PUBLIC VERSION

STATE OF IOWA
BEFORE THE IOWA UTILITIES BOARD

FILED WITH
Executive Secretary

OCT 22 2007

IOWA UTILITIES BOARD

IN RE:	)	
APPLICATION OF INTERSTATE POWER AND LIGHT COMPANY FOR A GENERATING FACILITY SITING CERTIFICATE	)	DOCKET NO. GCU-07-01

DIRECT TESTIMONY OF DAVID A. SCHLISSEL ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE

PUBLIC VERSION

OCTOBER 22, 2007

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1. Introduction

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

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

Q. Please describe Synapse Energy Economics.

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

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government and utilities. A complete description of Synapse is available at our website, www.synapse-energy.com.

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 New Mexico Public Regulation Commission, the General Staff of the Arkansas Public Service Commission, the Staff of the Arizona Corporation Commission, the U.S. Department of Justice, the Commonwealth of Massachusetts, the Attorneys General of the States of Massachusetts, Michigan, New York, and Rhode Island, the General Electric Company, 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, 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 and North Dakota and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Appendix A.

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

A. I am testifying on behalf of the Office of Consumer Advocate. ("OCA")

Q. Have you testified previously before this Commission?

A. Yes. I testified in Docket No. SPU-05-15.

Q. What is the purpose of your testimony?

A. Synapse was retained by the OCA to assist in its evaluation of the Application of Interstate Power and Light Company's ("IPL" or "the Company") for authority to construct, maintain and operate Sutherland Generating Station Unit 4, a new baseload coal-fired generation plant. ("SGS Unit 4")

This testimony presents the results of our analyses.

Q. Please identify the other Synapse witnesses who are presenting expert testimony in this proceeding on behalf of the OCA.

A. In addition to myself, the following witnesses also are presenting expert testimony in this Docket on behalf of OCA.

Dr. Ezra Hausman is explaining the scientific understanding and risks of global climate change.

Robert Fagan is addressing the potential for wind generation in IPL's service territory and the Company's use of an unreasonably high and unsupported 18 percent reserve margin in its 2007 Resource Plan modeling.

Michael Drunsic is addressing a significant limitation that biases the Company's EGEAS modeling in favor of adding SGS Unit 4, a new coal-fired power plant, in 2013.

Bill Powers from Powers Engineering is presenting a critique of Black & Veatch's assessments of IGCC technology and the suitability of employing air cooling at the SGS Unit 4 site.

Scudder Parker from Scudder Parker Consulting Services is evaluating the feasibility of deferring or avoiding the construction of SGS Unit 4 through increased investment in energy efficiency resources.

Larry Shi from the OCA staff is presenting the computer output from the OCA's EGEAS model runs.

Q. Were there other members of the Synapse staff who also assisted in the analyses undertaken by Synapse as part of its evaluation of IPL's proposed Sutherland Generating Station Unit 4?

A. Yes. Dr. David White, Bruce Biewald, Ben Warfield and Lucy Johnston from Synapse also were members of our project team. Copies of their resumes are available at www.synapse-energy.com.

Q. Please summarize your conclusions.

A. My conclusions are as follows:

1. IPL has not adequately considered the risks associated with building a new coal-fired power plant in its modeling analyses.

2. The most significant uncertainties and risks associated with the proposed Sutherland Generating Station Unit 4 project are the potential for future

federal restrictions on CO_2 emissions and further increases in the project's capital cost.

3. In particular, it is important for IPL to justify its participation in the SGS Unit 4 project in light of coming federal regulation of greenhouse gas emissions. It would be imprudent for the Company to continue its participation in the Project by merely considering a narrow range of CO_2 prices in its modeling analyses. Instead, to reflect the uncertainties and risks, IPL should use a wider range of possible CO_2 prices such as the forecasts presented by Synapse in this Docket.

4. Contrary to IPL's claim, it has not shown that adding SGS Unit 4 is the lowest risk option for its ratepayers.

5. The EGEAS analyses prepared by IPL in its 2007 Resource Plan modeling are flawed and unreasonably limited. These flaws and limitations bias the results of the modeling analyses in favor of adding a new coal-fired power plant in 2013.

