed do not pass the rate impact measure (RIM) test.

Q. Please explain what the rate impact measure test is.

A. The goal of the RIM test is to determine what the impact of DSM programs would be on non-participants. Like other cost/benefit tests for DSM screening, the RIM test results in a ratio of benefits to costs. The costs being all expenditures by the program administrator and "lost revenues" to the utility as a result of having to recover fixed costs over fewer sales. The benefits include the avoided utility costs. Under the RIM test, any program that would raise rates to non-participants would be rejected.

Q. Did Duke appropriately use the RIM test to conclude that no additional energy efficiency programs would be cost-effective?

A. No. Ms. Hager's analysis ignores a key fact-of-life in almost all utility planning: both demand-side *and* supply-side resources can be expected to raise rates to some degree across participants and non-participants. For example, while we don't believe that any of Duke's witnesses in this proceeding mentions the fact, the proposed Cliffside Project can be expected to raise rates for the Company's customers.

Indeed, new generating units are likely to be added because of new customers. In this case, the costs of new generating units are generally spread across customers according to a ratemaking methodology that ignores a customer's contribution to creating the need for the new unit. So while the RIM test will not pass any energy

[26] Testimony of Janice Hager, page 9, lines 10-11.

efficiency program that results in cross-subsidization, on the supply-side, cross-subsidization is tolerated, regardless of the magnitude of that cross-subsidization.

Let us give a hypothetical example of how extreme the RIM test is. Suppose we had a free efficiency measure. There was no cost to install and no cost to the participant or the utility. The RIM test would *reject* this measure because it reduces energy sales which would mean that the hypothetical utility's fixed costs would have to be recovered over fewer kWH sales, resulting in higher rates.

Q. If RIM test is not used how should Duke determine the rate impacts of potential energy efficiency programs?

A. To clarify, determining a program's RIM ratio whether it's 1 or .75 or .5, will give no indication of whether the rate impact of the program is .01% or 10%.

What is more useful to this Commission is to know what the rate impacts would be from the entire portfolio of energy efficiency programs that pass other, more informative cost-effectiveness tests like the Utility Cost test, Total Resource Cost test or Societal Cost test.

We would also note that the picture is not complete without rate impact information from supply-side additions; at this point, this Commission lacks both pieces of information.

Q. What impact does Duke Carolinas' use of the RIM test have on its 2005 Annual Plan?

A. First and foremost, without a complete investigation and consideration of the potential for cost-effective energy efficiency, it is impossible to conclude that the capacity additions proposed in Duke's 2005 Annual Plan represent the Company's least cost options. The specifics of the plan, that is, the type and timing of resource additions, could well be affected by the implementation of a reasonable energy efficiency program.

Q. Has Duke made any commitment to implement all cost effective and reasonably achievable energy efficiency?

A. Not explicitly. In his testimony, Mr. Rogers mentions his involvement with the National Action Plan for Energy Efficiency; he is the co-chair of the Leadership Group which created the plan. The Leadership Group came together with the recognition that "energy efficiency remains a critically underutilized resource in the nation's energy portfolio." Given the high-profile nature of the Group and the Action Plan, we take Mr. Rogers' participation as an implicit recognition of the importance of energy efficiency to a resource mix. As such, we hope that Duke will make that recognition explicit by presenting this Commission with a reasonable and complete plan to implement energy efficiency in its service territory.

Also noteworthy from the National Action Plan is that of all the utilities and program administrators mentioned in the chapter on "best practices," none used the rate-impact test as the primary decision-making test.

Q. Both Ms. Hager and Mr. Rogers point to the $2,000,000 Duke will be spending on energy efficiency as a result of the Duke/Cinergy merger. Doesn't this money demonstrate a commitment to energy efficiency?

A. Two million dollars is a only a very small start for a utility the size of Duke Energy Carolinas. To put that money in perspective, it is just .001% of the proposed Cliffside project, assuming that Duke is not underestimating the project's cost. A utility with a modest set of DSM programs is likely to spend 1% of revenues per year. Top performing DSM utilities will spend more. For example, the Vermont Public Service Board recently ordered increased funding for the state efficiency utility that represents roughly four percent of distribution utility annual revenues. [27]

[27] Vermont Public Service Board, Order Re: New 2006 EEC Rates, dated August 16, 2006.

In 2005, Duke Carolinas' retail revenues from sales were $4,694,835,094.[28] To spend just 1% of revenues on DSM, it would need to increase its investment in DSM by an additional $44,948,350 per year above the $2,000,000 that the Company is committing to spend. Clearly, more action on energy efficiency is needed and with Mr. Rogers' participation in the National Action Plan for Energy Efficiency we hope that Duke will seize the opportunity to take advantage of a very cost-effective resource *before* embarking on a very expensive and risky capital investment.

Q. But isn't it true that utilities that spend more on demand-side management have higher electricity rates?

A. No, this is a very common misconception. In fact, the best performing utilities on DSM are a mix of higher and lower cost states as shown in ACEEE's 3rd National Scorecard. The Scorecard is attached as Exhibit Synapse-4. Some, but not all, high cost states such as California are among the top performers. However, the top performers included low cost states like Minnesota.

Interestingly, there is no evidence that even the high cost states are yet capturing even close to the full potential for cost-effective energy efficiency. For example, Vermont, a state with a long history of energy efficiency, recently released a study showing that achievable, cost-effective energy efficiency has the potential to reduce state electricity usage by 19% by 2015.[29]

Most importantly, whether a state is currently high cost or low cost is irrelevant. As the National Action Plan for Energy Efficiency reminds us, the screening process for cost-effective energy efficiency compares programs to *new* supply-side resources, the costs of which are likely to be much more comparable across states:

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[28] Response to SACE First Data Request, No. 13.

[29] *Vermont Electric Energy Efficiency Potential Study: Executive Summary of the Final Report* by GDS Associates, July 21, 2006, page 1.

> Looking forward, all states face similar, higher cost options for new generation, suggesting that the current resource mix will be less important than future resource options in considering the value of new energy efficiency investments.[30]

Q. What would the benefits to Duke customers be from the implementation of new energy efficiency programs?

A. Again, we would refer to the National Action Plan for Energy Efficiency for a summary of the primary benefits of energy efficiency.[31]

- Lower energy bills, greater customer control and greater customer satisfaction.
- Lower cost than supplying new generation only from new power plants.
- Modular and quick to deploy.
- Significant energy savings (well designed programs can offset 1% of sales per year).
- Environmental benefits (reduced air pollution, reduced greenhouse gases, lower water use).
- Economic development (energy efficiency users often direct their bill savings toward other activities that increase local and national employment, with a higher employment impact than if the money had been spent to purchase energy).
- Energy security (reliability and natural disaster impacts).

[30] National Action Plan for Energy Efficiency, July 2006, 2-3.

[31] National Action Plan for Energy Efficiency, July 2006, page 4.

Q. Ms. Hager states on page 9, lines 19-23, of her testimony that the development of the Cliffside units will not impact Duke Energy Carolinas' strategy for pursuing additional DSM. Given this, can't issues like the RIM test and whether Duke can implement additional cost-effective DSM be addressed in the 2006 Annual Plan?

A. No. Ignoring these issues at this time, before a Certificate of Public Convenience and Necessity is issued, would be a costly mistake for the customers of Duke Energy Carolinas. Energy efficiency results in lower energy bills not just because customers use less energy, but because it can also defer or avoid the need for new power plants.

Approving the Certificate of Public Convenience and Necessity as the record stands would prevent this Commission from having the information to determine whether such programs could cost-effectively avoid, defer or reduce the size (and therefore cost) of the Cliffside project. We believe that it would be more prudent to require Duke to show that it has implemented all cost-effective and reasonably achievable energy alternatives *before* being granted a CPCN for one, let alone two, new units at the Cliffside site.

Renewable Technologies

Q. Have you seen any evidence that Duke has thoroughly investigated the potential for adding renewable generating capacity in place of the some or all of the 1600 MW of baseload capacity from the Cliffside Project?

