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February 19, 2010

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Clerk's Office
N.C. Utilities Commission

VIA HAND DELIVERY

Ms. Renne Vance
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603-5918

RE: Investigation of Integrated Resource Planning in North Carolina - 2009
Docket No. E-100, Sub 124

Dear Ms. Vance:

Enclosed please find for filing in the above-referenced docket on behalf of Environmental Defense Fund, the Sierra Club, Southern Alliance for Clean Energy and the Southern Environmental Law Center the following documents:

- An original and 30 copies of the Direct Testimony of David Schlissel ✓ (Confidential Version). This document contains confidential data and should be filed under seal.
- An original and 1 copy of the Direct Testimony of David Schlissel (Public ✓ Version).
- An original and 30 copies of the Direct Testimony of John D. Wilson ✓ (Confidential Version). This document contains confidential data and should be filed under seal.
- An original and 1 copy of the Direct Testimony of John D. Wilson (Public ✓ Version).

By copy of this letter and enclosures, I am serving a copy of the Public Version of each witness's testimony on all parties of record.

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Sincerely,

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Kate Double

Enclosures
cc: Parties of Record

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of Integrated Resource Planning in North Carolina - 2009	)))	DOCKET NO. E-100 SUB 124

DIRECT TESTIMONY OF DAVID A. SCHLISSEL ON BEHALF OF ENVIRONMENTAL DEFENSE FUND, THE SIERRA CLUB, SOUTHERN ALLIANCE FOR CLEAN ENERGY AND THE SOUTHERN ENVIRONMENTAL LAW CENTER

PUBLIC VERSION

FEBRUARY 19, 2010

List of Exhibits

Exhibit DAS-1	Current Resume for David A. Schlissel
Exhibit DAS-2C	Duke Energy Carolinas' *The 2030 Vision*, dated June 4, 2009 [CONFIDENTIAL]
Exhibit DAS-3C	Duke Energy Carolinas' *Duke Energy Low-Carbon Strategy*, dated 8/25/09 [CONFIDENTIAL]
Exhibit DAS-4	*Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project*, submitted by Entergy Louisiana to the Louisiana Public Service Commission, April 1, 2009
Exhibit DAS-5	*U.S. Natural Gas Supply: Then There Was Abundance*, American Gas Association, January 20, 2010
Exhibit DAS-6	*Synapse 2008 CO_2 Price Forecasts*

Q. What are your name, position and business address?

A. My name is David A. Schlissel. I am the President of Schlissel Technical Consulting, Inc., 45 Horace Road, Belmont, MA 02478.

Q. 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 recent clients have included the General Staff of the Arkansas Public Service Commission, the U.S. Department of Justice, the Attorney General of the State of New York, cities and towns in Connecticut, New York and Virginia, state consumer advocates, and national and local environmental organizations.

I have testified before state regulatory commissions in Arizona, New Jersey, California, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, Rhode Island, Wisconsin, Iowa, South Dakota, Georgia, Minnesota, Michigan, Florida, North Dakota and Mississippi and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit DAS-1.

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

A. I am testifying on behalf of Environmental Defense Fund, the Sierra Club, Southern Alliance for Clean Energy and the Southern Environmental Law Center.

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

A. Yes. I have testified before the North Carolina Utilities Commission in Dockets Nos. E-2, Sub 526; E-2, Sub 537; and E-7, Sub 790.

Q. What is the purpose of your testimony?

A. I have been asked to review the 2009 Integrated Resource Plans ("IRP") submitted by Duke Energy Carolinas ("Duke") and Progress Energy Carolinas ("Progress"). I was asked to focus on the following specific issues:

- The reasonableness of carbon dioxide ("CO_2") prices used in the IRPs.
- Projected carbon emissions.
- Planned retirements of existing coal units and opportunities for additional retirements.
- Natural gas-fired generation as an alternative to existing coal.
- The potential cost of compliance with environmental requirements.

This testimony presents the results of my review.

Q. Please summarize your conclusions.

A. My conclusions are as follows:

1. Federal climate change regulation currently under consideration will require significant reductions in the nation's annual CO_2 emissions over the coming decades. Duke, however, projects that its annual CO_2

emissions will increase between 2010 and 2029 in each of the resource portfolios that it has presented in the Revised 2009 IRP in spite of its announced plan to retire approximately 1,600 to 1,700 MW of cycling coal units by 2020.

2. It is not surprising that Duke's annual CO_2 emissions are projected to increase between 2010 and 2029 because of the planned addition of the Cliffside Unit 6 baseload coal unit. The new Cliffside Unit 6, on its own, can be expected to emit approximately six million tons of CO_2 each year, or more than two million tons more CO_2 than was emitted in 2008 by all of the cycling coal units that Duke discusses retiring.

3. In order to actually reduce its annual CO_2 emissions over the coming decades, Duke will have to reduce its reliance on coal-fired generation by retiring even more coal-fired generating capacity than it has so far proposed to retire. Given that Duke already is planning to add new nuclear units to its resource mix, the alternatives for displacing additional coal units are building more natural gas-fired combined cycle units, adding more renewable resources and adding more energy efficiency than the Company now includes in its resource plans.

4. Although new natural-gas fired combined cycle units will emit some CO_2, the amounts they emit will be significantly less than a comparable amount of coal-fired capacity.

5. The Commission should not be concerned that Duke would become unreasonably dependent on natural gas if it added more natural gas-fired

combined cycle units to replace additional coal-fired generating capacity. New assessments show that there is far more natural gas available in the domestic United States than was projected even two years ago. This should enhance the value of using natural gas as a bridge fuel to a lower carbon future and should ameliorate future natural gas prices.

6. Duke and Progress should consider the potential costs of EPA regulation of coal combustion wastes in their IRP analyses.

7. The Base case CO_2 prices that Duke used in its 2009 IRP analyses were reasonable. *However, given the uncertainties associated with the timing,* stringency and design of federal regulation of greenhouse gas emissions, Duke should have looked at a wider range of scenarios than only $\pm$ 15 percent around that Base case set of CO_2 prices. .

8. The CO_2 prices used by Progress in its 2009 IRP analyses are compared to the range of CO_2 prices that Duke used in its 2009 IRP and to the CO_2 prices used in resource planning by Synapse Energy Economics, state commissions and other utilities.

Annual CO_2 Emissions

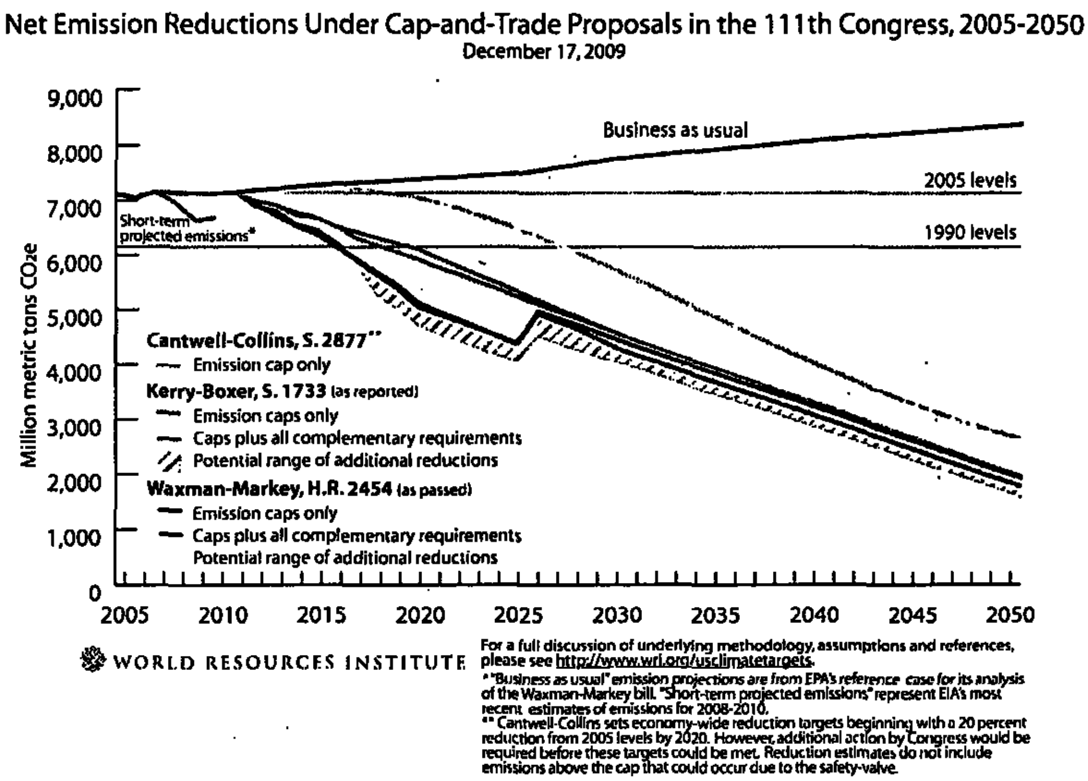
Q. What is the goal of the federal climate change legislation and policies that are being considered?

A. The general goal of most of the legislation and policies under consideration would be to reduce annual domestic U.S. CO_2 emissions by 60 percent to 80 percent from current levels by the middle of this century. It is generally believed by climate scientists that reductions of this magnitude might enable the world to avoid the most harmful effects of global climate change.

Q. What emissions reductions would be required under the bills that have been introduced in the current 111[th] U.S. Congress?

A. The emissions levels that would be mandated by some of these bills are shown in Figure 1 below:

Figure 1: Comparison of Legislative Climate Change Targets in the Current 111th U.S. Congress as of December 17, 2009



It is uncertain which, if any, of the specific climate change bills that have been introduced to date in the Congress will be adopted. Nevertheless, the general trend toward carbon regulation is clear; and it would be a mistake to ignore it in long-term decisions concerning electric resources. Over time the proposals are becoming more stringent as evidence of climate change accumulates and as the political support for serious governmental action grows.

Q. Duke Energy, the parent of Duke, is a member of the U.S. Climate Action Partnership ("USCAP"). Are the emissions targets in the proposed legislation shown in Figure 1 above consistent with the emissions reduction goals recommended by the USCAP?

A. Yes. The United States Climate Action Partnership has recommended that national CO_2 emissions be reduced by 14 percent to 20 percent from 2005 levels by 2020, by 42 percent by 2030 and by 83 percent by 2050.[1] As shown in Table 1 below, the emissions targets in the Waxman-Markey legislation that has been passed by the U.S. House of Representatives are extremely similar to the goals promoted by the USCAP.

	USCAP	Waxman-Markey
2012	97%-102% of 2005 levels	3% below 2005 levels
2020	80%-86% of 2005 levels	17% below 2005 levels
2030	58% of 2005 levels	42% below 2005 levels
2050	20% of 2005 levels	83% below 2005 levels

Table 1: USCAP and Waxman-Markey CO_2 Emission Targets

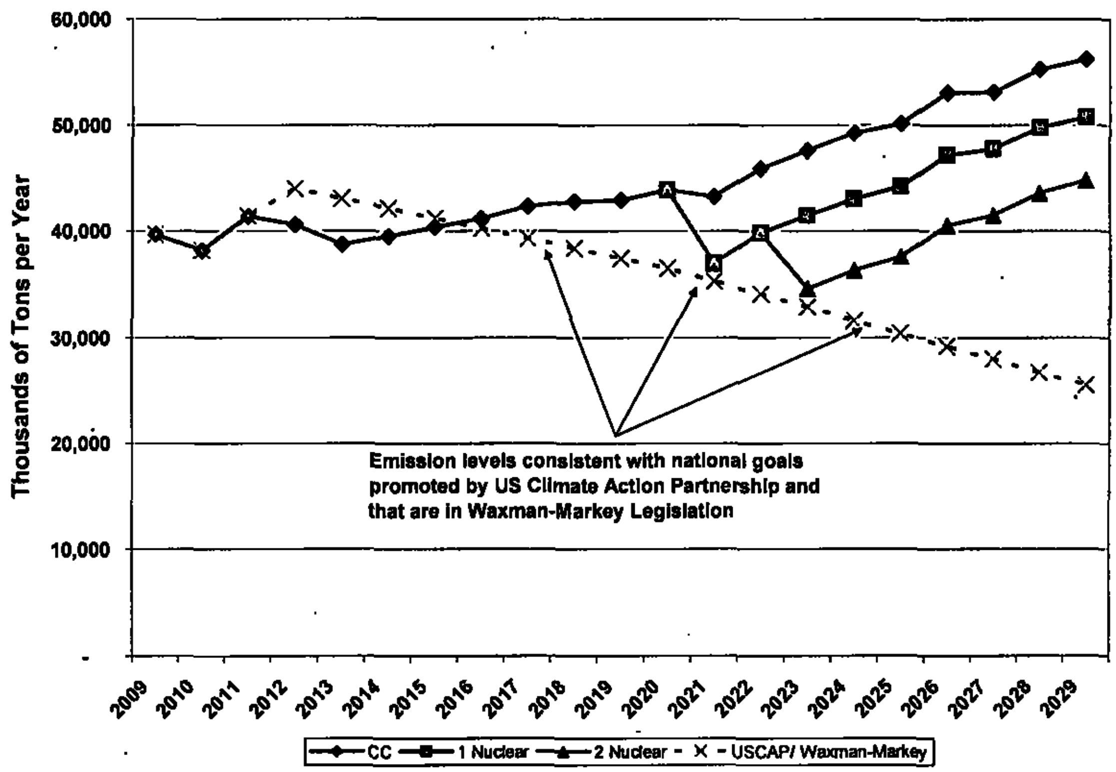
Q. What would Duke's annual CO_2 emissions be under its proposed IRP resource plan?

A. Duke discussed several modeling portfolios in its Revised 2009 IRP. These portfolios included no new nuclear units, one new nuclear unit and two new

1 The United States Climate Action Partnership's website describes the group as follows. "USCAP is a group of businesses and leading environmental organizations that have come together to call on the federal government to quickly enact strong national legislation to require significant reductions of greenhouse gas emissions." www.us-cap.org USCAP materials refer to "the urgent need for a policy framework on climate change." www.us-cap.org.

nuclear units, respectively.[2] The annual CO_2 emissions for these resource portfolios are shown in Figure 2, below.[3]

Figure 2: Duke's Projected Future Annual CO_2 Emissions through 2030



The three solid lines in Figure 2 represent the CC (that is, no new nuclear units), the one new nuclear unit in 2021 and the two new nuclear units in 2021 and 2023 scenarios discussed by Duke in its 2009 IRP.

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2 Duke Revised 2009 IRP, at pages 66 and 67.

3 Figure 2 shows the annual CO_2 emissions for the resource portfolios in which there were no new nuclear units, in which one new nuclear unit was added in 2021, and in which two new nuclear units were added in 2021 and 2023. Duke also modeled scenarios in which one new nuclear unit was added in 2018 and in which two new nuclear units were added in 2018 and 2019. Duke did not provide the annual CO_2 emissions for these other portfolios. However, it can be expected that their annual CO_2 emissions would be lower in the years 2018 through 2020 than the portfolios in which new nuclear units are added in 2021 and 2023 but would be approximately if not exactly the same in subsequent years.

Consequently, Duke's own projections show that its annual CO_2 emissions would increase in each of these three scenarios by between 13 percent and 42 percent (depending on the scenario) between 2009 and 2029 at the very time that legislation under consideration in Congress would be mandating reductions in emissions. In other words, Duke's CO_2 emissions would be going in the wrong direction, i.e. up, at a time when the mandated levels of emissions were being reduced.

Indeed, Duke's CO_2 emissions would be increasing during the very same years that its parent company Duke Energy is promoting, through the U.S. Climate Action Partnership, that national CO_2 emissions be significantly reduced.

Q. Do the CO_2 emissions trajectories shown in Figure 2 reflect the coal plant retirements that Duke discusses in the Revised 2009 IRP?

A. Yes. The CO_2 emissions trajectories shown in Figure 2 reflect the approximately 1,600 to 1,700 MW of coal plant retirements discussed at pages 40-43 of its January 11, 2010 Revised 2009 IRP.[4]

Q. Is it surprising that Duke is projecting that its annual CO_2 emissions will not go down between 2010 and 2029 given that it is proposing to retire more than 1,600 MW of existing coal capacity?

A. Not really. On its own, the proposed Cliffside Unit 6 coal unit will emit approximately six million tons of CO_2 each year, or more than two million tons more CO_2 per year than the total 2008 emissions of CO_2 from all of the coal units that Duke proposes to retire. In addition, Duke also is proposing to add between 5,700 MW and 6,700 MW of gas-fired capacity to its resource mix. Natural gas-fired units do emit CO_2 although they emit significantly less per MWh than coal-fired facilities.

Q. Is it possible that Duke will be required to actually reduce its CO_2 emissions between 2010 and 2030?

A. Yes. Duke's IRP modeling assumes that there will be legislation that will establish a cap-and-trade regime for CO_2 emissions allowances. Under a cap-and-trade scheme, Duke would not necessarily be required to reduce its emissions, but instead could purchase emissions allowances. It is possible, however, that, if Congress deadlocks on passing cap-and-trade legislation, the U.S. EPA will adopt regulations mandating actual reductions in CO_2 emissions under a command-and-control scheme. In those circumstances, Duke would have to actually reduce its CO_2 emissions rather than being able to simply purchase emissions allowances from other emitters.

Q. What actions will Duke have to take in order to reduce its annual CO_2 emissions?

A. Quite simply, Duke will have to reduce its reliance on coal-fired generation in order to significantly reduce its annual CO_2 emissions over the coming decades. To accomplish this, Duke will need to retire additional coal units beyond those already proposed for retirement. Given that the Company already is planning to include new nuclear units in its future resource mix, the alternatives for displacing additional coal units are building more natural gas-fired

[4] Duke Response to SELC Informal Data Request No. 13.

combined cycle facilities, adding more renewable resources and adding more energy efficiency than Duke now includes in its resource plans.

Q. Does the Company have any plans for actually reducing its CO_2 emissions?

A.

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[5] Exhibit DAS-2C, at slide 6.
[6] Exhibit DAS-3C, at page 16 – that is, the last slide

Q. You mentioned that one alternative for Duke to reduce its reliance on coal-fired generation is to build more natural gas-fired combined cycle facilities. Should the Commission be concerned that Duke would become unreasonably dependent on natural gas if it built more natural gas-fired combined cycle capacity to replace additional coal-fired generating capacity beyond the 1,600 MW that the Company currently is planning to retire by 2020?

A. No. First, it may not be necessary to replace coal-fired with gas-fired capacity on a MW for MW basis – in other words, some of the replacement capacity and energy may come from energy efficiency and renewable resources.

Second, Duke is projecting that gas-fired units will provide less than 0.4 percent of its needed energy from gas fired units in 2010 and only about 6 percent of its needed energy in 2029, even with the new combined cycle and combustion turbine capacity it is planning to add as part of its resource plan.[7] Thus, adding more natural gas-fired combined cycle capacity actually would help diversify Duke's current heavily coal-dependent generating mix.

Third, recent assessments suggest that there is far more natural gas available in the domestic U.S. This should enhance the value of using natural gas-fired generation as a bridge fuel to a lower carbon future and should ameliorate future natural gas prices.

In fact, the supplies of natural gas that have been identified in the past two years have been described as a structural change in the natural gas market. This structural change has two important impacts on future resource planning by companies such as Duke and Progress. First, as a result of the existing and expected supply glut, current and projected prices of natural gas have been reduced. At the same time, the dramatically increased supplies of natural gas that are being identified should be able to accommodate any increased demands from fuel switching as a result of federal regulation of greenhouse gas emissions without causing significant increases in natural gas prices.

The structural change in the natural gas markets already has had a significant impact on utilities' resource planning. For example, in early April of last year, Entergy Louisiana informed the Louisiana Public Service Commission of its intent to defer (and perhaps cancel) a proposal to retire an existing gas-fired power plant and, in its place, to build a new coal-fired unit. Entergy explained that it no longer believes that a new coal plant would provide economic benefits for its customers due to its current expectation that future gas prices would be much lower than previously anticipated:

> Perhaps the largest change that has affected the Project economics is the sharp decline in natural gas prices, both current prices and those forecasted for the longer-term. The prices have declined in large part as a result of a structural change in the natural gas market driven largely by the increased production of domestic gas through unconventional technologies. The decline in the long-term price of natural gas has caused a shift in the economics of the Repowering Project, with the Project currently – and for the first time – projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT) resource.[8]

> 4. Recent Natural Gas Developments
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> Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below $3.00/mmBtu (2006$). From 2000

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[7] Revised 2009 IRP, at page 59

[8] Exhibit (DAS-4). *Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project*, submitted by Entergy Louisiana to the Louisiana Public Service Commission, April 1, 2009, at pages 6-8.

> through May 2007, prices increased to an average of about $6.00/mmBtu (2006$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of $131.32/mmBtu (nominal). The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand resulting from the downturn in the U.S. economy.
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> * * * *
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> However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non-conventional gas" – so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract – emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract supplies economically in large volumes was not. **The recent success of non-conventional gas exploration techniques (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run....**
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> * * * *
>
> Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and [Entergy Louisiana] cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels for a sustained period of time because of the newly discovered ability to produce gas through non-traditional recovery methods...[9] [Emphasis added]

Entergy's conclusion that there has been a seismic shift in the domestic natural gas industry was confirmed in early June 2009 by the release of a report by the American Gas Association and an independent organization of natural gas experts known as the Potential Gas Committee, the authority on gas supplies.

This report concluded that the natural gas reserves in the United States are 35 percent higher than previously believed. The new estimates show "an exceptionally strong and optimistic gas supply picture for the nation," according to a summary of the report.[10]

A Wall Street Journal Market Watch article titled "U.S. Gas Fields From Bust to Boom" similarly reported that huge new gas fields have been found in Louisiana, Texas, Arkansas and Pennsylvania and cited one industry-backed study as estimating that the U.S. now has enough natural gas to satisfy nearly 100 years of current natural gas-demand.[11] It further noted that

> Just three years ago, the conventional wisdom was that U.S. natural-gas production was facing permanent decline. U.S. policymakers were resigned to the idea that the country would have to rely more on foreign imports to supply the fuel that heats half of American homes, generates one-fifth of the nation's electricity, and is a key component in plastics, chemicals and fertilizer.
>
> But new technologies and a drilling boom have helped production rise 11% in the past two years. Now there's a glut, which has driven prices down to a six-year low and prompted producers to temporarily cut back drilling and search for new demand.[12]

Finally, the American Gas Association ("AGA") has recently issued an assessment, "U.S. Natural Gas Supply: *Then There Was Abundance*," that detailed what the AGA term "the robust supply picture in the United States" and quelled

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[9] Id, at pages 17, 18 and 22.
[10] *Estimate Places Natural Gas Reserves 35 percent Higher*, New York Times, June 9, 2009.
[11] Available at *http://online.wsj.com/article/SB124104598912705585.html*.
[12] Id.

any doubts about the ability of natural gas to supply the country well into the next century."[13]

Q. What are Progress' *projected annual CO_2 emissions under its proposed* resource plan?

A. Unfortunately, Progress has not projected future CO_2 emissions as part of its IRP analyses.[14]

Potential Regulatory Compliance Costs

Q. In addition to carbon dioxide, are there other potential regulatory compliance issues and costs that electric utilities should take into account in their resource planning?

Yes. Electric utilities should include in resource planning the costs of other new or revised air emissions requirements and the proper disposal and management of coal combustion wastes.

Q. What are coal combustion wastes?

A. Coal combustion wastes ("CCW"), also known as "coal ash" or "coal combustion products," consist of fly ash, bottom ash, boiler slag and flue gas desulfurization sludge and are typically disposed of in landfills and surface impoundments. CCW contains heavy metals such arsenic, nickel, cadmium,

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[13] *Exhibit* DAS-6.

[14] Progress Response to SELC Data Request No. 1, Item 1-8.

chromium, lead, manganese, selenium and thallium, as well as sulfates, chlorides, boron, polyaromatic hydrocarbons, phenols, polychlorinated biphenyls, cyanide, dioxins and furans. These substances can leach into water supplies when the waste comes into contact with water.

Q. Are coal combustion wastes regulated under North Carolina law?

A. It is my understanding that there are only limited requirements for disposal of CCW under North Carolina. For instance, North Carolina law exempts CCW surface impoundments and certain new CCW landfills from solid waste regulations. N.C.G.S. § 130A-295.4. At the same time, depending on the applicable permitting regulations, a liner may not be required for CCW landfills. N.C.G.S. § 130A-295.4(b); 15A N.C.A.C. 13B .0503. Moreover, liners are not required for CCW structural fill sites. 15A NCAC 02T .1201.

For slurry ponds permitted by the N.C. Division of Water Quality, groundwater monitoring and reporting is required, unless an exemption is granted.15A NCAC 02L .0110. In fact, the N.C. Division of Water Quality recently ordered Duke and Progress to begin testing the groundwater around their ash ponds in the state for contamination with toxic metals.[15]

In addition, Senate Bill 1004, enacted during the 2009 legislative session, placed coal ash impoundments under the Dam Safety Act and subjects dams that create coal ash ponds to direct inspection by the N.C. Department of Environment

[15] *State to require monitoring of ash ponds*, The Charlotte Observer, February 2, 2010.

and Natural Resources. Previously, electric utilities were only required to file reports with the Commission every five years.

Q. Is the EPA considering regulating coal combustion wastes?

A. Yes. EPA is currently considering proposed regulations to address coal combustion wastes.

Q. *What has led to the EPA decision to consider regulating CCW?*

A. A number of factors appear to have led the EPA to consider regulating CCW. First, a series of spills in late 2008 and early 2009, including the major spill of approximately one billion gallons of CCW at Tennessee Valley Authority's Kingston, TN coal plant in December 2008, drew the nation's attention to CCW storage.

At the same time, the EPA has found in a series of regulatory determinations that improper management of and disposal of combustion wastes from coal-fired power plants can and has resulted in surface water and groundwater contamination. EPA also has identified risks to human health and the environment from the disposal of CCW in landfills and surface impoundments.

For example, EPA's "Coal Combustion Waste Damage Case Assessment" dated July 9, 2007, recognized 24 proven cases of danger to human health or the environment and another 43 "potential" damage cases related to CCW. All but one of the 24 proven damage cases involved unlined disposal units.[16] EPA recently updated this list of damage cases to include coal ash spills at Martins Creek, PA, Gambrills, PA as well as the catastrophic spill of approximately one billion gallons of coal ash at TVA's Kingston, TN plant.[17] The EPA also has identified gaps in state regulatory programs for disposal and management of CCW.[18]

Q. What are the possible forms that EPA regulation of CCW could take?

A. The EPA is evaluating whether to regulate CCW under the federal Resource Conservation and Recovery Act ("RCRA"). EPA is considering several options including 1) regulating CCW as hazardous waste under Subtitle C of RCRA, which would include a tracking system and federally enforceable permits; 2) regulating CCW as non-hazardous waste under Subtitle D of RCRA, which would include inducements for state solid waste programs and implementation of federal minimum regulations for landfills; 3) a hybrid approach, by which CCW would be considered a solid waste if certain conditions are met, but a hazardous waste if they are not; and 4) another hybrid approach whereby wet CCWs (in surface impoundments) would be regulated as hazardous wastes and dry CCWs (in landfills) would be regulated as non-hazardous wastes.

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16 U.S. EPA, Notice of Data Availability on the Disposal of Coal Combustion Wastes in Landfills and Surface Impoundments, 72 Fed. Reg. 49714, 49718-19 (Aug. 29, 2007).

17 75 Fed. Reg. 822 (Jan. 6, 2010).

18 72 Fed. Reg. 49716.

The EPA also recently announced that it may develop regulations setting financial responsibility requirements for power plants under the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA," better known as "Superfund"), citing, among other things, the "significant cleanup costs that can be generated by this industry sector."[19]

Q. When is the EPA expected to issue a proposed regulation concerned CCW?

A. It is my understanding that the EPA is expected to issue a draft of its proposed regulation on CCW in the very near future, perhaps by the date of the hearings in this proceeding.

Q. Are there any estimates of the cost of complying with the anticipated EPA regulations concerning CCW?

A. The costs associated with the EPA's anticipated regulation of coal combustion wastes are uncertain and will depend on how the EPA classifies the wastes and plant specific factors (that is, wet versus dry storage, lined versus unlined, whether stored on the surface or not). Progress has stated the following in its December 1, 2009 *Plan to Retire 550 MWs of Coal Units Without SO2Controls*, that was filed in Docket E-2, Sub 960:

> EPA is currently considering re-characterizing the nature of and regulation of coal combustion products (bottom ash, fly ash and related materials, hereinafter CCPs) in response to TVA's Kingston Plant ash pond impoundment failure. Speculation is focusing on EPA's regulation of CCPs as a hazardous waste. A narrow usage exclusion may be possible where the finished product of CCP is fully encapsulated. Existing uses that involve land application or unconfined uses may be prohibited. If EPA

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19 75 Fed. Reg. 816, 822 (Jan. 6, 2010).

> characterizes CCPs as a hazardous waste or otherwise increases the regulatory requirements applicable to CCPs, the handling, storage and disposal of this material will result in significantly increased costs of operation, and more sophisticated handling equipment and disposal requirements. Classification of power plant CCP operations as activities that produce hazardous wastes as defined by the Resource Conversion and Recovery Act (RCRA) would trigger a number of additional regulatory requirements as well as potential liability associated with closure of impoundments, leachate management and site remediation. Phase out of surface impoundments is under consideration by EPA.[20]

Q. What has the electric utility industry claimed regarding the cost impact of EPA regulation of coal combustion wastes?

A. Although the industry cost estimates may be exaggerated in order to dissuade the EPA from regulating CCW as hazardous waste, they do predict significant costs. For example, an October 30, 2009 letter to the Federal Office of Management and Budget from the Utility Solid Waste Activities Group[21] warned that:

> If [coal combustion wastes] were regulated as hazardous wastes, the economic impact on the utility industry would be enormous, resulting in power plant closures, increased electricity rates for consumers, corresponding power reliability concerns, and virtually eliminating all [CCW] beneficial uses.[22]

Testimony before Congress by a representative from EPRI similarly stated that:

> A national coal combustion products regulation will alter the technology and economics of coal-fired power plants. Some owners would decide to prematurely shut down rather than incur the costs of compliance, while others would convert their ash

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[20] At pages 7 and 8.
[21] The Utility Solid Waste Activities Group is described as an informal consortium of 80 utility operating companies, the Edison Electric Institute and others.
[22] At page 2.

handling and disposal systems and continue to operate in the post-regulation market.[23]

Q. What have been the costs of cleaning up CCW spills?

A. The cost to clean up the damage from the December 2008 release from Tennessee's Kingston plant has been estimated to range from $933 million to $1.2 billion.[24]

Q. How could Duke and Progress reflect this issue in their IRP analyses given all of the uncertainty associated with the EPA's possible regulation of coal combustion wastes?

A. The traditional way to address uncertainty in resource planning is to identify a wide range of the potential costs for key input assumptions.[25] Thus, Duke and Progress could identify ranges of the possible costs for the different ways in which the EPA may regulate coal combustion wastes (that is, hazardous or not, etc.) and then apply those ranges of costs in its IRP analyses.

Q. Have Duke and Progress properly taken the potential cost of CCW regulations into account in their IRPs?

A. No. Duke does not even discuss CCWs in its 2009 IRP. Progress mentions "consideration of coal ash as a hazardous waste" in a list of "significant challenges to deal with from a resource plan perspective," but does not appear to have reflected the potential costs in its actual planning analyses.

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23 Written Testimony of Ken Ladwig, Senior Research Manager at EPRI, before the Subcommittee on Energy and Environment of the United States House of Representatives, dated December 10, 2009.

24 "TVA Reports 2009 Fiscal Year Third Quarter Results," available at www.tva.gov/news/release/julsep09/3rd_quarter.htm.

25 For example, Duke considers ranges of potential CO_2, SO_2 and NOx allowance costs in its IRP analyses.

Q. Are there other potential regulatory compliance issues and costs that North Carolina also should be taken into account in their resource planning?

A. Yes. The already significant economic risks associated with operating coal plants will be heightened by imminent tightening of environmental regulation of pollutants produced by these plants. This year, the U.S. EPA already issued a new more demanding air quality standard for nitrogen oxides, and is scheduled to adjust standards relating to sulfur dioxide, particle pollution and ozone. EPA is also likely to issue regulations addressing interstate transport of air pollution. By 2011, EPA is scheduled to issue a federal implementation plan for regional haze, issue new source performance standards for key pollutants from electrical generating units and non-electrical generating unit boilers, and issue new standards for hazardous air pollutants, among other matters. It certainly is reasonable to expect that in most or all cases, EPA action will result in more stringent regulation of these pollutants.

Q. Do Duke and Progress adequately factor these impending air quality regulations into their IRP analyses?

A. It does not appear that Duke or Progress adequately factor into their IRP analyses the economic risks of continuing to operate existing coal-fired power plants in the face of new or more stringent air emissions requirements. Although Duke does say in its Revised 2009 IRP that it examined a range of potential SO_2 and NO_x emissions allowance prices, it does not discuss expected changes in air emissions requirements in much detail.[26] It also offers no evidence that the range

[26] Duke Revised 2009 IRP, at pages 30-34.

of SO_2 and NO_x allowance costs it considered was reasonable. Appendix F of Progress' 2009 IRP, Air Quality and Climate Change, offers a similarly brief discussion of impending changes in air emissions requirements and also fails to explain how Progress considered these expected changes in its IRP analyses.

However, Progress includes a more complete and accurate discussion of impending regulatory changes in its *Plan to Retire 550 MWs of Coal Units Without SO2 Controls* ("Retirement Plan"), which concedes that the changes are expected to result in more stringent pollution control standards. Progress' Retirement Plan also includes a fairly realistic estimation of some of the timelines involved and indicates that Progress understands that the new standards will require the utility to alter its plans accordingly. The Progress Retirement Plan is a start at a candid and more realistic discussion of how impending pollution controls will affect the cost of continue to operate existing pulverized coal plants and will also affect the cost of construction and operation of other supply-side resources. But there is no evidence that Progress has factored the regulatory issues discussed in the Retirement Plan into its 2009 IRP.

Q. What action do you suggest the North Carolina Utilities Commission take to address this weakness in the utilities' IRP discussion of the risks associated with continuing to operate existing coal plants?

A. The Commission should require Duke and Progress, as well as other utilities, to submit as part of their IRP in this docket a detailed and accurate discussion of the expected new pollution control standards and a demonstration of how the utility is factoring the financial risk of these standards into its IRP. If, as it appears, any of the utilities has failed to adequately monetize the risk of impending regulation in their IRPs, the modeling underlying the IRP should be rerun to reflect the additional cost of continuing to run existing coal plants, and of constructing and operating supply-side resources in future.

Q. Why is it important to discuss these risks now, instead of waiting until all the expected regulations are finalized?

A. Factoring in foreseeable future regulation now will result in the utility, this Commission, and the public having better information about the true costs associated with various supply side resources as well as their relative cost when compared to demand side resources. That will translate into an improved ability to provide low cost, low risk power to the citizens of North Carolina in the future.

Q. Are you aware of any state regulatory commissions that require utilities to consider compliance with current and projected future environmental regulations in their IRP process?

A. I have not conducted a thorough review of state policies on this issue, but I am aware that the Arizona Corporation Commission recently approved an amendment to the IRP rules that would require enhanced consideration of environmental impacts of power generation. The amendment reads as follows:

> Adding a new subsection to IRP rules, R14-2-703, Section D.
>
> "A plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and a plan for reducing water consumption. The costs for compliance with current and project future environmental regulations shall be included in the analysis of resources required by R14-2-703 (D) and (E). A load-serving entity or any interested parties may also provide, for the Commission's consideration, analyses and supporting data pertaining to environmental impacts associated with the generation or delivery of electricity, which may include monetized estimates of environmental impacts that are not included as costs for compliance. Values or factors for compliance costs, environmental impacts, or monetization of environmental impacts may be

developed and reviewed by the Commission in other proceedings or stakeholder workshops." [27]

CO_2 Prices

Q. What prices did Duke assume in its 2009 IRP for CO_2 emissions?

A. Duke assumed a Base set of CO_2 prices that begins at $24.62 per ton in 2013 and increases to $93.80 per ton in 2030.[28] Duke also assumed a High set of CO_2 prices that are 15 percent above its Base set in each year and a Low set of CO_2 prices that are 15 percent below its Base set.

Q. What was the source of the CO_2 prices that Duke used in its 2009 IRP analyses?

A. In response to a data request, Duke stated that the CO_2 prices that it used in its 2009 IRP analyses were derived from the planning model used by its consultant, ICF International.[29]

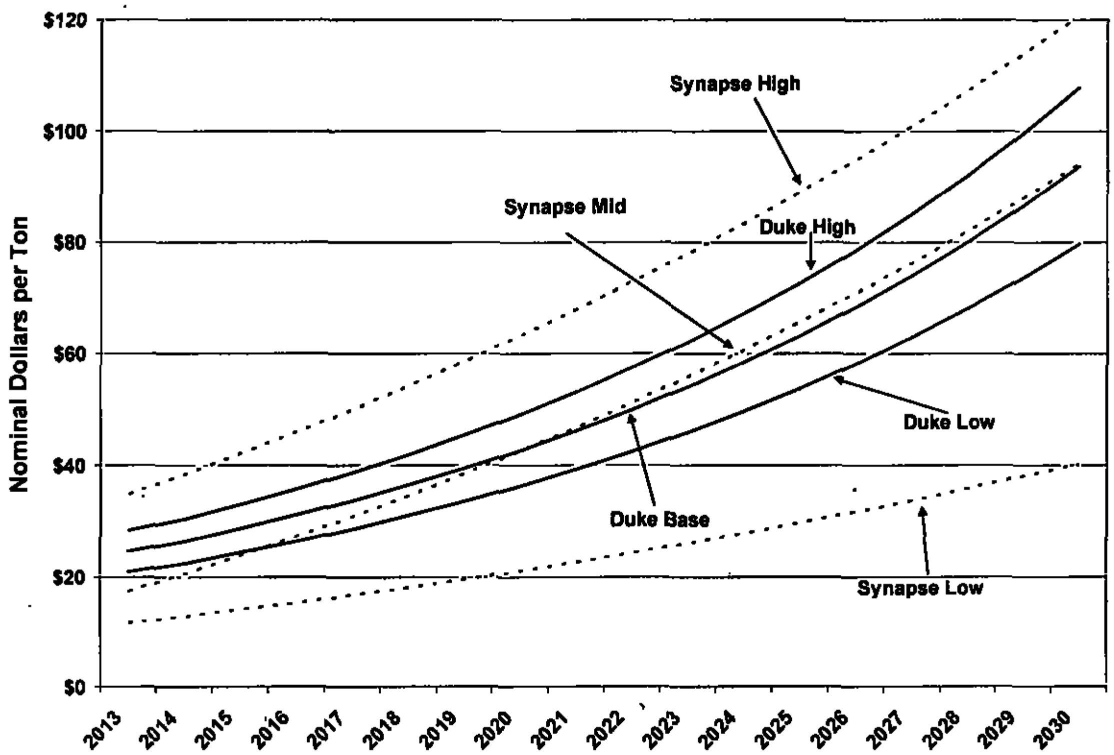
Q. Are the CO_2 prices that Duke has used in its 2009 IRP reasonable?