6. With our assistance, the OCA staff has rerun the EGEAS model to reflect more reasonable assumptions concerning wind availability, DSM availability, power plant construction costs and reduced reserve margins.

7. When IPL's higher CO_2 price forecast was used the EGEAS model did not select a coal plant as part of a lowest cost plan in any of the scenarios more reasonable input assumptions for wind availability, DSM availability, and power plant construction costs. The model only selected a new coal plant in one scenario in which natural gas prices were increased by ten percent and, in that scenario, the coal plant was not added until 2019, six years later than IPL proposes to install SGS Unit 4.

8. When Synapse's high CO_2 price forecast was used, the EGEAS model also did not select a coal plant as part of a lowest cost plan in any scenarios.

9. Even when IPL's low CO_2 price forecast was used, 2016 was the earliest year in which the EGEAS added a new coal-fired power plant as part of a lowest cost plan in any of the scenarios. In some scenarios a new coal plant was not added until 2019. In two scenarios involved increased wind and DSM availability, no new coal plant was added as part of a lowest cost plan even with IPL's unreasonably low CO_2 price forecast.

10. For these reasons, the Board should reject IPL's application for a generating facility siting certificate.

Q. Please explain how you conducted your investigations in this proceeding.

A. We have reviewed the application, testimony and exhibits filed by IPL in this proceeding. In addition, we have participated in discovery. As part of that work, we have reviewed the information and documents provided by IPL in response to data requests submitted by the OCA. We also have reviewed public information related to the issues addressed in IPL's application, testimony and exhibits and in our testimony and exhibits.

We also have worked with Larry Shi from the OCA staff in rerunning the EGEAS model.

2. IPL Has Not Adequately Considered The Risks Associated With Building A New Coal-Fired Generating Unit

Q. Why is it important that IPL consider risk when evaluating the economics of building SGS Unit 4?

A. Risk and uncertainty are inherent in all enterprises. But the risks associated with any options or plans need to be balanced against the expected benefits from each such option or plan.

In particular, parties seeking to build new generating facilities and the associated transmission face of a host of major uncertainties, including, for example, the expected cost of the facility, future restrictions on emissions of carbon dioxide, and future fuel prices. The risks and uncertainties associated with each of these factors needs to be considered as part of the economic evaluation of whether to pursue the proposed facility or other alternatives.

Q. Has IPL identified any risks associated with its proposed SGS Unit 4?

A. Yes. IPL has identified a number of risks associated with its proposed generation resource plan. For example, the following risks were identified at the June 24 and 25, 2007 Strategic Planning Conference of Alliant Energy's Board of Directors:

[redacted]

A March 2007 presentation for Alliant Energy's senior management as part of the Company's Strategic Planning Process 2008 summarized the risks and considerations related to the goal of building [redacted][2]

The same presentation also discussed the changing landscape for building new generation in more detail:

[redacted]

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1 IPL Confidential Response to OCA DR. No. 19, Attachment B, pages 10 and 11 of 15.
2 IPL's Confidential Response to OCA DR. No. 60, Attachment A, page 3 of 24.

[redacted]

■ [redacted][3]

This same presentation also noted the following:

■ [redacted][4]

[redacted]

- [redacted]

[redacted]

[redacted]

- [redacted]

[redacted][5]

Q. Have you seen any evidence that IPL has adequately considered these risks and uncertainties in its evaluations of the proposed SGS Unit 4?

A. No. The Company has claimed that SGS Unit 4 provides lower risk to IPL and its ratepayers than other options:

> It is IPL's opinion that constructing SGS Unit 4 provides lower risk to IPL and its ratepayers than other options. The term "risk" includes both economic and environmental factors. IPL believes that construction of SGS Unit 4 will, among other things, provide the least possible environmental impact with a significant cost to

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[3] Id, at page 4 of 24.
[4] Id, at page 5 of 24.
[5] Id, at page 15 of 24.

> ratepayers, will provide the capacity needed to serve future load with the greatest reliability, and will benefit the economy of the Marshalltown area as well as the state of Iowa.[6]

However, we have not found any evidence in the Company's Application or supporting testimony and exhibits to support this claim that building SGS Unit 4 represents a lower risk to IPL and its ratepayers than other options.