A. No. Duke's analysis of renewable generating alternatives has been inadequate.

Q. What is the basis for this conclusion?

A. We asked Duke to provide copies of the assessments of the potential for wind and other generating technologies, such as biomass, in the Company's service area that had been prepared since January 1, 2002, a period of 4 ½ years. The Company's only response was to refer us to its Annual Plan filings since 2001.[32]

A review of these documents reveals that Duke did not examine the potential for biomass generated electricity at all as part of its 2005 Annual Plan and had only looked at urban refuse derived fuels in its 2003 and 2004 Annual Plans. Similarly, although the Company looked at wind generated power in its Annual Plans, it repeatedly rejected wind because (a) it was not a reliably dispatchable resource, "limiting its competitiveness against peaking duty cycle technologies," and (2) because sufficient wind energy in the Company's service territory is found only in the ridge lines of the North Carolina mountains which is currently under development restrictions.[33]

Q. Have you seen any studies that show that biomass is a viable generating resource in the Carolinas?

A. Yes. For example, a July 2004 report by the North Carolina Solar Center at North Carolina State University titled "Use of Agricultural and Forest Waste as a Distributed Generation Power Resource in North Carolina"[34] found that the utilization of biomass for power production was a commercially proven and viable option for bioenergy generation in North Carolina.[35] The report also concluded that "North Carolina has an abundance of untapped biomass resources distributed across the state."[36] We also have seen estimates that there is perhaps the potential for 1700-2000 MW of potential biomass generation available in North Carolina alone.

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32 Duke's responses to SACE's First Data Request, Questions Nos. 10 and 11.

33 Hager Exhibit 1, at page 74.

34 This report is available at http://www.ncsc.ncsu.edu/research/documents/technical_papers/Final_Report_5-22809.rev2.pdf

35 At page 3.

36 Ibid.

Q. Do you agree with Duke that wind turbines are not a viable alternative for new generating facilities because they cannot be reliably dispatched?

A. No. Actual experience and studies have shown that wind power can reduce the need for other capacity and provide low-cost energy. The effects of short term wind variability can be mitigated by building a larger number of wind turbines and by siting the wind turbines in different geographic locations.

Indeed, Duke already has a large number of fully dispatchable facilities. It has not shown any evidence why every new increment of new generating capacity also must be fully dispatchable.

Q. As part of this assignment, have you quantified the amounts of biomass generated and wind power capacity and energy would be available to Duke in place of the Cliffside Project?

A. No.

Q. How should the Commission incorporate this potential for biomass and wind power capacity and energy into its evaluation of Duke's request for a Certificate of Public Convenience and Necessity?

A. We understand that there is currently a study underway to evaluate the potential for a Renewal Portfolio Standard in North Carolina. We believe that the Commission should review the results of that study before evaluating Duke's request for a Certificate of Public Convenience and Necessity for the Cliffside Project.

Q. Will the implementation of Duke's proposed new generation portfolio including the Cliffside Project increase the diversity of the Company's fuel mix?

A. No. The Company's proposed generation portfolio would not add any more renewable capacity and, instead, would make Duke more dependent on nuclear and fossil-fuels.

5. Duke Has Not Adequately Demonstrated that it Requires the 1600 MW of Baseload Capacity from the Cliffside Project in 2011

Q. Has Duke demonstrated in its 2005 Annual Plan, Certificate Application or supporting testimony that in order to ensure system reliability it has a need for 1600 MW of baseload capacity from the Cliffside Project in 2011?

A. No. At most, Duke has shown a need for additional capacity in 2011 during the peak summer hours. It has not shown that it has a need for an additional 1600 MW of baseload coal-fired capacity. Indeed, Duke has not presented any analyses that go beyond looking at system loads and capacity during the summer and winter peak demand periods.[37]

Q. Is there any other evidence that suggests that Duke does not need 1600 MW of baseload capacity from the Cliffside Project in 2011 for system reliability?

A. Yes. The very high system capacity reserves and reserve margins during the winter peak hours suggests that Duke does not require any additional baseload capacity through 2013.[38] These figures suggest that Duke's capacity reserves will be even higher during the non-peak winter hours and during the fall and shoulder month periods.

Indeed, at the same time that it is claiming a deficiency of 3400 MW in the summer of 2011, Duke is proposing to retire approximately 400 MW of existing capacity in 2010 and 2011 and to not renew 418 MW of off-system capacity purchase contracts that expire prior to the summer of 2011.

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37 For example, see the Testimony of Janice D. Hager, at page 5, and Duke's 2005 Annual Plan, Hager Exhibit 1, at pages 25 and 26.

38 For example, see the projected capacity reserves and reserve margins for the winters of 2011/2012 and 2012/2013 shown on the seasonal projections of load, capacity and reserves at page 25 of Hager Exhibit 1.

Q. Has Duke shown that it would be unable to purchase capacity and energy from another generator or that such purchases would be more expensive than power from the Cliffside Project?

A. No. Duke has not provide any evidence showing that it evaluated off-system capacity and energy purchases as an alternative to building the Cliffside Project.

Q. Did you ask Duke whether it attempted to extend any of the purchase power contracts that expire prior to and including 2011?

A. Yes. However, Duke did not directly answer the question. Instead, it answered that it will continue to use cost effective purchase power contracts when available as an integral part of its generating resource portfolio.[39] Duke further noted that it was presently finalizing its current outstanding RFP for capacity released April 1, 2005. Unfortunately, Duke refused, due to claimed confidentiality agreements with bidders, to provide any specifics about the proposals received in response to that RFP. Therefore, it is not possible to know whether any bidders have proposed to enter into long-term contracts for capacity and/or energy at prices comparable to those of the Cliffside Project.

Q. Isn't it reasonable to expect that at some point Duke will need to add additional baseload capacity?

A. Yes. However, delaying the need for such baseload capacity would permit additional time for the Company to implement cost-effective energy efficiency measures and renewable technologies such as wind and biomass capacity.

Q. What is your ultimate conclusion?

A. The Commission should reject Duke's request for a Certificate of Public Convenience and Necessity for the Cliffside Project and allow Duke an opportunity to resubmit a new Application that addresses the deficiencies we have identified in this testimony.

[39] Duke's response to SACE First Data Request, Question No. 7.

Q. Does this complete your testimony?

A. Yes.

EXHIBIT SYNAPSE-1

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SUMMARY

I have worked for thirty years as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School

PROFESSIONAL EXPERIENCE

Electric System Reliability - Evaluated whether new transmission lines and generation facilities were needed to ensure adequate levels of system reliability. Investigated the causes of distribution system outages and inadequate service reliability. Examined the reasonableness of utility system reliability expenditures.

Transmission Line Siting – Examined the need for proposed transmission lines. Analyzed whether proposed transmission lines could be installed underground. Worked with clients to develop alternate routings for proposed lines that would have reduced impacts on the environment and communities.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Examined power plant operating, maintenance, and capital costs. Analyzed power plant operating data from the NERC Generating Availability Data System (GADS). Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors.

Power Plant Repowering - Evaluated the environmental, economic and reliability impacts of rebuilding older, inefficient generating facilities with new combined cycle technology.

Power Plant Air Emissions – Investigated whether proposed generating facilities would provide environmental benefits in terms of reduced emissions of NO_x, SO_2 and CO_2. Examined whether new state emission standards would lead to the retirement of existing power plants or otherwise have an adverse impact on electric system reliability.

Power Plant Water Use – Examined power plant repowering as a strategy for reducing water consumption at existing electric generating facilities. Analyzed the impact of converting power plants from once-through to closed-loop systems with cooling towers on plant revenues and electric system reliability. Evaluated the potential impact of the EPA's Proosed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at existing power plants.