A. In general, yes. However, I believe that Duke should have used a wider range of scenarios than only ± 15 percent around its Base case set of CO_2 prices. It is important and prudent to consider such a wider range of possible CO_2 prices given the uncertainties associated with the timing, stringency and design of federal regulation of greenhouse gas emissions.

[27] Arizona State Corporation Commission website, available at http://images.edocket.azcc.gov/docketpdf/0000105829.pdf.
[28] *Duke Response to SELC Informal Data Request No. 1.*
[29] Duke Response to SELC Informal Data Request No. 11.

Figure 3, below, compares the annual CO_2 prices used by Duke in its 2009 IRP analyses with the CO_2 price projections that I helped developed in 2008 when I was with Synapse Energy Economics, Inc.[30]

Figure 3: Duke and Synapse CO_2 Prices in Nominal Dollars



As can be seen in Figure 3, the Duke Base and the Synapse Mid CO_2 price trajectories are very close – in fact, the Duke Base is above the Synapse Mid forecast in the early years. However, the Duke High CO_2 price forecast is significantly lower than the Synapse High forecast and the Duke Low CO_2 price forecast is significantly higher than the Synapse Low forecast. Because they

[30] The derivation of the Synapse CO_2 price forecasts is explained in Exhibit DAS-2.

encompass a wider range of possible future CO_2 prices, the Synapse forecasts allow for greater uncertainty than the Duke forecasts do.

Q. How do the CO_2 prices that Duke used in its 2009 IRP compare to other projections of future CO_2 prices?

A. Figure 4, below, compares the CO_2 emissions prices that Duke used in its 2009 IRP analyses with the current Synapse CO_2 price forecasts and the results of the independent modeling of the legislation that has been introduced in the U.S. Congress in recent years. These modeling analyses include:

- The U.S. Department of Energy's Energy Information Administration's ("EIA") assessment of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007* (July 2007).[31]
- The EIA's October 2007 Supplement to the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*.[32]
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007* (January 2008).[33]
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007* (April 2008).[34]
- The EIA's assessment of the *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009).[35]
- The U.S. Environmental Protection Agency's ("EPA")' *Analysis of the Climate Stewardship and Innovation Act of 2007 – S. 280 in 110th Congress* (July 2007).[36]
- The EPA's *Analysis of the Low Carbon Economy Act of 2007 – S. 1766 in 110th Congress* (January 2008).[37]

[31] Available at http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf(2007)04.pdf.
[32] Available at http://www.eia.doe.gov/oiaf/servicerpt/biv/pdf/s280_1007.pdf
[33] Available at http://www.eia.doe.gov/oiaf/servicerpt/lcea/pdf/sroiaf(2007)06.pdf
[34] Available at http://www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf(2008)01.pdf.
[35] Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.
[36] Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.

- The EPA's *Analysis of the Lieberman-Warner Climate Security Act of 2008 – S. 2191 in 110th Congress* (March 2008).[38]

- The EPA's *Analysis of the American Clean Energy and Security Act of 2009, H.R. 2454 in the 111th Congress* (June 2009)[39]

- *Assessment of U.S. Cap-and-Trade Proposals* by the Joint Program at the Massachusetts Institute of Technology ("MIT") on the Science and Policy of Global Change (April 2007).[40]

- *Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act – S. 2191* by the Joint Program at MIT on the Science and Policy of Global Change (April 2008).[41]

- *The Lieberman-Warner America's Climate Security Act: A Preliminary Assessment of Potential Economic Impacts*, prepared by the Nicholas Institute for Environmental Policy Solutions, Duke University and RTI International (October 2007)[42]

- *U.S. Technology Choices, Costs and Opportunities under the Lieberman-Warner Climate Security Act: Assessing Compliance Pathways*, prepared by the International Resources Group for the Natural Resources Defense Council (May 2008).[43]

- *The Lieberman-Warner Climate Security Act – S. 2191, Modeling Results from the National Energy Modeling System – Preliminary Results*, Clean Air Task Force (January 2008).[44]

- *Economic Analysis of the Lieberman-Warner Climate Security Act of 2007 Using CRA's MRN-NEEM Model*, CRA International, April 2008.[45]

- *Analysis of the Lieberman-Warner Climate Security Act (S. 2191) using the National Energy Modeling System (NEMS/ACCF/NAM)*, a report by

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37 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
38 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
39 Available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_Analysis.pdf.
40 Available at http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt146.pdf.
41 Available at http://mit.edu/globalchange/www/MITJPSPGC_Rpt146_AppendixD.pdf.
42 Available at http://www.nicholas.duke.edu/institute/econsummary.pdf.
43 Available at http://docs.nrdc.org/globalwarming/glo_08051401A.pdf.
44 Available at http://lieberman.senate.gov/documents/catflwcsa.pdf.
45 Available at http://www.nma.org/pdf/040808_crai_presentation.pdf.

the American Council for Capital Formation and the National Association of Manufacturers, March 2008.[46]

In total, these modeling analyses examined more than 85 different scenarios. These scenarios reflected a wide range of assumptions concerning important inputs such as: the "business-as-usual" emissions forecasts; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented, independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps international) and allowance banking; assumptions about technological progress and the cost of alternatives; and the presence or absence of a "safety valve" price. In Figure 4:

- S.280 refers to the McCain-Lieberman bill introduced in 2007 in the 110th U.S. Congress
- S.1766 refers to the Bingamán-Specter bill introduced in 2007 in the 110th U.S. Congress
- S. 2191 refers to the Lieberman-Warner bill introduced in 2007 in the 110th U.S. Congress
- HR. 2454 refers to the Waxman-Markey bill introduced in 2009 in the current 111th U.S. Congress

46 Available at http://www.accf.org/pdf/NAM/fullstudy031208.pdf.

Figure 4: Levelized Duke and Synapse 2008 CO_2 Prices Compared to Results of Modeling of Proposed Federal Legislation

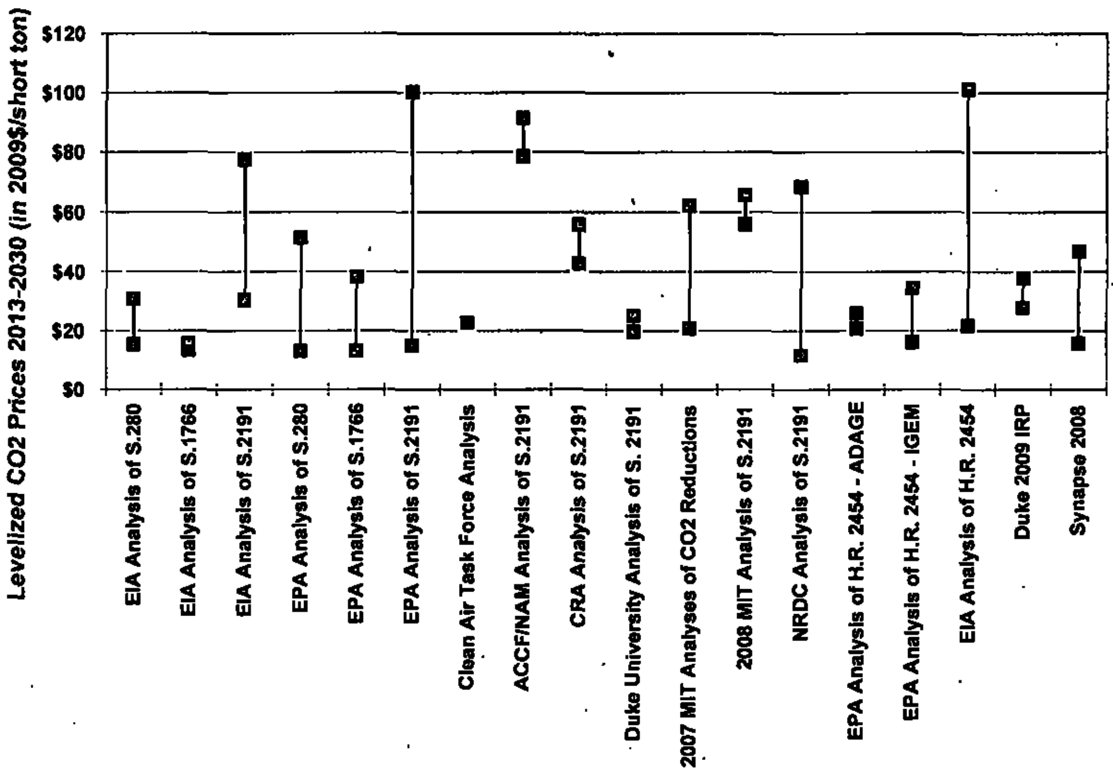

Figure 4 confirms that the range of CO_2 prices used by Duke was too narrow to reflect the potential uncertainties associated with the design and stringency of future federal regulation of greenhouse gas emissions.

Q. Does Figure 4 include the modeling of the recent Waxman-Markey bill that has been passed by the U.S. House of Representatives?

A. Yes. The third through fifth bars from the right in Figure 4 provide the ranges of levelized CO_2 prices from the recent modeling of the Waxman-Markey bill by the EIA and the EPA. However, it is not certain that whatever bill is ultimately passed by the U.S. Congress actually will reflect the terms of that legislation. This is the reason why the results of the modeling of the other legislation that has been introduced in previous U.S. Congresses remain relevant.

Q. What CO_2 prices did Progress use in its 2009 IRP analyses?

A.

Q. Are these CO_2 prices reasonable?

A. No. It is not reasonable to use a of CO_2 prices given the uncertainties associated with the timing, stringency and design of federal regulation of greenhouse gas emissions. Moreover, of CO_2 prices used by Progress in its 2009 IRP analyses is unreasonably for use as even a main or base case.

Q. How do the CO_2 prices used by Progress compare to the CO_2 prices used by Duke in its 2009 IRP analyses and to the Synapse CO_2 price forecasts?

A. As shown in Figure 5, below, the CO_2 prices used by Progress are compared to both the Duke Base CO_2 prices and the Synapse Mid CO_2 price forecast. In fact, as can be seen in Figure 5, of CO_2 prices used by Progress in its 2009 IRP analyses CO_2 prices but are than Duke's Low CO_2 prices after 2020.

Figure 5: Annual Progress, Duke and Synapse CO_2 Prices in Nominal Dollars [CONFIDENTIAL]

Figure 6, below, then compares the CO_2 prices used by Progress in its 2009 IRP analyses with the Duke and Synapse CO_2 prices and the results of the modeling of the legislative proposals that were included in Figure 2 above.

Figure 6: Levelized Progress, Duke and Synapse CO_2 Prices Compared to Results of Modeling of Proposed Federal Legislation [CONFIDENTIAL]

Q. How do the CO_2 prices that Progress used in its 2009 IRP analyses compare to the CO_2 prices that other utilities and state regulatory commissions are using in resource planning?

A. As Figures 5 and 6 above show, of CO_2 prices that Progress used in its 2009 IRP analyses compared to the range of CO_2 prices that Duke used in that company's 2009 IRP, as well as the CO_2 prices that Synapse Energy Economics has recommended be used in IRP and other resource planning analyses. Figure 7, below, compares the CO_2 prices that Progress has used with the CO_2 prices that some other utilities and some regulatory commissions have been using in resource planning analyses.

Figure 7: Levelized Progress Energy CO_2 Prices Compared to Prices Used by Other Utilities and State Regulatory Commissions in Resource Planning [CONFIDENTIAL]

Q. What is your recommendation concerning the CO_2 prices that Progress should use in its resource planning analyses?

A. Progress has said that it is currently evaluating numerous possible changes to its resource plan, including additional coal unit retirements, and that it anticipates making decisions on resource options prior to filing its next comprehensive IRP in 2010.[47] The Company should use CO_2 prices in these analyses and should examine a wide range of potential CO_2 prices such as the Synapse Mid, Low and High forecasts presented in Figures 3 and 5, above.

Q. Does this complete your testimony?

A. Yes.

[47] Progress 2009 IRP at page 3.

David A. Schlissel

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SUMMARY

I have worked for thirty six 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

Coal-fired Generation – Evaluated the economic and financial risks of investing in, constructing and operating new coal-fired power plants. Investigated whether project participants had adequately considered the risks associated with building a new coal-fired power plant. The most significant of these risks are the likelihood of federal regulation of greenhouse gas emissions and rising construction costs. Examined whether there are lower cost, lower risk alternatives than proposed coal-fired plants.

Electric System Reliability - Evaluated whether new generation facilities and transmission lines are 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.

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.

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.

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. Examined the reasonableness of utility decisions to sell nuclear power assets and evaluated the value received as a result of the auctioning of those plants. 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.

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.

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, auctions, and 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, DEPOSITIONS AND COMMENTS

Mississippi Public Service Commission (Docket No. 2009-UA-014) – December 2009
The costs and risks associated with the proposed Kemper County IGCC power plant.

Public Service Commission of Wisconsin (Docket No. 05-CE-137) –December 2009
The costs and risks associated with the proposed installation of emissions control equipment at the Edgewater Unit 5 coal-fired power plant.

Public Service Commission of Wisconsin (Docket No. 05-CE-138) –Sepember and October 2009
The costs and risks associated with the proposed installation of emissions control equipment at the Columbia 1 and 2 coal-fired power plants.

Georgia Public Service Commission (Docket No. 27800-U) – December 2008
The possible costs and risks of proceeding with the proposed Plant Vogtle Units 3 and 4 nuclear power plants.

Public Service Commission of Wisconsin (Docket No. 6680-CE-170) – August and Sepember 2008
The risks associated with the proposed Nelson Dewey 3 baseload coal-fired power plant.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 1) – July 2008
The estimated cost of Duke Energy Indiana's Edwardsport Project.

Public Service Commission of Maryland (Case 9127) – July 2008
The estimated cost of the proposed Calvert Cliffs Unit 3 nuclear power plant.

Ohio Power Siting Board (Case No. 06-1358-EL-BGN) – December 2007
AMP-Ohio's application for a Certificate of Environmental Compatibility and Public Need for a 960 MW pulverized coal generating facility.

U.S. Nuclear Regulatory Commission (Docket Nos. 50-247-LR, 50-286-LR) – November 2007 and February 2009
The available options for replacing the power generated at Indian Point Unit 2 and/or Unit 3.

West Virginia Public Service Commission (Case No. 06-0033-E-CN) – November 2007
Appalachian Power Company's application for a Certificate of Public Convenience and Necessity for a 600 MW integrated gasification combined cycle generating facility.

Iowa Utility Board (Docket No. GCU-07-01) – October 2007
Whether Interstate Power & Light Company's adequately considered the risks associated with building a new coal-fired power plant and whether that Company's participation in the proposed Marshalltown plant is prudent.

Virginia State Corporation Commission (Case No. PUE-2007-00066) – November 2007
Whether Dominion Virginia Power's adequately considered the risks associated with building the proposed Wise County coal-fired power plant and whether that Commission should grant a certificate of public convenience and necessity for the plant.

Louisiana Public Service Commission (Docket No. U-30192) – September 2007
The reasonableness of Entergy Louisiana's proposal to repower the Little Gypsy Unit 3 generating facility as a coal-fired power plant.

Arkansas Public Service Commission (Docket No. 06-154-U) – July 2007
The probable economic impact of the Southwestern Electric Power Company's proposed Hempstead coal-fired power plant project.

North Dakota Public Service Commission (Case Nos. PU-06-481 and 482) – May 2007 and April 2008
Whether the participation of Otter Tail Power Company and Montana-Dakota Utilities in the Big Stone II Generating Project is prudent.

Indiana Utility Regulatory Commission (Cause No. 43114) – May 2007
The appropriate carbon dioxide ("CO_2") emissions prices that should be used to analyze the relative economic costs and benefits of Duke Energy Indiana and Vectren Energy Delivery of Indiana's proposed Integrated Gasification Combined Cycle Facility and whether Duke and Vectren have appropriately reflected the capital cost of the proposed facility in their modeling analyses.

Public Service Commission of Wisconsin (Docket No. 6630-EI-113) – March 2007
Whether the proposed sale of the Point Beach Nuclear Plant to FPL Energy Point Beach, LLC, is in the interest of the ratepayers of Wisconsin Electric Power Company.

Florida Public Service Commission (Docket No. 070098-EI) – March 2007
Florida Light & Power Company's need for and the economics of the proposed Glades Power Park.

Michigan Public Service Commission (Case No. 14992-U) – December 2006
The reasonableness of the proposed sale of the Palisades Nuclear Power Plant.

Minnesota Public Utilities Commission (Docket No. CN-05-619) – November 2006, December 2007, January 2008 and November 2008
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 facility; and whether the proposed project is a lower cost alternative than renewable options, conservation and load management.

North Carolina Utilities Commission (Docket No. E-7, Sub 790) – September 2006 and January 2007
Duke's need for two new 800 MW coal-fired generating units and the relative economics of adding these facilities as compared to other available options including energy efficiency and renewable technologies.

New Mexico Public Regulatory Commission (Case No. 05-00275-UT) – September 2006
Report to the New Mexico Commission on whether the settlement value of the adjustment for moving the 141 MW Afton combustion turbine merchant plant into rate base is reasonable.

Arizona Corporation Commission (Docket No. E-01345A-0816) – August and September 2006
Whether APS's acquisition of the Sundance Generating Station was prudent and the reasonableness of the amounts that APS requested for fossil plant O&M.

U.S. District Court for the District of Montana (Billings Generation, Inc. vs. Electrical Controls, Inc, et al., CV-04-123-BLG-RFC) – August 2006
Quantification of plaintiff's business losses during an extended power plant outage and plaintiff's business earnings due to the shortening and delay of future plant outages. [Confidential Expert Report]

Deposition in South Dakota Public Utility Commission Case No. EL05-022 – June 14, 2006

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. [Confidential Expert Report]

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. [Confidential Expert Report]

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-115) - 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 Cloverdale, 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. [Confidential Testimony]

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, April 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) - June 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) - May 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) - November 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) – December 1985 and 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

Comments on Draft Portland General Electric Company 2009 Integrated Resource Plan, October 2009.

Energy Future: A Green Energy Alternative for Michigan, report, July 2009.

Energy Future: A Green Energy Alternative for Michigan, presentation, July 2009.

Comments on Consumers Energy's Electric Generation Alernatives Analysis for the Balanced Energy Initiative including the Proposed Karn-Weadock Coal Plant, July 2009.

Comments on Wolverine Power Cooperative's Electric Generation Alternatives Analysis for the Proposed Rogers City Coal Plant. July 2009

Preliminary Assessment of East Kentucky Power Cooperative's 2009 Resource Plan, June 2009.

The Financial Risks to Old Dominion Electric Cooperative's Consumer-Members of Building and Operating the Proposed Cypress Creek Power Station, April 2009.

An Assessment of Santee Cooper's 2008 Resource Planning, April 2009.

Nuclear Loan Guarantees: Another Taxpayer Bailout Ahead, Report for the Union of Concerned Scientists, March 2009.

New Hampshire Senate Bill 152: Merrimack Station Scrubber, March 2009.

The Risks of Building and Operating Plant Washington, Presentation to the Sustainable Atlanta Roundtable, December 2008.

The Risks of Building and Operating Plant Washington, Report and Presentation to EMC Board Members, December 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at the University of California at Berkeley Energy and Resources Group Colloquium, October 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at Georgia Tech University, October 2008.

Nuclear Power Plant Construction Costs, Synapse Energy Economics, July 2008.

Coal-Fired Power Plant Construction Costs, Synapse Energy Economics, July 2008.

Synapse 2008 CO_2 Price Forecasts, Synapse Energy Economics, July 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at the NARUC ERE Committee, NARUC Summer Meetings, July 2008.

Are There Nukes In Our Future, Presentation at the NASUCA Summer Meetings, June 2008.

Risky Appropriations: Gambling US Energy Policy on the Global Nuclear Energy Partnership, Report for Friends of the Earth, the Institute for Policy Studies, the Government Accountability Project, and the Southern Alliance for Clean Energy, March 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation to the New York Society of Securities Analysts, February 26, 2008.

Don't Get Burned, Report for the Interfaith Center for Corporate Responsibility, February 2008.

The Risks of Participating in the AMPGS Coal Plant, Report for NRDC, February 2008.

Kansas is Not Alone, the New Climate for Coal, Presentation to members of the Kansas State Legislature, January 22, 2008.

The Risks of Building New Nuclear Power Plants, Presentation to the Utah State Legislature Public Utilities and Technology Committee, September 19, 2007.

The Risks of Building New Nuclear Power Plants, Presentation to Moody's and Standard & Poor's rating agencies, May 17, 2007.

The Risks of Building New Nuclear Power Plants, U.S. Senate and House of Representative Briefings, April 20, 2007.

Carbon Dioxide Emissions Costs and Electricity Resource Planning, New Mexico Public Regulation Commission, Case 06-00448-UT, March 28, 2007, with Anna Sommer.

The Risks of Building New Nuclear Power Plants, Presentation to the New York Society of Securities Analysts, June 8, 2006.

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, Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company, 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

2010 - President, Schlissel Technical Consulting, Inc.
2000 - 2009: 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

Exhibit DAS-2C

REDACTED

Exhibit DAS-3C

REDACTED

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***EX PARTE*:**	)	
APPLICATION OF	)	
ENTERGY LOUISIANA, LLC	)	
FOR APPROVAL TO REPOWER	)	
THE LITTLE GYPSY UNIT 3	)	**DOCKET NO. U-30192**
ELECTRIC GENERATING FACILITY	)	
AND FOR AUTHORITY TO COMMENCE	)	
CONSTRUCTION AND FOR	)	
CERTAIN COST PROTECTION AND	)	
COST RECOVERY	)	

REPORT AND RECOMMENDATION
<u>CONCERNING THE LITTLE GYPSY UNIT 3 REPOWERING PROJECT</u>

NOW COMES Applicant, Entergy Louisiana, LLC ("ELL" or the "Company"), and, pursuant to the Commission's Order No. U-30192-B dated March 13, 2009, respectfully submits this Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project (the "Repowering Project" or the "Project"). For the reasons explained more fully below, ELL recommends to the Commission that ELL (i) continue the temporary suspension of the Repowering Project; and (ii) make a filing with the Commission seeking a longer-term delay (three years or more) of the Repowering Project as well as appropriate accounting for the Project costs until the Commission can determine the permanent ratemaking treatment of these costs. A longer-term delay of the Project is appropriate given the uncertainty of various key factors that drive the economics of the Project, including but not limited to:

1) The sharp fall off in natural gas prices, both in the short term but also as projected for the long term by many industry experts, which affects the economics of the Repowering Project;

2) The implementation of various new federal energy policies, including a mandatory Renewable Portfolio Standard and other policies that may affect the economics of the Project; and

3) The uncertainties caused by the recent financial crisis and its effects on the U.S. and global economies.

The longer-term delay will allow ELL to gain better clarity regarding these uncertainties and better understand the effects of these recent changes on the economic viability of the Repowering Project. This delay is consistent with the direction set forth in the Commission's Order Nos. U-30192, dated March 19, 2008, to monitor the economic viability of this Project as part of the Commission's Quarterly Monitoring Plan process.

I. Introduction

During the past few months, there have been dramatic and unforeseeable changes in the U.S. and world economies, the likelihood of various new federal energy policies, as well as a significant decline in the prices of various commodities, including natural gas and crude oil. While it is not possible to predict accurately what the future holds, the level of uncertainty associated with these issues causes concern and a need to pause when considering a commitment as significant as the Repowering Project.

Recognizing these changes, the Commission, at the March 11, 2009 Business & Executive Meeting, issued an Order requiring ELL to suspend, temporarily and to the extent practicable, the current development of the Repowering Project.[1] Specifically, the Commission adopted a Motion stating that:

[1] Order No. U-30192-B, dated March 13, 2009.

> *There have been significant changes that have occurred relating to the Little Gypsy Repowering Project during the past few months, including the recent structural change in the market for natural gas, changes in the capital and financial markets, and the general state of the economy.*
>
> *Given these changes, I move that the Commission direct that Entergy Louisiana, LLC immediately suspend, to the extent possible, on a temporary basis, the Repowering Project and take the steps reasonably necessary to minimize project spending during the period of suspension. I understand that ELL has issued letters formally suspending certain contracts associated with the Repowering Project, and I also move that the Commission direct that these suspensions shall remain in place during the period of suspension.*
>
> *ELL is directed to continue to review the current economics of the Repowering Project and develop a recommendation regarding whether it is appropriate for ELL to make a filing with the Commission to formally delay the Repowering Project for an extended time.*
>
> *By no later than the April 2009 B&E session, ELL shall inform the Commission whether ELL intends to make such a filing.*[2]

For the same reasons that the Commission noted in its Order, prior to the issuance of that Order, ELL proactively responded to the change in the risks and expected value of the Project by taking steps to minimize spending on the Project while the Company conducted further analysis with a view toward determining whether a longer-term delay of the Project would be in the best interest of customers. ELL's analysis shows that, although there are certain risks associated with the continued volatility of natural gas, the expiration of vendor contracts, and the potential expiration of existing environmental permits for the Project, a longer-term suspension and delay of the Project is nonetheless appropriate and would be a prudent action by ELL.

Since the Commission voted to certify the Repowering Project in November 2007, ELL has, as required by Order No. U-30192 and U-30192-A[3], continually monitored the economics of

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[2] *Id.*

the Project to ensure that the Project would provide the benefits contemplated by the LPSC when it certified the Project. As part of the Commission-approved Monitoring Plan, ELL has performed and provided to the Commission, through its Staff, ongoing analyses concerning the projected net benefits of the Project to customers, using the latest information concerning a host of assumptions, including but not limited to the projected costs of natural gas, petroleum coke, coal, and carbon dioxide ("CO_2") regulation through allowances and/or taxes.

As recently as the January 8, 2009 Supplemental Monitoring Report, the Project continued to show positive net benefits to customers when compared to the alternative of a CCGT facility. In the Monitoring Report for the Fourth Quarter 2008, however, which was submitted to the Commission Staff and the Intervenors on February 16, 2009, the Repowering Project's economics, using the most recent assumptions, for the first time projected negative net benefits – indicating that the Repowering Project was projected to cost customers more than the hypothetical CCGT alternative on a net present value basis. At about this same time, on February 25, 2009, the LDEQ issued the final air permit for the Project, which otherwise cleared the way for ELL to commence on-site construction activities for the Project.

In view of the recent adverse change in the projected economics of the Project and given the significant changes in the economy and the uncertainty created by the potential development of new and in some cases more aggressive federal energy policies under the new Administration, the Company believed that it would be appropriate to further evaluate whether continuing with the Repowering Project at this time would be in the best interest of customers. Thus, the Company undertook steps to minimize spending on the Project while further analysis was performed, including, on March 4, 2009, suspending all activity under three of the four largest

[3] LPSC Order No. U-30192-A, dated July 2, 2008.

contracts relating to the Project, pursuant to the suspension terms of the contracts, and directing the vendor under the fourth contract to take substantial steps to slow the rate of spending. While ELL believes these short-term suspension steps will not immediately delay the in-service date of the Project if the Company ultimately decided to proceed with construction in the near term, the suspension of these contracts allows ELL to minimize spending while it further analyzes whether the Project continues to satisfy the objectives set forth in the Commission's certification Order U-30192, dated March 19, 2008 given recent events.

Since suspending its largest contracts and minimizing the work performed by the Project contractor, ELL has determined that it is in the best interest of customers that the Project be placed into a longer-term delay, that is, a delay of three years or longer. To implement such a delay, it will be necessary for ELL to cancel its current contracts and otherwise terminate the Project activities. However, if total costs to customers are to be minimized under a long-term delay, such steps are immediately necessary. In addition, as ELL will discuss in the last section of this report, a longer-term delay may require ELL to start over in some or all of the permitting processes. Further, if the Project is delayed for an extended period, there is a material risk that one or more permits would not be granted or would be granted subject to conditions that make the Project less attractive economically.

II. Summary of the Recommendation

The Company recommends that the Project be placed in a longer-term delay in consideration of the significant uncertainty associated with this Project caused by the recent changes that have occurred in the commodity markets, the economy, and in U.S. energy policy. A longer-term delay will allow the Company to gain additional clarity regarding a number of these issues, thus mitigating the risk that the Project will not provide long-term benefits to customers.

Perhaps the largest change that has affected the Project economics is the sharp decline in natural gas prices, both current prices and those forecasted for the longer-term. The prices have declined in large part as a result of a structural change in the natural gas market driven largely by the increased production of domestic gas through unconventional technologies. The decline in the long-term price of natural gas has caused a shift in the economics of the Repowering Project, with the Project currently—and for the first time—projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT[4]) resource.[5]

The proposed changes in various energy policies by the Obama administration also could have significant effects on the future economics of the Repowering Project. While this administration has only been in office since mid-January, it is becoming more likely that a Renewable Portfolio Standard ("RPS") soon could be implemented. An RPS will require utilities such as ELL to incorporate various new technologies into their long-term resource

[4] The acronym "CCGT" refers to a Combined Cycle Gas Turbine, which is a relatively newer gas-fired technology.

[5] Prior to this time, the Project had consistently been expected to provide both fuel diversity benefits and positive net economic value on a present value basis relative to a CCGT. Although the LPSC recognized that the volatility of gas prices could cause the net benefits of the Project to become negative at times, all five of the Company's prior filings (direct and rebuttal, July 2008 Monitoring Report, December 2008 Supplemental Report, and January 2009 Supplemental Report) pointed to positive net benefits. As such, this was the first time in which the fuel diversity benefit from the Project was expected to come at an additional cost to ELL customers.

portfolios, including the potential for baseload resources such as biomass facilities and various other intermittent resources such as wind or solar powered generation. The effects of an RPS could mandate that up to 25% of a utility's total energy requirements be provided by renewable resources. Renewable resources are being evaluated by the Entergy System[6] and will be a key consideration in the 2009 Strategic Resource Plan.

With regard to CO_2 legislation, while the Commission and the Company certainly anticipated that CO_2 regulation would be in place over the life of this Project and incorporated CO_2 compliance costs into its evaluation, there seems to be an emerging momentum to implement CO_2 legislation during the next one to two years. If this occurs, it will allow the Company to gain much greater certainty regarding the cost of compliance with CO_2 legislation and how it will affect the Project economics. CO_2 costs, as the Company has always made clear, are an important factor in the Project economics, and while the possible implementation of CO_2 legislation is not a reason to delay the Project, one of the benefits of the longer-term delay will be greater level of certainty regarding this cost.[7]

In addition, the changes in the U.S. and world economies have caused great turmoil in the capital markets. This turmoil has affected both the cost of capital and the timing of its availability. As the Commission is aware, in addition to the Repowering Project, ELL is engaged in the Waterford 3 Steam Generator Replacement Project, which is estimated to cost

[6] The electric generation and bulk transmission facilities of the six Entergy Operating Companies are planned and dispatched as a single, integrated electric system, referred to as the "Entergy System" or the "System." In addition to ELL, the six Entergy Operating Companies include Entergy Arkansas, Inc., Entergy Gulf States Louisiana, L.L.C., Entergy Mississippi, Inc., Entergy New Orleans, Inc., and Entergy Texas, Inc. Entergy Arkansas, Inc. and Entergy Mississippi, Inc. have provided notice of their intention to terminate their participation in the Entergy System Agreement.

[7] There have been recent updates suggesting that CO2 costs may be higher than expected at the time of certification. For example, the 2009 ICF Multi-Client Study reflects CO2 costs that are much higher than ICF predicted in the Multi-Client Study that was presented during the certification proceeding in this matter. A higher CO2 cost would adversely affect the Project economics.

approximately $511 million. ELL also is in need of acquiring additional CCGT capacity and expects to make various investments in its transmission system during the period of time that the Repowering Project is under construction. When engaging in a large project such as the Repowering Project, which will drive the timing of the need for capital, there could be a constraint in obtaining—at the time it is needed and at rates that are attractive economically—the capital that is needed to fund the Repowering Project as well as ELL's other resource needs. Given the uncertainties in the economics of the Repowering Project, it would seem to be a more prudent use of capital for ELL to plan to fund these other projects and retain additional liquidity while delaying the Repowering Project until the additional clarity can be gained regarding the Project economics.

These revised market outlooks, particularly the sharply lower gas price forecasts, and potential policy outcomes create significant uncertainty in the economics of the Repowering Project. The change in the long-term gas forecasts reduces the value of the fuel savings that the Company and the LPSC anticipated would be provided by the Project. Thus, the "small premium" that the LPSC contemplated could be associated with the Project relative to the cost of an alternative resource such as a CCGT could be much higher—a change from all prior economic analyses, even those performed as late as January 2009. On a more near-term basis, over the first five years of the Project, the net cost to customers of the Repowering Project was originally estimated to equal $145 million; however, the current analysis indicates the total net cost to customers over the initial five years of the Project has more than doubled and is approximately $350 million.

Considered together, the uncertainties associated with the recent changes in the Project economics and market forces driving them, as well as the developments in the federal energy policy and issues raised by the turmoil in the financial markets, suggest that ELL should delay the Repowering Project for a longer term (three years or more) in an effort to gain more clarity and certainty and allow ELL to better determine whether the Project reflects the lowest reasonable cost alternative for customers or whether other alternatives will be better suited to address customer resource needs. Accordingly, ELL recommends to the Commission that ELL make a filing seeking to delay the Project for an extended period of time.

In recommending to the Commission that the Project be delayed for a longer-term, the Company is mindful of the Commission's guidance in Order No. U-30192 that the volatility of natural gas prices could cause the net benefits of the Project to become negative at times during the construction schedule and that a significant part of the justification for the Project is the fuel diversity benefits it offers – benefits not available from a CCGT alternative. The recent structural change in the natural gas market, however, suggests that, across a reasonable range of assumptions, the economics of the Project will be negative relative to a CCGT. Thus, the small "premium" caused by short-term fuel price volatility that the Commission believed could be offset by the fuel diversity benefit provided by the Repowering Project appears, to be materially larger than reasonably could have been expected. A longer-term delay will allow ELL to determine whether the Project, in fact, represents the lowest reasonable cost alternative available to diversify ELL's fuel mix to protect customers from volatile natural gas prices.[8]

[8] Although this filing is made on behalf of ELL, it should be noted that these same factors also merit a delay in the decision of Entergy Gulf States Louisiana, L.L.C. ("EGSL") to participate in the Project at this time. The Commission is considering whether to allow EGSL to participate in the Repowering Project as part of Phase 2 of this proceeding.

III. Recommendation

As noted above, ELL bases its recommendation that the Project be delayed for a longer-term on the recent and significant changes in the Project's economics. This report therefore begins by setting forth the details concerning the change in the Project's economics and discusses the uncertainties raised by the current state of the economy and possible changes in federal policy under the Obama administration. Then, to ensure that the Commission is fully informed of the Project status and spending, the report discusses the current status in some detail. Finally, the report details the current status of the various environmental permits for the Project and the effect on these permits of a longer-term delay in the Project. A longer-term delay is likely to require ELL to seek new or significantly modified permit approvals for the Project, and ELL cannot know today whether such approvals will be obtainable or what conditions may be imposed. This risk is one that ELL has considered and the Commission must consider in deciding whether a longer-term delay of the Project is appropriate.

A. Project Economics

1. Previous Economics

The Repowering Project was undertaken in large part to add supply diversity to the ELL generation portfolio and reduce reliance on gas-fired resources. ELL's generation portfolio was and continues to be weighted toward natural gas-fired resources. Relative to other utilities, ELL's natural gas dependency is high. This dependency on natural gas-fired resources exposes customers to risk relating to changes in natural gas prices. Based on the information available at the time of the original decision to proceed, the Repowering Project was the lowest reasonable cost alternative for reducing reliance on natural gas-fired resources. The Commission recognized in its Order approving the Project that the Project may result in a "small premium for customers over its useful life relative to the cost of a CCGT resource – that is, that the cost of the Little Gypsy Repowering Project over its useful life ultimately could exceed the cost of a CCGT.[9] Nevertheless, at the time that the Repowering Project was certified, the Company's analyses indicated that it was more likely than not that the Repowering Project would be a lower cost alternative than a CCGT. The Company's analysis did indicate that there was a risk that under certain sets of assumptions, the Repowering Project could become a more costly alternative than a CCGT. The Commission found, however, that the fuel diversity benefit provided by the Repowering Project was sufficiently important that the Project should be certified despite this risk.[10]

The positive economics of the Repowering Project continued through 2008, with each Monitoring Report and a supplemental report prepared by ELL reflecting benefits from the Project. These positive economics continued even though, in 2008, ELL was required to delay the Project in order to obtain additional environmental permitting. Because of then-increasing commodity prices and the additional financing costs for a longer construction period, this delay added to the cost of the Project, increasing the total cost, inclusive of AFUDC, from $1.55 billion to $1.76 billion. However, at this time, gas prices also were increasing and reaching record high levels. Thus, the July 2008 Monitoring Report indicated that the Repowering Project continued to be economic relative to the CCGT alternative. At that time, the Net Present Value of the Repowering Project relative to the CCGT was positive $236 million, similar to the benefit considered by the LPSC when the Project was certified. Gas prices continued to trend upward

[9] *See* LPSC Order No. U-30192 (March 19, 2008) at 17, 24.

[10] *Id.* at 24.

for the remainder of the Summer of 2008, further affirming the economics of the Repowering Project.

2. Economics Today

Recent developments in natural gas market and resulting changes in projections for long-term natural gas price levels have decreased the value of the Little Gypsy Repowering Project since the Commission certification. Thus, while the Repowering Project would provide a physical hedge against high natural gas prices, there now appears to be significant uncertainty as to the value of this hedge relative to a CCGT alternative. Given current forecasts of natural gas prices, it now appears that the CCGT alternative may be more economic than the Repowering Project across a range of assumptions.

ELL has prepared several economic analyses of the Repowering Project during the first quarter of 2009. Consistent with prior analyses, the Company used the PROSYM production cost modeling tool along with the current estimate of total Project cost, "sunk" costs, and assumptions about key inputs (forecasted natural gas prices, forecasted petroleum coke, and coal prices, etc.). These analyses compare the 40-year life-cycle economics of completing the Repowering Project with the alternative of canceling the Project and initiating a project to construct a new CCGT facility of equivalent capacity and utilization. The analyses follows the same methodology utilized by ELL in the prior viability analyses as well as the economic analysis presented in Exhibit APW-28 in the Company's Rebuttal Testimony filed in October 2007 in Phase I of this proceeding. The table below reflects the results of the ongoing Project analyses.