In fact, we have found that IPL has not adequately considered in its economic analyses the risks associated with building a new baseload coal-fired generating unit. For example, although the Company did prepare two CO_2 price sensitivity modeling runs, its base IRP plan, that includes SGS Unit 4, was developed through modeling that assumed no greenhouse gas regulation costs. As I will discuss below, this is an extremely unrealistic and imprudent assumption. Moreover, the two CO_2 price forecasts used in IPL's sensitivity analyses were based on old information and reflect an unreasonably low range of possible future CO_2 emissions allowances prices.

In addition, the IPL modeling analyses that we have examined do not include any assessment of the uncertainty or risks associated with higher capital costs.

Q. Is it reasonable to expect that IPL could reflect uncertainty and risk in its economic analyses of whether to pursue SGS Unit 4 or alternatives?

A. Yes. There are a number of ways that IPL could have considered uncertainty and risk. The most simple way would have been to perform sensitivity analyses reflecting engineering type bounding in which the key variables would be expected to vary by X% above or below their projected values. In my experience, utilities regularly consider risk in this way.

6 IPL Response to OCA DR. No. 90.B.

Q. Has IPL previously performed any such sensitivity analyses in its modeling of resource plans?

A. Yes. IPL's modeling for its 2005 Resource Plan presented expansion plans and costs for 18 scenarios:

- Reference Case (Proposed Plan)
- All Purchased Power
- Higher Coal Capital Cost
- High Reliability
- Some Retirements
- Higher Natural Gas Prices
- Lower Natural Gas Prices
- Higher Coal Fuel Prices
- Higher Wind Prices
- Lower Load Forecast
- Higher Load Forecast
- 50% of New Resources are DSM and Renewables
- 75% of New Resources are DSM and Renewables
- Minnesota DSM - base
- Minnesota DSM – high
- Minnesota DSM- medium
- Minnesota DSM - low

Each of these scenarios was evaluated in developing the 2005 Resource Plan at zero externalities, at minimum externalities and at maximum externalities.

Unfortunately, the Company's 2007 Resource Plan that now forms the basis for the SGS Unit 4 project consists of only one base case and two CO_2 price sensitivities. IPL apparently has not completed any other modeling runs.

Q. Should the Board rely on the analyses in IPL's 2005 Resource Plan when considering whether to approve the proposed SGS Unit 4 Project?

A. No. As I will discus in detail later in this testimony, there are a number of significant flaws and out-of-date assumptions in IPL's 2005 Resource Plan modeling that render the results of that modeling unreasonable and unrealistic given current circumstances. In particular, the Company's projected coal plant capital costs are much higher than the figures that were used in the 2005 Resource Plan modeling and that modeling did not reflect any federal regulation of greenhouse gas emissions – in other words, it assumed no CO_2 emissions allowance prices.

Q. What are the most significant fossil plant-specific uncertainties and risks associated with building new coal-fired generating plants like SGS Unit 4?

A. The most significant uncertainties and risks associated with new coal-fired generating plants like the proposed SGS Unit 4 are the potential for future restrictions on CO_2 emissions and the potential for further increases in the project's capital cost. Other potential uncertainties and risks for new coal plants include the potential for fuel supply disruptions that could affect plant operating performance and fuel prices and the potential for increasing stringency of regulations of current criteria pollutants.

Q. Have any proposed coal-fired generating projects been cancelled as a result of concern over increasing construction costs or the potential for federal regulation of greenhouse gas emissions?

A. Yes. A number of coal-fired power plant projects have been cancelled within the past year, in part, because of concern over rising construction costs and climate change. For example:

- Tenaska Energy cancelled plans to build a coal-fired power plant in Nebraska because of rising steel and construction prices. According to the company's general manager of business development:

> .. coal prices have gone up "dramatically" since Tenaska started planning the project more than a year ago.
>
> And coal plants are largely built with steel, so there's the cost of the unit that we would build has gone up a lot... At one point in our development, we had some of the steel and equipment at some very attractive prices and that equipment all of a sudden was not available.
>
> We went immediately trying to buy additional equipment and the pricing was so high, we looked at the price of the power that would be produced because of those higher prices and equipment and it just wouldn't be a prudent business decision to build it.[7]