Nuclear Power - Examined the impact of the nuclear power plant life extensions and power uprates on decommissioning costs and collections policies. Evaluated utility decommissioning cost estimates and cost collection plans. Investigated the significance of the increasing ownership of nuclear power plants by multiple tiered holding companies with limited liability company subsidiaries. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Electric Industry Regulation and Markets - Investigated whether new generating facilities that were built for a deregulated subsidiary should be included in the rate base of a regulated utility. Evaluated the reasonableness of proposed utility power purchase agreements with deregulated affiliates. Investigated the prudence of utility power purchases in deregulated markets. Examined whether generating facilities experienced more outages following the transition to a deregulated wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales and the auctions of power purchase agreements. Analyzed the impact of proposed utility mergers on market power. Assessed the reasonableness of contract provisions and terms in proposed power supply agreements.

Economic Analysis - Analyzed the costs and benefits of energy supply options. Examined the economic and system reliability consequences of the early retirement of major electric generating facilities. Evaluated whether new electric generating facilities are used and useful. Quantified replacement power costs and the increased capital and operating costs due to identified instances of mismanagement.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than ninety proceedings before regulatory boards and commissions in twenty three states, before two federal regulatory agencies, and in state and federal court proceedings.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY, AFFIDAVITS AND COMMENTS

South Dakota Public Utility Commission (Case No. EL05-022) – May and June 2006
Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the alternatives to the proposed facility; the need and timing for new supply options in the co-owners' service territories; and whether there are alternatives to the proposed facility that are technically feasible and economically cost-effective.

Georgia Public Service Commission (Docket No. 22449-U) – May 2006
Georgia Power Company's request for an accounting order to record early site permitting and construction operating license costs for new nuclear power plants.

California Public Utilities Commission (Dockets Nos. A.05-11-008 and A.05-11-009) – April 2006
The estimated costs for decommissioning the Diablo Canyon, SONGS 2&3 and Palo Verde nuclear power plants and the annual contributions that are needed from ratepayers to assure that adequate funds will be available to decommission these plants at the projected ends of their service lives.

New Jersey Board of Public Utilities (Docket No. EM05020106) – November and December 2005 and March 2006
Joint Testimony with Bob Fagan and Bruce Biewald on the market power implications of the proposed merger between Exelon Corp. and Public Service Enterprise Group.

Virginia State Corporation Commission (Case No. PUE-2005-00018)– November 2005
The siting of a proposed 230 kV transmission line.

Iowa Utility Board (Docket No. SPU-05-15) – September and October 2005
The reasonableness of IPL's proposed sale of the Duane Arnold Energy Center nuclear plant.

New York State Department of Environmental Conservation (DEC #3-3346-00011/00002) – October 2005
The likely profits that Dynegy will earn from the sale of the energy and capacity of the Danskammer Generating Facility if the plant is converted from once-through to closed-cycle cooling with wet towers or to dry cooling.

Arkansas Public Service Commission (Docket 05-042-U) – July and August 2005
Arkansas Electric Cooperative Corporation's proposed purchase of the Wrightsville Power Facility.

Maine Public Utilities Commission (Docket No. 2005-17) – July 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Eastern Maine Electric Cooperative's request for a CPCN to purchase 15 MW of transmission capacity from New Brunswick Power.

Federal Energy Regulatory Commission (Docket No. EC05-43-0000) – April and May 2005
Joint Affidavit and Supplemental Affidavit with Bruce Biewald on the market power aspects of the proposed merger of Exelon Corporation and Public Service Enterprise Group, Inc.

Maine Public Utilities Commission (Docket No. 2004-538 Phase II) – April 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Maine Public Service Company's request for a CPCN to purchase 35 MW of transmission capacity from New Brunswick Power.

Maine Public Utilities Commission (Docket No. 2004-771) – March 2005
Analysis of Bangor Hydro-Electric's Petition for a Certificate of Public Convenience and Necessity to construct a 345 kV transmission line

United States District Court for the Southern District of Ohio, Eastern Division (Consolidated Civil Actions Nos. C2-99-1182 and C2-99-1250)
Whether the public release of company documents more than three years old would cause competitive harm to the American Electric Power Company.

New Jersey Board of Public Utilities (Docket No. EO03121014) – February 2005
Whether the Board of Public Utilities can halt further collections from Jersey Central Power & Light Company's ratepayers because there already are adequate funds in the company's decommissioning trusts for the Three Mile Island Unit No. 2 Nuclear Plant to allow for the decommissioning of that unit without endangered the public health and safety.

Maine Public Utilities Commission (Docket No. 2004-538) – January and March 2005
Analysis of Maine Public Service Company's request to construct a 138 kV transmission line from Limestone, Maine to the Canadian Border.

California Public Utilities Commission (Application No. AO4-02-026) – December 2004 and January 2005
Southern California Edison's proposed replacement of the steam generators at the San Onofre Unit 2 and Unit 3 nuclear power plants and whether the utility was imprudent for failing to initiate litigation against Combustion Engineering due to defects in the design of and materials used in those steam generators.

United States District Court for the Southern District of Indiana, Indianapolis Division (Civil Action No. IP99-1693) – December 2004
Whether the public release of company documents more than three years old would cause competitive harm to the Cinergy Corporation.

California Public Utilities Commission (Application No. AO4-01-009) – August 2004
Pacific Gas & Electric's proposed replacement of the steam generators at the Diablo Canyon nuclear power plant and whether the utility was imprudent for failing to initiate litigation against Westinghouse due to defects in the design of and materials used in those steam generators.

Public Service Commission of Wisconsin (Docket No. 6690-CE-187) – June, July and August 2004
Whether Wisconsin Public Service Corporation's request for approval to build a proposed 515 MW coal-burning generating facility should be granted.

Public Service Commission of Wisconsin (Docket No. 05-EI-136) – May and June 2004
Whether the proposed sale of the Kewaunee Nuclear Power Plant to a subsidiary of an out-of-state holding company is in the public interest.

Connecticut Siting Council (Docket No. 272) – May 2004
Whether there are technically viable alternatives to the proposed 345-kV transmission line between Middletown and Norwalk Connecticut and the length of the line that can be installed underground.

Arizona Corporation Commission (Docket No. E-01345A-03-0437 – February 2004
Whether Arizona Public Service Company should be allowed to acquire and include in rate base five generating units that were built by a deregulated affiliate.

State of Rhode Island Energy Facilities Siting Board (Docket No. SB-2003-1) – February 2004
Whether the cost of undergrounding a relocated 115kV transmission line would be eligible for regional cost socialization.

State of Maine Department of Environmental Protection (Docket No. A-82-75-0-X) – December 2003
The storage of irradiated nuclear fuel in an Independent Spent Fuel Storage Installation (ISFSI) and whether such an installation represents an air pollution control facility.

Rhode Island Public Utility Commission (Docket No. 3564) – December 2003 and January 2004
Whether Narragansett Electric Company should be required to install a relocated 115kV transmission line underground.

New York State Board on Electric Generation Siting and the Environment (Case No. 01-F-1276) – September, October and November 2003
The environmental, economic and system reliability benefits that can reasonably be expected from the proposed 1,100 MW TransGas Energy generating facility in Brooklyn, New York.

Wisconsin Public Service Commission (Case 6690-UR-115209) - September and October 2003
The reasonableness of Wisconsin Public Service Corporation's decommissioning cost collections for the Kewaunee Nuclear Plant.

Oklahoma Corporation Commission (Cause No. 2003-121) – July 2003
Whether Empire District Electric Company properly reduced its capital costs to reflect the write-off of a portion of the cost of building a new electric generating facility.

Arkansas Public Service Commission (Docket 02-248-U) – May 2003
Entergy's proposed replacement of the steam generators and the reactor vessel head at the ANO Unit 1 Steam Generating Station.

Appellate Tax Board, State of Massachusetts (Docket No C258405-406) – May 2003
The physical nature of electricity and whether electricity is a tangible product or a service.

Maine Public Utilities Commission (Docket 2002-665-U) – April 2003
Analysis of Central Maine Power Company's proposed transmission line for Southern York County and recommendation of alternatives.

Massachusetts Legislature, Joint Committees on Government Regulations and Energy – March 2003
Whether PG&E can decide to permanently retire one or more of the generating units at its Salem Harbor Station if it is not granted an extension beyond October 2004 to reduce the emissions from the Station's three coal-fired units and one oil-fired unit.