Table – Results of PROSYM Economic Analyses At Points in Time ($'MM)*

EFFECT ON TOTAL SUPPLY COST LG3 COMPARED WITH CCGT ($MM)	Direct Testimony (July 2007)	Rebuttal Testimony (Oct 2007)	Quarterly Monitoring Report (July 2008)	Supplemental Monitoring Report (Jan. 2009)	Sensitivity ICF Fuel / Emission Outlook (2008 / 2009)	Quarterly Monitoring Report (Feb. 2009)	Current Analysis (March 2009)
With LG3 Repowering Project							
Total PROSYM Fuel and Purchased Power	$81,821	$147,107	$166,300	$163,288	$166,900	$150,660	$155,267
Incremental Non-Fuel Revenue Requirement	$2,174	$2,237	$2,420	$2,403	$2,403	$2,403	$2,399
Total	$83,995	$149,343	$168,720	$165,691	$169,303	$153,062	$157,666
With Equivalent CCGT							
Total PROSYM Fuel and Purchased Power	$83,575	$149,093	$168,214	$165,027	$168,295	$151,964	$156,521
Incremental Non-Fuel Revenue Requirement	$514	$594	$694	$691	$691	$691	$792
Total	$84,089	$149,687	$168,908	$165,717	$168,985	$152,655	$157,313
Net Benefit / (Cost) of LG3RP over CCGT	**$94**	**$344**	**$188**	**$26**	**($317)**	**($408)**	**($354)**
Less Value of Existing LG3 Unit		($31)	($31)	($31)	($31)	($31)	($31)
Add: Committed Cost			$80	$220	$243	$274	$291
Net Present Value	**$94**	**$313**	**$236**	**$215**	**($106)**	**($165)**	**($94)**

* Values for direct testimony represent 25-year NPV. All other analyses reflect 40-year NPV values.

The current economic analysis indicates that the Net Present Value of the Repowering Project relative to the CCGT is negative $94 million. That is, as compared to July 2008, the Project economics have deteriorated by $330 million even after taking increased committed costs into consideration.

The decrease in projected Project economics between July 2008 and today is driven by an assumption of lower long-term gas prices. The July 2008 analysis assumed long-term gas prices of (2007$ levelized 2013 – 2036). The current analysis assumes long-term gas prices of (2007$ levelized 2013 – 2036). Although there has been some movement in other assumptions, which, in combination, partially offset the decrease in the gas prices, the reduction in gas prices of $1.41/mmBTU is the principal driver of the change in the overall projected economics. The table below reflects the key assumptions used in the economic analysis and how those assumptions have changed over time.[11]

Table – Key Assumptions Used In Economic Analyses

KEY ASSUMPTIONS (Levelized 2007$)	Direct Testimony (July 2007)	Rebuttal Testimony (Oct 2007)	Quarterly Monitoring Report (July 2008)	Supplemental Monitoring Report (Jan. 2008)	Sensitivity ICF Fuel / Emission Outlook (2008 / 2009)	Quarterly Monitoring Report (Feb. 2009)	Current Analysis (March 2009)
All in Fuel Costs for LG3 ($/mmBtu)							
Henry Hub Natural Gas ($/mmBtu)							
CO_2 Emission Cost ($/ton)							

* Included in the fundamental analysis only.

ICF International, a global professional services firm that is recognized as one of the leaders in providing expert opinions regarding the outlook with respect to fuel and emissions pricing, updated its long-term natural gas and CO_2 emissions forecast in early 2009. ELL utilized ICF's 2006/2007 Multi-client previous natural gas and CO_2 forecasts in its Rebuttal testimony in October 2007 and, therefore, has presented a sensitivity analysis of the Project economics using the updated ICF Multi-Client information. As shown in the table above, ICF's

[11] The Table reflects the 40 year analysis period used to evaluate the Project economics. Because 40-year commodity price assumptions are not generally available to the Company, ELL simply trends the cost up at an assumed rate of inflation for the years not available through the forecast.

updated 2008/2009 forecast for CO_2 emission cost is more aggressive than ELL's forecast for CO_2 costs on a long-term basis for the period extending through 2052. This higher forecast has a negative effect on the Project economics.

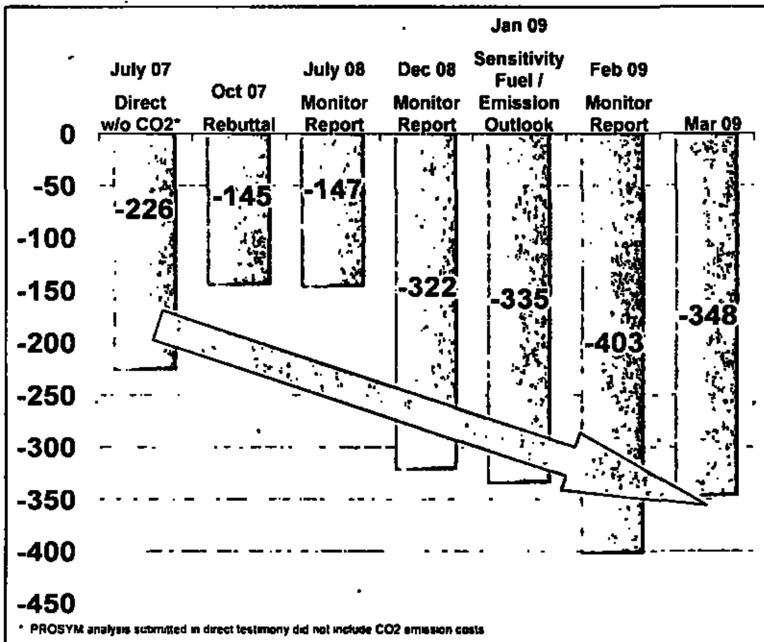
It should be noted that, in one sensitivity analysis the Company has prepared, the Project continues to reflect a break even or possibly positive economic value. This scenario assumes that the fuel mix for the Project is 80% pet coke and 20% coal, instead of the 60%-40% fuel mix that the Company has used as the reference case in all of its analyses. Utilizing a fundamental analysis consistent with the methodology used in Direct and Rebuttal testimony, if the Project burned 80% pet coke, the net benefit would improve by approximately $160 million and would, therefore, approach breakeven or, based on the recent PROSYM, be slightly positive.

ELL's most recent analysis suggests that the Repowering Project may no longer be economic relative to a CCGT alternative and addresses the effects of new and significant uncertainties that have emerged in the wake of the current economic crisis and changes that are being contemplated in federal energy policies. Although the economic results of the Project analysis are based largely on the assumed price of natural gas, as discussed subsequently, it appears that it is not unreasonable to assume that natural gas prices will remain significantly lower than the historic highs experienced in 2008. This means that the Project could, in fact, be a relatively costly physical hedge against high natural gas prices, as opposed to the "small premium" that the Commission contemplated as the possible cost of this hedge when it certified the Project. Further, one must consider these economics in light of the uncertainties caused by the current economic and policy changes.

3. Changes to the Early Year Project Economics

In assessing the potential effect of a long-term delay on the relative economics of the Project, the Company has reviewed the projected customer savings benefit or cost (when negative) over the initial five years of the Project and has compared this metric to previous analysis. As shown in the table below, the net cost to customers over the first five years has increased significantly when compared to the October 2007 Rebuttal testimony analysis.

Customer Benefits / (Costs) Over the First 5 Years of the Project ($MM)*



- ***Over the initial five years of the project, the cost to customers has increased significantly compared to previous analysis.***

* Based on PROSYM analysis.

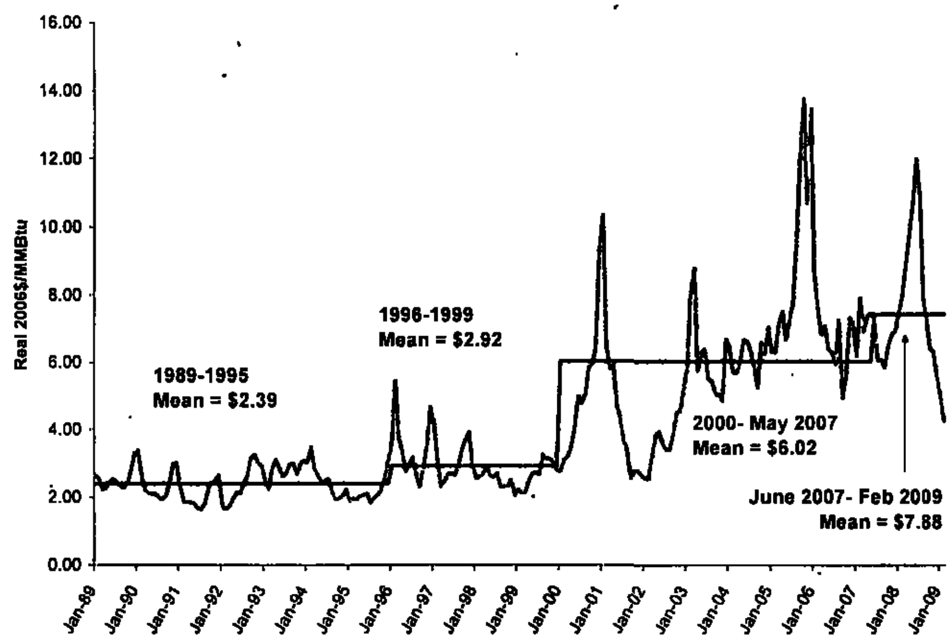
Whereas the net cost to customers was originally estimated to equal $145 million over the first five years, the current analysis indicates the total net cost to customers over the initial five years of the Project has more than doubled and is approximately $350 million. The Company recognizes this metric is not applicable when evaluating the overall life-cycle benefits of a resource; however, similar to the upward trend seen in the following discussion of the breakeven natural gas price, the trend in this metric indicates there is more risk in relying on the back-end cost benefits of the Project to produce benefits over its life-cycle. The higher customer costs in the first five years of the Project life, stemming mainly from lower expected natural gas prices in these years, supports the rationale for a longer-term delay in the Project. Delaying the Project provides headroom by avoiding substantial costs during the periods when gas prices are projected to be lower, and the Project does not provide customers with total savings.

4. Recent Natural Gas Developments

Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below $3.00/mmBtu (2006$). From 2000 through May 2007, prices increased to an average of about $6.00/mmBtu (2006$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of $13.32/mmBtu. Since that time, natural gas prices have declined sharply, with recent Henry Hub prices $3.63/mmBtu (nominal).[12] The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand resulting from the downturn in the U.S. economy.

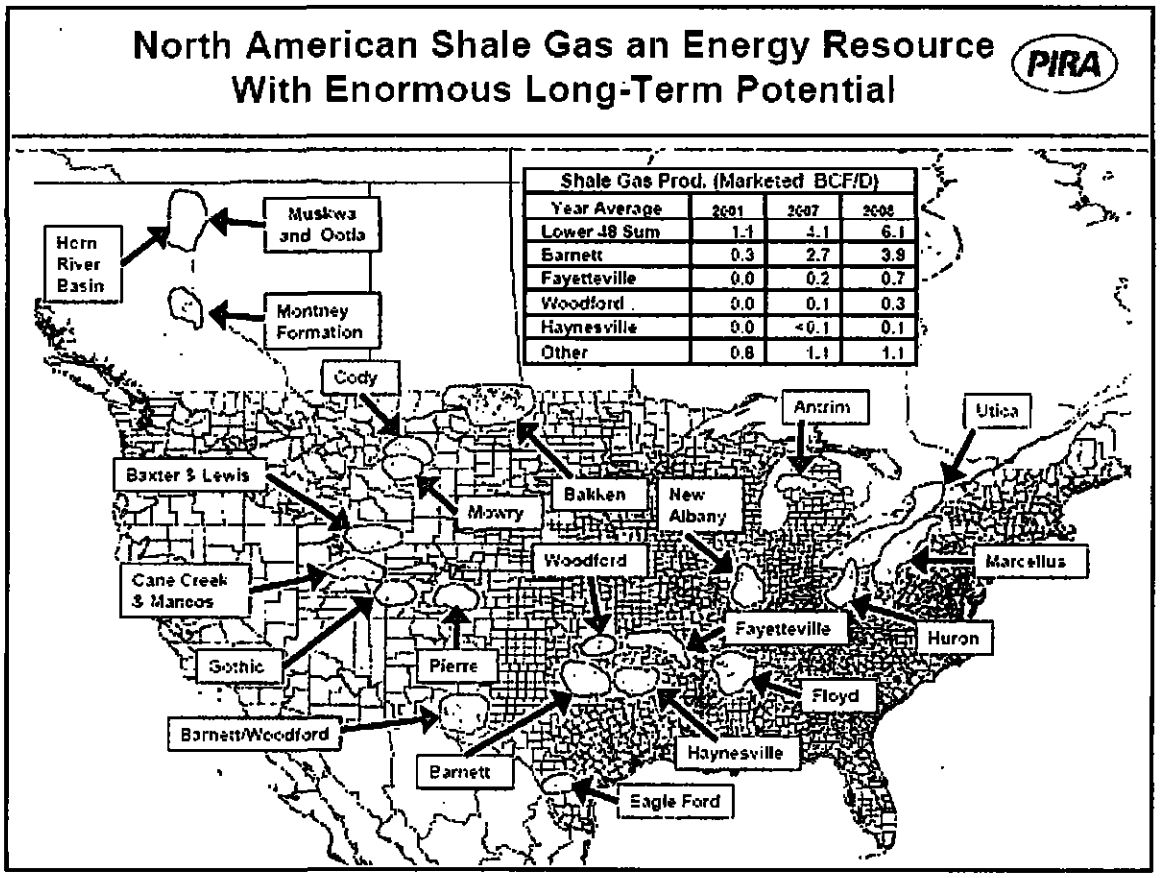
[12] NYMEX settlement for Henry Hub contracts for April 2009

Historical Natural Gas Prices and Volatility



However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non-conventional gas" – so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract – emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract supplies economically in large volumes was not. The recent success of non-conventional gas exploration techniques (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run. From 2001 to 2008, shale gas production in the lower 48 states increased from 1.1 billion cubic feet per day (BCF/D) to 6.1 BCF/D, an increase of more than 450%.

North American Shale Gas



Shale Gas Prod. (Marketed BCF/D)			
Year Average	2001	2007	2008
Lower 48 Sum	1.1	4.1	6.1
Barnett	0.3	2.7	3.9
Fayetteville	0.0	0.2	0.7
Woodford	0.0	0.1	0.3
Haynesville	0.0	<0.1	0.1
Other	0.8	1.1	1.1

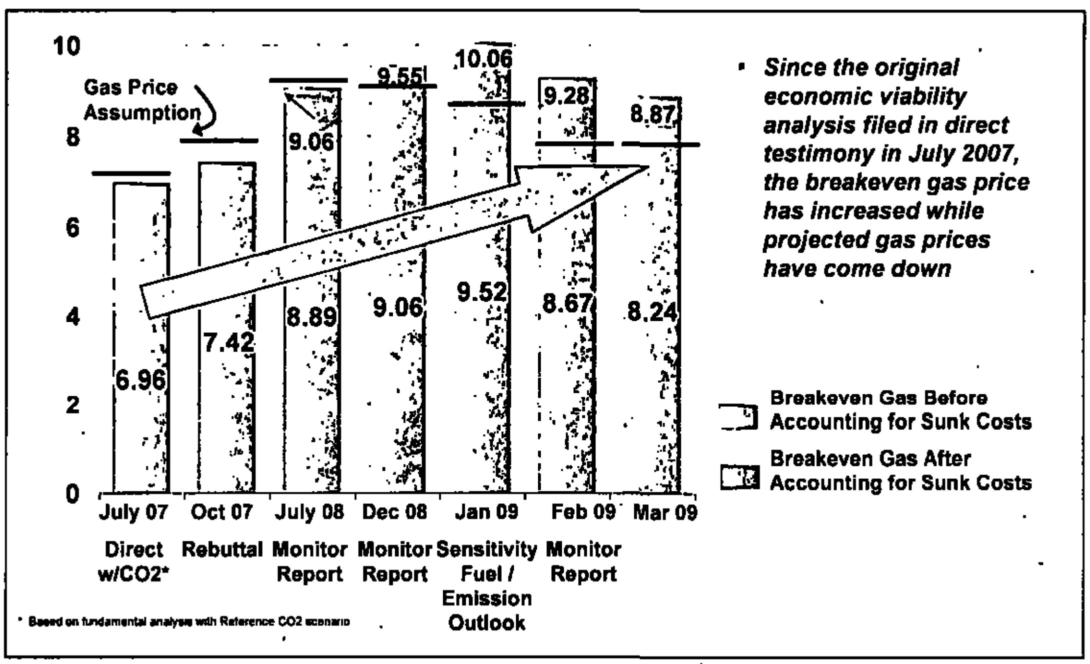
Source: PIRA

5. Breakeven Gas Price

In order to assess further the implications of current gas price projections on the long-term Project economics, the Company has assessed the "breakeven" gas price for the Project over the course of the Project. The "breakeven" gas price is the gas price at which the economics of the Project would match those of a CCGT alternative, that is, the gas price that would give the CCGT alternative the same net present value as the Repowering Project. If the price of natural gas is expected to exceed the breakeven price, then the Project would be economic (less expensive) relative to a CCGT alternative. If the price of natural gas is below the breakeven price, then the Project would be uneconomic (more expensive) relative to a CCGT.

The breakeven analysis relies on a fundamental analysis consistent with the methodology used in ELL's Direct and Rebuttal Testimony. The analysis indicates that, given current assumptions, including accounting for the Project's sunk cost, the breakeven gas price is approaching \$8.24/mmBtu (in real 2007 \$s). In other words, the Repowering Project is economic relative to the CCGT only if gas prices average above this level on a real, levelized basis over the life of the Project. Below is a chart comparing the breakeven price of natural gas that is required to cause the Project to be economic relative to a CCGT alternative across several different points in time.

Breakeven Gas Price (\$/mmBtu)



Notes:
1. All gas prices quoted in real 2007 dollars.
2. Direct and Rebuttal Testimony based on 30-year fundamental analysis for 2012 – 2041. All other analysis based on 40-year analysis for 2013 – 2052.

As shown in the above chart, the analyses conducted over the course of the Project indicated that long-term gas price projections were above the Project's breakeven gas price until early 2009. This relationship suggested that the Repowering Project was likely to be economic relative to a CCGT alternative in the long-run. In the current analysis, however, the relationship has reversed. The breakeven gas price is now above projected long-term gas prices. Moreover, the gap between projected long-term gas prices and the breakeven gas price is $0.45/mmBtu ($7.79 projected compared with $8.24 breakeven) in real 2007 dollars when including sunk costs and over $1.00/mmBtu when excluding sunk costs.

The conclusion from the breakeven analysis is that one must believe that the levelized price of natural gas must remain higher than $8.24 (real 2007 dollars) over the life of the Project if it is to provide economic benefits to customers. In this case, however, as discussed previously, there is a reasonable basis to question this assumption due to the enormous potential of non-conventional resources and other forces that will help to lower natural gas prices. Thus, the breakeven analysis supports a longer-term delay of the Project.

6. Conclusions Regarding Economic Analysis

The cost of the Repowering Project and that of other baseload generation alternatives are subject to significant uncertainties that can change materially their relative economics. In the case of the Repowering Project, a chief uncertainty is long-term natural gas price levels, but the Project also is influenced by the effects of potential energy, environmental and policy issues, which are discussed in the next section, and by whether the timing of this investment is appropriate given the current capital markets. As recognized in the Commission's Order certifying the Project, "the cost-effectiveness of the Repowering Project remains very uncertain because one cannot predict with certainty the ultimate cost of possible CO_2 regulation and natural gas prices over the next 30 years."[13]

At the time of the certification proceeding and through the beginning of 2009, the Project was expected to produce both fuel diversity benefits as well as net economic benefits relative to a CCGT supply alternative. Thus, the important fuel diversity benefit of the Project was expected, under most assumptions, to be economic relative to a CCGT alternative.

Today, this conclusion is uncertain, and this uncertainty is the reason that ELL seeks a longer-term delay of the Project. Recent significant changes in the natural gas market and resulting structural declines in projections of long-term gas prices now make the expected economics of the Repowering Project less attractive relative to a CCGT alternative. Given the current cost of the Project and projected long-term natural gas prices, the Repowering Project does not appear to represent the lowest reasonable cost alternative for meeting ELL's baseload needs at this time. Further, there are new risks to the Project's long-term economics raised by the structural change in the natural gas market and ongoing economic crisis and emerging federal response and potential policy initiatives and timing, which were not knowable at the time of the earlier Project decisions. These new uncertainties pose additional risks to long-term electricity demand and supply requirements that suggest the timing of the Project should be reconsidered.

Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and ELL cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels for a sustained period of time because of the newly discovered ability to produce gas through non-traditional recovery methods. Thus, the cost premium that the LPSC believed might be

[13] Order No. U-30192 (March 19, 2008) at 28 (referring to testimony of Staff witness Matthew Kahal).

"small," as stated in its Order,[14] could be much higher. Under these circumstances, ELL believes that it is appropriate to delay the Repowering Project at this time and revisit this option in the future.

C. Uncertainties that May be Resolved During the Longer-Term Delay

Although changes in the natural gas market (and the associated changes in the expected future path of natural gas prices) is a key driver of the Company's recommendation at this time, the ultimate economics of the Repowering Project are also a function of the outcome of a variety of additional factors, each of which is highly uncertain. These include the long-term effects of the current global recession on the demand for energy; the possible imposition of federally-mandated RPS, which could change the structure of ELL's portfolio and further depress the long-term price of natural gas; the sustainability of the long-term non-conventional natural gas supply, which is a key driver of the expected lower natural gas costs; additional clarity regarding the cost of CO_2 compliance; the possibility of capturing lower long-term commodity costs in a future project; and, other factors. Continuing with the Repowering Project at this time would result in an irreversible investment decision based on the significant capital requirements associated with this Project, yet the resolution of the various uncertainties could produce scenarios in which the outcome of a decision to proceed would not benefit the Company's customers.

At this time, because of lower natural gas prices, the Commission and the Company have the ability to mitigate the effects of these uncertainties by exercising flexibility and delaying decisions that otherwise would result in irrevocable capital expenditures. Delaying a final

[14] Order No. U-30192 (March 19, 2008) at 24.

investment decision can create value for ELL customers by providing time to clarify and resolve uncertainties, increasing the likelihood that the Project, if ultimately undertaken, will produce net benefits for ELL customers over its lifetime. For instance, during a two or three year delay period, ELL is likely to learn whether we are in a severe but short recession or a long-term period of slow growth; whether the U.S. Congress will pass RPS and/or CO_2 legislation and, if so what the cost of compliance might be and the effect on ELL's resource needs; and, the extent to which the development of North American non-conventional gas reserves will constrain domestic natural gas prices for an extended period of time. Greater clarity on all of these uncertainties, about which much will likely be learned over the next two to three years, will allow a better final investment decision to be made. Because it is reasonable to expect that at least some additional clarity regarding these key issues will emerge over the next few years, a decision to delay is reasonable and prudent.

D. Capital Considerations

As the Commission is no doubt aware, the United States and world are in the midst of a severe economic crisis. The capital markets have become increasingly constrained, and investors are charging large premiums to invest in bonds, even in the case of utilities, which traditionally have been considered so-called "safe harbor" investments. While ELL cannot know today how the financial turmoil will affect the funding of the Project, it is reasonable to expect challenges and possibly added cost, which would weaken further the Project economics. Given the uncertainties in the economics of the Repowering Project, it would seem to be a more prudent use of capital for ELL to plan to fund these other projects and preserve its liquidity for unexpected events while delaying the Repowering Project until the additional clarity can be gained regarding its economics.

ELL discussed issues involving access to capital in its Direct Testimony in Phase 2 of this proceeding. However, at the time of that filing, ELL did not know whether the current tightening of the credit markets would be sustained. It now appears that it could take several years for the financial markets to recover.

The turmoil in the financial markets must cause ELL to consider the timing of investing in a capital project of the size of the Repowering Project given its uncertain economics and ELL's need to fund a number of other large investments. ELL is engaged in the Waterford 3 Steam Generator Replacement Project, which was recently certified by the Commission, and is estimated to cost approximately $511 million. ELL also is in need of acquiring additional CCGT capacity and has opportunities currently available to it. ELL expects to make various investments in its transmission system during the period of time that the Repowering Project is under construction. On top of these capital needs, ELL must seek recovery for its costs associated with the 2008 Hurricanes Gustav and Ike. The current estimated cost of these storms to ELL is $390 to $405 million, and there is a need to fund the depleted storm reserve. Although ELL expects that it will be permitted to recover its prudently incurred storm costs, that recovery is not likely to begin until 2010, and ELL is, therefore, entering the 2009 hurricane season with no storm reserve and no funding in place for its outstanding storm costs. Taken together, the projects that ELL needs to complete and ELL's need to ensure that it has adequate liquidity to address storm events counsel against undertaking an investment of the size of the Repowering Project at this time given its declining economics.

The longer-term delay of the Repowering Project will allow ELL to concentrate its financial resources on projects such as the Waterford 3 Steam Generator Replacement Project and on CCGT and transmission investment, all of which will provide benefits to customers. The delay also will permit ELL to resolve its cost recovery for Hurricanes Gustav and Ike. Given the uncertain economics of the Repowering Project, ELL believes that it is prudent to concentrate its resources on these other projects and preserve its liquidity for unexpected events until additional clarity can be gained regarding the economics of the Repowering Project.

E. <u>Potential Supply Options</u>

As part of the ongoing supply planning process and in light of the uncertainty associated with this Project, the Entergy System currently is pursuing the following initiatives to evaluate other supply options:

- <u>Renewable Resources</u> – The Entergy System issued a Request for Information ("RFI") for Renewable Resources to the market on March 31, 2009 in an effort to obtain information from third parties regarding the potential for the development of renewable generation resources in the area in which the Entergy System provides service. This information will prove valuable as ELL assesses the effects of a likely RPS as discussed herein and which technologies may be most appropriate to meet the needs of customers as well as the RPS.
- <u>Energy Efficiency</u> – The System currently is pursuing various initiatives regarding energy efficiency, including fulfillment of a commitment in this proceeding to complete a study of the DSM potential in the areas served by

ELL and Entergy Gulf States Louisiana, L.L.C ("EGSL").[15] The role of DSM in long term planning also is included in the LPSC's ongoing Integrated Resource Planning ("IRP") Docket. Finally, demand response programs and time-of-use rates were piloted by EGSL in 2008 and will be further evaluated in 2009 as part of the second phase of the advanced metering infrastructure (AMI) pilot in Baton Rouge.

- Long Term CCGT Resources – The System continues to evaluate opportunities for the procurement of long-term CCGT resources and, on March 31, 2009, posted notice that it intends to move forward with a long-term RFP for these resources. This RFP will include a self build CCGT option at the Company's Ninemile site, which will be compared against other market alternatives. In addition, the System continues to be in discussions with various suppliers for resources that may provide compelling benefits to customers.

IV. Status of Project Development and Spending

ELL has incurred approximately $160 million of cost through February 28, 2009 on a life-to-date basis for the Repowering Project. ELL estimates that, should it cancel the Project, the total cost of the Project would be approximately $300 million, including actual spending and estimated contract cancellation costs, although the total cost could be higher depending upon when the contracts are cancelled. The portion of this figure attributable to contract cancellation

[15] As previously discussed in testimony before the LPSC, DSM is not a substitute for the supply role that would be provided by the Repowering Project. However, it will help meet the Companies' resource needs and may, with other initiatives, affect the total resource portfolio.

costs is only an estimate, as ELL must negotiate with many of the Project vendors in order to determine the actual cancellation costs. ELL has necessarily focused its discussions to date with vendors on issues surrounding the temporary suspension of the contracts; as such, ELL is not yet in a position to report on the status of the negotiation of cancellation costs for those contracts. ELL plans to begin canceling these contracts over the next few weeks and will be able to develop a complete cost estimate after it completes these cancellations and can determine the full costs to which it is obligated.

During February 2009, the Company determined that, in light of the deterioration in the Project's projected economics and other factors, including recent changes at the federal level, it would be appropriate to slow the rate of spending on the Project while further analysis was undertaken concerning the continued viability of the Project. During this time, the Company directed the Project Team to take necessary steps to minimize the costs incurred for the Project while also balancing the necessity of maintaining the projected in-service date. The Project Team analyzed the four largest contracts where the majority of dollars were being expended and identified discretionary steps that it could take to minimize spending during this period without immediately affecting the Project's construction schedule or projected in-service date. The Project Team also suspended entering into any new contracts unless they were required to maintain the construction schedule. For those that were required to maintain the construction schedule, when feasible, the Project Team bifurcated the new contracts to enter into only the required portions and to defer the remainder.

On March 4, 2009, as part of the above-described effort to slow Project spending, the Company instructed the Project Team to suspend substantially all activity under three of the Project's four largest contracts in order to minimize cost. The terms of these contracts permit

ELL to suspend activity under the contracts for a limited period of time, as it deems necessary, without having to cancel the contracts and renegotiate new contracts if the Project were to move forward. In addition, as of early March 2009, work under each of these contracts had progressed to a point that suspension would not be expected to affect the construction schedule significantly. However, the maximum time that these contracts may remain under suspension ranges from three months to one year. If the suspension exceeds the maximum time allotted, the contracts accord the vendors a right either to cancel their contracts or require a renegotiation of terms. Suspensions longer than three months are therefore impracticable, as the resulting contract cancellations would require that new contracts be negotiated and priced with either the same or new vendors.

Further, ELL is generally responsible under the contract terms for reimbursing incremental costs incurred during suspension. These incremental costs could include costs of storage, transportation to storage, and corrosion protection, among other items.

In addition to the above efforts to suspend activities under significant contracts, ELL directed its Engineering, Procurement, and Construction ("EPC") contractor, which is the principal contractor for the Project, to slow spending, including, specifically to do the following:

- defer any planned personnel moves, site mobilization, or additions to the project team;
- allow project team reductions for all personnel not listed as key personnel (reduction in key personnel must have ELL approval, per the contract);
- continue requests for proposals and evaluations of pending purchase orders and subcontracts, but not to approve any additional subcontracts or purchase orders without ELL approval;
- demobilize the site preparation subcontractor as required to limit activities to returning the site to an acceptable condition, and, further, to demobilize all personnel and equipment not required for this activity; and

• work with ELL to determine other cost control actions to reduce cost commitments and evaluate the requirements to maintain Work and Agency Orders that ELL suspends.

ELL believes that it should manage the Project spending consistently with the objective of obtaining a longer-term delay and further minimizing costs to customers, unless otherwise directed by the Commission. Thus, ELL plans to take immediate steps to minimize spending further on the Project, including the termination and/or cancellation of current contracts with vendors.

The timing of the cancellation of the contracts is important; in general, the sooner the contracts are cancelled, the lower the cancellation costs. The Project contracts have limited suspension periods, generally ranging from three months to one year, and contract provisions allow vendors to be compensated to maintain the suspensions. Thus, ELL must establish a timely suspension management plan. As part of this plan, ELL intends to cancel its contracts in April 2009.

It is important to understand that the management of the Project spending and contracts would differ if the contracts were being managed with a view to being able to restart the Project in the next three months to one year and that, if the Project were to be restarted within this time, there could be additional costs beyond those contemplated by the current Project estimate such as, for example, storage costs and costs to treat and protect fabricated materials so that they would be available for use when the Project resumed. However, given the high probability that the economic viability of the Project will not materially improve over the near term and considering the need to minimize overall costs for ELL and its customers, ELL believes that it is appropriate to implement a longer-term delay and immediately begin the orderly winding down of Project activities

V. Status of Environmental and Other Permits

ELL has obtained all major environmental permits required to begin construction of the Project. As detailed below, however, a delay in the Project places these permits at risk and may adversely affect the Project's economics and technological feasibility in the event the Project were later re-initiated. Below is a list of the major environmental permits that it needs to commence construction, including the following:

Type	Permit	Issuer
Air	Prevention of Significant Deterioration Permit To Construct	Louisiana Department of Environmental Quality ("LDEQ")
Air	Title V Operating Permit, including case-by-case Maximum Achievable Control Technology ("MACT") analysis	LDEQ
Air	Title IV Acid Rain Permit	LDEQ
Water	Section 404 Dredge and Fill ("Wetlands") Permit/Section 10 Rivers and Harbors Act Permit	U.S. Army Corps of Engineers
Water	Section 401 Water Quality Certification	LDEQ
Water	Coastal Use Permit	Louisiana Department of Natural Resources ("LDNR")
Water	Stormwater Control Permit/General Permit Coverage	LDEQ
Land Use	Project Approval	Lake Ponchartrain Levee Board

In addition to the above permits, which have been obtained, additional permits – (i) for modifications to wastewater discharges (Louisiana Pollutant Discharge Elimination System permit modification) and (ii) for the proposed post-combustion product landfill (solid waste permit) –must be obtained. These last two permits are not required to commence construction on the Project but would be required prior to operation of the new generating unit (for the wastewater permit) and prior to the start of landfill construction (for the solid waste permit).

Importantly, a short-term or longer-term delay in the Project would affect the above-described permits in a variety of ways. A short-term delay in the Project – lasting approximately 60-90 days – would affect only the Prevention of Significant Deterioration Permit To Construct. Specifically, if construction on the Project does not begin by May 30, 2009, an extension of the required start-by construction date included in the Prevention of Significant Deterioration Permit To Construct would be required. LDEQ originally issued this permit on November 30, 2007, *and it expires on* May 30, 2009 *unless construction has begun or binding commitments to begin* construction have been entered by that date. However, an extension of the construction start date requirement can be requested from LDEQ. Nonetheless, this is the most pressing deadline related to the environmental permits.

A suspension or multi-year delay in the Project would affect the permits in other, more significant ways. ELL would be required to seek renewal of existing permits, permit extensions, or new permits for the Project, including new air permits. Moreover, it is possible that any extensions, renewals, or new permits would contain new provisions that would have a significant effect on the economics or technological feasibility of the Project. If it proceeds with implementing a longer-term delay in the Project, ELL would seek extensions or renewals of the permits, when allowed by law or regulation and when beneficial to continuing Project viability, but it is not possible to know whether such extensions would be granted or for what period of time. Thus, if a decision is made to delay the Project for an extended period, that choice should be made with an awareness and acceptance of the fact that, as a result, ELL may be required to start over in some or all of the permitting processes. Further, if the Project is delayed for an extended period, there is a material risk that one or more permits would not be granted or would be granted subject to conditions that make the Project less attractive economically.

In particular, and in addition to the effects described above, the longer-term delay of the Project would affect the various permits as follows:

- Title V Operating Permit: LDEQ issued this permit initially on November 30, 2007 (without the MACT determination, which was added later as a modification). The permit expires on November 30, 2012 unless an application for renewal is filed on or before May 30, 2012. The permit also requires that construction begin within two years of permit issuance, or by November 30, 2009. ELL can request an extension of this deadline.

- New Regulatory Requirements: ELL may be required to comply with new regulatory requirements relating to air emissions that become effective before the onset of construction or before permits are extended or renewed. Examples of these requirements are limits on the emission of carbon dioxide and other greenhouse gases, technological standards for mercury and similar emissions, and additional controls required by tightened national ambient air quality standards for ozone that may affect St. Charles Parish. In particular, a designation of St. Charles Parish as not in attainment of EPA's new ozone standard could require LDEQ to deny an extension of the construction start-date requirement in the PSD permit in favor of requiring a new permitting process.

- Wetlands Permit/Section 10 Rivers and Harbors Act Permit: The Corps of Engineers permit expires on February 28, 2014. ELL would require an extension to continue construction operations regulated by this permit after that date.

- Coastal Use Permit: This permit expires on January 9, 2014. Extensions are not provided for this type of permit, so a new permit may be required if construction activities allowed by the permit are not completed by that date. The permit requires that "reasonable progress" continue to be made on the project during the life of the permit. If a new permit were required, new proposed regulations that would require the "beneficial use" of dredged materials could apply to the project, increasing mitigation costs.

Recently, new issues have arisen regarding EPA's jurisdiction over CO_2 emissions. In the wake of the United States Supreme Court's decision in *Massachusetts v. EPA*, EPA is expected to publish a determination in April 2009 that CO_2 emissions cause or contribute to an endangerment to human health and welfare. This "endangerment finding" is a condition precedent to EPA's regulation of CO_2 emissions from mobile sources, such as automobiles and trucks, under Title II of the Clean Air Act, § 201(a)(1). Once EPA makes the endangerment finding, the agency must then develop applicable emissions standards for mobile sources. These emission standards are not to take effect, however, until "after such period as the Administrator finds necessary to permit the development and application of the requisite technology, giving appropriate consideration to the cost of compliance within such period." CAA § 202(a)(2). It is unknown whether the endangerment finding would have an effect on the pending permit; however, assuming that the Company was able to gain an extension of the PSD permit, if construction did not begin by the expiration of the extension period, and a new PSD permit was required after the promulgation of CO_2 regulations, that permit likely would include CO_2 limits or technology requirements that differ from those present under the existing PSD permit.

VI. Conclusion and Recommendation

For the reasons set forth above, ELL recommends to the Commission that ELL (i) continue the temporary suspension of the Repowering Project; and (ii) make a filing with the Commission seeking a longer-term delay (three years or more) of the Repowering Project as well as appropriate accounting for the Project costs until the Commission can determine the permanent ratemaking treatment of these costs.

Respectfully submitted,

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I, the undersigned counsel, hereby certify that a copy of the above and foregoing has been served on the persons listed below by facsimile, electronic mail, hand delivery and/or by mailing said copy through the United States Postal Service, postage prepaid, and addressed as follows:

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U.S. Natural Gas Supply: *Then There Was Abundance*

Introduction

Approximately 22 to 23 trillion cubic feet (tcf) of natural gas have been consumed each year in the United States since 1995. That demand requirement has been met by a variety of natural gas supply sources – sources that have evolved and changed for more than a decade. However, for most of the past 30 years, messaging around natural gas supply (and all hydrocarbons in the United States for that matter) has often been negative with outlooks reflecting supply shortages, precipitous decline of known reserves and inevitable annual production reductions. At best, natural gas may have been viewed as a *bridge* to our energy future, however, even that possibility was tempered by the need to import large volumes of liquefied natural gas (LNG) into the United States – a sometimes less than popular outlook leading to political outrage over additional foreign imports of oil and natural gas. In fact, for many years promoting natural gas as a long-term solution within our national energy supply mix was simply considered to be irrational.

Today, that view has changed. Natural gas is abundant in North America. It is found in conventional oil and gas reservoirs – it is found offshore and onshore. Reservoir geology includes sandstones, fractured tight sands, carbonate rocks, coal seams and even low-permeability shales. Organic-rich sediments, ancient stream beds and tectonically complex subsurface layers can provide environments conducive to hydrocarbon accumulations. Discoveries and development plays are found in deepwater or shallow and in present day arctic or temperate climates. Wells can be remote or drilled next to a farmer's barn. They come as horizontal, directional or vertical wellbores. In short, they come in all shapes and sizes and it is this diversity that has made the United States the largest natural gas producing country in the world (recently surpassing the Russian Federation).