- TXU cancelled 8 of 11 proposed coal-fired power plants, in large part because of concern over global warming and the potential for federal legislation restricting greenhouse gas emissions.[8]
- Westar Energy announced in December 2006 that it was deferring site selection for a new 600 MW coal-fired power plant due to significant increases in the facility's estimated capital cost.
- Tampa Electric just cancelled a proposed integrated gasification combined cycle plant ("IGCC") due to uncertainty related to CO2 regulations, particularly capture and sequestration issues, and the potential for related project cost increases. According to a press release, "Because of the economic risk of these factors to customers and investors, the company believes it should not proceed with an IGCC project at this time," although it remains steadfast in its support of IGCC as a critical component of future fuel diversity in Florida and the nation.
- Four public power agencies suspended permitting activities for the coal-fired Taylor Energy Center because of growing concerns about greenhouse gas emissions.[9]

Q. Have you seen any instance where a participant in a jointly-owned coal-fired power plant project has withdrawn because of concern over increasing construction costs or potential CO_2 emissions costs?

A. Yes. Great River Energy ("GRE") just withdrew from the proposed Big Stone II coal-fired power plant project in South Dakota. According to GRE, four factors

7 Available at www.swtimes.com/articles/2007/07/09/news/news02.prt.
8 See www.marketwatch.com/news/story/txu-reversal-coal-plant-emissions.
9 See www.taylorenergycenter.org/s_16asp?n=40.

contributed most prominently to the decision to withdraw, including uncertainty about changes in environmental requirements and new technology and that fact that "The cost of Big Stone II has increased due to inflation and project delays."[10]

Q. Have any proposed coal-fired generating projects been rejected by state regulatory commissions due to concerns over increasing construction costs or the potential for federal regulation of greenhouse gas emissions?

A. Yes. Just since last December, proposed coal-fired power plant projects have been rejected by the Oregon Public Utility Commission, , the Florida Public Service Commission, and the Oklahoma Corporation Commission. The North Carolina Utilities Commission rejected one of the two coal-fired plants proposed by Duke Energy Carolinas for is Cliffside Project.

The decision of the Florida Public Service Commission in denying approval for the 1,960 MW Glades Power Project was based on concern over the uncertainties over plant costs, coal and natural gas prices, and future environmental costs, including carbon allowance costs.[11] In addition, the Oklahoma Corporation Commission has just voted to reject Public Service Company of Oklahoma's application to build a new coal-fired power plant although the Commission has not yet issued a written order.

On October 18, 2007, the Kansas Department of Health and Environment rejected an application to build two 700 MW coal-fired units at an existing power plant site. In a prepared statement explaining the basis for this decision, Rod Bremby, Kansas's secretary of health and environment noted that "I believe it would be irresponsible to ignore emerging information about the contribution of carbon dioxide and other greenhouse gases to climate change and the potential harm to our environment and health if we do nothing."[12]

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10 See ww.greatriverenergy.com/press/news/091707_big_stone_ii.html.
11 Order No. PSC-07-0557-FOF-EI, Docket No. 070098-EI, July 2, 2007.
12 See www.kansascity.com/105/story/323833.html.

Q. Is IPL aware that coal-plant projects are under greater scrutiny by state regulatory commissions?

A. Yes. A March 2007 presentation for Alliant Energy's senior management reported that:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted][14]

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[13] IPL's Confidential Response to OCA DR. No. 60, Attachment A, at page 4 of 24.
[14] Id, at page 15 of 24.

Q. Is it important to evaluate the uncertainties and risks associated with alternatives to the SGS Unit 4 Project as well?

A. Yes. The risks associated with building natural gas-fired alternatives include potential CO_2 emissions costs, possible capital cost escalation and fuel price uncertainty and volatility.

Renewable alternatives and DSM also have some uncertainties and risks. These include potential capital cost escalation, contract uncertainty and customer participation uncertainty.