New Jersey Board of Public Utilities (Docket No. ER02080614) – January 2003
The prudence of Rockland Electric Company's power purchases during the period August 1, 1999 through July 31, 2002.

New York State Board on Electric Generation Siting and the Environment (Case No. 00-F-1356) – September and October 2002 and January 2003
The need for and the environmental benefits from the proposed 300 MW Kings Park Energy generating facility.

Arizona Corporation Commission (Docket No. E-01345A-01-0822) – March 2002
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002
Repowering NYPA's existing Poletti Station in Queens, New York.

Connecticut Siting Council (Docket No. 217) – March 2002, November 2002, and January 2003
Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

Vermont Public Service Board (Case No. 6545) – January 2002
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001
The market power implications of the proposed merger between Conectiv and Pepco.

Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001
Commonwealth Edison Company's management of its distribution and transmission systems.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001

The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

Illinois Commerce Commission (Docket 00-0361) - August 2000
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

Vermont Public Service Board (Docket 6300) - April 2000
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.

Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

Arkansas Public Service Commission (Docket 98-065-U) - October 1998
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996
Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992
United Illuminating Company off-system capacity sales.

Public Utility Commission of Texas (Docket 10894) - August 1992
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992
Whether the July 1991 outage of Millstone Unit 3 due to the fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, March 1992, June and July 1993
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - July 1991
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

Public Utility Commission of Texas (Docket 9300) - June and July 1990
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989
Boston Edison's corporate management of the Pilgrim Nuclear Station.

Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989
United Illuminating Company's off-system capacity sales.

Kansas State Corporation Commission (Case 164,211-U) - April 1989
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

Public Utility Commission of Texas (Docket 8425) - March 1989
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

New Mexico Public Service Commission (Case 2146, Part II) - October 1988
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

Illinois Commerce Commission (Docket 87-0695) - April 1988
Illinois Power Company's planning for the Clinton Nuclear Station.

North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

North Carolina Utilities Commission (Docket E-2, Sub 526) - June 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - December 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and May 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) - January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

South Carolina Public Service Commission (Case 84-122-E) - August 1984
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

Vermont Public Service Board (Case 4865) - May 1984
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

New York State Public Service Commission (Case 28347) -January 1984
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - February 1983 and February 1984
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

REPORTS, ARTICLES, AND PRESENTATIONS

Conservation and Renewable Energy Should be the Cornerstone for Meeting Future Natural Gas Needs. Presentation to the Global LNG Summit, June 1, 2004. Presentation given by Cliff Chen.

Comments on natural gas utilities' Phase I Proposals for pre-approved full cost recovery of contracts with liquid natural gas (LNG) suppliers and the costs of interconnecting their systems with LNG facilities. Comments in California Public Utilities Commission Rulemaking 04-01-025. March 23, 2004.

The 2003 Blackout: Solutions that Won't Cost a Fortune, The Electricity Journal, November 2003, with David White, Amy Roschelle, Paul Peterson, Bruce Biewald, and William Steinhurst.

The Impact of Converting the Cooling Systems at Indian Point Units 2 and 3 on Electric System Reliability. An Analysis for Riverkeeper, Inc. November 3, 2003.

The Impact of Converting Indian Point Units 2 and 3 to Closed-Cycle Cooling Systems with Cooling Towers on Energy's Likely Future Earnings. An Analysis for Riverkeeper, Inc. November 3, 2003.

Entergy's Lost Revenues During Outages of Indian Point Units 2 and 3 to Convert to Closed-Cycle Cooling Systems. An Analysis for Riverkeeper, Inc. November 3, 2003.

Power Plant Repowering as a Strategy for Reducing Water Consumption at Existing Electric Generating Facilities. A presentation at the May 2003 Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms. May 6, 2003.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-tiered Holding Companies to Own Electric Generating Plants. A presentation at the 2002 NASUCA Annual Meeting. November 12, 2002.

Determining the Need for Proposed Overhead Transmission Facilities. A Presentation by David Schlissel and Paul Peterson to the Task Force and Working Group for Connecticut Public Act 02-95. October 17, 2002.

Future PG&E Net Revenues From The Sale of Electricity Generated at its Brayton Point Station. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

PG&E's Net Revenues From The Sale of Electricity Generated at its Brayton Point Station During the Years 1999-2002. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants. A Synapse report for the STAR Foundation and Riverkeeper, Inc., by David Schlissel, Paul Peterson, and Bruce Biewald, August 7, 2002.

Comments on EPA's Proposed Clean Water Act Section 316(b) for Cooling Water Intake Structures at Phase II Existing Facilities, on behalf of Riverkeeper, Inc., by David Schlissel and Geoffrey Keith, August 2002.

The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line. A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

ISO New England's Generating Unit Availability Study: Where's the Beef? A Presentation at the June 29, 2001 Restructuring Roundtable.

Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability. A Synapse Report for the Clean Air Task Force. May 2001.

Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability. A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

Cost, Grid Reliability Concerns on the Rise Amid Restructuring, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

Report on Indian Point 2 Steam Generator Issues, Schlissel Technical Consulting, Inc., March 10, 2000.

Preliminary Expert Report in Case 96-016613, <u>Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company</u>, October 28, 1999.

Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation, February 1997.

Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs, May, 1996.

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Reviewed the salt deposition mitigation strategy proposed for Reliant Energy's repowering of its Astoria Generating Station. October 2002 through February 2003.

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

WORK HISTORY

2000 - Present: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981
- American Nuclear Society
- National Association of Corrosion Engineers
- National Academy of Forensic Engineers (Correspondent Affiliate)

EXHIBIT SYNAPSE-2

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. Research Associate. June 2003 - Present. Consulting on economic analysis of technologies and polices, electric policy modeling, evaluation of air emissions of electricity generation, and other topics including energy efficiency, consumer advocacy, environmental compliance and technology strategy within the energy industry.

EFI/Xenergy (now KEMA Consulting, Inc.), Burlington, MA Intern, September 2000 – May 2003. Co-authored three regional sections in a nationwide annual review of regional transmission organizations (RTOs). Researched and wrote client reports and intra-company memos about various energy technologies such as wind, solar, geothermal, fuel cells and ethanol. Interviewed energy stakeholders and experts in order to answer client policy and legislative questions. Wrote sections of a guidebook on utility, local, state and federal incentives for renewable energy.

Zilkha Renewable Energy (now Horizon Wind Energy), Houston, TX. Intern, May - August 2002. Authored comprehensive strategy for developing wind power projects on federal lands in eight states, including legislation, financial incentive, wind resource, transmission and public support overviews. "Wind prospected" possible sites for wind farms throughout the western United States. Identified and monetized value of renewable energy attributes as part of power supply bids to utilities.

EDUCATION

Tufts University, BS in Economics and Environmental Studies, Medford, MA, 2003.

Harvard University Extension School, graduate level course in Corporate Finance, Spring 2005.

ONGOING PROJECT WORK

- Evaluating an Energy Efficiency Collaborative Process in the District of Columbia
- Integrated Resource Planning and Portfolio Management in Ohio
- Integrated Resource Planning for Tallahassee Utilities.
- Advising Electric Utility on Carbon Dioxide Regulation.

TESTIMONY AND COMMENTS

South Dakota Public Utilities Commission (Docket No. EL05-022) – July 2006
Evaluation of a proposal to build a new supercritical pulverized coal plant including alternatives to the plant and potential for greenhouse gas regulation.

Wisconsin Public Service Commission (Docket #6685-CE-108) – February 2006
Evaluating Wisconsin Public Power Inc.'s request for approval of a Certificate of Authority to exercise its option to own a portion of Prairie State Energy Campus, a supercritical pulverized coal plant.

REPORTS

Ensuring Delaware's Energy Future: A Response to Executive Order No. 82, prepared by the Delaware Cabinet Committee on Energy with technical assistance at Synapse Energy Economics from William Steinhurst, Bruce Biewald, David White, Kenji Takahashi, Alice Napoleon, Amy Roschelle, Anna Sommer and Ezra Hausman. March 8, 2006.