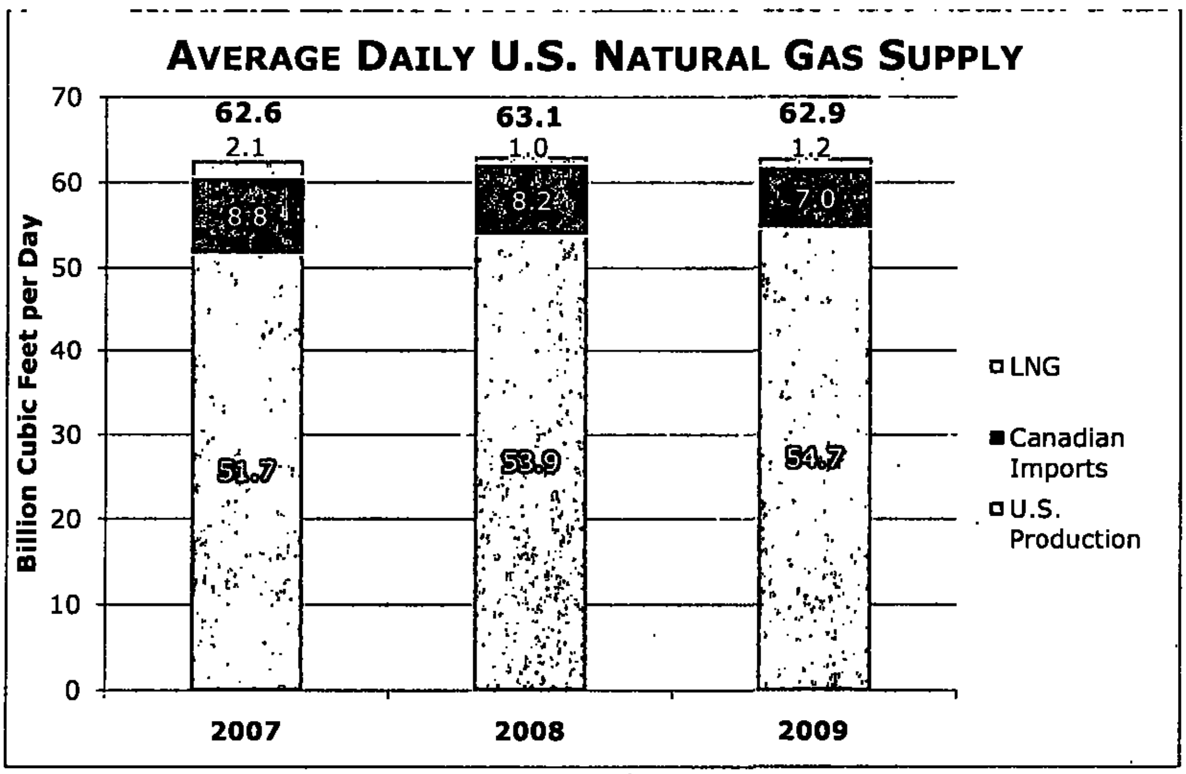
Natural gas resource abundance specific to the United States is currently being assessed and defined by groups such as the Potential Gas Committee (Colorado School of Mines). The numbers are large – 100 years of natural gas supply in the United States at current production levels – and they are poised to grow even more. So what changed? Not only quantitatively, but what is the qualitative view of potential natural gas supply in the United States from existing and future sources including, domestic production, pipeline imports, LNG and even arctic gas?

This energy analysis examines the current view of natural gas supply in and available to the United States, the sources of that supply and comments on future potential. It is intended to be a simple and direct reflection of the key natural gas supply sources and does not capture every nuance of national or world energy markets. The question answered with this paper is relatively straight forward. If natural gas continues to be consumed at 23 tcf per annum or consumption even grows, what are the most likely sources of supply to meet market demand?

I. U.S. Natural Gas Supply Summary

Describing the U.S. natural gas supply market is, as might be expected, both exquisitely simple and devilishly complex. This analysis is designed to emphasize the simplicity in the supply system rather than trying to detail every nuance. Figure 1 is an

FIGURE 1
PRIMARY U.S. NATURAL GAS SUPPLY SOURCES
(2007-2009)



Source: Bentek Energy, LLC

example of that effort. With all of the complexities of the system, the reality is that U.S. gas supply comes from three primary sources, which include domestic production of natural gas, net pipeline imports from Canada and LNG. There are other sources of gas such as imports from Mexico, synthetic or substitute natural gas (SNG) produced from coal and even landfill methane. However, the major sources are the three previously identified.

Critical Questions Regarding Gas Supply Today

One way to examine the simplicity and complexity of the gas supply picture in the United States today is to focus on the most often asked questions regarding supply elements and to quickly note some straight forward answers.

1. ***How have the revelations in shale-gas development changed the U.S. gas supply picture?***
   The Potential Gas Committee now identifies about 600 trillion cubic feet of natural gas resource potential attributable to shales alone. It is the success of drilling and completion technologies among other factors that have allowed the inclusion of this significant resource volume in the U.S. undiscovered resource base. This recent recognition of the shale-related resource potential has increased the overall view of domestic gas supply compared to annual production from a 65 to 100 year life. In addition, some analysts that point to 8 billion cubic feet (bcf) per day of shale-gas production in the United States, today, believe that the volume could be increased to 13-15 bcf per day (or higher) in only a matter of years not decades and thus become a prominent factor in meeting future gas requirements or even meeting growing natural gas demand.

2. ***To what extent will pipeline supplies of natural gas from Canada be sustained in the U.S. market?***
   Daily natural gas production in Canada has fallen from about 16 bcf per day to less than 13 bcf per day in less than five years. About half of current Canadian production is exported to the United States. Both domestic use and the struggle to sustain production in Canada may limit future exports of natural gas to the United States – in fact, may significantly limit pipeline exports – in the eyes of many energy analysts. With that said the addition of LNG import capacity and the potential for unconventional resource development in Canada (following the technology path established in the United States) may tip the pessimism around future Canadian gas supply to a more favorable view in the future.

3. ***Will the United States become a major importer of liquefied natural gas or an exporter of the same?***
   The United States currently boasts about 14 bcf per day of LNG import capacity. It has never been fully utilized. A strong day for vaporized LNG placed in to the domestic pipeline grid (based on history) has been 3-4 bcf per day. Permission to accept LNG, store it and ultimately re-export the liquid has been granted to some facilities on the U.S. gulf coast. The question of whether this critical asset is more fully utilized to meet U.S. customer needs in the future will be dependent on world market conditions, on supply-demand balances in Europe and Asia (not just the United States), relative pricing between all corners of the globe and other

market conditions well out of the control and influence of the U.S. trading partners. However, the potential for LNG to supply new demand growth in this country is real.

4. ***What of arctic natural gas to the lower-48 states – will it ever happen?*** Understanding incremental sources of new gas supply for the United States is not just a matter of looking at shale-gas or LNG. Known quantities of natural gas exist in the arctic areas of Alaska and significantly more potential exists. Creating the pipeline transportation system to connect those arctic supplies to the North American pipeline grid has been proposed for over 30 years. The concept seems to have more tangible momentum with key players like TransCanada, ExxonMobil, British Petroleum, ConocoPhillips and the state of Alaska moving closer to measurable progress. Competing projects have been proposed. That aside, many analysts believe that a pipeline connecting North Slope gas reserves to the lower-48 states is closer than ever and that by 2020 or soon after as much as 4.5 bcf per day may be flowing.

5. ***What are the implications of a growing underground storage capacity?*** Operational underground working gas storage capacity in the United States increased by about 100 bcf from the spring of 2008 to April 2009. In fact, the new total of more than 3.8 tcf was essentially filled prior to the 2009-2010 winter heating season, resulting in the largest inventory of working gas ever recorded. A very cold start to winter in December 2009 and January 2010 attested to the value of storage in an overall gas supply mix that draws 15-20 percent of all gas consumed from November to March from working gas and may account for 30 percent of all gas supply during the peak month for winter heating season demand. This flexibility is crucial to meeting heating load peak demands by local gas utility customers and all customers for that matter.

Having noted these questions and short answers above, there is more. The American Gas Association believes that the strength of gas supply in the United States is not only founded on the *abundance* of methane to be found in North America but also the *diversity* of those supplies. America will not demonstrate a secure, reliable supply of natural gas to meet a lower-carbon future based solely on potential shale-gas, for example. That security and reliability will come from all of the domestic supply sources available including onshore unconventional, deep-water, subsalt, arctic gas, tight sands in the intermountain west, LNG and a practically endless list of other options. It will be dependent on infrastructure growth associated with pipelines and underground storage and it will be dependent on effective regulatory and policy measures that protect all interests in securing a stronger domestic energy future.

Average Daily U.S. Natural Gas Supply

Figure 1 (noted previously) plots U.S. natural gas supply sources for 2007 through 2009 and helps to highlight a share of the optimism currently attributed to domestic supplies of natural gas. That optimism is also reflected in the following key facts and observations.

- Total natural gas supply in the United States is approximately 63-65 billion cubic feet (bcf) per day (after production extraction losses) – everyday.

- Current U.S. dry gas production represents the largest share of the natural gas supply shown – about 55-57 bcf per day or approximately 86 percent of the total.

- Figure 1 specifically shows that domestic natural gas production has grown since 2007 and by 2009 on a daily average basis was six percent higher.

- Since 1990, 17 to 20 trillion cubic feet (tcf) have been produced from the U.S. known reserves inventory each year. However, rather than decline, natural gas reserves have actually grown from 169 tcf in 1990 to over 245 (a 45 percent increase) at year-end 2008 because new discoveries, extensions and revisions of prior reserves data have outgained the pace of production. Much of the most recent reserves growth has come in the form of less conventional sources of natural gas such as coal seams and gas shales.

- Recent estimates of undiscovered natural gas resources from groups such as the Potential Gas Committee point to a total resource (including proved reserves) of over 2,000 tcf. Like proved reserves, the estimate of future supply has grown over time – not precipitously declined. Future domestic natural gas supply today is estimated to be 77 percent higher than the resource assessment in 1990.

- Pipeline imports from Canada are the second largest supply source of natural gas available for U.S. energy consumers. They currently average 5-9 bcf per day or about 12 percent of total U.S. natural gas consumption. Daily production of natural gas in Canada has been falling in recent years (from about 16 to about 12.5 bcf per day) just as U.S production has been growing. Some analysts believe it will continue to fall.

- LNG has been a marginal source of natural gas supply in the United States during 2009, generally averaging 1-2 bcf per day. Domestic import capacity (about 13.5 bcf per day) far exceeds current import levels. Utilization of that capacity is ultimately dependent on U.S. natural gas demand, pricing relationships, such as that existing between the Henry Hub (U.S.) and the National Balancing Point (UK), as well as numerous other world market conditions that influence the flow of LNG to consuming destinations in Europe,. Asia, South America and North America.

- A critical element of U.S. natural gas supply is the huge underground storage infrastructure available to all segments of the natural gas industry. The record working gas volume entering a winter was set in November 2009 and reached 3,837 bcf. Although total working gas design capacity is estimated by the Energy Information Administration to be 4.3 tcf, the record volume recorded for November 2009 is considered to be essentially "full" in terms of preparation for the winter heating season.

- Contributions from storage during the winter can be as much as 40 Bcf per day and 800 Bcf or more for a month. Overall, more than 2 tcf of gas supply for the winter can originate from domestic underground storage fields and storage generally accounts for 15-20 percent of seasonal gas supply; for the coldest month it can be as much as 30 percent of gas supply; and for a given company on the coldest day it can be 75 percent or more of gas supply.

Mexican Natural Gas Trade

- On balance, and unlike the natural gas relationship between the United States and Canada, the net of pipeline cross border trade in natural gas with Mexico results in net exports from the United States (to Mexico) of about 1 bcf per day or slightly less.

- To date, the in-ground resources of natural gas in Mexico have been estimated to be much smaller than those identified in the United States. However, no compatible assessments can be identified in Mexico compared to those consistently completed in the U.S., so comparisons are difficult.

- Having said that, Mexico has added two LNG import terminals – Altamira on the east coast and Costa Azul on the west coast of Baja California – both, of which, have added diversity to Mexico's gas supply picture.

Other Natural Gas Sources

- Synthetic pipeline quality gas is produced from lignite coal at the Great Plains facility in North Dakota. The total annual volume produced compared to domestic production is tiny. However, other proposals have evolved for creating synthetic gas from coal, particularly given a desire to create clean coal alternatives as part of our national energy mix.

- More than 170 landfill gas projects in the United States produce methane, which is consumed in commercial, industrial, electric utility and independent power producer applications around the country. The volume of gas is small compared to national consumption or production, however, the resource can be important and economical on a local basis. Most is used to generate electricity. However, beyond that, landfill gas has been creatively used to source local LNG production for transportation applications, for example.

- Some analysts believe that biogas (and bio-methane) from animal and human waste and other sources could supply over 1 tcf annually to domestic gas supply. So-called digesters use bacteria to generate methane from the waste and in examples such as farm applications provide a source of methane for power generation that may sustain commercial operations.

Peak Natural Gas Supplies

Another way in which to examine and summarize natural gas supply is to account for peak-month sources of gas during critical winter periods. It is, to be certain, these critical demand periods that local gas utilities plan to meet under even the most extreme of conditions, with tools that not only include the flowing sources of natural gas noted above but also gas from underground storage and even short-term peaking sources such as propane-air and on-site LNG storage.

Table 1 estimates the relative contribution of each supply source anticipated to meeting customer needs during the 2009-2010 coldest winter month. It should be no surprise that domestic natural gas production remains the largest source of peak-month gas supply, as it is for a calendar year. However, the flexibility of the largest underground storage system in the world (about 4.3 tcf of working gas design capacity) can account for as much as 30 percent of natural gas consumed during a cold winter month.

TABLE 1

ESTIMATED PEAK MONTH GAS SUPPLIES
2009-2010 Winter Heating Season

Source	Bcf	%
o Domestic Production	1,720	60.6
o Underground Storage	840	29.6
o Supplementals	6	0.3
o Net Canadian Imports	240	8.5
o LNG Imports	35	1.3
Subtotal	**2,841**	**100**
o Mexico Exports	35	
Total Gas Supplies	**2,806**	
Peak Gas Consumption	**2,720 Bcf (January 2008)**	

Canadian imports and internationally traded LNG are also important sources of key winter supplies, while supplemental sources, including propane-air and peaking LNG facilities, meet that last needle peak for some local gas distributors on the coldest days. It is the balance of availability of each of these sources of natural gas, the contracting and planning necessary to have the supplies available during critical periods at a competitive cost and the uncertainty of weather that make each local gas utility unique in terms of its planning process and ultimate service to customers.

Conclusions

- The American Gas Association believes firmly that natural gas is not only a bridge to a cleaner energy future but is one of the solutions to a sustained, secure energy future for the United States and its natural gas customers.

- That point of view is supported by an abundant resource base, critical technology development applied to natural gas extraction, infrastructure investment in pipeline transportation and storage and the fundamental fact that among fossil fuels natural gas is the cleanest.

II. Domestic Natural Gas Resources, Reserves and Production

During the five-year period 2004-2008 approximately 150,000 new natural gas wells were drilled and completed in the United States. That investment in a secure domestic energy resource proved the existence of new sources of commercially producible natural gas, sustained and grew domestic production and was carried forward by key technology advances still being built upon today. Even though approximately 17-20 tcf is produced annually in the United States, proved reserves and estimated resource volumes have grown, not precipitously declined. In a word, natural gas supply in North America, particularly during the past five years, can be described as *dynamic*. What does that mean?

Lower-48 Natural Gas

Natural gas resources and future supply in the United States, in theory, include all of the molecules of methane existing in the ground. It is the yet undiscovered gas resource that ultimately supports the development of new reserves and the production that serves gas customers, today and into the future. To understand and to estimate this unknown requires a keen understanding of geology, energy economics and technology and, of course, each changes with time. That makes estimating natural gas resources in this country both art and science – but it is done. For example, the Potential Gas Committee (PGC), which operates through the Colorado School of Mines, estimates the endowment of natural gas resources in the United States every two years, capturing the nuances and changes in technology, geologic understanding and the economics of natural gas exploration and development. Table 2 illustrates the dynamic nature of resource estimates made by the PGC since 1990.

TABLE 2

Potential Gas Committee
Determination of Future Supply of Natural Gas in the United States

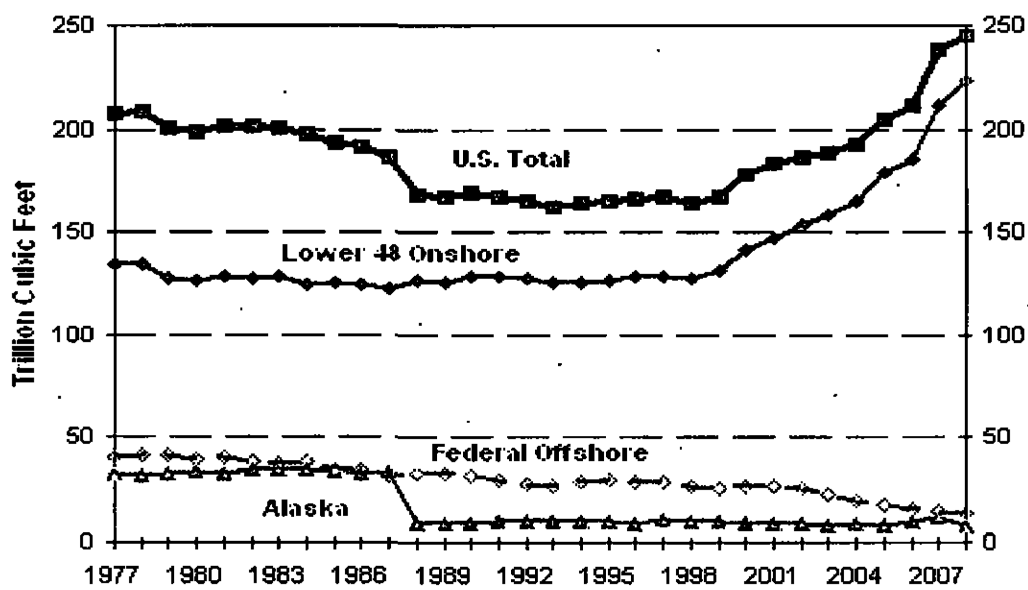
	DOE Reserves	+ Traditional Resources	+ Coal Gas =	Future Supply	+ Cumulative Production =	Ultimate Resource
1990	169	855	147	1,172	777	1,949
1992	165	854	147	1,166	815	1,981
1994	164	881	147	1,192	853	2,045
1996	166	921	146	1,234	893	2,127
1998	164	896	141	1,202	933	2,134
2000	177	936	155	1,268	973	2,241
2002	187	958	169	1,314	1,013	2,327
2004	193	950	169	1,312	1,053	2,364
2006	211	1,155	166	1,532	1,091	2,623
2008	238	1,673	163	2,074	1,132	3,206

The committee volunteers have no particular axe to grind. They are volunteers that work in the areas they are assessing and incorporate current views of technology, critical geologic and geophysical data and a vision of foreseeable economics. The data is statistically aggregated, validated and published. The numbers are what they are. In fact, the most recent estimate of future supply (for year-end 2008), as determined by the PGC (2,074 tcf), which included reserves data published by the Energy Information Administration, U.S. Department of Energy, was 77 percent higher than the estimate made in 1990 (1,172 tcf). The steady growth in future gas supply estimates is shown in Table 2.

What these resource estimates simply show is that the United States is not running out of natural gas. The growth in resource estimates, since 1990, reflect the additions of coal seam natural gas, source rocks such as tight sands, successful deepwater gas discoveries in the Gulf of Mexico and the newest member of the resource club, shale-gas. Each was evaluated and added to the resource base as the geologic data available and evolving technology supported it. That is the dynamic of the resource base that exists here in the United States. North America is gas-prone and producers get better at extracting it every year, every month and every day.

Like natural gas resources, domestic gas reserves have been growing over time. Reserves are the known quantities of natural gas associated with existing wells. Each year new gas is discovered, known fields are extended and some productive capacity is retired. If the net of those changes is greater than the corresponding annual production then reserves grow. If the net is less, then the reserves inventory shrinks. As Figure 2 demonstrates, natural gas proved reserves in the United States have steadily grown, particularly since 1998.

Figure 2. U.S. Dry Natural Gas Proved Reserves, 1977-2008

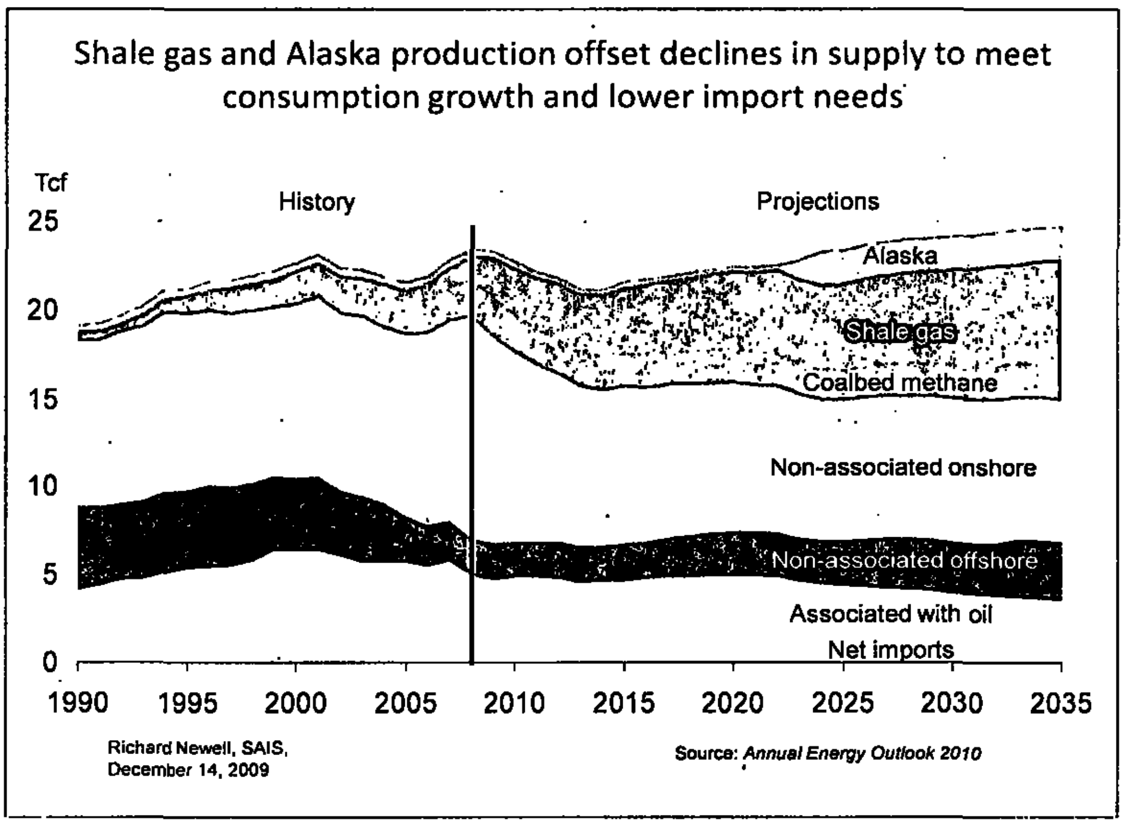


Source: EIA / U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2008

Using the same timeframe as the resource discussion above, natural gas reserves (known inventories with reasonable certainty) have grown 45 percent from 169 tcf in 1990 to 245 tcf at year-end 2008. Figure 2 also shows that the growth in reserves has come on the back of drilling activity focused on onshore resources and, in particular, less conventional gas reservoirs such as coal seams, tight sands and shales. In fact, *according to the Energy Information Administration* (EIA) *coal seams and shales alone* now account for 54 of the 245 tcf of proved gas reserves in the United States or 22 percent of the total. They are a third of lower-48 states onshore resources, also, according to PGC. Tight sands are more difficult to separate from conventional gas reservoirs but some analysts point to half of the country's reserves as 'unconventional.'

With that said, most of the attention around new gas supply in the United States today is focused on shale-gas. Figure 3 below shows likely sources of future domestic natural gas production, according to the Energy Information Administration's *2010-2035 Annual Energy Outlook*. Shales are expected to be the most significant incremental contributor to domestic gas production during the next 25 years in the EIA outlook.

FIGURE 3

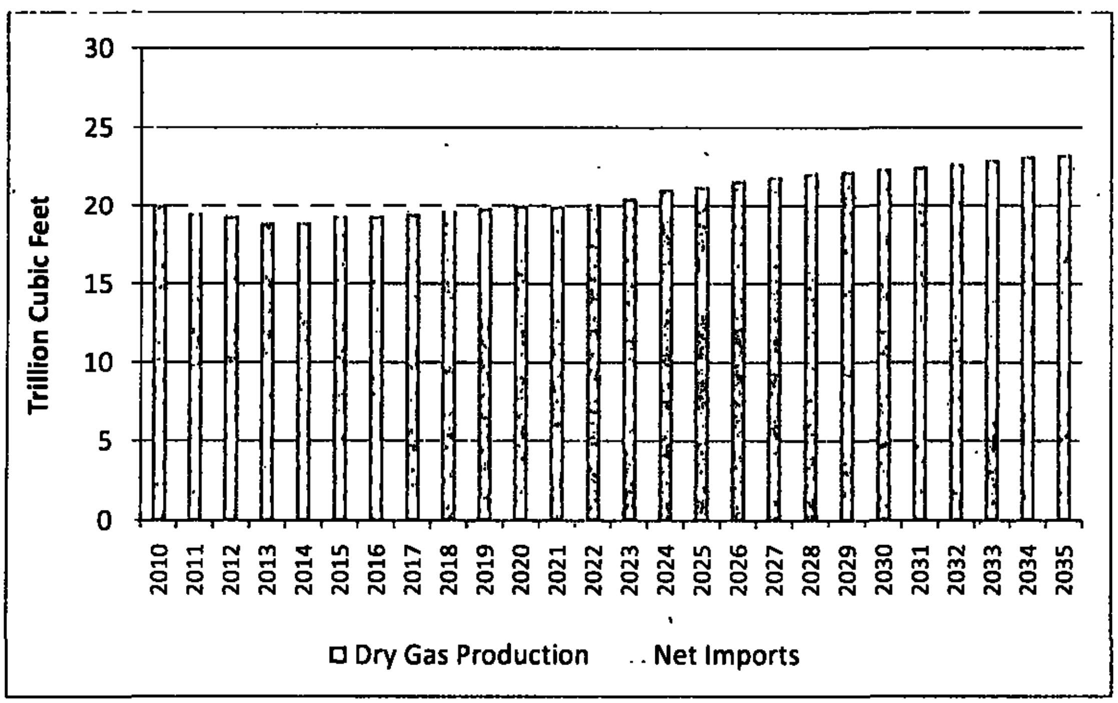


Along with the good news surrounding shale resource potential come the responsibility to develop the gas in the most environmentally sensitive manner possible. Understanding and implementing precautions taken to protect water resources and other environmental remediation strategies is important. As noted above, shale reservoirs are unconventional. They are low porosity, low permeability rocks that require stimulation in order to produce economic quantities of gas. In addition, because they tend to drain a smaller area than many traditional reservoirs, more wells have to be drilled to develop the resource in the ground, which means a significant surface footprint exists in many shale activity areas. However, interest in the shale seems justified. Of the 2,074 tcf identified as potential future supply by the PGC at year-end 2008, 600 tcf was attributed to shales alone. The breakout of potential shale resources by the committee is new and may grow as more is learned about the productive characteristics of those formations being explored and developed.

Names such as the Barnett Shale, Woodford, Fayetteville, Marcellus and numerous others are likely to become ingrained in natural gas production outlooks. If natural gas production is to be sustained or grown from the 20 tcf produced in 2008 (the largest produced volume in the United States since 1974), then these resource and rapidly developing reserves plays will play prominent roles. Again, the Energy Information Administration models domestic natural gas supply expecting it to become decidedly more domestic during the next 25 years. Figure 4 shows the 2010-2035 outlook.

FIGURE 4

U.S. Natural Gas Supply
EIA, AEO 2010-2035 Reference Case



Under these conditions it is likely that drilling investment, sustainable rig counts and many of the other indicators of producing industry health may change. Efficiency of operations is the key. Weekly rig counts during 2009 on average were half of what they were in 2008 (approximately 1,000 total rigs operating compared to 2,000 rigs operating at its peak), however, domestic production has actually been sustained and grown in 2009 compared to 2008. This has occurred, in part and particularly with respect to natural gas directed activities, because the new drilling fleet dedicated to unconventional gas development is high tech, efficient and fully utilized. Simply put, one rig does more today than an operating rig ten years ago – significantly more.

Arctic Natural Gas

Figure 3, which illustrates the key components of future gas supply according to EIA also points to the evolving potential for gas in Alaska to be transported to Canada and on to the lower-48 states – perhaps within the next 15 years. More than 30 tcf of gas reserves on the North Slope have been previously identified and perhaps hundreds of tcf of future resource potential make Alaska an attractive region for developing new gas supply. Pipeline infrastructure has been the primary stumbling block along with a $30 billion price tag for connecting North Slope gas with the rest of the North American grid.

An Alaska Natural Gas Transportation System (ANGTS) has been on the drawing board for years, however, it has been recent legislative action by the State of Alaska and the interest of two groups in constructing a pipeline that has given the concept new life. TransCanada Pipeline and ExxonMobil (a North Slope oil producer) have teamed to follow up on the concession won by TransCanada during a competitive proposal process conducted by the state. The other two North Slope producers, Conoco-Phillips and British Petroleum have also proposed a pipeline (the Denali Pipeline) as a solution to Alaskan gas access. Both of the projects propose serving Alaska and the North American grid with a 4-5 Bcf per day capacity pipeline. Such an addition to U.S. gas supply would mean an eight percent increase in domestic productive capacity, which makes the project very significant.

Of course, neither is yet built and it is almost certain that both would not be constructed. The important issue is that once constructed an Alaska pipeline would deliver an additional 4-5 Bcf per day of natural gas to the Alaska and greater North American market. Once constructed and flowing many analysts believe that the pipeline would operate full and thus become a part of baseline gas supply through direct gas capacity increases or displacement. It could be an incredibly long-lived, stable and secure source of gas for decades to come and that is what makes it so important.

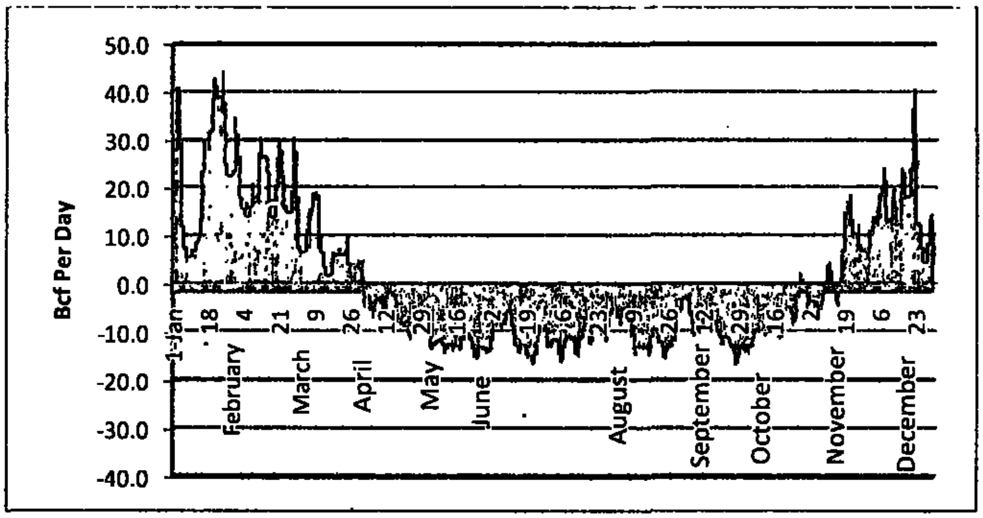
U.S. Underground Storage

The United States has the largest capacity for underground storage of natural gas in the world. Natural gas supply not required for consumption during the warmer months of the year is injected and stored in more than 425 facilities across the country in geologic settings that primarily include depleted oil and gas reservoirs, aquifers and salt cavern or bedded salt formations. Volumes can be written regarding the function, utility and engineering of domestic underground storage, however, one of the tenants of this report is to keep the summary simple and direct.

There are numerous very good reasons to store natural gas for peak demand periods and this report will focus on two of them. As noted in the summary section of this report, total supplies of natural gas available to domestic markets are about 65 bcf per day – every day. Particularly during the warmer periods of the year, consumption of natural gas across the country can be considerably less – many days less than 50 bcf per day. Underground storage provides a place for the additional gas supply to go during periods of less demand and thus there is an underground storage injection season that lasts generally from late April into November. The record working gas volume (the quantity of natural gas actually circulated in and then out of storage facilities – as opposed to base gas volumes that remain in the ground) was set in November 2009 and reached 3,837 bcf. Although total working gas design capacity is estimated by the Energy Information Administration to be 4.3 tcf, the record volume recorded for November 2009 is considered to be essentially "full" in terms of preparation for the winter heating season.

FIGURE 5

**Net Daily Withdrawals and Injections
Working Gas in Underground Storage (2008)**



Source: Bentek Energy, LLC.

The five-month period including November through March reverses the process, however, as natural gas is withdrawn to meet weather-sensitive heating loads. This is the crucial period for which local gas utilities anticipate and develop supply plans. Storage is often a key component because a flowing gas market that is supplied at 65 bcf per day may be required to meet demand that routinely increases to 80 bcf per day and may reach 100 bcf per day across the country.

Figure 5 shows both the winter supply capability of underground storage and the injection season for a full calendar year, 2008. Positive values reflect the additional seasonal supply of natural gas from underground storage and the negative values represent net injections during spring, summer and early fall months. Note that contributions from storage during the winter can be as much as 40 Bcf per day and looking back at Table 1 monthly contributions from working gas in underground storage can be 800 Bcf or more. Overall, more than 2 tcf of gas supply for the winter can originate from domestic underground storage fields although the actual volume varies from year to year based on weather conditions and other factors. In fact, for a whole winter heating season storage generally accounts for 15-20 percent of seasonal gas supply; for the coldest month it can be as much as 30 percent of gas supply; and for a given company on the coldest day it can be 75 percent or more of gas supply. It is a very versatile supply source for natural gas consumers.

A second obvious use of underground storage applies more to natural gas producers, supply aggregators and marketers. Storage provides a physical tool in which to store volumes of gas seeking future arbitrage opportunities and is thus one of the tools that balance the value of gas from day to day, week to week and month to month. In addition, storage can be used as a physical balancing tool for pipeline system integrity and other applications. Natural gas storage, ample indigenous gas resources and a flexible pipeline grid help to make the natural gas system work efficiently in the United States.

Mexico-United States Natural Gas Trade

Many people know that Mexico is a player in world oil markets. The country also has significant natural gas reserves. However, those reserves are not necessarily located near demand centers. In fact, one area with concentrated demand for natural gas in Mexico is the border area with the United States where industries and power generators use natural gas routinely. That geographic proximity has made for a robust energy trade at the border and one that is the opposite of that shared with Canada.

The Energy Information Administration reports annual data on the U.S/Mexico natural gas trade for the years 1973-2008. Except for the five-year period 1980-1984, the United States has actually been a net exporter of gas to Mexico and that net volume has been about one Bcf per day since 2003. That relationship may very well continue although the construction of two LNG receiving terminals may influence the future. Import terminals have been constructed at Altamira on the east coast (Atlantic-Caribbean trade) and Costa Azul on the west coast of Baja California (Pacific trade) – both, of which, have added diversity to Mexico's gas supply picture.

Synthetic Natural Gas

Creating synthetic or substitute natural gas (SNG) from coal is not a new idea. Town gas supplies before the era of interstate pipelines were created from various hydrocarbons and coal more than a century ago. However, concerns about cleaning coal used for power generation in a carbon constrained energy economy have renewed interest in some synthetic gas applications. In some cases, gases created using a chosen technology might be immediately used to generate power, while in other cases it might be used as feedstock in an industrial process, or might even be converted to pipeline quality gas.

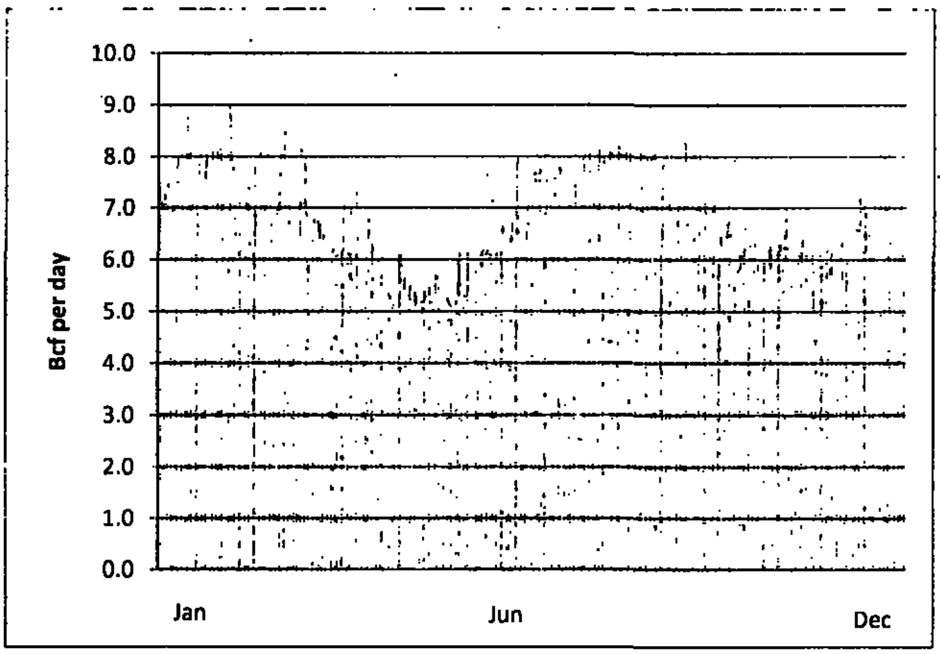
The Energy Information Administration now attributes about 60 Bcf per year of natural gas supply to SNG origins in its long-term outlook. That is about 170 million cubic feet per day and as such is a minor part of total domestic gas supply. But again, like so many other technologies, gas produced synthetically can be an important local supply source and adds more than just more molecules to the picture. It can be an environmental enhancement and can produce products (other than a synthetic methane stream) that produce economic value.

III. Pipeline Imports-Canada

Canada is the third-largest producer of natural gas in the world (behind the United States and the Russian Federation), producing about 12.5 Bcf per day, which is less than one-quarter of daily U.S. production. In recent years about half (5-9 bcf per day) of Canadian production has been exported to the United States, making pipeline supplies of natural gas from Canada the largest source of gas to U.S. consumers outside of that provided by U.S. producers.

FIGURE 6

Net U.S. Pipeline Imports from Canada
January 1-December 31, 2009



Source: Bentek Energy, LLC.