3. IPL Has Not Adequately Considered The Risks Associated With Future Federally Mandated Greenhouse Gas Reductions

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

A. Yes. The prospect of global warming and the resultant widespread climate changes has spurred international efforts to work towards a sustainable level of greenhouse gas emissions. These international efforts are embodied in the United Nations Framework Convention on Climate Change ("UNFCCC"), a treaty that the U.S. ratified in 1992, along with almost every other country in the world. The Kyoto Protocol, a supplement to the UNFCCC, establishes legally binding limits on the greenhouse gas emissions of industrialized nations and economies in transition.

Despite being the single largest contributor to global emissions of greenhouse gases, the United States remains one of a very few industrialized nations that have not signed the Kyoto Protocol.[15] Nevertheless, individual states, regional groups

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15 As I use the terms "carbon dioxide regulation" and "greenhouse gas regulation" throughout our testimony, there is no difference. While I believe that the future regulation we discuss here will govern emissions of all types of greenhouse gases, not just carbon dioxide ("CO_2"), for the purposes of our discussion we are chiefly concerned with emissions of carbon dioxide. Therefore, we use the terms "carbon dioxide regulation" and "greenhouse gas regulation" interchangeably.

of states, shareholders and corporations are making serious efforts and taking significant steps towards reducing greenhouse gas emissions in the United States. Efforts to pass federal legislation addressing carbon, though not yet successful, have gained ground in recent years. These developments, combined with the growing scientific understanding of, and evidence of, climate change as outlined in Dr. Hausman's testimony, mean that establishing federal policy requiring greenhouse gas emission reductions is just a matter of time. The question is not whether the United States will develop a national policy addressing climate change, but when and how. The electric sector will be a key component of any regulatory or legislative approach to reducing greenhouse gas emissions both because of this sector's contribution to national emissions and the comparative ease of regulating large point sources.

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

Q. If there are uncertainties with regard to such important details as timing, emission limits and other details, why should a utility engage in the exercise of forecasting greenhouse gas prices?

A. First of all, utilities are implicitly assuming a value for carbon allowance prices whether they go to the effort of collecting all the relevant information and create a price forecast, or whether they simply ignore future carbon regulation. In other words, a utility that ignores future carbon regulations is implicitly assuming that the allowance value will be zero. The question is whether it's appropriate to assume zero or some other number. There is uncertainty in any type of utility forecasting and to write off the need to forecast carbon allowance prices because of the uncertainties is not prudent.

Similarly, the terms "carbon dioxide price," "greenhouse gas price" and "carbon price" are interchangeable.

For example, there are myriad uncertainties that utility planners have learned to address in planning. These include randomly occurring generating unit outages, load forecast error and demand fluctuations, and fuel price volatility and uncertainty. These various uncertainties can be addressed through techniques such as sensitivity and scenario analyses.

Q. If SGS Unit 4 were to be built, is carbon regulation an issue that could be definitely could be addressed in the future, and at a reasonable cost, once the timing and stringency of the regulation is known?

A. No. Unlike for other power plant air emissions like sulfur dioxide and oxides of nitrogen, there currently is no commercial or economical method for post-combustion removal of carbon dioxide from supercritical pulverized coal plants. IPL agrees on this point, noting that "Unlike with other criteria air emissions, commercially-available back-end CO2 emissions control technologies do not currently exist."[16] This conclusion is consistent with that of other coal utilities and with the general view in the electric industry.

Even if such technology were available, retrofitting an existing coal plant with the technology for carbon capture and sequestration is expected to be very expensive, increasing the cost of generating power at the plant by perhaps as much as 68 percent to 80 percent, or higher.

Q. Do other utilities have opinions about whether and when greenhouse gas regulation will come?

A. Yes. A number of utility executives have argued that mandatory federal regulation of the emissions of greenhouse gases is inevitable.

For example, in April 2006, the Chairman of Duke Energy, Paul Anderson, stated:

> From a business perspective, the need for mandatory federal policy in the United States to manage greenhouse gases is both urgent and

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16 Response to OCA DR No. 19, Attachment A, page 46 of 55.