Mohave Alternatives and Complements Study: Assessment of Carbon Sequestration Feasibility and Markets, a Sargent & Lundy and Synapse Energy Economics, Inc. report prepared for Southern California Edison by Anna Sommer and William Steinhurst. February 2006.

Potential Cost Impacts of a Renewable Portfolio Standard in New Brunswick, prepared by Tim Woolf, David White, Cliff Chen and Anna Sommer for the New Brunswick Department of Energy, October 2005.

Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value, a Synapse Energy Economics, Inc. report prepared by Lucy Johnston, Amy Roschelle, Ezra Hausman, Anna Sommer and Bruce Biewald. September 20, 2005.

Potential Cost Impacts of a Vermont Renewable Portfolio Standard, a Synapse Energy Economics, Inc. report prepared for the Vermont Public Service Board, by Tim Woolf, David E. White, Cliff Chen, and Anna Sommer. October 16, 2003.

Estimating the Environmental Benefits of Renewable Energy and Energy Efficiency in North America: Experience and Methods, a report for the Commission for Environmental Cooperation, by Geoffrey Keith, Bruce Biewald, Anna Sommer, Patrick Henn, and Miguel Breceda, September 22, 2003.

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Evaluation of Boston Edison's claim of negative impacts to the purchase price of Pilgrim nuclear station resulting from the DOE's failure to begin accepting spent nuclear fuel.

Public Utilities Commission of Nevada (Docket No. 06-030) – Ongoing
Evaluation of Nevada Power Company's demand side-management (DSM) portion of its integrated resource plan.

Nova Scotia Utility and Review Board (P-128.05) – May 2006
Evaluation of Nova Scotia Power Inc.'s proposal to install Low NOx Combustion Firing Systems and a common Flue Gas Desulfurization Unit on its coal-fired power plants.

Indiana Utility Regulatory Commission (Cause No. 42873) – March 2006
Issues regarding the proposed merger of Duke Energy and Cinergy, Inc. including compliance with DSM goals in previous mergers.

Indiana Utility Regulatory Commission (Cause No. 42861) – March 2006
Issues regarding Vectren Energy's proposal to install emission controls for SO_2, NOx, PM and Hg including compliance with present and future emissions regulations and planning analysis.

Utah Public Service Commission (Docket No. 05-035-54) – November 2005
Issues regarding the acquisition of PacifiCorp by MidAmerican Energy Holdings Company including underinvestment in grid infrastructure, environmental compliance with air regulations and investment in IGCC.

Iowa Utilities Board (Docket No. SPU-05-15) – November 2005
Evaluation of proposed sale of the Duane Arnold nuclear power plant from Interstate Power & Light to FPL.

Arkansas Public Utilities Commission (Docket No. 05-042-U) – August 2005
Issues regarding the purchase of Wrightsville, a gas-fired power plant, by Arkansas Electric Cooperative including appropriateness and reasonableness of the purchase.

Indiana Utility Regulatory Commission (Cause No. 42718) – May 2005
Issues regarding PSI Energy's proposal to install $1.4 billion in control technologies for SO_2, NOx and Hg including rate of return on investment, analysis of emissions regulation risk, scenario planning, estimates of control technology cost and equity of plan to ratepayers.

Nuclear Regulatory Commission (Docket No. 52-007) – April 2005
Issues regarding Exelon Generation's petition for early site permit approval for a baseload nuclear generating facility in Illinois including the Company's analysis of alternatives.

Georgia Public Service Commission (Docket No. 18300-U) – February 2005
Georgia Power Company rate case involving issues of cost allocation and consideration of public benefits in rate-making for the Metropolitan Atlanta Rapid Transit Authority.

Indiana Utility Regulatory Commission (Cause No. 42612) – November 2004
Evaluation of PSI Energy's plan to offer demand side management (DSM) programs to its customers including issues of program scope, funding, lost revenue recovery, shared savings incentive recovery, and third-party administration issues.

California Public Utilities Commission (Rulemaking 04-04-003) – August 2004
Issues in the San Diego Gas & Electric, Pacific Gas & Electric and Southern California Edison long-term resource plans including modeling the cost of carbon regulation, modeling of renewables, scenario planning and debt equivalency.

Texas Public Utility Commission (Docket No. 29526) – June 2004
Issues in CenterPoint Energy Houston Electric LLC's true up filing, including environmental cleanup costs, excess mitigation credits, and construction work in progress.

PROFESSIONAL MEMBERSHIPS

- Air & Waste Management Association

Resume dated September 2006.

EXHIBIT SYNAPSE-3

Climate Change and Power:

Carbon Dioxide Emissions Costs and Electricity Resource Planning

Prepared by:
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August 31, 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 65% to 90% of energy-related carbon dioxide emissions reductions are likely to come from the electric sector under a wide range of economy-wide federal policy scenarios.[2]

[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.

[2] EIA 2003, page 13; EIA 2004, page 5; EIA 2006, page 19.

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, 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	2003	Cap at 2000 levels	Economy-wide, large emitting sources
National Commission on Energy Policy (basis for Bingaman-Domenici legislative work)	Greenhouse Gas Intensity Reduction Goals	2005	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.

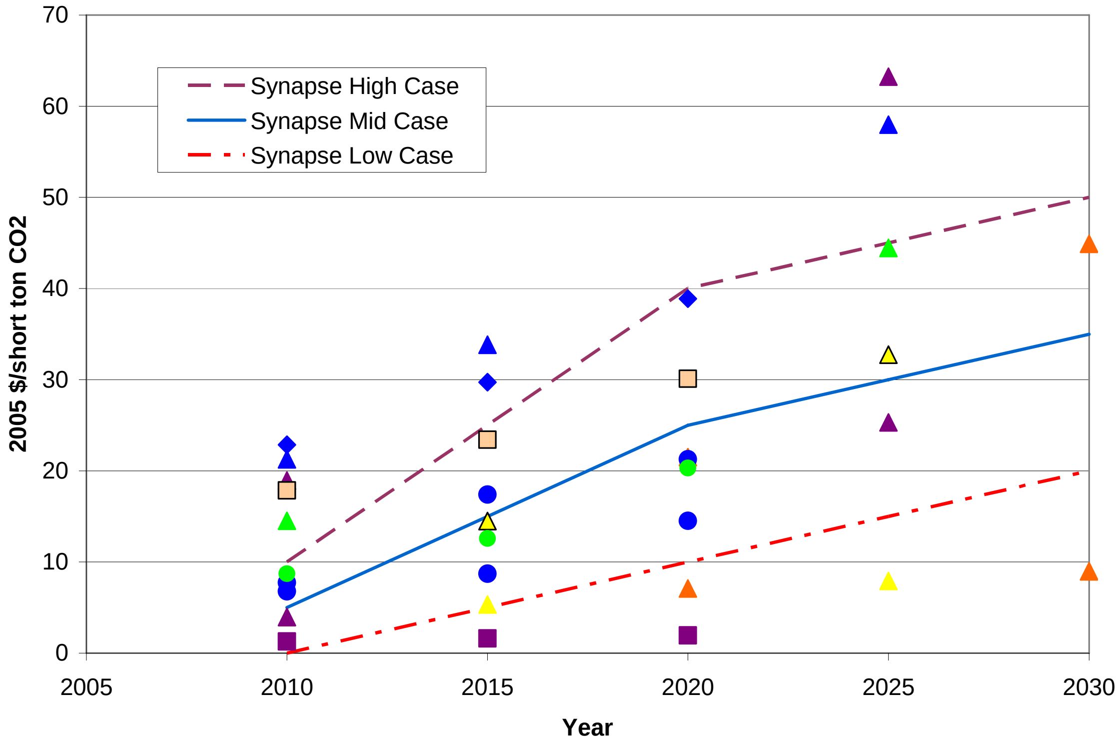

Figure ES-1. Synapse Forecast of Carbon Dioxide Allowance Prices

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

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.

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.[3]

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.[4] 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

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

[4] 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.[5]

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.[6] 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."[7] 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.[8] 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.[9]

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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[5] Ibid., pages 45-48.