As shown in Figure 6, exports of natural gas to the U.S. from Canada fluctuate. For example, during the winter months of early 2009, daily volumes approximated as much as 8 bcf per day and were used to meet winter heating loads, while similar summer volumes may have been directed to U.S. underground storage fields and power generators. However, with domestic supplies abundant and at relatively low cost, Canadian gas can be squeezed out of the U.S. market, particularly when demand requirements are low. That certainly occurred in 2009 with the reduction in domestic economic activity and lower levels of natural gas demand from the industrial sector in the United States. Peak daily pipeline imports from Canada that had been 10 Bcf per day in 2008 dropped to about 8 bcf per day (occasionally peaking at 9 bcf) and daily import volumes during the swing months for gas demand fell as low as 5 bcf per day, primarily because the gas just wasn't needed.

Most Canadian gas supply destined for the United States originates in the Western Sedimentary Basin, which is centered in Alberta and British Columbia. Natural gas is also produced in Saskatchewan, as well as minor amounts in other provinces. However, as natural gas production and proved reserves have grown in the United States during the past several years, they have fallen in Canada. Proved reserves in Canada at about 60 tcf are only about a quarter of that identified in the United States. Yet Canada remains a critical supplier of natural gas to the U.S. Pacific Northwest, Midwest and New England. Even a new LNG import terminal, Canaport, in eastern Canada (New Brunswick) serves U.S. markets through existing pipeline infrastructure.

With that said, many analysts view the future contribution of Canadian gas supply to U.S. markets as one destined to decline. In fact, the Energy Information Administration's *Annual Energy Outlook 2010-2035* reduces all pipeline imports of natural gas in the United States by about two-thirds to 3 bcf per day or less by 2020. This outlook is not universally held and changes with new policy developments, as well as economic issues. However, the reasons for this view most often cited are declining Canadian natural gas production and burgeoning requirements for home grown gas supply in Canada, including natural gas for cleaner power generation and thermal requirements associated with bitumen extraction and processing from oil sands in western Canada.

Might there be something that counteracts this anticipated trend? As with the United States, natural gas producers in Canada are investigating the potential of shales to produce economic quantities of natural gas utilizing evolving technologies. Canada's National Energy Board (NEB) has published a primer, which concludes that significant shale-gas potential may exist in traditional producing areas such as , Alberta, British Columbia and Saskatchewan but also in onshore areas lesser known for oil and gas production including Quebec, Nova Scotia and New Brunswick. The NEB points to the possibility of 1,000 tcf of gas in place and guesses that 20 percent may be recoverable – all the while noting that any estimates today are highly speculative until more work is done.

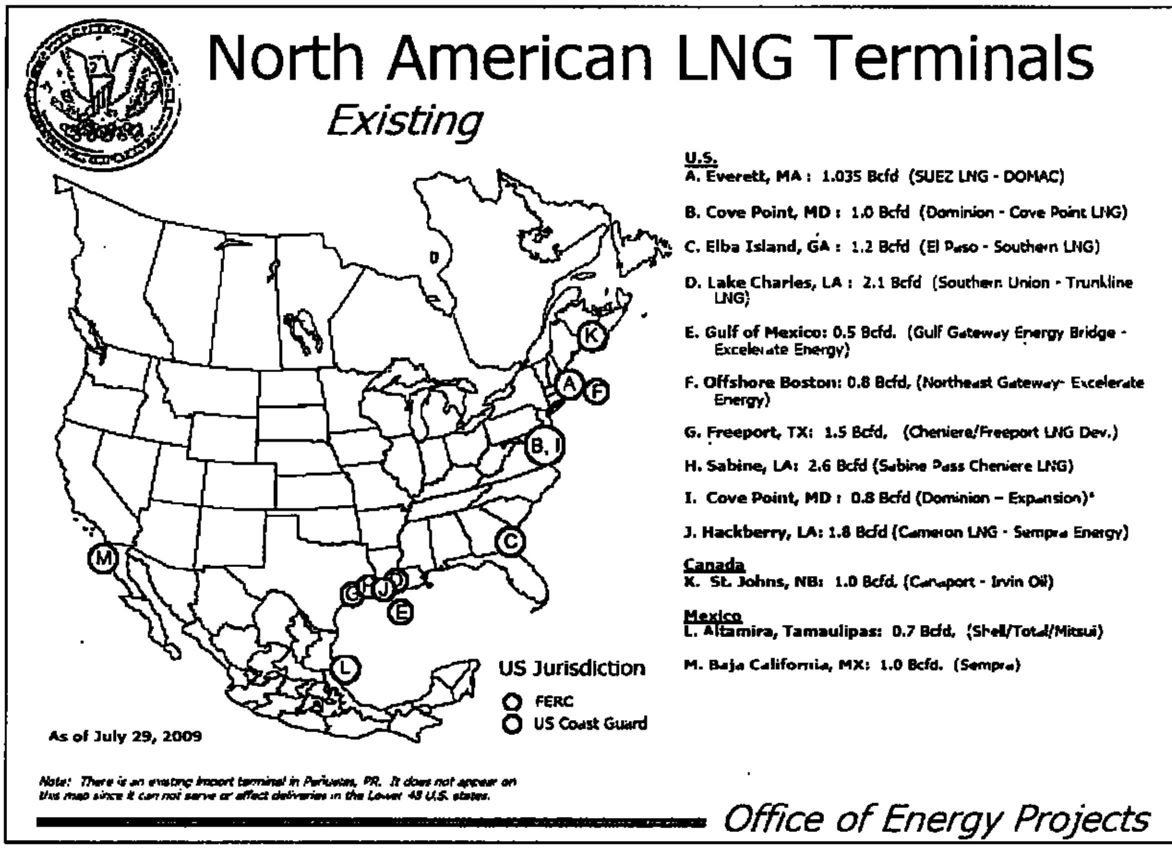
IV. Liquefied Natural Gas

The third major source of natural gas supply for the U.S. pipeline grid is imported liquefied natural gas or LNG. Some local gas utilities create LNG from pipeline supplies during the summer months, store it then inject it at peak periods to meet the most critical moments of natural gas demand – often lasting only days or even hours. These peak-shaving facilities are not the focus of this discussion. Instead, this paper examines the capacity for receiving shipments of LNG, which originate in countries such as Trinidad and Tobago, Nigeria, Norway, Qatar, Egypt and others and land at import terminals located in the Gulf of Mexico region or the Atlantic coast of the United States.

Figure 7 shows the location of the import facilities currently operating in the United States, as well as operational import terminals in Canada and Mexico. The majority of import capacity is centered in onshore facilities where LNG is unloaded from ships, stored in onshore tanks and ultimately vaporized and injected into the domestic pipeline grid. Two offshore unloading facilities are also part of the mix with one located in the Gulf of Mexico and another offshore of Boston, Massachusetts. Together these U.S. facilities account for more than 13 bcf per day of import capacity. Those import terminals located in Mexico and Canada that may serve, in part, regional U.S. markets add another 2.7 bcf per day to North American import capacity. Having said that, total U. S. LNG import capacity is currently only being used at a rate of 25 percent or less on most days.

For most of 2009 about 1 bcf per day of LNG was received, vaporized and placed into the pipeline grid in the United States. That means that LNG accounts for about two percent of daily U.S. gas supply. The strongest LNG import year to date was 2007 when 780 bcf of LNG was imported. During that year the largest daily import volumes occurred during the summer (gas essentially going to power generation or to storage) and totaled 3 per day. By any measure these numbers indicate that U.S. LNG import capacity is underutilized.

FIGURE 7



Source: Federal Energy Regulatory Commission

Whether or not it is more fully utilized depends on many factors. Estimates of world LNG liquefaction (supply) capacity, today, place the volume at about 800 bcf per month. That number is expected to reach 950 bcf per month by March 2010. With so much unused import capacity in the United States and with the largest underground storage system in the world, analysts often point to North America as a potential place of last resort for LNG suppliers and it may be so. However, that dumping ground scenario has not materialized in recent years as requirements for LNG in Asia and European markets has absorbed available supplies for a myriad of reasons and often at higher selling prices than could have been obtained at Henry Hub.

Domestic LNG facilities are being used in other ways, however. One facility in the Cook Inlet area of Alaska has been exporting about 60 Bcf per year (a small volume in the scheme of U.S. gas supply) to countries in the Pacific basin for decades. In addition, recently constructed facilities like that at Freeport, Texas have received approval from the Federal Energy Regulatory Commission to accept LNG import volumes, store the LNG in the facility tanks then reload the LNG on ships for export depending on market conditions.

V. Other Natural Gas Sources

The prior sections of this report have touched on the most prominent sources of natural gas in the United States, today. But, as is so often the case, there are others in the market and in waiting. For the most part, these sources of gas account for small volumes of gas. However, they can be important locally from an economic standpoint, as well as responsible environmental policy. In the here-and-now, the most visible alternative to the gas sources previously described is bio-methane.

Bio-Methane

Renewable gas, biogas or bio-methane are descriptors for methane-based gas that may be produced from anaerobic bacteria digestion or the gasification of biomass. Sources of biogas, therefore, may be human and animal waste, landfills, wood and other possible biomass products. It is not synthetic natural gas (SNG) made from coal, nor is it the gas stream created by chemical processes where organic material is added to gasifiers in a technology such as integrated gasification and combined cycle (IGCC). It is gas reflecting organic origins often from substances considered renewable.

Biogas and bio-methane (essentially cleaned biogas) are used in various applications around the world, including as a fuel source (from landfills or digesters) for onsite electricity generation or collected and compressed for transportation fuel (fleet applications). Used locally, at a dairy farm or other agricultural site or landfill, biogas can be an important source of electricity supply and gas for lighting or other processes and can add to the economic welfare of the aforementioned operations. With that said and given its source diversity, a stream of biogas may contain not only methane but, also, carbon dioxide and small amounts of nitrogen, ammonia, hydrogen, sulfur dioxide and even hydrogen sulfide. In many cases the gas mixture must be cleaned to be used in other applications.

So how much can bio-methane contribute to energy needs in the United States? The Energy Information Administration reported that landfill and municipal solid waste accounted for about .312 quadrillion btus (quads) of energy to consumers in 2004. Almost all (.308) went to electric power generation. In addition, a 1998 Department of Energy study estimated that as much as 1.25 quads of bio-energy could be captured and used in the United States. That energy value represents about six percent of current U.S. natural gas consumption – not an insignificant volume. The Gas Technology Institute (GTI) has recently published data indicating that the manure from the nine million dairy cattle in the United States could potentially produce sufficient methane to meet one percent of total U.S. consumption of natural gas.

Beyond just the energy value, other issues make capturing and using bio-methane attractive, particularly in an environment of climate change and carbon remediation strategies. Methane is a major greenhouse gas if it escapes to the atmosphere. Many current disposal practices for slurry and food residues cause methane to be released through natural processes. Anaerobic digestion (AD) exploits this process so the gas can be used as a fuel. A well-managed AD scheme may aim to maximize methane generation, but not release any gas to the atmosphere, thereby reducing overall emissions.

When burning bio-methane, for example, to generate electricity, each unit of methane has 21 times the global warming potential of carbon dioxide. During the process, 21 units of GHG are eliminated and 1 unit is created for each unit of methane that is captured and combusted, creating an overall net gain of 20 units. This benefit will occur as long as the methane is combusted—whether the biogas is flared, used to generate electricity, or upgraded to bio-methane and then combusted to produce energy. This benefit is in addition to the benefit when energy created by this renewable fuel replaces energy created by combusting a fossil fuel.

Methane Hydrates

Methane hydrates are purposely not discussed in any detail in this report primarily because the gas supply focus of the analysis is in the here-and-now. Methane hydrates (or essentially ice crystals that have captured methane molecules usually of some biogenic origin within the ice matrix) exist in many areas of the world. Shallow sediments at ocean bottom along continental margins in North America, for example, are thought to contain thousands of tcf of methane potential. For the most part, recovering this gas resource asset is a technology and economic challenge yet to be overcome. Sediments on the North Slope of Alaska also contain methane hydrates and may be producible using known drilling technologies, according to the United States Geological Survey, but the region lacks pipeline infrastructure for moving the methane to markets.

Even with research opportunities, it seems unlikely that hydrates will play a significant role in U.S. gas supply within the next decade or so.

VI. Conclusions

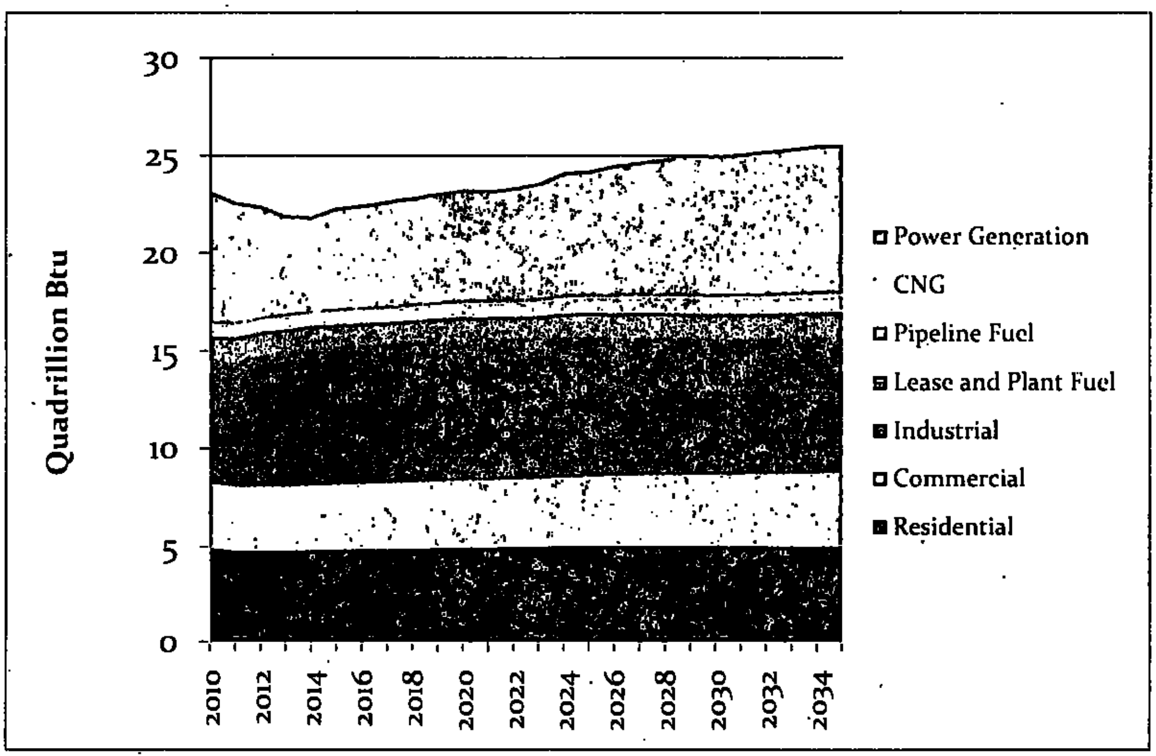
The American Gas Association believes firmly that natural gas is not only a bridge to a cleaner energy future but is one of the solutions to a sustained, secure energy future for the United States and its natural gas customers. That point of view is supported by an abundant resource base, critical technology development applied to natural gas extraction, as well as burner tips, infrastructure investment in pipeline transportation and storage and the fundamental fact that among fossil fuels natural gas emits the least carbon dioxide when burned.

Currently, natural gas is supplied and consumed at a level of about 22-23 quadrillion btus per year (a quad is roughly the same as 1 tcf). The Energy Information Administration's (US Department of Energy) 2010-2035 long-term outlook places natural gas consumption in the United States at only slightly more than 25 quadrillion btus per annum by 2035 (see Figure 8). With that said, EIA outlooks are based on current law and as such (at this time) do not reflect aggressive measures to reduce greenhouse gas emissions.

Whether or not this accurately portrays the future is questionable. If new laws or regulations are put in place in the United States aimed primarily at reducing carbon emissions, then many analysts believe that natural gas consumption will significantly increase in the foreseeable future. Most point to cleaner technology for power generation and with that come the potential for new gas-fired generation or gas-fired generation used to back up renewable generation projects such as wind and solar applications. Since no overt carbon reduction strategy is currently law, it is just a guess as to how gas demand might grow in a carbon constrained world and there is significant disagreement.

FIGURE 8

U.S. Natural Gas Consumption by Sector
(EIA, AEO 2010-2035 Reference Case)



With that said, the purpose of this paper has been to review natural gas sources and answer the question – can U.S. natural gas supply sources meet a growing market for natural gas no matter the origin of the demand? The simple answer is *yes* and is supported by the prior discussions regarding natural gas supply sources.

For example, on paper a 3 Tcf per year increase in current natural gas consumption (an incremental volume sometimes cited when examining various climate change legislation scenarios) is about 8 Bcf per day more than the 64 per day (on average) currently supplied into the U.S. market, today. Could that incremental demand be met? Many analysts believe that new shale-gas production could easily meet that target alone. Indeed, current unused LNG capacity could meet that volume requirement on its own, also. The implementation of an arctic natural gas pipeline to the North American grid could meet half of that requirement. Incremental commercial, industrial or farm requirements for gas or electricity on a local basis could be met with bio-methane, which might even improve the environmental impacts of energy consumption in those localities. The fact is that there are numerous sources of natural gas supply still available to the market or potentially available to meet new incremental demand– they are not pie-in-the-sky.

Clearly there are other issues to consider beyond the simplicity of more gas supply potential. Not knowing the federal policy regarding carbon remediation is an issue that will ultimately be resolved but will take time – not only for the policy development but for implementation. Impacts on natural gas acquisition prices are likely to be uneven in the short-term, even in a well supplied market, if there is a sudden demand for more natural gas. Supply-side or upstream investment, if directed primarily toward unconventional gas shales, may cut into sustaining production from other in-the-ground sources of natural gas. All of these questions can be asked and examined.

However, this summary review of natural gas supply in the United States and North America, in general, clearly points to a sense of optimism regarding supply potential. Heroic assumptions are few with the facts pointing to a diverse, versatile and competitive energy source (in natural gas) poised to meet existing and incremental future demands whether that be for residential, commercial, industrial, power generation or transportation applications.

Synapse
Energy Economics, Inc.

Synapse 2008
CO_2 Price Forecasts

July 2008

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1. INTRODUCTION

Synapse has prepared a 2008 CO_2 price forecast for use in Integrated Resource Planning (IRP) and other electricity resource planning analyses. The 2008 Synapse Low CO_2 Price Forecast starts at $10/ton[1] in 2013, in 2007 dollars, and increases to approximately $23/ton in 2030. This represents a $15/ton levelized price over the period 2013-2030, in 2007 dollars. The 2008 Synapse High CO_2 Price Forecast starts at $30/ton in 2013, in 2007 dollars, and rises to approximately $68/ton in 2030. This High Forecast represents a $45/ton levelized price over the period 2013-2030, also in 2007 dollars. Synapse also has prepared a Mid CO_2 Price Forecast that starts close to the low case, at $15/ton in 2013 in 2007 dollars, but then climbs to $53/ton by 2030. The levelized cost of this mid CO_2 price forecast is $30/ton in 2007 dollars.

In 2006, Synapse developed a set of CO_2 price forecasts for use in IRP and other electricity resource planning analyses.[2] Those forecasts ranged from a low of $10.23 levelized over the years 2013-2030, to a high of $37.11 levelized over the same period (all in 2007 dollars).

Significant developments in the past two years led Synapse to re-examine and revise its 2006 CO_2 price forecasts to ensure that these forecasts reflect an appropriate level of financial risk associated with greenhouse gas emissions. Most importantly, the political support for serious climate change legislation has expanded significantly in Federal and State governments, as well as in the public at large, as the scientific evidence of climate change has become more certain. Concurrently, the new greenhouse gas regulation bills under consideration in the 110th U.S. Congress contain emissions reductions that are significantly more stringent than would have been required by proposals introduced in earlier years. Moreover, an increasing number of states have adopted policies, either individually and/or as members of regional coalitions, to reduce greenhouse gas emissions. In addition, in the past two years, additional information has been developed regarding technology innovations in the areas of renewables, energy efficiency, and carbon capture and sequestration, leading to greater clarity about the cost of emissions mitigation; however, cost estimates for many of these technologies are still in the early stages. Taken together these developments lead to higher financial risks associated with future greenhouse gas emissions and justify the use of higher projected CO_2 emissions

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1 Throughout this paper, emission allowance prices are quoted in dollars per ton. This should be interpreted as dollars per short ton of CO_2. Prices in the economic literature and in international trading are often quoted in dollars per metric ton of CO_2 or dollars per metric ton of carbon, but the units we use are more typical of US carbon pricing schemes.

2 CO_2 price: Carbon dioxide (CO_2) is one of a cohort of six gases known to contribute to the atmospheric greenhouse effect which are collectively called greenhouse gases, or GHG. Most of the policies being designed at state, federal, and international levels propose to limit emissions of CO_2 as well as methane (CH_4), and nitrous oxide (N_2O), amongst others. Although these other gases are more potent greenhouse gases than CO_2, carbon dioxide is far more abundant and is the primary greenhouse gas emitted as a result of fossil fuel combustion. The "allowance price" is the price to emit one unit of CO_2, or more precisely, quantity of GHG equivalent to the 100-year global warming potential of one unit of CO_2. In shorthand and for simplicity, we refer to the "allowance price to emit one short ton of carbon dioxide equivalent greenhouse gas" as the "CO_2 price".

allowance prices in electricity resource planning and selection for the period 2013 to 2030.

As discussed in our earlier carbon price reports, we conclude that federal regulation of greenhouse gas emissions is certain. However, the costs of any program will be affected by important details that are still uncertain, such as the timing, goals, and design of the program that will ultimately be adopted and implemented. Therefore, it is critical to consider a reasonable range of CO_2 emissions allowance prices in resource planning to achieve decisions that are robust in an uncertain future just as resource planners normally consider a range of fuel prices. For this reason, we provide high, low and mid CO_2 allowance price forecasts.

This report discusses the specific factors and developments that we have considered in re-examining and revising the Synapse forecast of CO_2 prices for use in resource planning and selection. In general, our CO_2 price forecasts are based on:

1. Our review of the current political conditions in the U.S. concerning the issue of climate change and responses thereto;
2. The results of publicly available modeling analyses of greenhouse gas regulatory proposals in the current U.S. Congress;
3. The ranges of CO_2 prices used by utility regulatory commissions and utilities in electric resource planning;
4. Our review of the estimated costs for technological solutions to electric sector carbon emissions such as energy efficiency, renewable resources, nuclear power, and carbon capture and sequestration;
5. Our work experience and professional judgment on global climate change and electric resource planning issues.

2. NEW DEVELOPMENTS SINCE THE SPRING OF 2006

The most significant new developments since Synapse released its original CO_2 price forecasts in the spring of 2006 include the following:

Increasing Evidence of Climate Change

The Intergovernmental Panel on Climate Change (IPCC) released the IPCC Fourth Assessment Report, in 2007.[3] This report, a consensus document reflecting the views of hundreds of the world's top climate scientists, concluded in far stronger language than had any previous version that the climate of the Earth has been, and will continue to be, adversely affected by human-induced climate change. The report noted that "warming of the climate system is unequivocal", and that "Observational evidence from all continents and most oceans shows that many natural systems are being affected by regional climate changes, particularly temperature increases." The report documents increases in both surface temperature and sea level, as well as reductions in snow cover, that result directly from human activities. Finally, the report notes that "Continued GHG emissions at or above current rates would cause further warming and induce many changes in the global climate system during the 21st century that would *very likely* be larger than those observed during the 20th century."

The IPCC report, and numerous related scientific studies and reports, continue to corroborate and strengthen a consistent message: while uncertainties remain in the nature and timing of certain specific *impacts* of climate change, human-caused climate change is now established beyond any credible scientific doubt. The social and economic costs of climate change will be large and detrimental to societies all over the world, although those in less-developed regions are more likely to suffer greater damages in the short term. Importantly, the expected damages and costs associated with climate change rise with increasing levels of greenhouse gases in the atmosphere, as do the risks of crossing dangerous thresholds into cataclysmic impacts, such as the loss of the largest Antarctic glaciers and the resulting inundation of coastal regions around the world. Actions taken by governments and societies today will make an enormous difference in the ultimate economic and societal costs and dislocations associated with climate change.

Increased Political Support for Serious Government Action on Climate Change

A number of developments demonstrate growing political support for, and anticipation of, serious action by federal and state governments in the U.S. to mitigate climate change. These developments include:

- Bipartisan support for climate change legislation – Senators and representatives of both major parties support the climate change legislation introduced in the

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[3] http://www.ipcc.ch/

current Congress, and the presumptive nominees for President from both major parties also support some form of aggressive climate change legislation.

- Carbon Principles issued by three leading financial institutions – Citi, JPMorgan Chase, and Morgan Stanley developed climate change guidelines for advisors and lenders to power companies in the United States. These Principles create an approach to evaluating and addressing carbon risks in the financing of electric power projects.[4] Several other financial institutions, such as Bank of America and Credit Suisse, have adopted the Principles.
- State and Regional Actions to reduce greenhouse gas emissions – More than 30 states have developed or are developing climate change plans. Some states, like California, Montana, Oregon and Washington, have adopted explicit performance based standards regarding long-term investments in baseload generation. The California Energy Commission requires that new investments in baseload generation comply with a standard of 1,100 lbs of CO_2 per MWh. The Northeast states are implementing a regional cap on carbon emissions. States in the upper Midwest and the West are also acting regionally to address CO_2 emissions. As of Dec. 2007, 25 states had adopted Renewable Portfolio Standards that require certain percentages of energy consumption be supplied by renewable resources.
- Judicial decisions regarding greenhouse gases– In April 2007, the U.S. Supreme Court found in Massachusetts v. EPA that CO_2 is an air pollutant under the Clean Air Act.5 For this reason the EPA has statutory authority to regulate emissions of CO_2. The court found that EPA's refusal to do so or to provide a reasonable explanation of why it could not regulate was arbitrary, capricious and otherwise not in accordance with law. The Supreme Court also found that the "harms associated with climate change are serious and well recognized."
- A state court in Georgia has subsequently ruled that an air permit cannot be issued for a new coal-fired power plant without CO_2 emission limitations based on a Best Available Control Technology ("BACT") analysis.[6]
- Increasingly stringent federal legislative proposals that would require much more substantial reductions in greenhouse gas emissions than the proposals introduced in earlier sessions of Congress (see below).
- A 2007 resolution adopted by the National Association of Regulatory Utility Commissioners (NARUC) encouraged utility requirements to "assess and incorporate carbon-related risks in their planning and decision-making processes."[7]

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4 Carbon Principles adopted February 8, 2008. For more information see: http://www.carbonprinciples.com/

5 127 S. Ct. 1438 (2007)

6 *Friends of the Chattahoochie, Inc. and Sierra Club v. Dr. Carol Couch, Direct Environmental Protection Division, Georgia Department of Natural Resources and Longleaf Energy Associates*, LLC, Final Order in the Superior Court of Fulton County, State of Georgia, Docket No. 2008CV146398, issued on June 30, 2008.

7 NARUC, *Resolution on State Regulatory Policies Toward Climate Change*, adopted November 2007.

Federal Legislative Proposals

To date, the U.S. government has not required greenhouse gas emission reductions in the private sector. However, a number of legislative initiatives for 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 various details pertaining to offsets, allowance allocation, "safety valve" maximum allowance prices and other issues. The major federal proposals that would require greenhouse gas emission reductions that had been submitted in the 110th U.S. Congress are summarized in Table 1 below.

Table 1. Summary of Mandatory Emissions Targets in Proposals Discussed in the current U.S. Congress

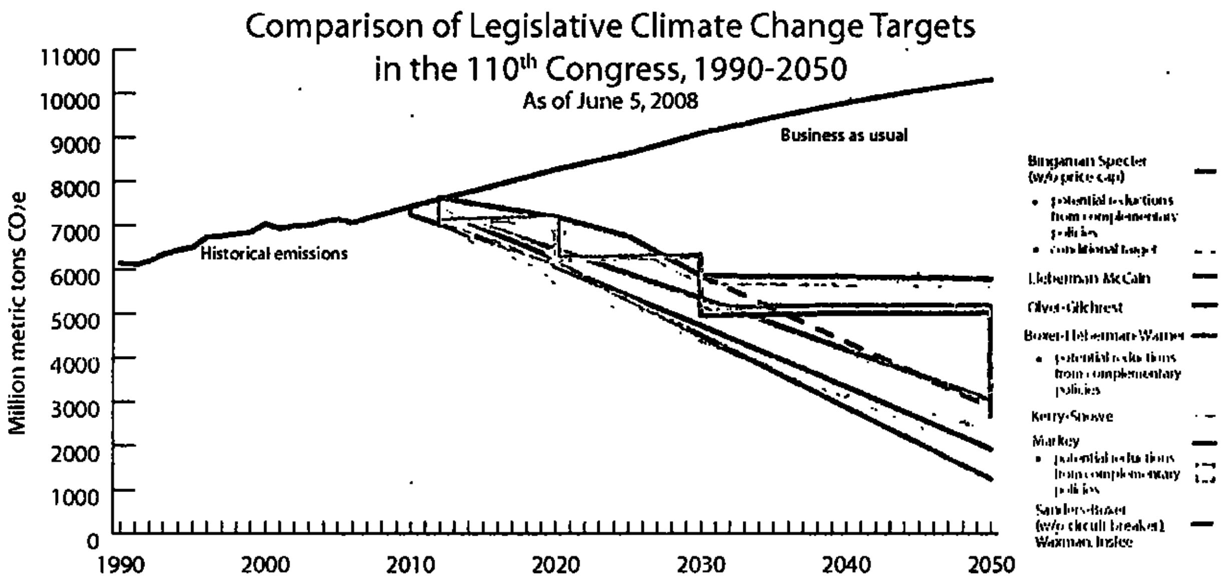
Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
Feinstein-Carper S.317	Electric Utility Cap & Trade Act	2007	▪ 2006 level by 2011 ▪ 2001 level by 2015 ▪ 1%/year reduction from 2016-2019 ▪ 1.5%/year reduction starting in 2020	Electricity sector
Kerry-Snowe S.485	Global Warming Reduction Act	2007	▪ 2010 level from 2010-2019 ▪ 1990 level from 2020-2029 ▪ 2.5%/year reductions from 2020-2029 ▪ 3.5%/year reduction from 2030-2050 ▪ 65% below 2000 level in 2050	Economy-wide
McCain-Lieberman S.280	Climate Stewardship and Innovation Act	2007	▪ 2004 level in 2012 ▪ 1990 level in 2020 ▪ 20% below 1990 level in 2030 ▪ 60% below 1990 level in 2050	Economy-wide
Sanders-Boxer S.309	Global Warming Pollution Reduction Act	2007	▪ 2%/year reduction from 2010 to 2020 ▪ 1990 level in 2020 ▪ 27% below 1990 level in 2030 ▪ 53% below 1990 level in 2040 ▪ 80% below 1990 level in 2050	Economy-wide
Olver, et al HR 620	Climate Stewardship Act	2007	▪ Cap at 2006 level by 2012 ▪ 1%/year reduction from 2013-2020 ▪ 3%/year reduction from 2021-2030 ▪ 5%/year reduction from 2031-2050 ▪ equivalent to 70% below 1990 level by 2050	US national
Bingaman–Specter S.1766	Low Carbon Economy Act	2007	▪ 2012 levels in 2012 ▪ 2006 levels in 2020 ▪ 1990 levels by 2030 ▪ President may set further goals ≥60% below 2006 levels by 2050 contingent upon international effort	Economy-wide
Lieberman-Warner S. 2191	America's Climate Security Act	2007	▪ 2005 level in 2012 ▪ 1990 level in 2020 ▪ 65% below 1990 level in 2050	U.S. electric power, transportation, and manufacturing sources.
Boxer-Lieberman-Warner S. 3036	Substitute for S. 2191	2008	▪ 4% below 2005 level in 2012 ▪ 19% below 2005 level in 2020 ▪ 71% below 2005 level in 2050	Economy-wide
Markey HR. 6186	The Investing in Climate Action and Protection Act	2008	▪ 2005 level in 2012 ▪ 20% below 2005 level by 2020 ▪ 80% below 2005 level by 2050	Economy-wide

The emissions levels that would be mandated by these bills that are shown in Figure 1 below; reproduced from a recent World Resources Institute analysis.[8]

[8] Version as of June 2008, available at http://pdf.wri.org/usclimatetargets_2008-06-18.pdf.

Each of the major legislative proposals that have been introduced in the 110th Congress would require far more substantial reductions in greenhouse gas emissions than would have been required by the proposals that had been introduced in Congress by the spring of 2006. For example, Figure 2 compares the emissions caps that would have been required by Senate Bill S. 2028 in the 109th Congress with the emissions levels that would be mandated under Senate Bills S. 2191 and S. 3036.

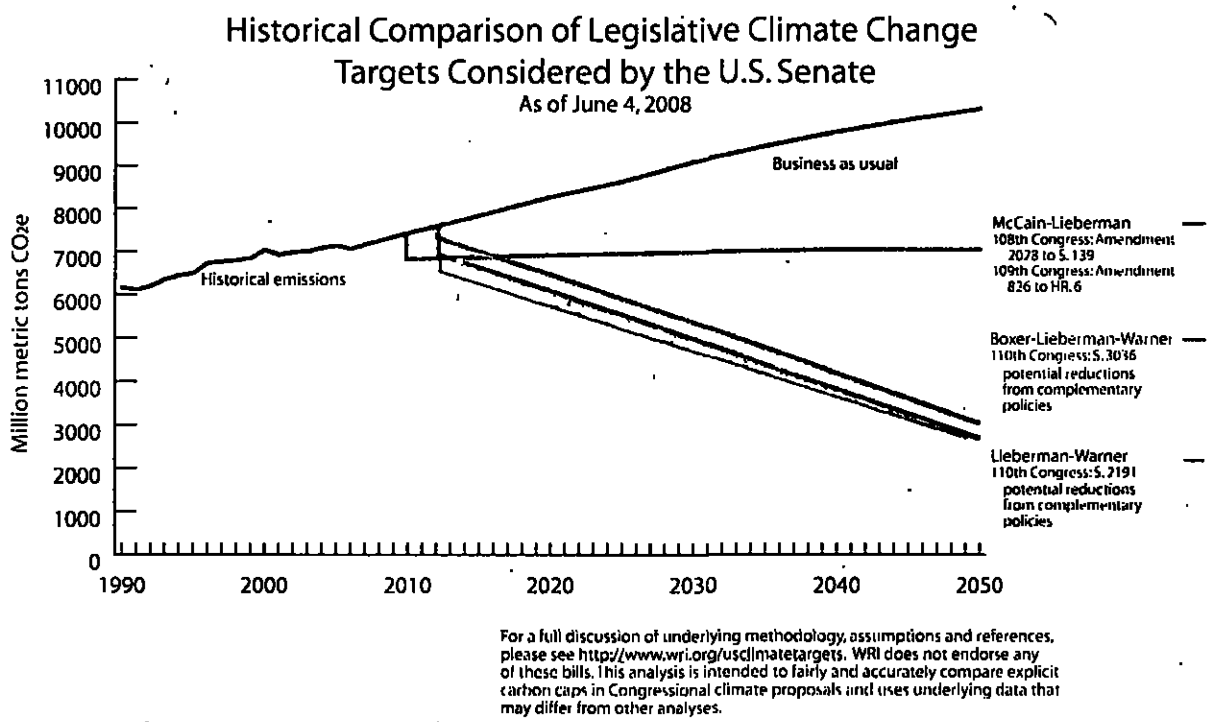
Figure 1: Comparison of Legislative Climate Change Targets in the Current 110th U.S. Congress



WORLD RESOURCES INSTITUTE

For a full discussion of underlying methodology, assumptions and references, please see http://www.wri.org/usclimatetargets. WRI does not endorse any of these bills. This analysis is intended to fairly and accurately compare explicit carbon caps in Congressional climate proposals and uses underlying data that may differ from other analyses. Price caps, circuit breakers and other cost-containment mechanisms contained in some bills may allow emissions to deviate from the pathways depicted in this analysis.

Figure 2: Historical Comparison of Legislative Climate Change Proposals in U.S. Congress



It is uncertain which, if any, of the specific climate change bills that have been introduced to date in the Congress will be adopted. The general trend is clear, however, and it would be a mistake to ignore it in long-term decisions concerning electric resources: over time the proposals in Congress are becoming more stringent as evidence of climate change accumulates and as the political support for serious governmental action grows.

3. FACTORS THAT INFLUENCE CO_2 PRICES

A large number of modeling analyses have been undertaken to evaluate the CO_2 allowance prices that would result from the major climate change bills introduced in the current Congress. It is not possible to compare the results of all of these analyses directly because the specific models and the key assumptions vary. However, the results of these analyses do provide important insights into the ranges of possible future CO_2 allowance prices under a range of potential scenarios.

These analyses included the following:

- The Energy Information Administration of the U.S. Department of Energy's ("EIA") assessment of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007* (July 2007).[9]
- The October 2007 Supplement to the EIA's assessment of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*.[10]
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007* (January 2008).[11]
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007* (April 2008).[12]
- The U.S. Environmental Protection Agency's ("EPA") *Analysis of the Climate Stewardship and Innovation Act of 2007 – S. 280 in 110th Congress* (July 2007).[13]
- The EPA's *Analysis of the Low Carbon Economy Act of 2007 – S. 1766 in 110th Congress* (January 2008).[14]
- The EPA's *Analysis of the Lieberman-Warner Climate Security Act of 2008 – S. 2191 in 110th Congress* (March 2008).[15]
- *Assessment of U.S. Cap-and-Trade Proposals* by the Joint Program at the Massachusetts Institute of Technology ("MIT") on the Science and Policy of Global Change (April 2007).[16]
- *Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act – S. 2191* by the Joint Program at MIT on the Science and Policy of Global Change (April 2008).[17]

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9 Available at http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf(2007)04.pdf.
10 Available at http://www.eia.doe.gov/oiaf/servicerpt/biv/pdf/s280_1007.pdf
11 Available at http://www.eia.doe.gov/oiaf/servicerpt/lcea/pdf/sroiaf(2007)06.pdf
12 Available at http://www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf(2008)01.pdf.
13 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
14 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
15 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
16 Available at http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt146.pdf
17 Available at http://mit.edu/globalchange/www/MITJPSPGC_Rpt146_AppendixD.pdf.