> real. In my view, voluntary actions will not get us where we need to be. Until business leaders know what the rules will be – which actions will be penalized and which will be rewarded – we will be unable to take the significant actions the issue requires.[17]

Similarly, James Rogers, who was the CEO of Cinergy and is currently CEO of Duke Energy, has publicly said "[I]n private, 80-85% of my peers think carbon regulation is coming within ten years, but most sure don't want it now."[18] Mr. Rogers also was quoted in a December 2005 *Business Week* article, as saying to his utility colleagues, "If we stonewall this thing [carbon dioxide regulation] to five years out, all of a sudden the cost to us and ultimately to our consumers can be gigantic."[19]

Not wanting carbon regulation from a utility perspective is understandable because carbon price forecasting is not simple and easy, it makes resource planning more difficult and is likely to change "business as usual." For many utilities, including IPL, that means that it is much more difficult to justify building a pulverized coal plant. Regardless, it is imprudent to ignore the risk.

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

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

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

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

In fact, several electric utilities and electric generation companies have incorporated assumptions about carbon regulation and costs into their long term planning, and have set specific agendas to mitigate shareholder risks associated with future U.S. carbon regulation policy. These utilities cite a variety of reasons for incorporating risk of future carbon regulation as a risk factor in their resource planning and evaluation, including scientific evidence of human-induced climate change, the U.S. electric sector's contribution to emissions, and the magnitude of the financial risk of future greenhouse gas regulation.

Duke Energy and FPL Group are participating in the high profile U.S. Climate Action Partnership ("USCAP") which advocates for federal, mandatory legislation of greenhouse gases. The six principles of this group are:

- Account for the global dimensions of climate change;
- Create incentives for technology innovation;
- Be environmentally effective;
- Create economic opportunity and advantage;
- Be fair to sectors disproportionately impacted; and
- Reward early action.[20]

Most significantly, USCAP has argued that CO_2 emissions should be reduced by 60% to 80% by 2050. As I will discuss later, this is relatively the same goal as many of the climate change bills that have been introduced in the current U.S. Congress.[21]

Some of the companies believe that there is a high likelihood of federal regulation of greenhouse gas emissions within their planning period. For example, Pacificorp states a 50% probability of a CO_2 limit starting in 2010 and a 75%

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[20] www.us-cap.org.
[21] *A Call for Action*, at page 7, available at www.us-cap.org.

probability starting in 2011. The Northwest Power and Conservation Council models a 67% probability of federal regulation in the twenty-year planning period ending 2025 in its resource plan. Northwest Energy states that CO_2 taxes "are no longer a remote possibility."[22]

Even those in the electric industry who oppose mandatory limits on greenhouse gas regulation believe that regulation is inevitable. David Ratcliffe, CEO of Southern Company, a predominantly coal-fired utility that opposes mandatory limits, said at a March 29, 2006, press briefing that "There certainly is enough public pressure and enough Congressional discussion that it is likely we will see some form of regulation, some sort of legislation around carbon."[23]

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

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

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

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

Q. How does IPL view the prospects for carbon regulation?

A. IPL's parent, Alliant Energy, has said that "goals to achieve sustainable development and economic growth can be met while simultaneously reducing GHG emissions. While the scientific research is not complete on the rate and cause of climate change, Alliant Energy recognizes that public and political consensus indicates sufficient evidence exists to take action. Alliant Energy agrees the time for action is now."[24] Alliant also has concluded that

> "Recent events indicate that mandatory requirements to stabilize and reduce greenhouse gas emissions are likely. What remains uncertain is the nature, extent and timing of such requirements. Alliant Energy's position on climate change embraces the need for action – while clearly articulating our preference for methods that will produce tangible and measurable outcomes.[25]

An April 2006 presentation on [redacted].[26] The same presentation reported that "[redacted]."[27]

A March 2007 presentation to Alliant Energy's senior management, part of its Strategic Planning Process for 2008, further reported that the [redacted].[28] This same presentation also noted the [redacted] of federal regulation of greenhouse gas emissions:

> [redacted][29]

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[24] IPL Response to OCA DR. No. 19, Attachment A, page 29 of 55.
[25] Id, at page 19 of 55.
[26] IPL's Confidential Response to OCA DR. No. 31, Attachment D, at page 4 of 20.
[27] Id.
[28] IPL's Confidential Response to OCA DR. No. 60, Attachment A, page 4 of 24.
[29] Id, at page 5 of 24.