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

[7] Ibid., p. 6

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

[9] 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.[10] 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.[11] 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

[10] 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.

[11] 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.[12]

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.[13] 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:[14]

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[12] IPCC, *Climate Change 2001: Synthesis Report*, Fourth Volume of the IPCC Third Assessment Report. IPCC 2001. Question 6.

[13] *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.

[14] 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.[15]

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.[16] Figure 3.1 shows the top twenty carbon dioxide emitters in the world.

[15] Several websites provide summary information on climate change science including www.ipcc.org www.nrdc.org, www.ucsusa.org, and www.climateark.org.

[16] International Energy Agency, "CO_2 from Fuel Combustion – Fact Sheet," 2005

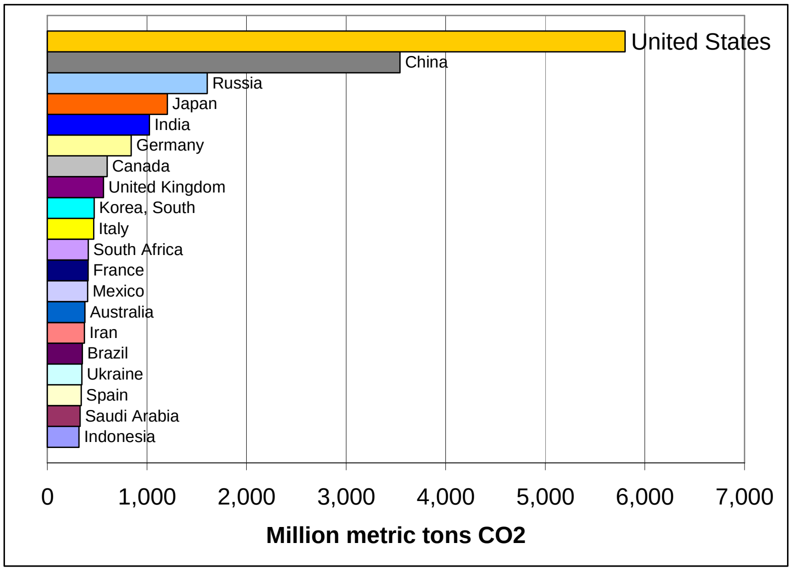

Figure 3.1. Top Worldwide Emitters of Carbon Dioxide in 2003

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.

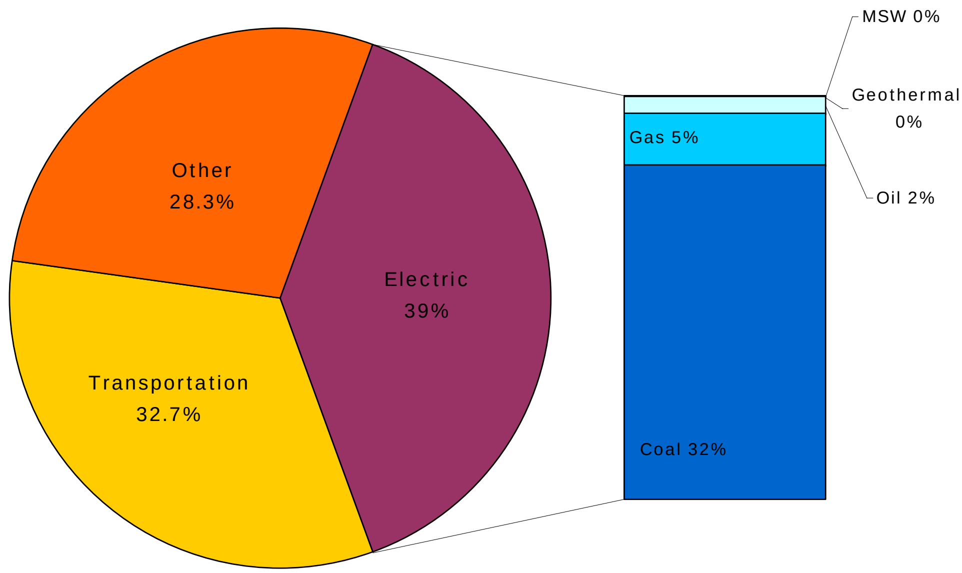

Figure 3.2. US CO_2 Emissions by Sector in 2004

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. [17] 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.[18] 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. [19] 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.

[17] EIA, "Emissions of Greenhouse Gases in the United Sates, 2004;" Energy Information Administration; December 2005, xiii

[18] EIA *Emissions of Greenhouse Gases in the United States 2004*, December 2005.

[19] 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.[20] 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.[21] 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."[22] 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.[23] 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.[24] 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

[20] 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/.

[21] 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.

[22] From Article 3 of the United Nations Framework Convention on Climate Change, 1992.

[23] 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

[24] Greenhouse gases covered by the Protocol are CO_2, CH_4, N_2O, HFCs, PFCs and SF_6.

February 2005.[25] 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[26]

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.[27] The leaders

[25] 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.

[26] Background information at: http://unfccc.int/essential_background/kyoto_protocol/items/3145.php

[27] 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.[28] 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.[29] The EU has committed to emission reductions of 20-30% below 1990 levels by 2020, and reduction targets for 2050 are still under discussion.[30]

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

[28] Council of the European Union, *Information Note – Brussels March 10, 2005.* http://ue.eu.int/uedocs/cmsUpload/st07242.en05.pdf

[29] 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

[30] 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."[31] 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.[32] 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. [33]

[31] The UNFCC was signed by President George H. Bush in 1992 and ratified by the Senate in the same year.

[32] "Bush acknowledges human contribution to global warming; calls for post-Kyoto strategy." Greenwire, July 6, 2005.

[33] 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.[34]

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.

[34] "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	2003	Cap at 2000 levels	Economy-wide, large emitting sources
National Commission on Energy Policy (basis for Bingaman-Domenici legislative work)	Greenhouse Gas Intensity Reduction Goals	2005	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 109^{th} 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.[35] 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.[36] 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.[37]

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.[38] 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,

[35] National Commission on Energy Policy, *Ending the Energy Stalemate,* December 2004, pages 19-29.

[36] 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.

[37] 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

[38] 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.[39]

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.

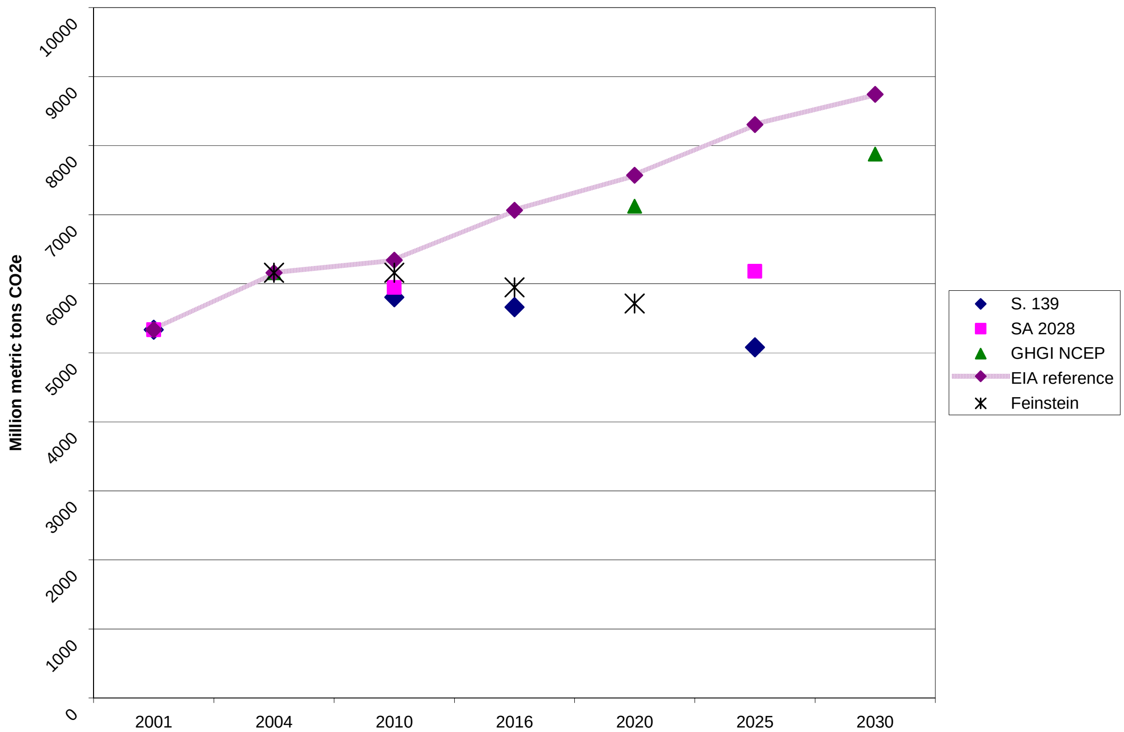

Figure 5.1. Emission Trajectories of Proposed Federal Legislation

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.