- *The Lieberman-Warner America's Climate Security Act: A Preliminary Assessment of Potential Economic Impacts, prepared by the Nicholas Institute for Environmental Policy Solutions, Duke University and RTI International,* (October 2007)[18]
- *U.S. Technology Choices, Costs and Opportunities under the Lieberman-Warner Climate Security Act: Assessing Compliance Pathways*, prepared by the International Resources Group for the Natural Resources Defense Council, *NRDC (May 2008)*[19]
- *The Lieberman-Warner Climate Security Act – S. 2191, Modeling Results from the National Energy Modeling System – Preliminary Results*, Clean Air Task Force, (January 2008).[20]
- *Economic Analysis of the Lieberman-Warner Climate Security Act of 2007 Using CRA's MRN-NEEM Model*, CRA International, (April 2008).[21]
- *Analysis of the Lieberman-Warner Climate Security Act (S. 2191) using the National Energy Modeling System (NEMS/ACCF/NAM)*, a report by the American Council for Capital Formation and the National Association of Manufacturers, NMA, (March 2008).[22]

The results of these and other analyses show that there are a number of factors that affect projections of allowance prices under federal greenhouse gas regulation. These include: the base case emissions forecast; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented, independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps international) and allowance banking; assumptions about technological progress; the presence or absence of a "safety valve" price; and emissions co-benefits.[23]

Based on our review of the more than 75 scenarios examined in the modeling analyses listed above we conclude that:

1. Other things being equal, more aggressive emissions reductions will lead to higher allowance prices than less aggressive emissions reductions.
2. Greater program flexibility decreases the expected allowance prices, while less flexibility increases prices. This flexibility can be achieved through increasing the percentage of emissions that can be offset, by allowing banking of allowances or by allowing international trading.[24]

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18 Available at http://www.nicholas.duke.edu/institute/econsummary.pdf
19 Available at http://docs.nrdc.org/globalwarming/glo_08051401A.pdf
20 Available at http://lieberman.senate.gov/documents/catflwcsa.pdf.
21 Available at http://www.nma.org/pdf/040808_crai_presentation.pdf ....
22 Available at http://www.accf.org/pdf/NAM/fullstudy031208.pdf.
23 Discussed in more detail in *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning* Synapse Energy Economics, May 2006
24 One drawback to programs with higher flexibility is that they are much more complex to administer, monitor, and verify. 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,

3. The rate of improvement in emissions mitigation technology is a crucial assumption in predicting future emissions costs. For CO_2, looming questions include the future feasibility and cost of carbon capture and sequestration, and cost improvements in integrating carbon-free generation technologies. Improvements in the efficiency of coal burning technologies and in the costs of nuclear power plants could also be a factor.

   In general, those scenarios in the modeling analyses with lesser availability of low-carbon alternatives have the higher CO_2 allowance prices. When low carbon technologies are widely available, CO_2 allowance prices tend to be lower.

4. Complementary energy policies, such as direct investments in energy efficiency or policies that foster renewable energy resources are a very effective way to reduce the demand for emissions allowances and thereby lower their market prices. A policy scenario which includes aggressive energy efficiency and/or renewable resource development along with carbon emissions limits will result in lower allowance prices than one in which these resources are not directly addressed.

5. Most technologies which reduce carbon emissions also reduce emissions of other criteria pollutants, such as NO_x, SO_2 and mercury. Adopting carbon reduction technology results not only in cost savings to the generators who no longer need criteria pollutant permits, but also in 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.

6. Projected emissions under a business-as-usual scenario (in the absence of greenhouse gas emission restrictions) have a significant bearing on projected allowance costs. The higher the projected emissions, the higher the projected cost of allowance to achieve a given reduction target.

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verifiable, permanent and enforceable." Still, there appears to be a 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 greater program flexibility are likely to predict lower compliance costs for reaching any specified goal.

4. THE SYNAPSE 2008 CO_2 ALLOWANCE PRICE FORECASTS

The Synapse 2008 CO_2 price forecasts begin in 2013. This is a reasonable assumption since it is likely that climate change legislation will be passed by the next Congress and that the implementation of the regulatory scheme may take two years.

The Synapse Low CO_2 Price Forecast starts at $10/ton[25] in 2013, in 2007 dollars, and increases to approximately $23/ton in 2030. This represents a $15/ton levelized price over the period 2013-2030, in 2007 dollars.

This Low Forecast is consistent with the coincidence of one or more of the factors discussed above that have the effect of lowering prices. For example, this price trajectory may represent a scenario in which Congress begins regulation of greenhouse gas emissions slowly by either:

1. including a very modest or loose cap, especially in the initial years,
2. including a safety valve price similar to the Technology Accelerator Payment in the current Bingaman-Specter Legislation (S. 1766), or
3. allowing for significant offset flexibility, including the use of substantial numbers of international offsets.

The factors could also include a decision by Congress to adopt a set of aggressive complementary policies as part of a package to reduce CO_2 emissions. These complementary policies could include an aggressive federal Renewable Portfolio Standard, more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario), and/or substantial energy efficiency investments. Such complementary policies would lead directly to a reduction in CO_2 emissions independent of federal cap-and-trade or carbon tax policies, and would lower the expected allowance prices associated with the achievement of any particular federally-mandated goal.

The 2008 Synapse High CO_2 Price Forecast starts at $30/ton in 2013, in 2007 dollars, and rises to approximately $68/ton in 2030. This High Forecast represents a $45/ton levelized price over the period 2013-2030, also in 2007 dollars.

This High CO_2 Price Forecast is consistent with the occurrence of one or more of the factors identified above that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets, greater restrictions on the use of offsets, some restrictions on the availability of or the high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration, and more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters).

There are some CO_2 price scenarios identified in recent analyses that are significantly higher than our Synapse High Price Forecast. These scenarios represent situations with

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[25] Throughout this paper, emission allowance prices are quoted in dollars per ton. This should be interpreted as dollars per short ton of CO_2. Prices in the economic literature and in international trading are often quoted in dollars per metric ton of CO_2 or dollars per metric ton of carbon, but the units we use are more typical of US carbon pricing schemes.

limited availability of alternatives to carbon-emitting technologies and/or limited use of international and domestic offsets. We do not believe that the CO_2 prices characteristic of such scenarios are likely in the current political environment, given that there may potentially be avenues available for meeting likely emissions goals that would mitigate the costs to below these levels. This may change over time due to changes in technical, economic, and political circumstances, more stringent CO_2 emissions targets, and/or developments in scientific evidence and of the impacts of a changing climate.

Synapse also has prepared a Mid CO_2 Price Forecast that starts close to the low case, at $15/ton in 2013 in 2007 dollars, but then climbs to $53/ton by 2030. The levelized cost of this mid CO_2 price forecast is $30/ton in 2007 dollars, which is the midpoint between the $15/ton Low CO_2 Price Forecast and the $45/ton High CO_2 Price Forecast. The Mid CO_2 price forecast represents a scenario in which CO_2 allowance prices begin rather low, perhaps reflecting the hesitance of the U.S. Congress to impose high costs in the short run, but then climb significantly over time as federal regulation of CO_2 emissions becomes progressively more stringent.

The 2008 Synapse High, Mid and Low CO_2 Price Forecasts are shown in Figure 3 and Table 2 below:

Figure 3: Synapse 2008 CO_2 Price Forecasts

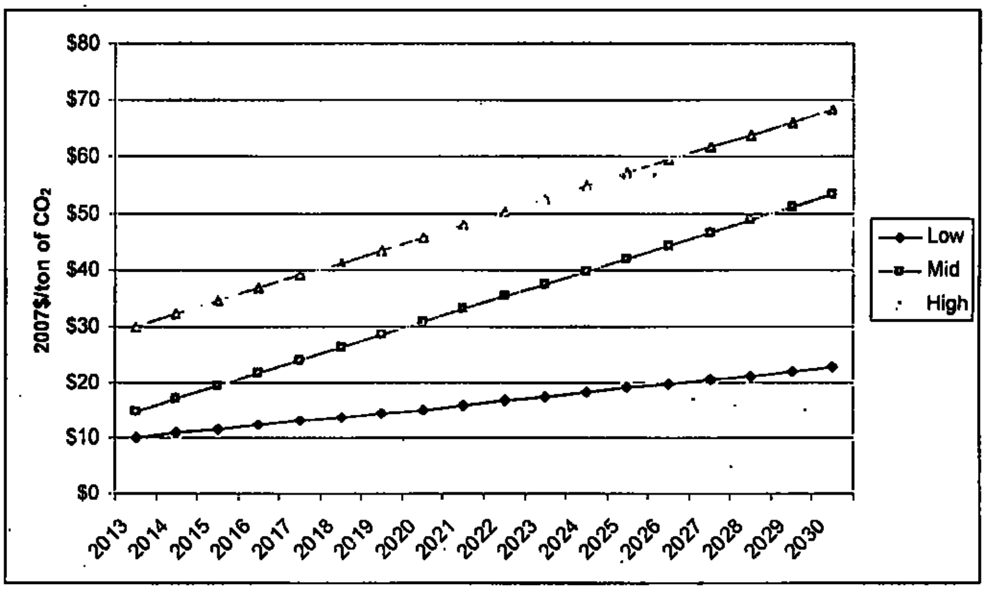

Table 2: Synapse 2008 CO_2 Price Forecasts (in 2007 dollars)

Year	Low	Mid	High
2013	$10.00	$15.00	$30.00
2014	$10.80	$17.30	$32.30
2015	$11.50	$19.50	$34.50
2016	$12.30	$21.80	$36.80
2017	$13.00	$24.00	$39.00
2018	$13.80	$26.30	$41.30
2019	$14.50	$28.50	$43.50
2020	$15.30	$30.80	$45.80
2021	$16.00	$33.10	$48.10
2022	$16.80	$35.30	$50.30
2023	$17.50	$37.60	$52.60
2024	$18.30	$39.80	$54.80
2025	$19.00	$42.10	$57.10
2026	$19.80	$44.30	$59.30
2027	$20.50	$46.60	$61.60
2028	$21.30	$48.80	$63.80
2029	$22.00	$51.10	$66.10
2030	$22.80	$53.40	$68.40

Given the significant uncertainty in the timing and design of CO_2 regulatory programs, we believe that the use of a range of CO_2 prices, such as that represented by the Synapse Low and High CO_2 Price Forecasts ($15/ton to $45/ton on a levelized basis between 2013 and 2030) is appropriate in utility resource planning.

The Synapse CO_2 price forecasts are consistent with the results of the analyses of current legislative proposals and recent forecasts by regulatory commissions and utilities. For example, Figure 4 compares the annual CO_2 prices in the Synapse Low, Mid and High Forecasts with the CO_2 prices in the scenarios examined by the EIA, EPA, MIT, and Duke University in their assessments of the proposals that have been introduced in the current U.S. Congress. The Synapse forecasts are shown in the solid red lines. A number of the analyses resulted in allowance price trajectories that were significantly higher than the Synapse forecasts. As noted earlier, however, we do not believe that the highest scenarios are realistic given the current political environment and the options available for mitigating high price impacts from carbon regulation.

Figure 4: **Synapse 2008 CO_2 Price Forecasts vs. Results of Modeling Analyses Major Bills in Current U.S. Congress – Annual CO_2 Prices (in 2007 dollars)**

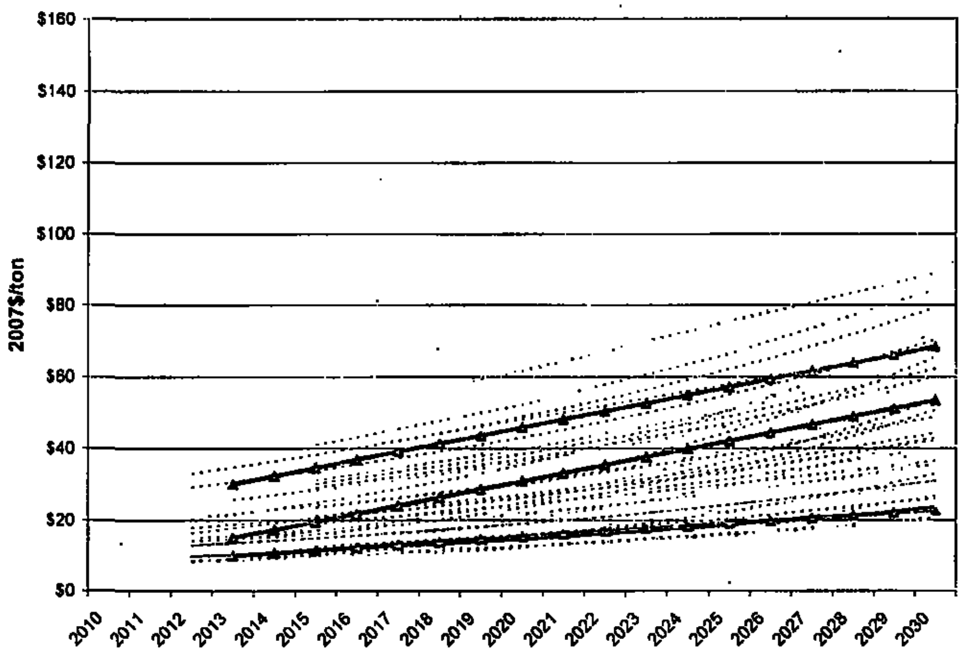

Figure 5 presents a similar comparison but in a simplified format. In Figure 5, rather than annual costs, the comparison is in terms of levelized costs for the years 2013 through 2030, also in 2007 dollars.[26] Also, in Figure 5 only the high, low, and median cases for each study are presented.

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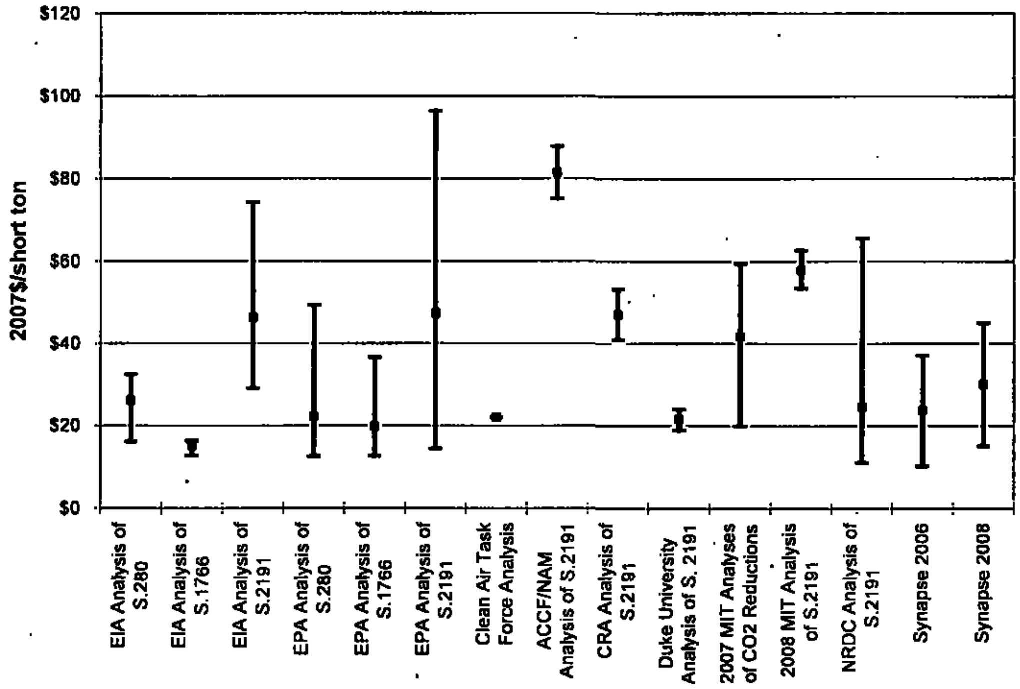
26 Synapse used a real discount rate of 7.32% for calculating levelized values. This is equivalent to 10% nominal and 2.5% inflation. We used the CPI to convert past year dollars to 2007 dollars. At the same time, we used a 2.5% inflation rate to convert future year dollars back to 2007 dollars.

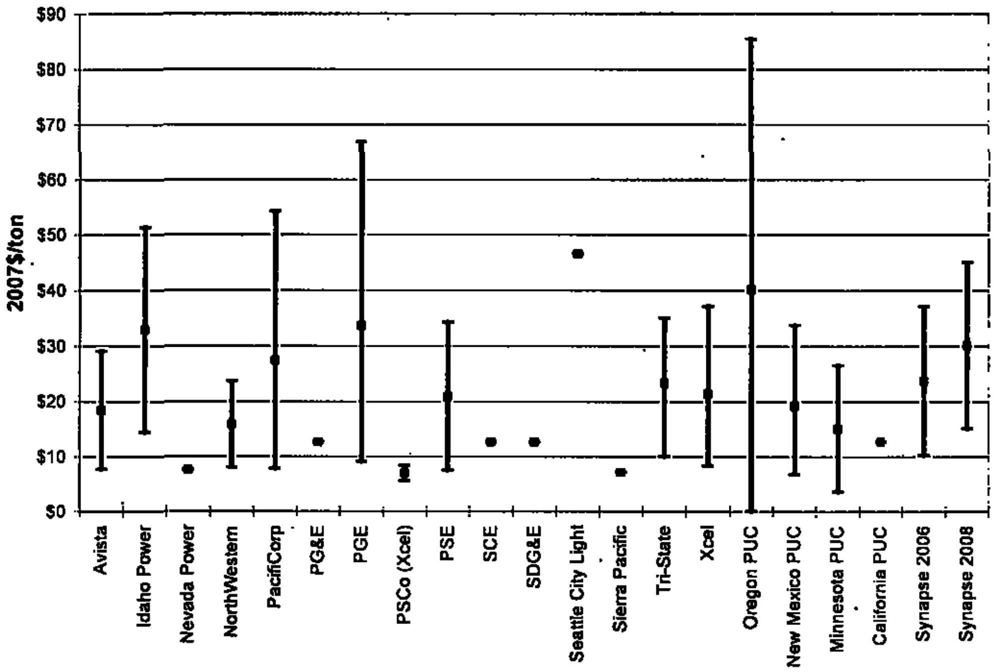
Figure 5: Synapse 2008 CO_2 Price Forecasts vs. Results of Modeling Analyses Major Bills in Current U.S. Congress – Levelized CO_2 Prices (2013-2030, in 2007 dollars)



As shown in Figure 6, the 2008 Synapse CO_2 Price Forecasts also are consistent with the ranges of CO_2 prices that an increasing number of regulatory commissions and utilities are using in electric resource planning analyses. [27]

[27] Synapse used a real discount rate of 7.32% for calculating levelized values. This is equivalent to 10% nominal and 2.5% inflation. We used the CPI to convert past year dollars to 2007 dollars. At the same time, we used a 2.5% inflation rate to convert future year dollars back to 2007 dollars.

Figure 6: Synapse 2008 CO_2 Price Forecasts vs. CO_2 Prices Used by Regulatory Commissions and Utilities in Resource Planning Analyses (2013-2030, in 2007 dollars)



5. CONCLUSION

In 2006, Synapse developed an initial forecast of CO_2 allowance prices for use in electricity resource planning. In the past two years, we have seen a number of developments that have caused us to refine our expectations for the likely emission allowance costs under federal greenhouse gas regulation. More recent legislative proposals reveal a greater understanding, in Congress and among the pubic, of climate change and the emissions reductions that will be necessary to avoid dangerous climate change. As a result, long-term emission reduction targets contained in current federal proposals are more stringent than those from prior sessions, approaching the reduction levels identified by the scientific community as necessary to avoid dangerous climate change. This trend leads us to conclude that allowance prices will be higher than we projected back in 2006.

Simultaneously, today's legislative proposals reveal a more sophisticated understanding of the advantages and value of a comprehensive approach to achieving emission reductions. These proposals incorporate complementary energy policies, such as incentives for technology innovation, funds targeted to energy efficiency, restrictions on non-CCS new coal, and/or emissions performance standards, which are likely to mitigate the cost of achieving aggressive emissions goals. Further, provisions for program flexibility and trends in technological innovation hold promise to limit the price impact in the long term. Based on all of these factors, we believe our allowance price projections for the period 2013 to 2030 represent an appropriate range of values to facilitate robust decision-making for an uncertain future, in which carbon emissions will be regulated by some as-yet undefined federal regime.

CERTIFICATE OF SERVICE

I hereby certify that the following persons have been served with the Testimony of David Schlissel (Public Version) on behalf of Environmental Defense Fund, Southern Alliance for Clean Energy, the Southern Environmental Law Center and the Sierra Club either by electronic mail or by deposit in the U.S. Mail, postage prepaid:

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This 19 day of February, 2010.

Brienne McKay

Brienne McKay

FILED
FEB 19 2010
Clerk's Office
N.C. Utilities Commission

PUBLIC VERSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

OFFICIAL COPY

In the Matter of Investigation of Integrated Resource Planning in North Carolina - 2009	)))	DOCKET NO. E-100 SUB 124

DIRECT TESTIMONY OF JOHN D. WILSON ON BEHALF OF ENVIRONMENTAL DEFENSE FUND, THE SIERRA CLUB, SOUTHERN ALLIANCE FOR CLEAN ENERGY AND THE SOUTHERN ENVIRONMENTAL LAW CENTER

PUBLIC VERSION

FEBRUARY 19, 2010

List of Exhibits

Wilson Exhibit 1	Official Resume of John D. Wilson
Wilson Exhibit 2	Net Customer Bill Savings *After* Considering Energy Efficiency Rate Impact
Wilson Exhibit 3	Comparison of Electric Rate and Efficiency Impacts, Iowa and North Carolina
Wilson Exhibit 4	Energy Efficiency Impacts Are Large in Some States Where Rates are Comparable to the Southeast
Wilson Exhibit 5	Overcoming Unique Challenges to Energy Efficiency Resources
Wilson Exhibit 6	Aggressive Energy Efficiency Programs Reduce Price Spike Risk
Wilson Exhibit 7	Utility Energy Efficiency Resources
Wilson Exhibit 8	Annual Energy Savings Implied by 24 State Energy Efficiency Targets or Mandates
Wilson Exhibit 9	Duke Energy Efficiency Program Trend and Recommended Adjustment
Wilson Exhibit 10	Home Energy Comparison Report
Wilson Exhibit 11	Building Re/Retro/Commissioning Report
Wilson Exhibit 12	Energy Recycling, Including Combined Heat and Power

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is John D. Wilson. I am Director of Research for Southern Alliance for Clean Energy ("SACE"), and my business address is 1810 16th Street, NW, 3rd Floor, Washington, DC 20009.

Q. PLEASE STATE BRIEFLY YOUR EDUCATION, BACKGROUND AND EXPERIENCE.

A. I graduated from Rice University in 1990 with a Bachelor of Arts degree in physics and history. I received a Masters in Public Policy Degree from the John F. Kennedy School of Government at Harvard University in 1992 with an emphasis in energy and environmental policy and economic and analytic methods. Since 1992, I have worked in the private, non-profit and public sectors on a wide range of public policy issues, usually related to energy, environmental and planning topics.

I became the Director of Research for SACE in 2007. I am the senior staff member responsible for our energy efficiency program advocacy, as well as being responsible for work in other program areas.

I have testified before the North Carolina Utilities Commission (Docket E-7 Sub 831) and before the South Carolina Public Service Commission (Dockets 2007-358-E and 2009-226-E). I have testified and presented before the Florida Public Service Commission (including Dockets 080407 – 080413) and presented to the Board of the Tennessee Valley Authority regarding energy efficiency and renewable energy.

I have also testified before the legislatures of Florida, North Carolina and Texas, the Texas Natural Resource Conservation Commission, and the U.S. Environmental Protection Agency on numerous occasions. I have participated in North Carolina Climate Action Plan Advisory Group and the South Carolina Climate, Energy & Commerce

Advisory Committee as an alternate for Dr. Stephen A. Smith, Executive Director of SACE. I have also served as a member of various technical work groups dealing with energy supply and efficiency issues. I have served on numerous state and local government advisory committees dealing with environmental regulation and local planning issues in Texas. I have been an invited speaker to a wide variety of academic, industry and government conferences on a number of energy, environmental and planning related topics.

A copy of my resume is attached as Wilson Exhibit 1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of SACE, Environmental Defense Fund ("EDF"), North Carolina Sierra Club ("NCSC"), and the Southern Environmental Law Center ("SELC") (collectively, the "Environmental Intervenors").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present my evaluation of the Integrated Resource Plans ("IRPs" or "resource plans") filed by Duke Energy Carolinas ("Duke ") and Progress Energy Carolinas ("Progress").[1] Specifically, I focus on whether Duke and Progress adequately incorporate energy efficiency[2] resources into their IRPs.

[1] Although the IRP of Dominion North Carolina Power ("Dominion") is also at issue in this docket, my testimony focuses on the Duke and Progress IRPs because they are the major utilities in the state.

[2] I note that throughout my testimony, I generally refer to energy efficiency as a general term encompassing demand response and energy conservation programs, as well as using the term "demand-side resources" to refer to energy efficiency as North Carolina rules require it to be considered in resource planning.

Q. WHAT IS THE BASIS FOR YOUR TESTIMONY?

A. In preparing my testimony, I evaluated the resource plans and REPS Compliance Plans reports of Duke[3] and Progress,[4] as well as those utilities' responses to data requests.[5] My review focused on the 2009 plan submissions, but also included review of material submitted for the 2008 docket to confirm my conclusions.

Q. WHAT IS THE PURPOSE OF ELECTRIC UTILITY RESOURCE PLANNING?

A. As the Commission recognized in its October 16, 2009 Order in this docket, the Integrated Resource Planning process is intended to identify the least cost electric utility resource options, consistent with adequate, reliable service and other legal obligations. In selecting resource options, utilities must consider demand-side options such as conservation, efficiency and load management, as well as supply-side resources.

Q. WHAT ARE YOUR OVERALL CONCLUSIONS?

A. North Carolina's electric utilities are offering substantial energy efficiency programs for the first time. For 2010, the utilities forecast reducing system sales by 0.3% through energy efficiency programs.

While these efforts are a good start, energy efficiency is still treated as a second-class resource by North Carolina utilities. Even as North Carolina utilities have given greater consideration to energy efficiency in selecting near-term resource options, they

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[3] The Duke Energy Carolinas Integrated Resource Plan (Annual Report) Rev 1 (Jan. 11, 2010) ("Duke IRP").

[4] Progress Energy Carolinas Integrated Resource Plan (Sept. 1, 2009) ("Progress IRP")..

[5] For comparative purposes, I also reviewed the plans or reports of Dominion North Carolina Power ("Dominion"), EnergyUnited Electric Membership Corporation ("EnergyUnited"), North Carolina Electric Membership Corporation ("NCEMC"), Haywood Electric Membership Corporation ("Haywood"), Piedmont Electric Membership Corporation ("Piedmont"), Rutherford Electric Membership Corporation ("Rutherford"), and the utilities represented by GreenCo Solutions.

are not making long-term resource decisions with full consideration of energy efficiency. The forecasts of energy efficiency during the 15-year resource planning horizon are based on a process which fails to consider potential demand-side resource options on an equivalent basis to supply-side resource options. As a result, the IRP process conducted by North Carolina utilities does not result in the "least-cost mix of resource options." In fact, utilities are only forecasting cumulative energy savings of 3.1% over the next fifteen years, which is less than the two-year goals of some leading utilities.

North Carolina utilities should evaluate demand-side resources on an equivalent basis to supply-side resources, considering a comprehensive set of options and evaluating them in a systematic basis, particularly over the long term.

Q. PLEASE DESCRIBE THE INTEGRATED RESOURCE PLANNING REQUIREMENTS IN NORTH CAROLINA RELATED TO ENERGY EFFICIENCY.

A. N.C. Gen. Stat. § 62-2(3a) establishes a state policy that utility resources include "use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs." The statute also requires energy planning to result in "the least cost mix of generation and demand-reduction measures which is achievable . . . ." Consistent with this policy, the Commission is required to "develop, publicize and keep current an analysis of the long-range needs" for electricity in the state, and to consider this analysis in ruling upon an application for construction of a new power plant. N.C. Gen. Stat. § 62-110.1.

Commission Rule R8-60 requires each utility to file a biennial report of its integrated resource planning process, with updates filed in the off years. Commission Rules R8-60 and R8-61 provide a framework for the evaluation of energy efficiency in each utility's IRP.

- Rule R8-60(c)(1) requires each utility to offer a 15-year forecast of demand-side resources.
- Rule R8-60(c)(2) and (f) requires each utility to conduct a "comprehensive analysis" of demand-side resource options. Rule R8-60(i)(6) further requires each utility to "provide the results of its overall assessment of existing and potential demand-side management programs, including a descriptive summary of each analysis performed or used by the utility in the assessment" as well as "general information on any changes to the methods and assumptions used in the assessment . . ." Among the specific requirements of this rule is the direction to discuss programs "evaluated but rejected" by the utility.
- Rule R8-60(g) requires each utility to "consider and compare . . . both demand-side and supply side [resource options] to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options and combinations of resource options to serve its system needs." Rule R8-60(i)(8) requires the utility to describe and summarize "its analyses of potential resource options and combinations of resource options performed by it . . . to determine its integrated resource plan."

Commission Rule R8-67 requires a REPS compliance plan and compliance report to be filed with the utility's IRP.

I. Overview of Energy Efficiency Benefits and Role in Resource Planning

Q. PLEASE DESCRIBE THE BENEFITS OF ENERGY EFFICIENCY PROGRAMS.

A. Utility-led energy efficiency programs are the least-cost energy resource from a system perspective. Unlike supply-side resources, addressing system needs with energy efficiency resources provide net utility bill reductions to consumers.

Energy efficiency provides both energy-related and capacity-related benefits. The *National Action Plan for Energy Efficiency* ("NAPEE"),[6] a consensus report of leading regulatory, utility and advocacy experts, reports that the benefits of energy efficiency also include environmental quality improvements (particularly air quality, water supply and reductions in greenhouse gas emissions), energy market price reductions (e.g., lower wholesale costs of natural gas), lower portfolio risk (a hedging or insurance value against price spikes), local and in-state economic development and jobs, and low-income population assistance.

A recent report summarizes the benefits of energy efficiency well:

> Energy efficiency offers a vast, low-cost energy resource for the U.S. economy – but only if the nation can craft a comprehensive and innovative approach to unlock it . . . If executed at scale, a holistic approach would yield gross energy savings worth more than $1.2 trillion, well above the $520 billion needed through 2020 for upfront investment in efficiency measures . . . Such a program is estimated to reduce end-use energy consumption in 2020 by 9.1 quadrillion BTUs, roughly 23 percent of projected demand, potential abating up to 1.1 gigatons of greenhouse gases annually.[7]

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[6] *National Action Plan for Energy Efficiency,* US Department of Energy and Environmental Protection Agency (July 2006).

[7] McKinsey & Company, *Unlocking Energy Efficiency in the U.S. Economy*, July 2009.

Each of these numbers tells a rich story in itself. Saving the national economy $1.2 trillion frees up capital and gives greater budget flexibility to ratepayers. If we fail to pursue available savings aggressively, we will instead build expensive, unnecessary power plants. Efficiency also helps reduce the impact of energy price spikes on the bottom line or family budget – a tool that helps prevent account defaults and even business closures.

Spending $520 billion to achieve those savings will also create jobs. Today, nearly 2 million jobs are "supported by efficiency-related investments," according to a study by the American Council for an Energy-Efficient Economy ("ACEEE").[8]

The prospect of using cost-effective energy efficiency measures to cut electricity demand by 23 percent represents a transformative opportunity. Those states and utilities leading the country with strong programs are experiencing fundamental shifts in load growth and characteristics.[9]

Finally, energy efficiency's potential to abate up to 1.1 gigatons of greenhouse gases annually will allow utilities and their customers to avoid the very significant cost of compliance with impending greenhouse gas regulations. The North Carolina Climate Action Plan Advisory Group found that energy efficiency programs at a "top ten states" investment level would reduce North Carolina greenhouse gas emissions by 12 million

[8] Ehrhardt-Martinez, K. and J.A. Laitner, "The Size of the U.S. Energy Efficiency Market," American Council for an Energy-Efficient Economy, Report E083, May 2008.

[9] Kushler, M., et al., "Meeting Aggressive New State Goals for Utility-Sector Energy Efficiency: Examining Key Factors Associated with High Savings," American Council for an Energy-Efficient Economy, Report U091, March 2009.

metric tons in 2020, accounting for roughly 10% of all potential mitigation measure savings.[10]

Q. DOES ENERGY EFFICIENCY REDUCE CUSTOMER ENERGY BILLS?

A. Yes. A frequent, but misplaced, criticism about energy efficiency programs is that they have an adverse effect on some or even all customers. In fact, historical evidence and utility rate simulations show precisely the opposite – that customer energy bills are reduced over the long term by aggressive energy efficiency programs. ***Customer savings occur even though rates may increase slightly, even at aggressive levels of energy efficiency***, as demonstrated in a recent study by Lawrence Berkeley National Laboratory ("LBNL").[11] In Wilson Exhibit 2, I have summarized LBNL's findings relating rate increases of less than ½ cent per kilowatt hour to ***net customer bill savings of up to 6%***.

State program impacts also demonstrate that energy efficiency programs do not automatically drive rates upward. This is illustrated in Wilson Exhibit 3, a comparison of rate and energy efficiency trends of Iowa to North Carolina.

Q. HOW DOES NORTH CAROLINA COMPARE TO OTHER STATES ON ENERGY EFFICIENCY?

A. North Carolina trails far behind the top-performing states. According to "The 2009 State Energy Efficiency Scorecard," North Carolina ranks 26th overall on energy efficiency and 26th on its utility and public benefits programs and policies. In 2007, North Carolina's annual savings from energy efficiency programs were 40th in the country, less than 0.01%

[10] North Carolina Climate Action Plan Advisory Group, "Recommended Mitigation Options for Controlling Greenhouse Gas Emissions," North Carolina Department of Environment and Natural Resources, October 2008.

[11] Cappers et al., "*Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility*," LBNL-1598E, March 2009.

of retail sales.[12] To put this in perspective, LBNL estimated that energy efficiency programs resulted in savings equivalent to 0.34% of total national retail electricity sales in 2008, an average dragged down due to about half of the states (including North Carolina) reporting insignificant energy savings.[13] North Carolina can and should do better.

Q. ARE STATES WITH LEADING ENERGY EFFICIENCY PROGRAMS THOSE WITH HIGH ELECTRIC RATES?

A. No, several states with electricity rates comparable to, even lower than, North Carolina have demonstrated much higher rates of energy savings. This is illustrated in Wilson Exhibit 4, which presents a comparison of average state electricity rates to annual energy savings reported by energy efficiency programs. Low electricity rates are simply ***not*** a barrier to investment in energy efficiency.

An ACEEE report reached the same conclusion: although the relationship between higher rates and higher energy efficiency savings is "intuitively logical," the actual "magnitude of the relationship is slight."[14] While low rates are not a barrier to energy efficiency, Wilson Exhibit 5 describes a number of well-recognized barriers that must be addressed through sound policies and best practice program design.

Q. WHAT IS NEEDED TO PROVIDE THE BENEFITS OF ENERGY EFFICIENCY TO CUSTOMERS IN NORTH CAROLINA?

A. The NAPEE report, a widely accepted strategy to take action on energy efficiency, makes the following five recommendations:

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[12] American Council for an Energy-Efficient Economy (ACEEE), "The 2009 State Energy Efficiency Scorecard," Report Number E097, October 2009.

[13] Barbose, G., C. Goldman and J. Schlegel, "The Shifting Landscape of Ratepayer-Funded Energy Efficiency in the U.S.," Lawrence Berkeley National Laboratory, LBNL-2258E, October 2009.

[14] Kushler (2009).

1. Recognize energy efficiency as a high-priority energy resource.
2. Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.
3. Broadly communicate the benefits of and opportunities for energy efficiency.
4. Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.
5. Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.

The NAPEE report identified two challenges to incorporating energy efficiency into resource planning: "determining the value of energy efficiency in the resource planning," and "setting energy efficiency targets and allocating budgets, which are guided by resource planning, as well as regulatory and policy decisions."

Q. ARE NORTH CAROLINA UTILITIES EFFECTIVELY IMPLEMENTING THE NAPEE RECOMMENDATIONS ?

A. Duke and Progress are investing in energy efficiency at meaningful levels in the near-term, and all three investor-owned utilities have committed to sustain meaningful energy efficiency programs. With these large-scale utility efficiency programs, North Carolina is stepping forward as the energy efficiency leader in the Southeast.

Nevertheless, energy efficiency remains confined to a second-class status in the Duke and Progress resource plans. The IRPs neither "recognize energy efficiency as a high-priority energy resource" nor have they made "a strong, long-term commitment to implement cost-effective energy efficiency as a resource." Duke and Progress must improve their resource planning practices to fulfill the NAPEE recommendations.

On a more positive note, recent decisions by the Commission to approve new rate structures for Duke and Progress are consistent with the NAPEE recommendations to "promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective" and to "align utility incentives with the delivery of cost-effective energy efficiency and modify[ing] ratemaking practices to promote energy efficiency investments."[15]

Q. HOW SHOULD THE BENEFITS OF ENERGY EFFICIENCY BE REFLECTED IN RESOURCE PLANNING?

A. Utilities and states use a variety of methods to ensure that the benefits of energy efficiency are reflected in the resource planning process. As the NAPEE report points out, there are "no standard approaches on how to appropriately quantify and incorporate [the] benefits [of energy efficiency] into utility resource planning." One challenge to standardization is that some planners consider only the simplest energy and capacity related benefits of energy efficiency, while others consider a wider range of benefits, such as those summarized from the NAPEE report earlier in my testimony.

The role of energy efficiency in a utility resource plan is often quantified through either a performance targets or a program budget. North Carolina rules call for these targets or budgets to be established in a least-cost integrated resource planning process, with further consideration in other regulatory proceedings. Alternatives to use of a resource planning process to establish energy efficiency targets or budgets include public

[15] With the exception of non-intervenor NCSC, the organizations that I am testifying on behalf of supported the approved Duke Energy save-a-watt cost recovery mechanism. However, we opposed the lack of a performance-based incentive mechanism and the overall incentive level in the approved Progress Energy cost recovery mechanism.

goods funding budgets, market-based resource allocation, and resource loading order considerations.

Some states use public goods-funded charges to deliver energy efficiency, through either a utility or, more often, a third party administrator. Changes in funding levels are the primary drivers of program impact, and the forecast impacts of this spending are reflected in the resource plans of utilities as an input.

Another approach is to evaluate energy efficiency as a market resource rather than using a cost-effectiveness test approach. This can be quite literal, in the sense that the deregulated New England region includes demand-side resources in an annual capacity "market." A market resource approach to energy efficiency requires a rigorous evaluation, measurement and verification process.[16] Or it may be a portfolio modeling exercise, such as that used in the Pacific Northwest, in which supply-and-demand-side resources compete with each other in an optimization model that both allocates and schedules resources to reduce both energy cost and energy price risk.[17]

Placing energy efficiency programs first in the "loading order" is another alternative. California's principal energy agencies adopted a loading order in the *2003 Energy Action Plan* as a foundation for policies and decisions. The "loading order calls for (1) decreasing electricity consumption by increasing energy efficiency and conservation, (2) reducing demand during peak periods through demand response and (3) meeting new generation needs first with renewable and distributed generation and then

[16] ISO New England Inc., "ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources Manual M-MVDR," October 1, 2007.

[17] Northwest Power and Conservation Council, "Chapter 9: Developing a Resource Strategy," *Sixth Northwest Power Plan*, January 2010.

with clean fossil-fueled generation." This approach has turned out to be quite successful due to strong regulatory oversight.