Q. Do you agree with IPL's assessment of the potential for federal regulation of greenhouse gas emissions?

A. Yes. We at Synapse believe that it is not a question of "if" with regards to federal regulation of greenhouse gas emissions but rather a question of "when." However, we also agree with Alliant Energy that there are uncertainties as to the design, timing and details of the CO_2 regulations that ultimately will be adopted and implemented.

Q. What mandatory greenhouse gas emissions reductions programs have begun to be examined in the U.S. federal government?

A. To date, the U.S. government has not required greenhouse gas emission reductions. 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 details pertaining to offsets, allowance allocation, restrictions on allowance prices and other issues. Some of the federal proposals that would require greenhouse gas emission reductions that had been submitted in Congress are summarized in Table 1 below.[30]

Table 1. Summary of Mandatory Emissions Targets in Proposals Discussed in Congress[31]

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
McCain Lieberman S.139	Climate Stewardship Act	2003	Cap at 2000 levels 2010-2015. Cap at 1990 levels beyond 2015.	Economy-wide, large emitting sources
McCain Lieberman SA 2028	Climate Stewardship Act	2003	Cap at 2000 levels	Economy-wide, large emitting sources

30 Table 1 is an updated version of Table ES-1 on page 5 of Exhibit___DAS-1, Schedule C.

31 More detailed summaries of the bills that have been introduced in the U.S. Senate in the 110th Congress are presented in Exhibit___DAS-1, Schedule B.

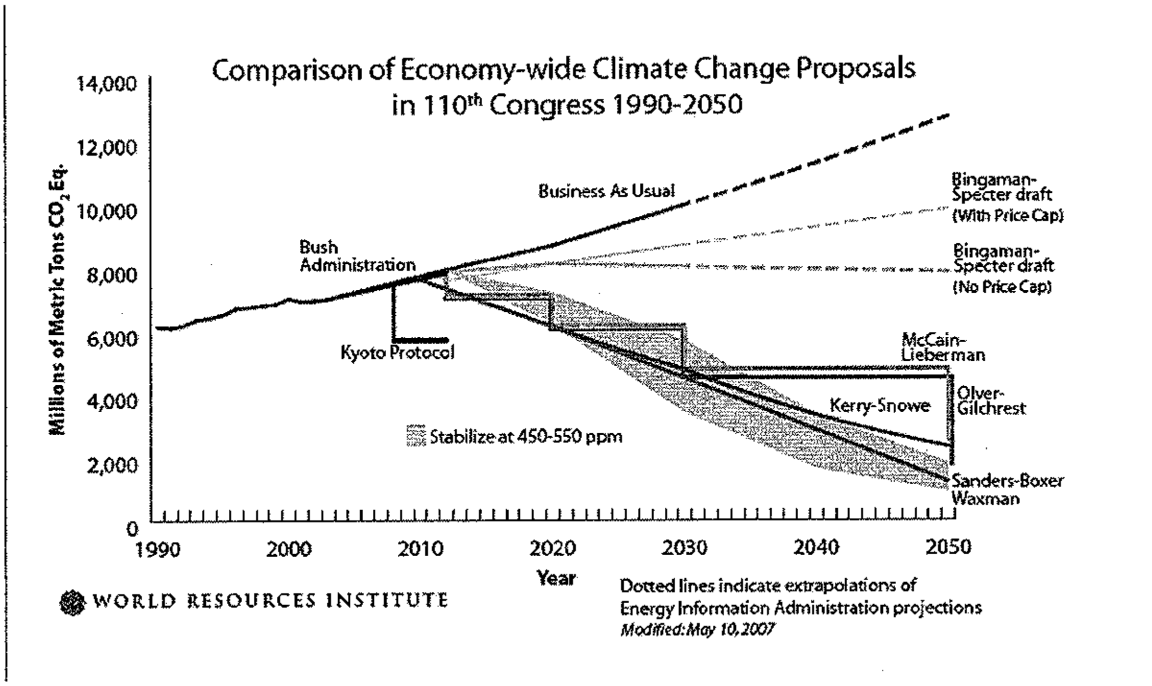
McCain Lieberman S 1151	Climate Stewardship and Innovation Act	2005	Cap at 2000 levels	Economy-wide, large emitting sources
National Commission on Energy Policy (basis for Bingaman-Domenici legislative work)	Greenhouse Gas Intensity Reduction Goals	2005	Reduce GHG intensity by 2.4%/yr 2010-2019 and by 2.8%/yr 2020-2025. Safety-valve on allowance price	Economy-wide, large emitting sources
Jeffords S. 150	Multi-pollutant legislation	2005	2.050 billion tons beginning 2010	Existing and new fossil-fuel fired electric generating plants > 15 MW
Carper S. 843	Clean Air Planning Act	2005	2006 levels (2.655 billion tons CO_2) starting in 2009, 2001 levels (2.454 billion tons CO_2) starting in 2013.	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants > 25 MW
Feinstein	Strong Economy and Climate Protection Act	2006	Stabilize emissions through 2010; 0.5% cut per year from 2011-15; 1% cut per year from 2016-2020. Total goal would be 7.25% below current levels.	Economy-wide, large emitting sources
Rep. Udall - Rep. Petri	Keep America Competitive Global Warming Policy Act	2006	Establishes prospective baseline for greenhouse gas emissions, with safety valve.	Energy and energy-intensive industries
Carper S.2724	Clean Air Planning Act	2006	2006 levels by 2010, 2001 levels by 2015	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants > 25 MW
Kerry and Snowe S.4039	Global Warming Reduction Act	2006	No later than 2010, begin to reduce U.S. emissions to 65% below 2000 levels by 2050	Not specified
Waxman H.R. 5642	Safe Climate Act	2006	2010 – not to exceed 2009 level, annual reduction of 2% per year until 2020, annual reduction of 5% thereafter	Not specified
Jeffords S. 3698	Global Warming Pollution Reduction Act	2006	1990 levels by 2020, 80% below 1990 levels by 2050	Economy-wide
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	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 $\geq$60% below 2006 levels by 2050 contingent upon international effort	Economy-wide