[39] Press release, "Udall and Petri introduce legislation to curb global warming," March 29, 2006.

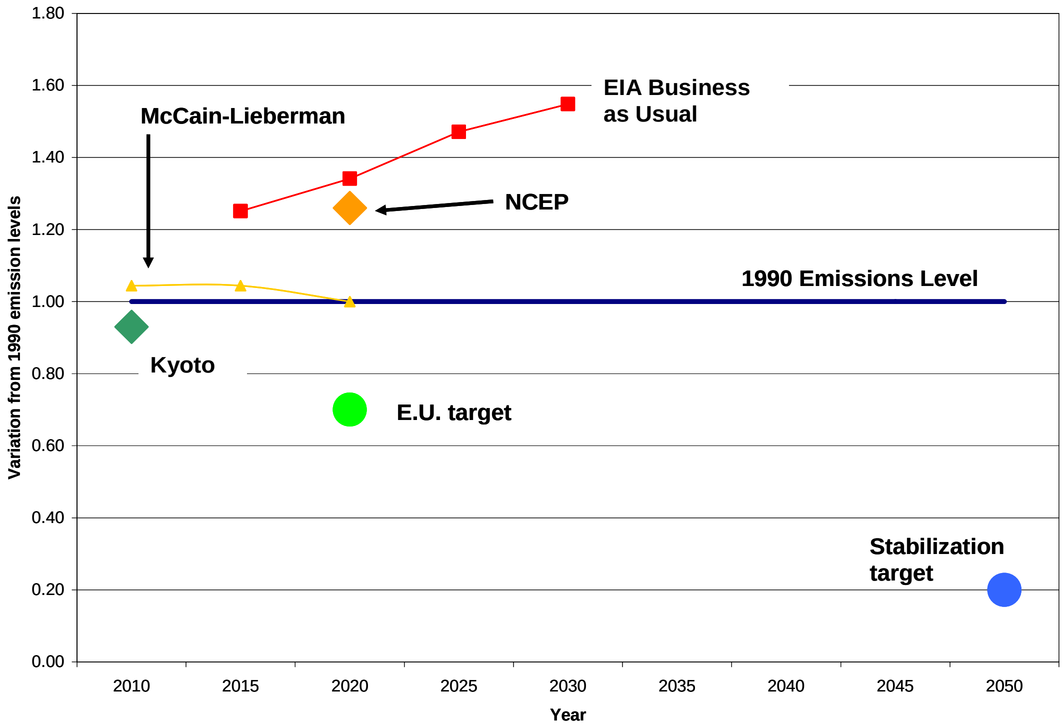

Figure 5.2 Comparison of Emission Reduction Goals

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.[40] 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).[41]

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.[42] 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

[40] 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.

[41] Press release, "Codey Takes Crucial Step to Combat Global Warming," October 18, 2005.

[42] 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.[43] Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process.[44]

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.[45]

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.[46] 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.[47]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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[43] Maryland Senate Bill 154 *Healthy Air Act*, signed April 6, 2006.

[44] Information on this effort is available at www.rggi.org

[45] 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.

[46] the US Mayors Climate Protection Agreement, 2005. Information available at http://www.ci.seattle.wa.us/mayor/climate

[47] 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.[48]

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."[49] 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.[50]

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.[51] Similarly, in a 2005 survey of the North American electricity industry, 93% of respondents anticipate increased pressure to take action on global climate change.[52]

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[48] 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

[49] 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/

[50] 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.

[51] PA Consulting Group, "Environmental Survey 2004" Press release, October 22, 2004.

[52] 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.[53] 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.[54]

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.[55] 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.[56] 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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[53] "US Companies Face Record Number of Global Warming Shareholder Resolutions on Wider Range of Business Sectors," CERES press release, February 17, 2005.

[54] "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.

[55] 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.

[56] 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.[57] 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.[58]

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.[59]
- 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.[60]

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.[61]

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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[57] See: http://www.cdproject.net/aboutus.asp

[58] 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.

[59] FT 500 is the Financial Times' ranking of the top 500 companies ranked globally and by sector based on market capital.

[60] CDP press release, September 14, 2005. Information on the Carbon Disclosure Project, including reports, are available at: http://www.cdproject.net/index.asp.

[61] *Greenwire*, February 16, 2005

reduction targets and supporting a national policy to limit greenhouse gas emissions. [62] 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."[63] The President of Duke Energy urges a federal carbon tax, and states that Duke should be a leader on climate change policy.[64] 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.[65] 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

[62] Goldman Sachs Environmental Policy Framework, http://www.gs.com/our_firm/our_culture/corporate_citizenship/environmental_policy_framework/docs/EnvironmentalPolicyFramework.pdf

[63] Jacobson, Sanne, Neil Numark and Paloma Sarria, "Greenhouse Gas Emissions: A Changing US Climate," *Public Utilities Fortnightly*, February 2005.

[64] Paul M. Anderson Letter to Shareholders, March 15, 2005.

[65] 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.[66] 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.[67] 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.[68] 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.[69] 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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[66] Lempert, Popper, Resitar and Hart, "Capital Cycles and the Timing of Climate Change Policy." Pew Center on Global Climate Change, October 2002. page

[67] US EPA, *Analysis of Emissions Reduction Options for the Electric Power Industry,* March 1999.

[68] US EPA, *Briefing Report,* March 1999.

[69] 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. [70]

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).[71] 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.[72]

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

[70] "What determines the Price of Carbon," Carbon Market Analyst, *Point Carbon*, October 14, 2004.

[71] These prices are from Evolution Express trade data, http://www.evomarkets.com/, accessed on 3/31/06.

[72] 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.[73]

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.[74] 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.[75] 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).[76] 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."[77] 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.

[73] 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

[74] California Public Utilities Commission, Decision 04-12-048, December 16, 2004

[75] California Public Utilities Commission, Decision 05-04-024, April 2005.

[76] Montana Public Service Commission, "Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229," August 17, 2004.

[77] 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 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). [78]

In 2003 researchers at the Massachusetts Institute of Technology also analyzed potential costs of the McCain Lieberman legislation.[79] 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).[80] 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

[78] 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

[79] 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.