While it is not a "loading order" in the sense used in California, Commission Rule R8-61(b)(13) requires utilities to demonstrate that energy efficiency measures and other resources "would not establish or maintain a more cost-effective and reliable generation system" prior to being certified to construct a generating facility. Rather, the practice in North Carolina is to look to the resource plan for evidence that alternatives to new generation have already been considered and rejected in a methodical process. For this reason, it is critical for North Carolina to ensure that a comprehensive analysis of energy efficiency resource opportunities is a foundation for a least cost strategy to provide reliable electric utility service.

The diversity of policies that are used to reflect the benefits of energy efficiency in resource planning is a result of the substantial differences between demand-side and supply-side energy efficiency resources, as described in Wilson Exhibit 5.

Q. PLEASE DESCRIBE HOW ENERGY EFFICIENCY SHOULD BE INCORPORATED INTO A LEAST COST INTEGRATED RESOURCE PLANNING PROCESS.

A. There are two common approaches to ensure that energy efficiency is fully utilized in a least cost integrated resource planning process. States or utilities may either determine the potential for energy efficiency in a utility's service territory, or they may set a performance target, which may be revisited based on experience.

In many circumstances, a "bottom-up" efficiency potential study is the basis for determining how much energy efficiency should be included in resource plans. Often, this process is a result of a utility or state authority policy to achieve "all cost-effective energy efficiency." Iowa, Colorado, California and Florida are among the states that use this approach. This is also the approach favored by NAPEE in its "Guide to Resource Planning with Energy Efficiency," (November 2007). Another approach to setting an energy efficiency target is to rely on industry experience to set energy efficiency goals. The Tennessee Valley Authority and Minnesota are examples of this approach. After energy efficiency goals are established, either by administrative direction or through legislation. a detailed efficiency study is typically commissioned. However, this study may differ from a "potential study" because of a strong focus on program scope, scale and design rather than on identifying a total potential.[18]

Q. WHAT ADDITIONAL BENEFITS COULD IMPROVED PLANNING PRACTICES OFFER?

A. Beyond long-term cost savings, an additional benefit of energy efficiency is a reduction in the risk of rate spikes driven by factors such as fuel costs, extreme weather events, or demand growth. Energy efficiency is a resource that delivers energy savings benefits to customers under virtually any scenario; while the benefits vary somewhat among different "futures" that may be studied, even if benefits are not twice the cost (a typical utility program estimate), the benefits still outweigh the costs. In contrast, an idled or underutilized power plant is a cost to the system that benefits no one.

Northwest Power and Conservation Council, the planning body for the Bonneville Power Administration, explicitly considers the "insurance" or "hedging" value of risk reduction due to energy efficiency in its formal planning process. The results of this

[18] Neither a potential study nor industry experience can provide a precise measure of "cost-effective energy efficiency" in the same way that a supply-side generation plan can anticipate generation capacity with reasonable accuracy. These methods may either under- or overstate the potential for energy efficiency to meet system resource needs in much the same way that a system load forecast is unable to provide an accurate prediction of future energy demand and use.

analysis are illustrated in Wilson Exhibit 6, an annotated version of a figure produced for the council's fifth plan.

The council has recently released the "Sixth Northwest Power Plan." The plan ***"seeks an electrical resource strategy that minimizes the expected cost and risk of the regional power system over the next 20 years. Across multiple scenarios considered in the development of the Sixth Power plan, one conclusion was constant: the most cost-effective and least risky resource for the region is improved efficiency of electricity use."***[19]

North Carolina utilities have not adopted resource planning practices that quantify the risk and cost implications of different choices. The current practice of using scenarios and sensitivities does provide some directional guidance on these topics; however, as some utilities are using only two resource options for energy efficiency (existing programs vs. no programs), it is not realistic to expect those analytic methods to offer even a directional estimate of the price spike risk of different resource mixes.

II. <u>Adequacy of 15-year Demand-Side Resource Forecast</u>

Q. PLEASE SUMMARIZE THE 15-YEAR FORECAST OF DEMAND-SIDE RESOURCES EXPECTED TO CONTRIBUTE TOWARDS SATISFACTION OF NATIVE LOAD REQUIREMENTS FOR EACH UTILITY.

A. As described earlier in my testimony, each utility is required to provide a 15-year forecast of demand-side resources which are expected to contribute towards satisfaction of native load requirements for each utility. A summary of demand-side resource plan data from seven North Carolina utilities is presented in Wilson Exhibit 7. I have included four

[19] Northwest Power and Conservation Council, *Sixth Northwest Power Plan*, pre-publication version, February 10, 2010.

cooperatives in addition to the three investor-owned utilities in this exhibit for comparative purposes.

For each utility, I calculated the forecast energy and capacity savings due to energy efficiency programs and summarized those results in terms of the percent impact.[20] I have also calculated a North Carolina total, weighted by in-state energy use for each investor-owned utility. In 2015, for example, forecast energy savings are 1.8% of annual energy, and forecast capacity savings are 6.9% of load.[21] However, after 2015, forecast energy efficiency program growth rates decline. This disturbing trend is one reason that I do not believe North Carolina utilities have demonstrated "a strong, long-term commitment to implement cost-effective energy efficiency as a resource," as recommended in the NAPEE report.

In comparison, at least twenty-three states have established targets, mandates or other forms of energy efficiency goals that exceed those indicated in the utility resource plans. As illustrated in Wilson Exhibit 8, North Carolina's forecast energy savings of 0.3% per year over the next decade is among the lowest in the country.

Q. HAS DUKE PROVIDED AN ADEQUATE AND ACCURATE 15-YEAR FORECAST OF PROGRAM IMPACTS?

A. In general, Duke's demand-side resource forecast demonstrates its commitment to ramp up its energy efficiency offerings in the Carolinas to levels that will make it a leader in the industry. The "High Case" included in Duke's resource plan is a reasonable

[20] In my evaluation of each utility, I have limited the peak load analysis to the summer peak. In some instances, the summer peak is less than the winter peak but limiting the analysis to summer peak provides a consistent framework in which to compare utilities.

[21] This result, incidentally, reflects the higher degree of utility interest in peak reduction than in energy savings, in spite of recent Commission action to authorize lost revenue recovery mechanisms.

representation of its commitments and aspirational goals included in the "modified save-a-watt" proposal approved by the Commission in Docket E-7, Sub 831.

However, there are two problems with Duke's forecast. First, the IRP includes descriptions of each program, but it does not describe the capacity, energy, number of customers and other required information for each program over the 15-year period. This information is likely available in other dockets, but not necessarily in a manner that corresponds to the assumptions used to develop this resource plan.

Second, there are important technical defects in the Duke forecast. Both the "Base Case" and the "High Case" appear to have been developed in a manner that does not reflect the program design principles and intent of the approved programs. I have calculated the annual incremental impact of Duke's forecast energy efficiency programs and presented those data in Figure 9A of Wilson Exhibit 9.

In the "Base Case," the annual program impacts peak in 2012, 2016 and 2020. It appears that this irregular trend in program development is due to the method by which the conservation impacts were assumed. According to Duke Witness McMurry, "The projected load impacts from the conservation programs were based upon three bundles of the save-a-watt portfolio of programs. This was accomplished by allowing a new bundle to enter every four years." McMurry Direct Testimony at 15. Each "new bundle" represents what amounts to an effective "restart" of program development. In my opinion, Duke's use of the "new bundle" approach understates the likely impact of its energy efficiency programs.

The trend illustrated for the "High Case" also illustrates an irregular, albeit less severe, pattern. There is a two-year dip in 2013-14, and an irregular increase in 2021.

In order to illustrate a more typical straight-line forecast of program development, I have created adjusted "base" and "high" cases as illustrated by the dashed lines in Figure 9A of Wilson Exhibit 9. I believe my adjusted cases are a more accurate forecast of energy savings from Duke's programs because there is no reason to believe that program performance will suddenly drop off and then pick back up on a four-year cycle. The adjustments I suggest smooth out the irregularities in the forecast program impacts without assuming a different level of effort.

In Table 9B of Wilson Exhibit 9, I provide the cumulative energy efficiency program impacts associated with Duke's cases and the adjusted cases. By 2024, the adjusted base case represents an increase of 73% over the Duke Energy base case. However, the adjustment for the high case represents an increase of only 5%.

Even with these adjustments, the high case falls slightly short of Duke's goals for its modified save-a-watt programs. Meeting the targets set out in the agreement approved by the Commission would result in about 6,784 GWh of energy savings by 2020, which is about 776 GWh more than the "High Case" as adjusted above.

It is not necessarily the case that Duke's resource plan should assume full achievement of the performance target established in the approved save-a-watt financial mechanism. As I discussed earlier in my testimony, the actual capacity of a demand-side resource is only discovered through effective program execution. Yet it should be noted that a resource plan which directs investment to energy efficiency should not also direct investment to supply-side resources to meet the same forecast energy demand. To the extent that Duke is uncertain that it will achieve its targets, its alternative plans should have a resource delivery schedule that is consistent with updated efficiency program impact forecasts.

Q. WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE REGARDING DUKE'S FORECAST OF PROGRAM IMPACTS?

A. I recommend that Duke should revise its resource plan to reflect a consistent trend in energy efficiency program growth consistent with available energy efficiency potential and opportunities for reasonable program growth. With these adjustments, I believe that the Duke resource plan would adequately reflect the terms of the approved save-a-watt program.

Q. HAS PROGRESS ENERGY PROVIDED AN ADEQUATE AND ACCURATE 15-YEAR FORECAST OF PROGRAM IMPACTS?

A. In general, the Progress resource plan provides a useful description of its energy efficiency offerings in the Carolinas. However, there are two problems with Progress's forecast.

First, as in Duke's plan, the Progress IRP includes descriptions of each program, but it does not describe the capacity, energy, number of customers and other required information for each program over the 15-year period. Second, the Progress plan includes confusing or inconsistent data describing the capacity and energy impacts of its demand-side resource forecast. According to Table 1 of the resource plan, Progress forecasts a system summer peak load of 12,731 MW without DSM and 12,230 MW with DSM in 2010. Thus, Table 1 suggests demand-side resources contribute a total of 501 MW in 2010.

According to the table on page E-5 of the Progress resource plan, new programs are expected to contribute 150 MW to meeting system summer peak demand in 2010.

According to the table on page E-8, existing demand-side resources contributed 883 MW (not specified as to summer or winter peak) in 2008. Based on the data in Table 1, however, it appears that Progress has only accounted for 351 MW of existing demand-side resources for 2010. The contribution of existing demand-side resources to summer system peak demand grows slightly to 360 MW, 366 MW and 373 MW in 2015, 2020, and 2024 respectively.

For this reason, I conclude that Appendix E is not clearly reconciled with Table 1 in presentation of demand-side resources.

I made certain assumptions regarding the data presented by Progress in order to estimate the total impact of energy efficiency programs on the Progress forecast. I assumed that the forecast of annual system energy in Table 1 is the "with" energy efficiency forecast. To calculate the "without" forecast, I adjusted this estimate using the energy savings forecast for new programs and the single-point estimate of energy savings attributed to one existing energy savings, as presented in Appendix E.

I was unable to be certain that my calculations are accurate for three reasons. First, although Appendix E specifies that the energy savings are forecast "at generator" for new programs, it is not clear whether these savings are directly comparable to the annual system energy as presented in Table 1. Second, I have assumed 100% of 2008 energy savings for the 2007 CFL Buy-Down Pilot in 2010 and 2015, then no energy savings thereafter. A better approach would be to use a program-specific forecast. Third, any other reasons that capacity forecasts in Appendix E are not reconciled with Table 1 likely apply to system energy forecasts as well.

Q. WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE REGARDING PROGRESS'S FORECAST OF PROGRAM IMPACTS?

A. I recommend that Progress should revise its resource plan to provide a clear "with" and "without" energy efficiency forecast that reconciles the information in Appendix E with Table 1.

Q. YOU MENTIONED THAT YOU REVIEWED THE DOMINION IRP FOR COMPARATIVE PURPOSES. DO YOU HAVE ANY COMMENTS ON DOMINION'S 15-YEAR FORECAST OF PROGRAM IMPACTS?

A. Yes. Dominion has not proposed to offer new demand-side resource programs in North Carolina. Its demand-side resource forecast is based on programs filed in Virginia on July 28, 2009 (over six months ago) and Dominion indicates that it "plans to file for NCUC approval of a portfolio of energy efficiency programs at the appropriate time." Dominion should file its proposed programs expeditiously so that its North Carolina customers may have access to the opportunity to save energy and lower their electric bills as early as practicable.

In general, the Dominion demand-side resource plan provides a useful description of energy efficiency programs it hopes to offer in Virginia and North Carolina. However, there are two problems with Dominion's forecast.

First, as with the Duke and Progress IRPs, although the Dominion resource plan includes descriptions and cost-effectiveness estimates for each program that it has proposed in Virginia, it does not describe the capacity, energy, number of customers and other required information for each program over the 15-year period, other than what appears to be cumulative impacts in 2024. This information is likely available in its Virginia program plans, but not necessarily in a manner that corresponds to the assumptions used to develop this resource plan.

Second, its demand-side resource plan appears to include a program that appears to be a supply-side resource program. Dominion's proposed Commercial Distributed Generation Program provides for customers to enroll with a contractor to install a generator on customer property that may be dispatched by Dominion for up to 120 hours of dispatch during the year. The proposed distributed generation program described by Dominion is more properly characterized as a supply-side resource since the contractor will be providing the resource as either "owned/leased generation capacity" or "firm purchased power arrangements," as described in Rule R8-60(c)(1).

Q. WHAT RECOMMENDATIONS DO YOU HAVE TO CORRECT SYSTEMATIC DEFICIENCIES IN THE UTILITIES' 15-YEAR FORECASTS OF ENERGY EFFICIENCY PROGRAM IMPACTS?

A. I recommend that the Commission direct the investor-owned utilities to describe the capacity, energy, number of customers and other required information for each program over the 15-year period. These elements of the annual plans and reports are described in Commission Rule R8-60(c)(1), (h) and (i). I found only a few, partial instances where these data were provided in the resource plans of the investor-owned utilities.

Descriptive data for demand-side resources are important in order for the Commission to determine whether demand-side resources are considered on an equal basis with supply-side resources. For example, Rule R8-60(i)(6)(i) and (ii) require each utility to provide "information for each resource" for "demand-side programs." This is similar to the language in Rule R8-60(i)(2)(i) and (ii) that requires each utility to provide data for "each listed unit" and "each listed generation addition."

In contrast to the full and orderly data describing existing and planned supply-side resources required by Rule R8-60, existing and planned demand-side resources are incompletely described and what data are made available are fragmentary and inconsistently treated. In addition to giving second-class treatment to demand-side resources, it is impossible to determine from these resource plans if they were developed using reasonable and internally consistent practices.

III. Adequacy of Analysis of Demand-Side Resource Options

Q. DID DUKE AND PROGRESS RELY UPON A COMPREHENSIVE ANALYSIS OF DEMAND-SIDE RESOURCE OPTIONS IN DEVELOPING THEIR RESOURCE PLANS?

A. No. Neither Duke nor Progress has performed a comprehensive analysis of demand-side resource options. Although Duke and Progress have each conducted some analysis of demand-side resource options, these analyses vary in their adequacy. Neither utility has performed a comprehensive energy efficiency potential study, as discussed earlier in my testimony. Notably, the entire analysis conducted by Progress is being treated as confidential and is not even mentioned in its resource plan.

Q. PLEASE DESCRIBE YOUR REVIEW OF THE DUKE AND PROGRESS ANALYSES OF DSM OPTIONS.

A. I reviewed each utility's plans and reports to determine whether they evaluated demand-side resource options as thoroughly as Rule R8-60(g) requires, while recognizing that the rule does not prescribe any single evaluation method. I expected to find that each utility clearly explained and justified its methods and assumptions, included a comprehensive scope of study, and had results that were either consistent with the results of similar studies for other states or utilities, or included an explanation of unusual circumstances that resulted in distinctive findings.

Q. HOW CAN YOU TELL WHETHER A UTILITY'S SCOPE OF STUDY IS COMPREHENSIVE?

A. There are several indicators of a comprehensive scope of study. One simple indicator is the number of efficiency measures considered.[22] For example, the study completed for Duke by Forefront Economics, Inc. ("Forefront"),[23] while a useful indication of energy efficiency opportunities, covers only 40 residential and 31 non-residential efficiency measures. In contrast, a recent assessment of energy efficiency potential for Florida (including Progress Energy Florida and six other utilities) included 276 unique measures: 70 residential, 92 commercial and 114 industrial measures.[24]

Another indicator is the degree to which all key areas of energy use are represented in the findings. For example, some efficiency studies have failed to consider energy savings opportunities from outdoor and street lighting, traffic signal, wastewater utility, and water supply utility end-use sectors, even though there are widely used energy efficiency measures applicable to these sectors.

Q. IS A NON-COMPREHENSIVE ENERGY EFFICIENCY STUDY ADEQUATE?

A. No, a non-comprehensive energy efficiency potential study can result in a substantial underestimate of energy efficiency potential. To demonstrate this point, I conducted a comparative analysis of the residential energy efficiency potential from three studies conducted for North Carolina: the 2007 Forefront study for Duke, a study by Appalachian State University ("ASU"), and a study by GDS Associates for this Commission. I adjusted the ASU and GDS study findings to correspond to the energy use

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[22] It should be noted that while they are a useful indicator, measure counts may be misleading, since some may be overlapping technologies (e.g., LED and CFL lighting options).

[23] Forefront Economics, Inc., H. Gil Peach & Associates LLC, and PA Consulting Group, "Duke Energy Carolinas DSM Action Plan: North Carolina Report," prepared for Duke Energy Carolinas (August 2007) (hereinafter the "Forefront Study").

[24] Itron, Inc., "Technical Potential for Electric Energy and Peak Demand Savings in Florida," March 12, 2009.

of residential customers served by Duke in order to ensure that the comparison was on an equal scale.[25]

The similarity in the three studies' findings is striking at first glance. Forefront found 5,500 GWh potential at 6 c/kWh by 2026, GDS found 4,805 GWh potential at 5 c/kWh, and ASU found 5,241 GWh potential in its "moderate" scenario. However, at the measure level, the results are quite different. I summarized the cost-effective potential estimates from each study into thirty-one measure categories. Notably, only six of the thirty-one measure categories are represented in all three studies. I selected the maximum study result for each measure category and found that the estimated cost-effective energy efficiency potential approximately doubled to 11,934 GWh. This finding suggests that each of these studies may have missed approximately half of the cost-effective energy efficiency potential for residential customers in North Carolina.

The main reason that these studies appeared to miss large amounts of cost-effective energy efficiency potential is that they did not include a comprehensive scope of study. They may also have differed based on different assumptions about the cost of individual measures, customer adoption rates, or cost-effectiveness thresholds.

These are important factors, and can also skew the results of a potential study. For example, Florida utilities chose to exclude about four-fifths of otherwise achievable, cost-effective energy efficiency potential opportunities from their recommended goals because they felt that it was unfair for ratepayers to cross-subsidize each other to take steps that were in the customer's financial self-interest.[26] Mixing arguments about fairness and

[25] I have not conducted a similar analysis of the study performed for Progress because I would not be permitted to make these data public under the confidentiality agreement required by Progress.

[26] Florida Public Service Commission, Order No. PSC-09-0855-FOF-EG (Dec. 30, 2009).

program design with the question of whether or not energy efficiency potential exists can confuse the discussion about the opportunity to save energy at a lower long-term cost than to meet demand with supply-side resources.

Q. IS THERE AN ALTERNATIVE TO A COMPREHENSIVE ENERGY EFFICIENCY STUDY?

A. Another approach to setting an energy efficiency target is to rely on industry experience. Based on the perspective of highly regarded experts and the review of a number of programs, I recommend that utilities should be encouraged to strive to meet an annual energy savings goal of 1%. This goal is consistent with the actual achievements in leading states,[27] as eight states now exceed 0.8% in average savings as a percent of energy sales.[28] A large number of individual utilities have exceeded this threshold, including two in the Southeast.[29] Duke Energy adopted this goal in a non-binding agreement with a number of national energy efficiency advocacy organizations, and later formalized it as part of its modified save-a-watt proposal that has been approved by the Commission. Industry experience strongly suggests that an annual energy savings goal of 1% is a reasonable estimate of what an aggressive, cost-effective energy efficiency program can deliver.

A 1% annual energy savings goal is also consistent with the findings of a recent Georgia Tech meta-analysis of several potential studies, which found that ***"the***

[27] Kushler (2009).

[28] ACEEE (2009).

[29] Wilson, J., "Energy Efficiency Program Impacts and Policies in the Southeast," Southern Alliance for Clean Energy, May 2009.

achievable electric efficiency potential for the South ranges from 7.2 to 13.6% after 10 years."[30]

Utilities that claim to have conducted a comprehensive analysis of energy efficiency program options and suggest a substantially lower (or higher) program scale should be expected to make a convincing case for unusual circumstances that resulted in distinctive findings. Comparing a utility's assumptions and methods to that of other utilities is a recognized technique used by resource planning experts.[31]

Q. DID DUKE AND PROGRESS PERFORM COMPREHENSIVE ENERGY EFFICIENCY POTENTIAL STUDIES?

A. No, it does not appear that either utility's study was comprehensive. I note that neither utility has filed its study in this docket. The Forefront study for Duke has been in public circulation since its completion. Progress disclosed in a prior proceeding that it had commissioned a market potential study, and provided a confidential copy in response to a data request.

The first problem with both studies is that their findings suggest a substantially lower achievable energy efficiency potential than similar studies at the national or regional level without describing any unusual circumstances that may explain the results. In my review of the available documentation, neither utility nor its consultants explored any possible reasons for the unusually low energy efficiency potential found in these two studies.

[30] Chandler, S. and M.A. Brown, "Meta-Review of Efficiency Potential Studies and Their Implications for the South," Working Paper # 51 (August 2009).

[31] See, for example, testimony of Duke Energy Witness Riddle, p. 15.

Progress's potential study indicates that the findings . However, the results of that are not discussed in the report or any other material I had the opportunity to review.

Duke's potential study included only a brief comparison of its findings and recommendations to programs operated by utilities serving 500,000 to 2,000,000 customers. However, the comparison in Duke's study focuses on spending, not energy savings impacts. (The study indicates that the recommended spending levels are somewhat above average, but within the range of typical programs.) The Forefront study does compare its five-year potential of 1.9% energy savings to other utility DSM program savings, but the comparison is so cursory that the reported impact of 2.9% for other utility DSM programs is not clearly represented as to whether it refers to cumulative or annual program impacts.[32] Even though this average 2.9% impact is more than 50% higher than the recommended five-year program, the report does not provide any explanation for this substantial deviation, let alone justify a 1.9% five-year savings potential in comparison to the 7.2 to 13.6% ten year savings potential discussed above.

The lack of a comparison to findings by comparable utilities is of concern because the assumptions and methods selected may result in an inaccurate estimate of energy efficiency potential. For these studies to be considered credible and comprehensive, a thorough and convincing explanation for the unusually low potential estimates in these studies should be provided. .

The second problem with both the Duke and Progress potential studies is that the measures studied exclude substantial energy savings opportunities. As discussed above,

[32] Forefront Study at 94.

the Duke study included too few measures to be considered comprehensive. For example, its residential sector analysis only identified two cost-effective measures, programmable thermostats and "set back HVAC," omitting commonly considered measures such as heat pump upgrades.

The Progress study does include . However, the measure count is somewhat . For example, over the measures are . The measure list used by Progress Energy appears to I made a cursory comparison to the measure list for the Florida potential study conducted for Progress Energy Florida and other utilities. Among the residential measures not found in the North Carolina study are

The study also omits

Q. DID THE STUDIES ADDRESS ALL SECTORS AND MEASURES THAT WOULD YIELD SIGNIFICANT ENERGY SAVINGS?

A. No. I identified three substantial measures or practices that are missing from the Duke studies: a Home Energy Comparison Report, a building re/retro/commissioning program, and various energy recycling technologies, including combined heat and power. As described in Wilson Exhibits 10-12, these three energy efficiency measures or practices alone could double the energy savings impact forecast by North Carolina Utilities.

Furthermore, several end use sectors, including the transportation, communications and utilities sector, appear to be omitted from the Duke studies. This is a significant omission, as this sector has highly energy-intensive customer applications that likely have substantial opportunities for energy savings. In the Florida energy efficiency potential study, for example, the transportation, communications, and utilities end-use sector represented 7% of total retail electric sales.[33]

Q. DOES THE DUKE RESOURCE PLAN INCLUDE A COMPREHENSIVE ANALYSIS OF DEMAND-SIDE RESOURCE OPTIONS?

A. No, there are three important problems with its analysis of demand-side resource options. Although Duke did analyze more than one demand-side resource option, it did so without a comprehensive analysis of energy efficiency options. Furthermore, the linkage between its market potential study and the options it considered in its resource plan is not well explained. Finally, Duke failed to explain how it selected its preferred demand-side resource portfolio.

As discussed above, Duke's market potential study is not comprehensive. In my review the Duke IRP, there was not any other discussion or analysis that compensated for the shortcomings of the study. Duke's commitment to a long-term goal of 1% annual energy savings is not backed up by a comprehensive analysis of energy efficiency and other demand-side options in its resource plan.

Duke's resource plan did analyze two demand-side resource portfolios, a base case and a high case. In its base case, "conservation impacts were assumed 85% of the target impacts" from the approved save-a-watt portfolio of programs. In its high case, Duke analyzed the "full target impacts of the save-a-watt bundle of programs for the first five years and then increased the load impacts at 1% of retail sales every year after that

[33] Itron (2009).

until the load impacts reach the economic potential identified by the 2007 market potential study."[34]

Although Duke states that the high case scenario is capped by the "economic potential identified by the 2007 market potential study," the high case does not appear to reach this cap. In its high case, Duke estimates its conservation program load impacts to be 10,621 GWh in 2026. Duke IRP, Table 4.2. In contrast, the Forefront study found that the cost-effective potential for energy efficiency was about 13,200 GWh through 2026. There is no alternative explanation in the resource plan or testimony that explains why the high case was limited to 10,621 GWh in 2026.

Moreover, Duke's resource plan does not describe why the base case was selected. First of all, it is not clear that the high case was analyzed as a demand-side resource option. The high case appears to be one of the "sensitivities evaluated in each scenario" during the portfolio analysis. Duke IRP at 67. However, Duke concluded that "In every scenario and sensitivity, the portfolios with the new EE and DSM were lower cost than the portfolios with the existing EE and DSM." Thus, although the plan seemed to imply that the portfolio analysis would compare the base case and high case, the conclusion refers to a comparison between the "new" and "existing" EE and DSM. The term "new" appears to refer to the base case and not the high case since the "483 MW of new energy efficiency" in the selected portfolio (Duke IRP at 73) corresponds to the value in the base case (Duke IRP at 49). If the portfolio analysis included consideration of the high case, the results of such a sensitivity analysis do not appear to be included in the report.

[34] Duke IRP at 48.

Second, even if the high case was analyzed, the IRP does not explain why the base case was the preferred option.

If Duke had selected the high case for its resource plan, its supply-side resource plan would be adjusted to delay or avoid additional generation capacity. Duke should explain why it selected a particular demand-side resource option, just as it carefully explains why it selected a particular supply-side resource option.

Over the long-term, none of the demand-side resource options considered by Duke are likely to represent what would be suggested by a comprehensive analysis of energy efficiency potential. As indicated in Table 9B of Wilson Exhibit 9, the adjusted high case suggests that Duke Energy would achieve 5,286 GWh in energy savings after ten years, or about 5.3% cumulative energy savings impacts.

Even this adjusted high case estimate of 5.3% over ten years does not come close to fully utilizing the market potential of 7.2 to 13.6% suggested by the Georgia Tech study. Thus, in no respect is it reasonable to conclude that the Duke Energy resource plan relies upon a comprehensive analysis of demand-side resource options over the long term.

Q. WHAT STEPS SHOULD DUKE TAKE TO DEVELOP A COMPREHENSIVE ANALYSIS OF DEMAND SIDE OPTIONS?

A. Duke Energy should develop a comprehensive analysis of demand-side resource options, using one of the methods described above. It should correct the technical errors I have pointed out in my testimony to the extent that they remain relevant to a revised plan. It should develop several demand-side resource options for evaluation in its resource plan. It should evaluate each of those options in its resource plan until it determines that it has identified the maximum amount of cost-effective demand-side resources that are suitable to meet the various goals of a resource plan, as discussed earlier in my testimony.

The Duke resource plan would reduce annual energy use by 3.4% in 2024 (see Table 7B of Wilson Exhibit 7). If Duke were to adopt the suggested adjustments to its high case and incorporate those into its plan, it would reduce annual energy by 8.8% by 2024 (see Table 9B of Wilson Exhibit 9). Energy savings of 8.8% would be on the low end of the achievable potential range identified in the Georgia Tech study and would be consistent with a moderately aggressive long-term energy efficiency effort. Considering the goals and demonstrated energy savings of other utilities around the country, ***Duke Energy could consider resource plans with savings of up to 15% by 2024.***

Q. DOES THE PROGRESS ENERGY RESOURCE PLAN INCLUDE A COMPREHENSIVE ANALYSIS OF DEMAND-SIDE RESOURCE OPTIONS?

A. No. In fact, the Progress IRP fails to disclose and explain its analysis of demand-side resource options, as required by Commission Rule R8-60. The discussion of demand-side resources in Progress's resource plan is limited to its existing energy efficiency and demand response programs (including new programs). In both the 2008 and 2009 resource plans, Progress indicates that it "has not rejected any evaluated energy efficiency or demand side management resources since the last Resource Plan filing."

The existence of the potential study demonstrates that Progress has not accurately represented its evaluation process. This study is not mentioned in its resource plan or supporting testimony, and Progress has marked the entire study (rather than only those portions containing sensitive business information) confidential, making it impossible for interested parties to evaluate and comment on its scope and findings.

Rather than being driven by a "bottom-up" analysis of options, the scale of the Progress demand response and energy efficiency programs appear to be driven by a May 2007 goal to double "the amount of peak load reduction capability available through DSM and EE programs, about 1,000 megawatts (MW)." Progress IRP at 17. No basis for this goal is explained in the IRP. It is perhaps no coincidence that its year 15 portfolio would save almost exactly 1,000 MW, the amount of the goal announced by Progress in 2007. While the expansion of its program is laudable, Progress has not associated this target with a completion date nor an energy savings target.[35] It would be just as incomplete if Progress announced a supply-side resource development program without a timeline or anticipated level of resource use.

Progress does appear to be actively moving forward with its energy efficiency programs. According to Progress Witness Edge, Progress "is investigating the potential for new DSM/EE program opportunities on an on-going basis . . ." The company is seeking approval of new residential programs, and is considering "a residential behavioral change initiative and other DSM/EE research and development pilots." Direct Testimony of David Christian Edge at 8-9. These programs are also briefly described as "prospective program opportunities" in the resource plan. (p. E-5) While it is encouraging to learn that Progress is considering new unspecified programs, it is unclear whether their program development is informed by the type of comprehensive analysis required by Rule R8-60(g).

[35] In the testimony of Progress Energy Witness B. Mitchell Williams, he testified that PEC is "relying upon achieving a approximately 1,000 megawatt reduction in peak load by 2014" (transcript volume 4, p. 143, line 19); the 2009 IRP indicates 1,000 MW of peak load reduction would be achieved in 2019; and the potential study prepared by indicates that

An examination of the potential study demonstrates that Progress has not fully disclosed in its IRP its consideration of energy efficiency resources. examples of programs that Progress has considered but did not discuss in its resource plan

is not included in any of the energy efficiency programs discussed in the Progress IRP. For example, Progress's Residential Home Energy Improvement Program does not include Neither does the Progress resource plan explain why Progress may have rejected an program.

Progress's potential study also recommends

The Progress resource plan does include the Commercial, Industrial, and Governmental (CIG) Energy Efficiency Program, which is "available to all CIG customers interested in improving the energy efficiency of their new construction projects or within their existing facilities." The program offers both prescriptive incentives that appear to cover a broad range of end-use categories as well as custom incentives available for "opportunities not covered by the prescriptive measures." However, during the first two months of the program, Progress reported only one transaction. If Progress is making effective use of the opportunities in the CIG sectors, it is not evident in either the resource plan or its supporting testimony.

Even if Progress had incorporated its potential study into its resource plan, the resource plan would still lack a comprehensive analysis of demand-side resource options. Furthermore, Progress appears to have considered only one alternative demand-side resource portfolio in its analysis. In contrast, there is an entire section of its report discussing "Screening of Generation Alternatives." These systematic shortcomings demonstrate that energy efficiency resources are a second-class resource in Progress's plan.

Q. WHAT STEPS SHOULD PROGRESS TAKE TO PROVIDE A COMPREHENSIVE ANALYSIS OF DEMAND SIDE OPTIONS?

A. Progress should publicly disclose those portions of its potential study that do not include sensitive business information, and any other related research or materials, and discuss the implications of its research in a revised resource plan. That plan should be based on a comprehensive analysis of demand-side resource options, using one of the methods described above. It should correct the technical errors I have pointed out in my testimony to the extent that they remain relevant to a revised plan. It should develop several demand-side resource options for evaluation in its resource plan. It should evaluate each of those options in its resource plan until it determines that it has identified the maximum amount of cost-effective demand-side resources that are suitable to meet the various goals of a resource plan, as discussed earlier in my testimony.

The Progress resource plan would reduce annual energy use by 2.7% in 2024 (see Table 7B of Wilson Exhibit 7). This forecast is far below the achievable potential range identified in the Georgia Tech study and does not appear to represent even the full amount of energy efficiency allowed for REPS compliance purposes. Considering the goals and demonstrated energy savings of other utilities around the country, ***Progress Energy could consider resource plans with savings of up to 15% by 2024.***

Q. DO YOU HAVE ANY OVERALL RECOMMENDATIONS FOR IMPROVING THE ANALYSIS OF DEMAND-SIDE RESOURCE OPTIONS IN DEVELOPING THE RESOURCE PLANS OF NORTH CAROLINA UTILITIES?

A. Yes. First, I recommend that the Commission reject the simplistic approach of offering only one or two options regarding demand-side resources and direct utilities to explain how it selected its preferred portfolio. The current treatment of demand-side resources is fundamentally inferior to the degree of variation and specificity allowed for supply-side resources. Among the best practices recommended in a Lawrence Berkeley National Laboratory review of resource planning practices in the West are that utilities should "construct candidate portfolios with the maximum achievable EE potential" and use a transparent process for "selecting the preferred portfolio."[36]

Second, the Commission should direct North Carolina utilities to adopt resource planning practices that include consideration of risks that can cause short-term rate spikes. As discussed above, this practice has been used by the Northwest Power and Conservation Council and helped utilities in that region reduce the risk of short-term rate increases. The current practice of using scenarios and sensitivities does provide some directional guidance on these topics; however, considering that some utilities are using only two resource options for energy efficiency (existing programs vs no programs), this practice is not useful in helping select lower-risk plans.

Third, in support of strong energy efficiency resource analysis and program development, I would also recommend the creation of a regional energy efficiency database and collaboration process. Three widely used models exist. The Northwest

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[36] Barbose, G., "Valuing Energy Efficiency as a Hedge Against Carbon Regulatory Risk: Current Resource Planning Practices in the West," Lawrence Berkeley National Laboratory, EMP Group Meeting Presentation, September 21, 2007.

Power and Conservation Council's Regional Technical Forum is a regional advisory committee established to develop standards to verify and evaluate conservation savings; it is currently updating its measure database, which is available to the public. The California Energy Commission maintains the widely used Database for Energy Efficiency Resources (DEER). The New York State Energy Research and Development Authority (NYSERDA) maintains the widely-used Deemed Savings Database. These three existing energy efficiency databases and forums are widely utilized by consultants and utilities in other parts of the country for design and initial verification.

A useful starting point for a Southeast regional database would be the North Carolina Measures Database, prepared by Morgan Marketing Partners for several North Carolina utilities. I note that this database is not disclosed or discussed in any utility filing in this proceeding, even though it is an essential part of the analysis of potential demand-side resource programs. I learned of the existence of this database in the process of reviewing a Progress response to a data request. The database itself is considered confidential.

Establishing a regional energy efficiency database and collaboration process would be a useful step for three reasons. First, it would provide a process and repository for the development of authoritative regional energy efficiency performance benchmarking. Second, a regional energy efficiency database would also help to *minimize overall program evaluation costs of utilities, thereby maximizing more of the* program budget that could be directed towards incentives, generating greater energy savings and benefits to customers. Third, it would provide an opportunity for business and program partners to engage with utility and government staffs to improve and expand energy efficiency programs.

As noted above, the need for collaboration between utilities and their business and program partners is substantively different for demand-side resources than for supply-side resources. Many of the services provided by business and program partners are not designed to exclusively meet the utility's needs, but also designed to respond to diverse customer interests. Building a regional database and collaboration process creates the opportunity for effective dialogue through the process of ensuring performance accountability.

IV. Adequacy of Energy Efficiency Compliance Reporting

Q. **ARE NORTH CAROLINA'S INVESTOR OWNED UTILITIES PROVIDING ADEQUATE REPORTING OF ENERGY EFFICIENCY IMPACTS FOR PURPOSES OF REPS COMPLIANCE?**

A. Neither Progress nor Dominion submitted any documentation that indicates they intend to report energy efficiency impacts from 2007 or 2008 for purposes of REPS compliance. Duke commented regarding its interest in banking energy efficiency impacts beginning in 2008, but did not indicate what impacts occurred in 2008. This would only become a concern if the utilities submit five years worth of energy efficiency program results in a single filing to demonstrate REPS compliance for the 2012 compliance year. I do not have any reason to believe this will occur, but point out the lack of compliance filings to date in order to suggest that compliance filings should begin next year in order to avoid unnecessary challenges.