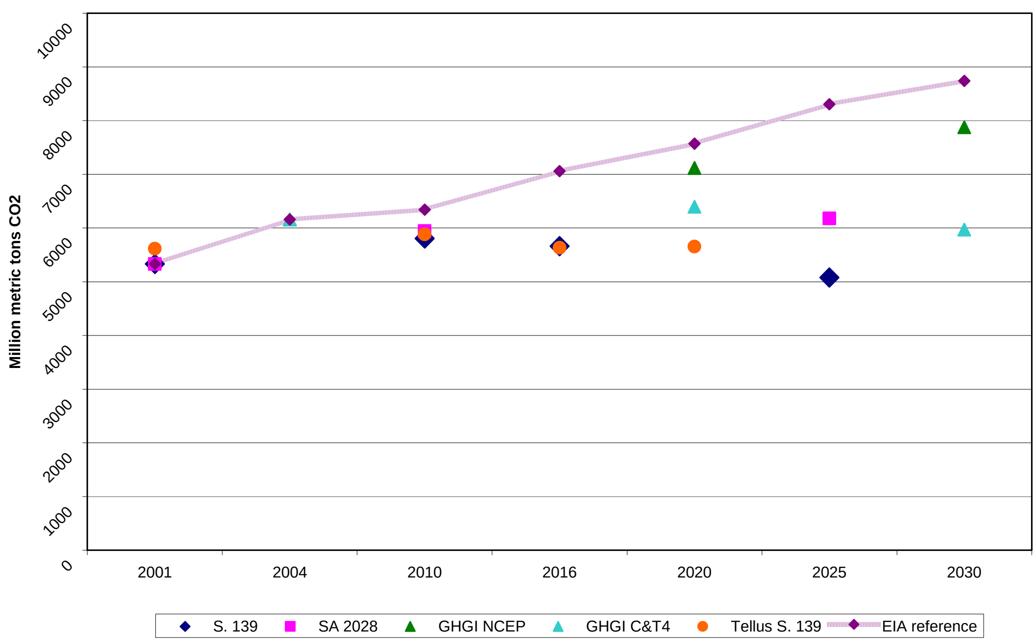
[80] Bailie et al., *Analysis of the Climate Stewardship Act*, July 2003; Bailie and Dougherty, *Analysis of the Climate Stewardship Act Amendment*, Tellus Institute, June, 2004. Available at http://www.tellus.org/energy/publications/McCainLieberman2004.pdf

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.[81] 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).[82] EPA also analyzed the power sector proposal from Senator Jeffords (S. 150).[83]

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.



[81] EIA, *Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals,* March 2006. SR/OIAF/2006-01.

[82] 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.

[83] 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 2005 dollars per ton of carbon dioxide.

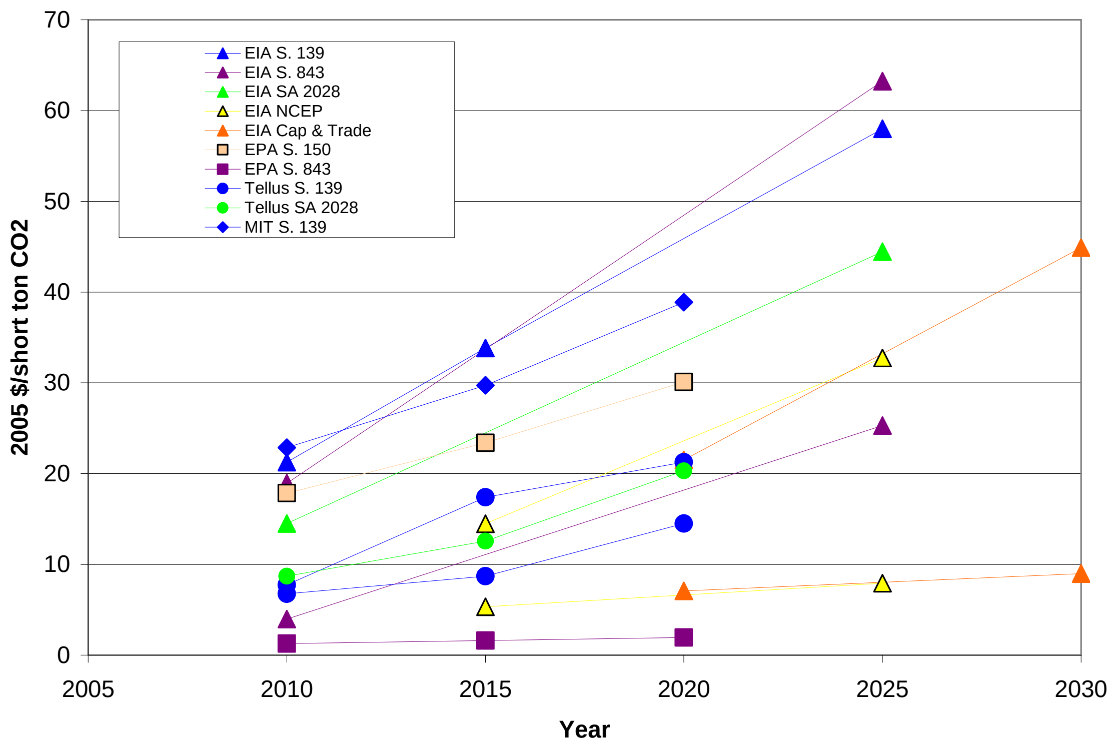


Figure 6.2. Allowance Cost Estimates From Studies of Economy-wide and Electric Sector US Policy Proposals

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.[84] In 1999 EIA performed a very similar study, but looked at phasing in carbon prices beginning in 2000 instead of 2005 as in the

[84] EIA, "Impacts of the Kyoto Protocol on US Energy Markets and Economic Activity," October 1998. SR/OIAD/98-03

original study.[85] 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.[86] 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.[87]

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.

[85] EIA, "Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol," July 1999. SR/OIAF/99-02.

[86] ICF Consulting presentation of "RGGI Electricity Sector Modeling Results," September 21, 2005. Results of the ICF analysis are available at www.rggi.org

[87] 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.[88] 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.[89]

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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[88] 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

[89] 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. [90] 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."[91] 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

[90] 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.

[91] 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
• **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.

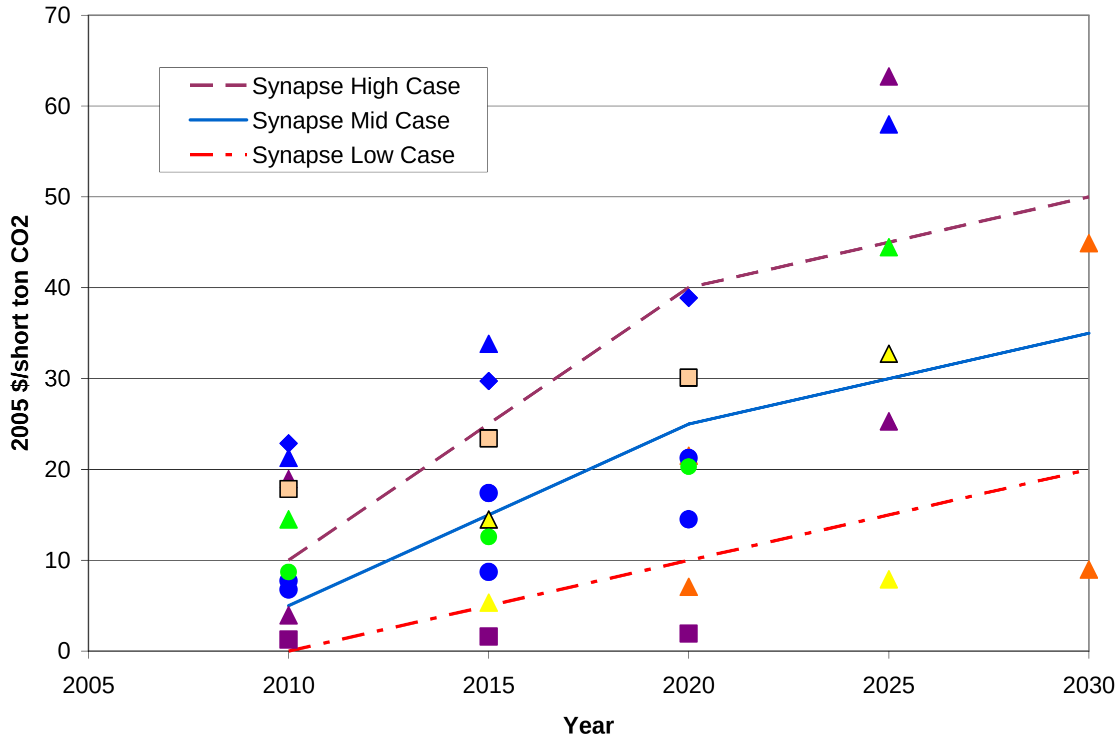

Figure 6.3. Synapse Forecast of Carbon Dioxide Allowance Prices

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. This report is unchanged from the May 18, 2006 version except for the correction of typographical errors. This version also includes additional links in the reference section.

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EXHIBIT SYNAPSE-4