Q. **DOES THAT CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

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EXPERIENCE

Southern Alliance for Clean Energy

Director of Research, Asheville, North Carolina and Washington, DC, 2007 – present
http://www.cleanenergy.org/

- Manage energy efficiency programs
- Conduct supporting research and policy development across all program areas

Galveston-Houston Association for Smog Prevention

Executive Director, Houston, Texas, 2001 – 2006
http://www.ghasp.org/

- Member, Regional Air Quality Planning Committee
- Member, Transportation Policy Technical Advisory Committee
- Member, Steering Committee, TCEQ Interim Science Committee
- Published over a dozen reports
- In the media over 250 times
- Awards & recognition from the City of Houston, *Houston Press*, and environmental groups
- First executive director, grew staff to three full time plus several part time & consulting

The Goodman Corporation

Senior Associate, Houston, Texas, 2000 – 2001
http://www.thegoodmancorp.com/

- Project Manager, Houston Main Street Corridor
- Project Manager, Houston Downtown Circulation Study
- Project Manager, Austin Corridor Planning
- Project Manager, Ft. Worth Berry Street Corridor Initiative

Florida Legislature

Senior Legislative Analyst and Technology Projects Coordinator, Office of Program Policy Analysis and Government Accountability, Tallahassee, Florida, 1997- 1999
http://www.oppaga.state.fl.us/

- Coordinator, Florida Government Accountability Report, 1999
- Coordinator, Project Management Software Implementation, 1999
- Creator and Editor, *Florida Monitor Weekly*, 1998 - 99
- Author or team member for reports on water supply policy, environmental permitting, community development corporations, school district financial management and other issues – most recommendations implemented by the 1998 and 1999 Florida Legislatures

Florida State University

Environmental Management Consultant, Tallahassee, Florida, 1997
http://www.pepps.fsu.edu/FACT97/index.html

- *Project staff, Florida Assessment of Coastal Trends*, 1997

Houston Advanced Research Center

Research Associate, Center for Global Studies, Woodlands, Texas, 1992 - 96
http://www.harc.edu/mitchellcenter/index.html

- Performance Award, 1995
- Coordinator, Houston Environmental Foresight, 1993 - 96
- Coordinator, Rio Grande/Rio Bravo Basin Initiative, 1992 - 94
- Secretary, Task Force on Climate Change in Texas, 1992 - 94
- Researcher, *Policy Options: Responding to Climate Change in Texas*, 1992 - 93

US Environmental Protection Agency

Student Assistant, Climate Change Division, Washington, DC, 1991 - 92

- Special Achievement Award, 1991

EDUCATION

Harvard University

Master in Public Policy, John F. Kennedy School of Government, 1992

- Concentration areas: Environment, negotiation, economic and analytic methods

Rice University

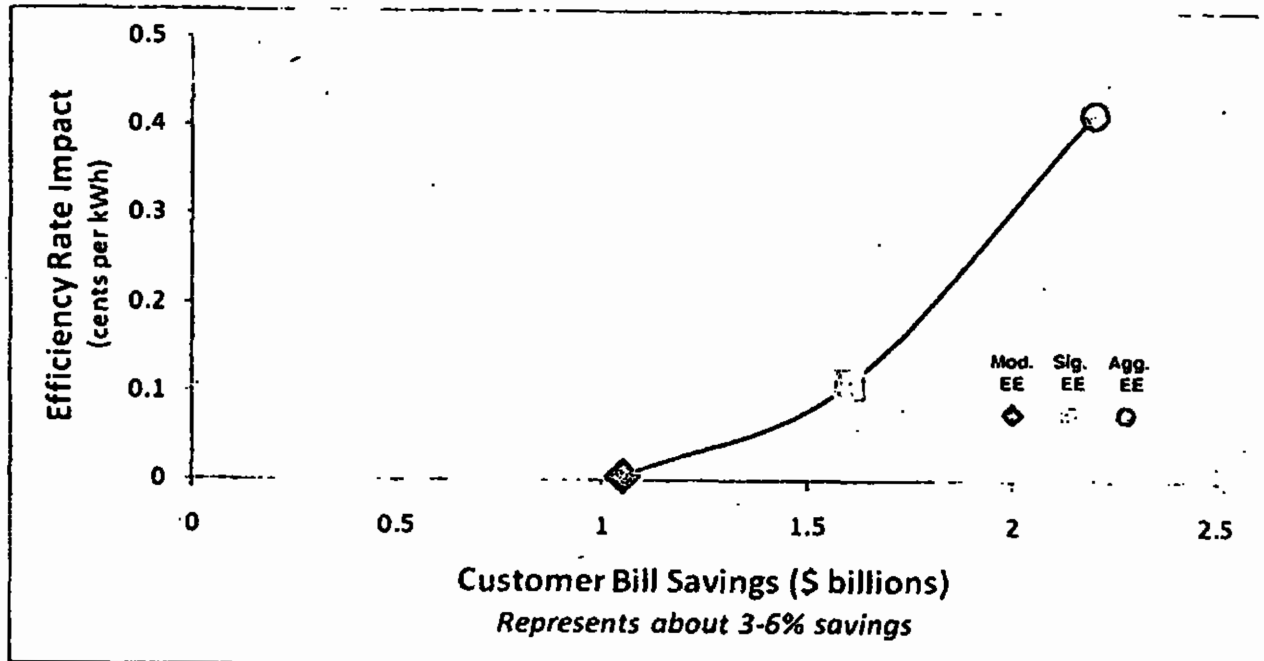
Bachelor of Arts, conferred cum laude, 1990

- Majors: Physics (with honors) and history

Additional Training and Experience

Spanish language; Advanced computer skills; Served and led political committees for the Sierra Club and Clean Water Action; Certified Master Wildlife Conservationist, Leon County Extension Service

Wilson Exhibit 2: Net Customer Bill Savings *After* Considering Energy Efficiency Rate Impact



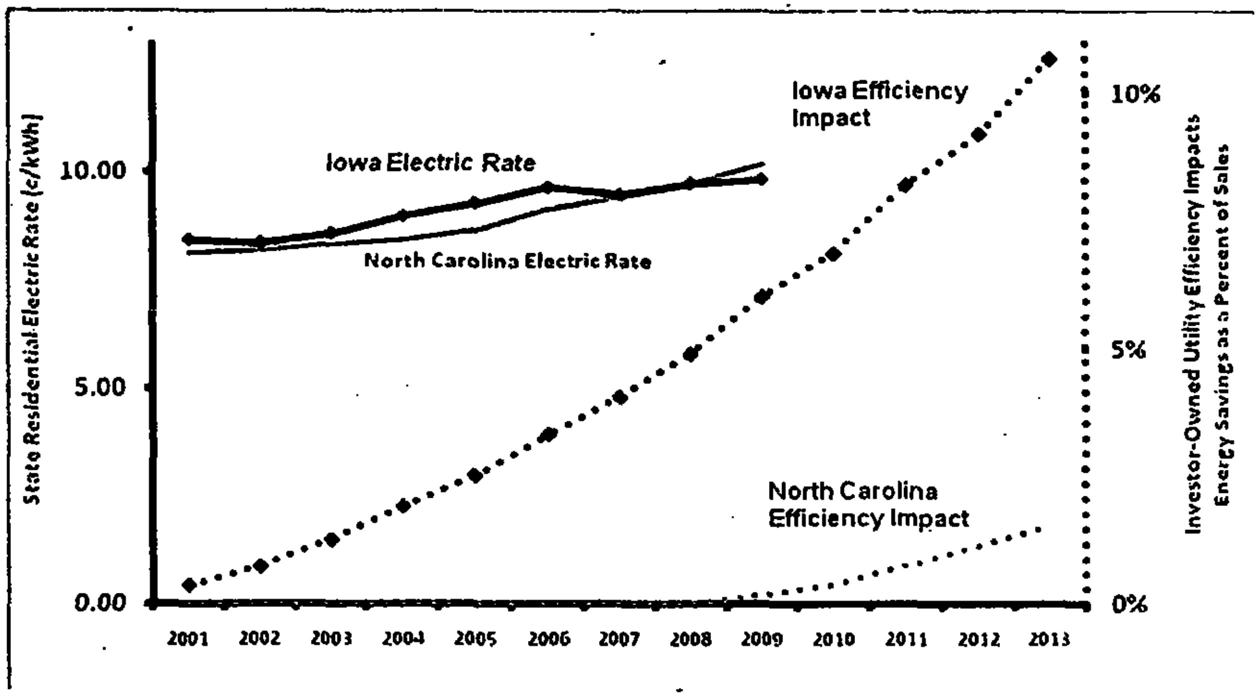
Source: Cappers et al., "Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility," LBNL-1598E (March 2009).

Wilson Exhibit 3: Comparison of Electric Rate and Efficiency Impacts, Iowa and North Carolina

Contrary to some claims, energy efficiency programs do not automatically drive rates upward. This exhibit, compares residential electric rate and energy efficiency program impacts for the state of Iowa to those of North Carolina.

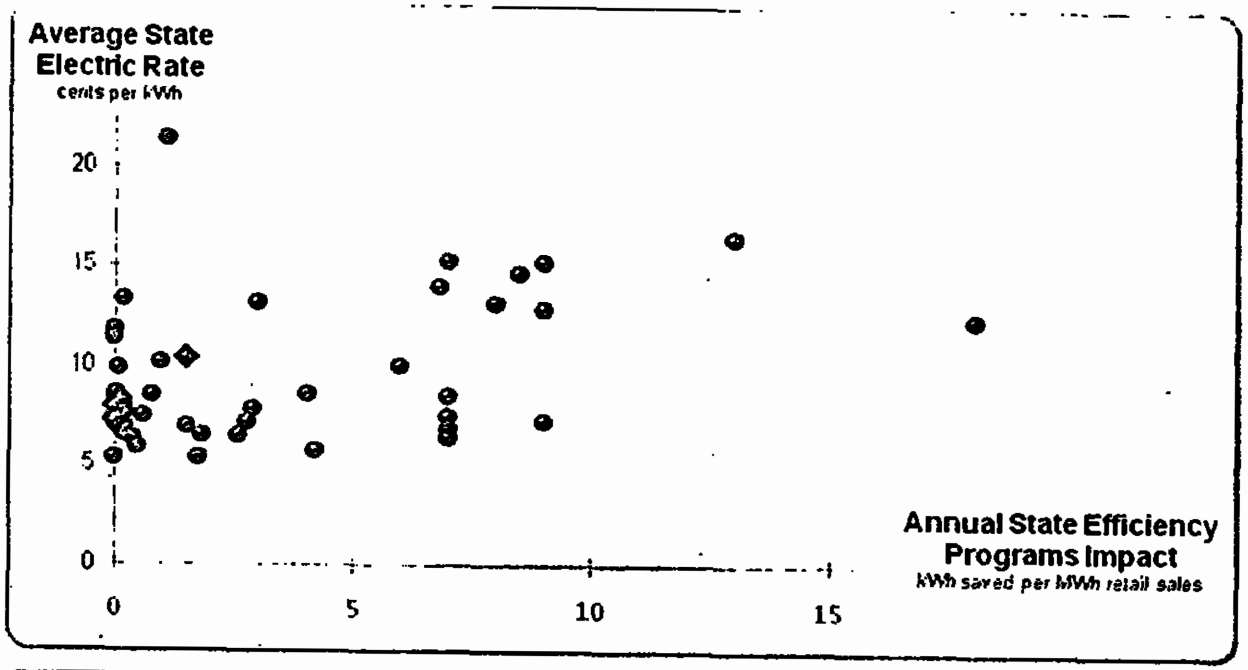
The past decade has seen North Carolina shift from a position of having lower rates than Iowa to having higher rates. Yet during this time period, North Carolina has had effectively no energy efficiency programs from an energy savings perspective, compared to Iowa energy savings programs which are expected to reach 6% cumulative savings over the same time period. This 6% energy savings has been achieved at a modest cost: since 2004, about 3.5% of Iowa utility retail sales revenue has been spent on energy efficiency and load management programs.

Of course, successful energy efficiency programs are only one of several reasons that Iowa has maintained (or improved on) rate parity with North Carolina while helping many of its customers save energy and cut bills. This result should be neither surprising nor controversial; as in North Carolina, Iowa utility-led energy efficiency programs are estimated to have benefits that are twice their cost.



Source: Analysis of data from Iowa Utilities Board, 2009 resource plans for North Carolina utilities, and the US Energy Information Administration.

Wilson Exhibit 4: Energy Efficiency Impacts Are Large in Some States Where Rates Are Comparable to the Southeast



Southeast States

Source: Analysis of data ACEEE, EIA Form 861, as described in Wilson, J., "Energy Efficiency Program Impacts and Policies in the Southeast," Southern Alliance for Clean Energy, May 2009.

Wilson Exhibit 5: Overcoming Unique Challenges to Energy Efficiency Resources

Energy efficiency resources are different because in three critical ways. Energy savings or conservation resources cannot be controlled or stored in the same way that conventional supply-side resources can be managed. Second, energy efficiency impacts cannot be measured in the same way that supply-side resources can be metered at the plant and customer site. Third, energy efficiency resources are typically delivered by a service provider network and customer base that is far more diverse and complex than the contractors who assist utilities in building and maintaining power plants. In a utility resource plan, these differences must be considered when assessing the uncertainties and risks associated with energy efficiency resources.

The uncertainties and risks of energy efficiency are associated with several "well-recognized barriers" responsible for the "current underinvestment in energy efficiency," including:

- Lack of information, awareness
- Lack of capital
- Utility financial regulation – disincentive to utility support
- Utility planning policy – energy efficiency not equal to supply resources
- Efficiency programs not up to date
- Transaction costs
- "Split-incentive" or "Principal-Agent" problem[1]

Leading energy efficiency programs address each of these customer and market barriers from the policy level all the way down to implementation – and back again.

One technique that leading energy efficiency programs use to address these barriers is to ramp up gradually over time as the program builds success in overcoming customer and market barriers such as lack of information. This delivery schedule is a marked contrast to that of conventional generation resources, which are typically delivered in large chunks on a particular capital improvement schedule. The ramp up approach is also needed because the actual capacity of a demand-side resource is only discovered through effective program execution – potential studies and industry experience are merely forecasts of actual program results.

Energy efficiency resources are measured differently than supply-side resources. An extensive professional practice has developed with the goal of providing useful estimates of the value of energy efficiency. While a review of the field of measurement and verification techniques is beyond the scope of this exhibit, The National Action Plan's *Model Energy Efficiency Program Impact Evaluation Guide* (November 2007) describes this process in detail. The consolidation of evaluation, measurement and verification (EM&V) procedures into guides and manuals reflects the growing rigor and reliability of these tools. Although different approaches are used, these typically reflect different decisions regarding the balance to be struck between cost and level of detail in these measurements.

Bringing utility energy efficiency programs up to date requires an investment in training and resource acquisition by utilities, but it also requires convincing business partners in service provider networks to do the same. The fact that our organizations, as well as all southeastern utilities, routinely draw on consulting expertise from outside the region speaks directly to the overall shortage of energy efficiency leading companies with relevant experience in this region.

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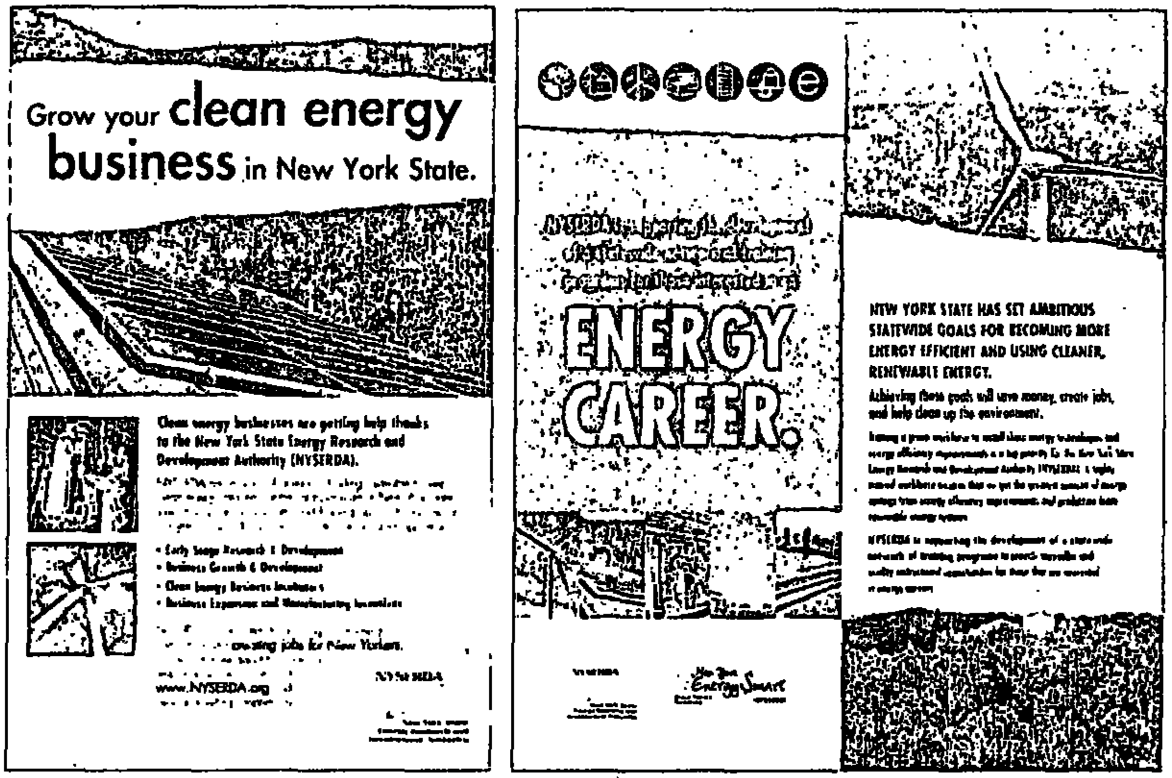
[1] National Action Plan for Energy Efficiency (2009).

Utilities with leading energy efficiency programs (e.g., Alliant Energy) as well as state administered programs (e.g., NYSERDA) offer business partner network benefits including marketing, technical, and trade show assistance – as well as a role in improving program design. [2] For example, NYSERDA has an extensive business and workforce development strategy, as illustrated below.

NYSERDA Business and Workforce Development Marketing Materials



Source: New York State Energy Research and Development Authority, *Annual Report 2008-2009*.

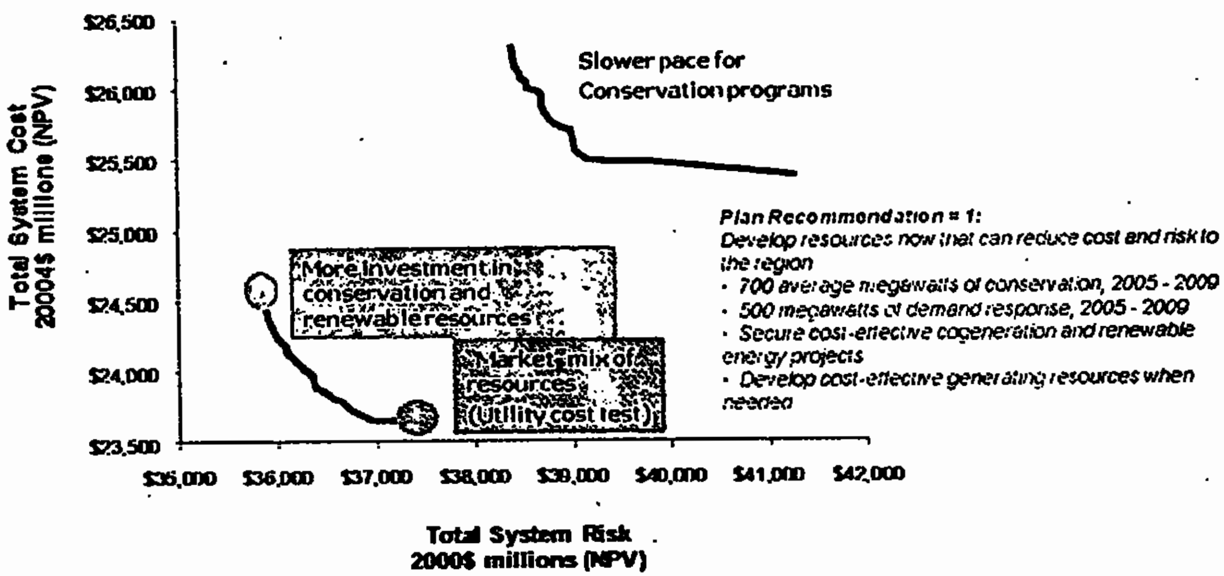
[2] Duke Energy has recently established a new stakeholder advisory group which will formally meet for the first time in March, 2010. I have accepted their invitation to participate and have participated in some preliminary activities. I am not aware that either Progress Energy or Dominion has established an ongoing stakeholder consultation process focused on their energy efficiency programs. Progress Energy does have a Community Energy Advisory Council in Western North Carolina, but this council meets infrequently and does not have an ongoing role in the development of energy efficiency programs.

Wilson Exhibit 6: Aggressive Energy Efficiency Programs Reduce Price Spike Risk

The Northwest Power and Conservation Council (NWPCC) considers a wide range of portfolio options in its resource plan analysis. Its resource portfolio planning analysis is a multi-variable sensitivity analysis which forecasts the cost and risk associated with the best combinations of various available resources. The portfolio option that offers the "least cost" is the one with the "market mix" of energy resources, what a typical least cost planning exercise might suggest:

However, by examining the price spike risk associated with each portfolio option, utilities in the region served by the Bonneville Power Administration (of which NWPCC is the statutory planning authority) determined that portfolio options with more conservation and renewable energy could cost up to 4% more, but would reduces system risk by up to 5%. The portfolio options selected by NWPCC in its last two planning cycles have a cost that was somewhat above the "market" mix in cost, with somewhat lower risk. The policy of the NWPCC is that the additional cost in the selected option represents a regional insurance hedge that is in the interests of customers concerned about the risk of price shocks.

Another aspect of the NWPCC analysis illustrated in this exhibit is the impact of a "slower pace" option for energy efficiency programs. With delayed implementation of energy efficiency, all of the portfolio options had both higher cost and higher risk than the "faster pace" option.



Source: The Fifth Northwest Electric Power and Conservation Plan, 2005

Wilson Exhibit 7: Utility Energy Efficiency Resources

Table 7A: Utility Load Forecasts

	Load Forecast without Energy Efficiency Programs								Load Forecast with Energy Efficiency Programs							
	Summer Capacity (MW)				Annual Energy (GWh)				Summer Capacity (MW)				Annual Energy (GWh)			
	2010	2015	2020	2024	2010	2015	2020	2024	2010	2015	2020	2024	2010	2 015	2020	2024
Duke'	17,668	19,670	.21,596	23,OU	89,315	96,967	106,224	115,276	16,879	18,334	20,044	21,453	89,005	95,048	102,540	111,450
Progress'	12,731	14,624	15,808	16,840	66,243	72,481	78,783	84,385	12,230	13,581	14,381	15,240	66,137	71,581	n.10s	82,140
Dominion	16,973	19,165	21,162	22,667	85,224	97,715	108,733	117,976	16,908	18,523	20,278	21,712	84,685	94,537	105,447	114,647
NCEMC	2,891	3,24S	3,649	• 4,012	12,822	14,674	16,499	18,287	2,808	3,106	3,484	3,848	12,761	14,337	16,038	17,826
EnergyU.[3]	566	608	683	751	2,506	2,701	3.000	3,265	566	597	670	738	2,505	2,601	.2,880	3,142
Piedmont•	127	239	152	163	542	596	649	695	127	239	152	163	538	580	629	675
Haywood[4]	57	61	65	69	322	344	366	386	57	61	65	69	320	331	350	369
NCTotal[5]	27,791	31,450	34,305	36,710	139,914	153,379	168,004	181,708	26,721	29,433	31,761	34,000	139,515	150,655	163,231	176,326

(1) Duk Energy did not present system load without demand response programs. These values are calculated from the plan.
(2) Progress Energy did not present annual energy without energy efficiency programs. These values are calculated from the plan.
(3) I assumed that the "anticipated" programs referred lo in Table 12 of the EnergyUnited plan are the two approved programs discussed briefly in the plan.
(4) Haywood and Piedmont did not provide a load forecast with energy efficiency programs or the data necessary to calculate such a forecast.
(5) The North Carolina Total.is calculated using NC system percentages of 68% for Duke, 89% for Progress, and 5% for Dominion.

Table 78: Utility Energy Efficiency Resource Forecast System Impacts

	Cumulative Energy Efficiency Program Impacts							
	Summer Capacity (MW)				Annual Energy (GWh)			
	2010	2015	2020	2024	2010	2015	2020	2024
Duke	4.7%	7.3%	7.7%	7.3%	0.3%	2.0%	3.6%	3.4%
Progress	4.1%	7.7%	9.9%	10.5%	0.2%	1.3%	2.2%	2.7%
Dominion	0.4%	3.5%	4.4%,	4.4%	0.6%	3.4%	3.1%	2.9%
NCEMC	3.0%	4.5%	4.7%	.4.3%	0.5%	2.4%	2.9%	2.6%
EnergyUnited	0.1%	1.8%	1.99'	1.8%	0.0%	3.8%	4.1%	3.9%
Piedmont	0.0%	0.0%	0.0%	0.0%	0.7%	2.8%	3.2%	3.0%
Haywood	0.0%	0.0%	0.0%	0.0%	0.6%	3.9%	4.6%	4.6%
Total	4.0%	6.9%	8.0%	8.0%	0.3%	1.11%	-2.9%	3.1%

Wilson Exhibit 8: Annual Energy Savings Implied by 24 State Energy Efficiency Targets or Mandates

State	Implied Annual Energy Savings Goal	Date Established	Target End Date	Efficiency Goal Details
California	> 2.0 %	2004	2013	EE is first resource to meet future electric needs; All achievable efficiency potential
Connecticut	> 2.0 %	2007	2018	All achievable cost effective
Massachusetts	> 2.0 %	2008	n/a	All achievable cost effective
Rhode Island	> 2.0 %	2008	n/a	All achievable cost effective
Washington	> 2.0 %	2006	2025	All achievable cost effective
Arizona	2.0 %	2009	2020	20% by 2020
Illinois	2.0 %	2007	2015	2.0% per year
Maryland	2.0 %	2008	2015	Per capita energy use reduced 15%
Vermont	2.0 %	2008	2011	2.0% per year (contract goals)
New Jersey	≤2.0 %	2008	2020	20% of 2020 load
Iowa	1.5 %	2009	2010	1.5% per year
Minnesota	1.5 %	2007	2010	1.5% per year
New York	1.5 %	2008	2015	10.5% of 2015 load
Ohio	1.4 %	2008	2019	2.0% per year
Colorado	1.0 %	2007	2020	1.0% per year
Michigan	1.0 %	2008	2012	1.0% per year
New Mexico	1.0 %	2009	2020	Minimum 10% of 2005 load
Nevada	0.6 %	2005	n/a	0.6% of 2006 annually
Pennsylvania	0.6 %	2008	2013	3.0% of 2009-2010 load
Hawaii	0.5 %	2004	2020	0.4-0.6% per year
Texas	0.5 %	2007	2010	20% of load growth
Virginia	0.5 %	2007	2022	10% of 2006 load
Florida	0.4 %	2009	2019	3.6% by 2019
North Carolina	***0.3 %***	***2007***	***2018***	***Cumulative forecast of 2.9% energy savings: Wilson Exhibit 2***

Notes: The form of state energy efficiency targets, mandates, goals or resource standards vary. The "implied annual energy savings goal" is a point estimate reflecting the magnitude of annual energy savings due to typical or peak program year impacts. States which require all achievable energy efficiency

Sources:

- Except as noted, from Exhibit PHM-1, "Direct Testimony of Philip H. Mosenthal." Florida Public Service Commission Dockets 080407 through 080413-EG,.July 6, 2009. The exhibit is the witnesses' analysis of data compiled in American Council for an Energy-Efficient Economy, "Laying the Foundation for Implementing a Federal Energy Efficiency Standard, March 2009, report no. E091.
- Florida data are calculated from Florida Public Servic.e Commission, Final Order No. PSC-09-0855-FOF-EG for Dockets 080407 through 080413-EG, December 30, 2009.
- Maryland, Ohio and Virginia data are calculated from Federal Energy Regulatory Commission, "Energy Efficiency Resource Standards (EERS) and Goals," July 8, 2009.
- Arizona data are calculated from Arizona Corporation Commission, Decision No. 71436 for Docket No. RE-00000C-09-0427, December 18, 2009.

Wilson Exhibit 9: Duke Energy Efficiency Program Trend and Recommended Adjustment

Figure 9A: Annual Energy Efficiency Program Impacts and Recommended Impacts

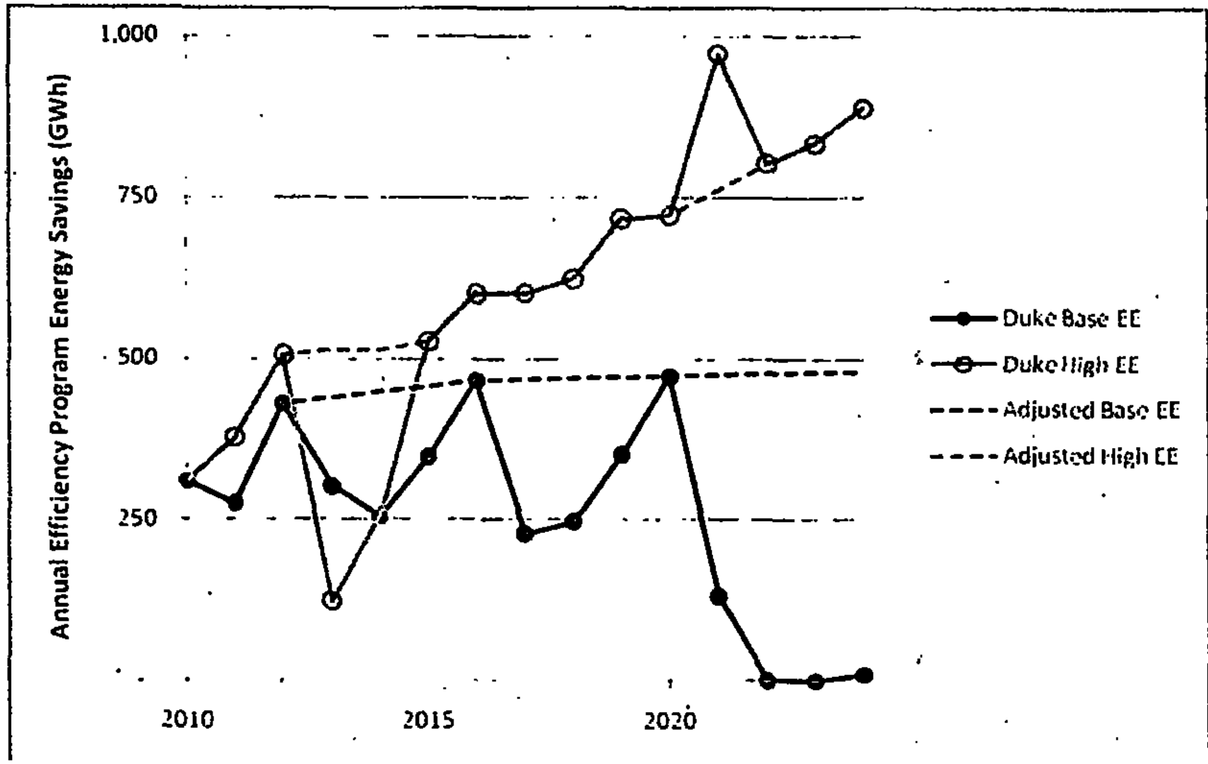


Table 8B: Cumulative Energy Efficiency Program Impacts and Recommended Impacts

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Duke Base EE	310	585	1,015	1,317	1,572	1,919	2,385	2,613	2,860	3,211	3,684	3,816	3,817	3,817	3,826
Adj. Base EE	310	585	1,015	1,454	1,902	2,359	2,825	3,293	3,762	4,234	4,707	5,181	5,658	6,136	6,616
Duke High EE	310	688	1,194	1,317	1,572	2,098	2,698	3,300	3,923	4,639	5,361	6,333	7,135	7,968	8,856
Adj. High EE	310	688	1,194	1,707	2,219	2,746	3,346	3,947	4,570	5,286	6,008	6,770	7,572	8,405	9,293

Wilson Exhibit 10: Home Energy Comparison Report

A home energy comparison report is a mailed or online tool that allows a residential customer to obtain a customized comparison of energy use with similar residences. Recent measurement and verification studies of similar programs indicate an opportunity for an almost immediate 2% residential energy savings, which in the case of Duke Energy or Progress Energy could represent a 1% system energy savings from just this single program.[3] Considering that these programs are available from established vendors, it is remarkable that these programs are not being deployed rapidly by every utility energy efficiency program.

[3] Even though this measure is not mentioned in its market potential study, I am aware that Duke Energy is currently considering developing a home energy comparison report program.

Wilson Exhibit 11: Building Re/Retro/Commissioning Program

Building commissioning is the systematic and documented process of ensuring that the owner's operational needs are met, building systems perform efficiently and building operators are properly trained during the period immediately following new construction. Building re-commissioning or retro-commissioning (generally, "commissioning") refers to the same practice on a periodic basis during the lifetime of the building. These programs are most often offered to commercial, government, and/or industrial buildings, although multifamily residential buildings may also be suitable properties.

The presence of building retrofit measures in a utility's energy efficiency portfolio should not be regarded as an adequate substitute for a commissioning program. For example, even though a number of building retrofit measures were included in the technical potential study conducted for Florida utilities, the technical potential of those measures represented less than 20% of the total potential energy savings that could be achieved in a commissioning program. This missed opportunity represents about 5% of statewide retail electricity sales.

The potential energy savings due to commission has reported over the past decade by organizations including the Energy Systems Laboratory of Texas A&M University, National Association of Energy Service Companies, and Energy Service Coalition. In particular, Lawrence Berkeley National Laboratories reports median whole-building energy savings of 16% for existing buildings and 13% for new construction.[4]

Based on the LBNL estimated savings potential and data presented in the Florida study, the statewide energy savings potential for commissioning in Florida is 9,785 GWh of annual energy savings. After adjusting for the technical potential associated with retrofit measures identified by the study consultant as being typical components of a building commissioning program, the technical potential of the remaining practices performed in a commissioning project is 8,105 GWh of energy savings.

The reason that retrofit measures alone fail to represent the full potential of building commissioning programs is that the programs emphasize improving the way that a building is used and operated. The ENERGY STAR *Building Upgrade Manual* identifies nine categories of "retrocommissioning opportunities commonly found during a building walk-through. Their presence indicates potential problems that can be identified and fixed through a retrocommissioning project:

- Systems that are inefficient due to simultaneous heating and cooling of the same air volume
- Repair or adjustment of economizers due to frozen dampers, broken or disconnected linkages, malfunctioning actuators and sensors, and improper control settings
- Pumps with throttled discharges
- Equipment or lighting that is on when it may not need to be
- Improper building pressurization due to doors that stand open or are difficult to get open
- Equipment or piping that is hot or cold when it should not be; unusual flow noises at valves or mechanical noises
- Short cycling of equipment

[4] Evan Mills, "Building Commissioning: A Golden Opportunity for Reducing Energy Costs and Greenhouse Gas Emissions," Lawrence Berkeley National Laboratory, prepared for California Energy Commission and Public Interest Energy Research, July 2009.

- Variable-frequency drives that operate at unnecessarily high speeds, or at a constant speed even though the load being served should vary"5

The majority of the interventions listed are not typically captured in a "measures database."

The omission of this important demand-side resource cannot be justified by its novelty or obscurity. The widespread understanding of building commissioning is demonstrated by the recent release of the US EPA Rapid Deployment Energy Efficiency Toolkit, which "provides detailed program design and implementation guides for *10 broadly applicable energy efficiency programs*."(emphasis added) One of the ten programs cited is "Retro-commissioning" for "Commercial/Government/Schools."[6] A number of model utility commissioning programs were recognized by the American Council for an Energy-Efficient Economy in its 2008 *"Compendium of Champions: Chronicling Exemplary Energy Efficiency Programs* from Across the U.S" and could serve as models for North Carolina utilities.

*Furthermore, in 2002 the national commissioning market was estimated to include annual retro-*commissioning projects valued at $175 million and new commissioning projects valued at of $114 million. Notably, the potential market opportunity for retro-commissioning services is estimated to be nearly 50 to 100 times greater than new commissioning.[7]

Building commissioning programs are ideal for a utility energy efficiency program because the barriers to customer adoption tend to be awareness and technical expertise, rather than financial. The cost-effectiveness of commissioning is indicated by median costs with a payback time of 1.1 years and 4.2 years for existing and new buildings, respectively.[8]

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[5] US Environmental Protection Agency, *Energy Star Building Upgrade Manual*, Office of Air and Radiation, 2008 Edition, p. 5-7.

[6] US Environmental Protection Agency, *Rapid Deployment Energy Efficiency Toolkit*, version dated May 20, 2009.

[7] FMI, "NEMI Retro-commissioning Existing Building Inventory," February 2002.

[8] Mills (2009).

Wilson Exhibit 12: Energy Recycling, Including Combined Heat and Power

Energy recycling technologies extract useful energy from what would otherwise be waste heat, and can be a highly cost effective means of producing energy. It is proven technology that is already widely adopted around the nation, and is applied in both new and existing facilities.

The most widely used form of energy recycling technology is combined heat and power (or CHP). Use of CHP technology increases the overall efficiency of fuel use by combining the electricity and thermal (heat) operations to meet the same demand rather than obtaining them from separate sources. North Carolina has over 1,500 MW of CHP systems installed at industrial, educational, government and other locations.[9]

Energy recycling, including combined heat and power (or co-generation), waste heat recovery, and other similar applications, are considered energy efficiency measures by North Carolina Utility Commission Rule R8-67,[10] provided that the measure uses waste heat to produce electricity or other useful energy, and results in less energy used. Many industries and commercial buildings produce significant amounts of waste heat that could be captured and transformed into useable, productive steam, heat, or cooling.

Energy recycling offers an opportunity to put currently wasted energy to work for our economy, and to spark new economic development opportunities in North Carolina. However, there remains some uncertainty regarding the market potential of energy recycling. According to a Duke University Study, the national impact of effective policies to promote energy recycling could reach $234 billion in new investments, creating nearly 1 million new jobs.[11] The most recent study of regional energy recycling potential is by the American Council for an Energy Efficient Economy (ACEEE), covering both North and South Carolina. For South Carolina, ACEEE estimated that utilization of CHP could result in an annual electricity savings of as much as 2,484 GWh by 2025.[12] Preliminary results for North Carolina indicate that an additional 1-4% of annual electric sales demand could be met through relatively straightforward adoption of highly cost-effective CHP systems.[13]

Utilities have shown reluctance to encourage energy recycling technologies. Yet utilities are best positioned to identify suitable locations for these technologies and assist in smooth implementation. Considering the scale and cost-effectiveness of these technologies, energy recycling surely qualifies as a demand-side resource that should be among the options considered in a utility resource plan.

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[9] American Council for an Energy-Efficient Economy, "Energy Efficiency Opportunities in North Carolina: Draft Report Findings," presented to North Carolina Energy Policy Council (January 2010).

[10] Credit as an energy efficiency measure is available under the REPS only if the fuel is nonrenewable. Otherwise, the electricity generated is considered renewable energy.

[11] Center on Globalization, Governance and Competitiveness, Duke University, "Manufacturing Climate Solutions: Carbon Reducing Technologies and U.S. Jobs" (February 2009).

[12] American Council for an Energy-Efficient Economy, "South Carolina's Energy Future: Minding its Efficiency Resources"," Report E-99 (November 2009).

[13] See note 9. Note that the ACEEE study only considered "CHP thermal energy for boiler loads only and markets that employ the thermal energy for both boiler loads and air conditioning" using natural gas fuel. Other technologies, such as waste heat recovery microturbines, are applicable at a wider range of sites but are less well established in the market.

CERTIFICATE OF SERVICE

I hereby certify that the following persons have been served with the **Direct Testimony of John D. Wilson (Public Version)** on behalf of Environmental Defense Fund, Southern Alliance for Clean Energy, the Southern Environmental Law Center and the Sierra Club either by electronic mail or by deposit in the U.S. Mail, postage prepaid:

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