In addition, Senators Lieberman and Warner have issued a set of discussion principles for proposed greenhouse gas legislation. This legislation would mandate 2005 emission levels in 2012, 10% below 2005 levels by 2020, 30% below 2005 levels by 2030, 50% below 2005 levels by 2040, and 70% below 2005 levels by 2050.

The emissions levels that would be mandated by the bills that have been introduced in the current Congress are shown in Figure 1 below:

Figure 1: Emissions Reductions Required under Climate Change Bills in Current US Congress



The shaded area in Figure 1 above represents the 60% to 80% range of emission reductions from current levels that many now believe will be necessary to stabilize atmospheric CO_2 concentrations by the middle of this century.

Many of the bills that have been introduced in the 110th Congress call for emissions reductions to levels that are far below the levels considered in the studies on which IPL has based its CO_2 price forecasts.

Q. Is it reasonable to believe that the prospects for passage of federal legislation for the regulation of greenhouse gas emissions have improved as a result of last November's federal elections?

A. Yes. As shown by the number of proposals being introduced in Congress and public statements of support for taking action, there certainly are an increasing numbers of legislators who are inclined to support passage of legislation to regulate the emissions of greenhouse gases.

Nevertheless, my conclusion that significant greenhouse gas regulation in the U.S. is inevitable is not based on the results of any single election or on the fate of any single bill introduced in Congress.

Q. Are individual states also taking actions to reduce greenhouse gas emissions?

A. Yes. A number of states are taking significant actions to reduce greenhouse gas emissions. In fact, as Alliant Energy has noted: [redacted][32]

For example, Table 2 below lists the emission reduction goals that have been adopted by states in the U.S. Regional action also has been taken in the Northeast and Western regions of the nation.

[32] IPL's Confidential Response to OCA DR. No. 60, Attachment A, page 6 of 24.

Table 2: Announced State and Regional Greenhouse Gas Emission Reduction Goals

State	GHG Reduction Goal	Western Climate Initiative member (15% below 2005 levels by 2020)	Regional Greenhouse Gas Initiative member (Cap at current levels 2009-2015, reduce this by 10% by 2019)
Arizona	2000 levels by 2020; 50% below 2000 levels by 2040	yes	
California	2000 levels by 2010; 1990 levels by 2020; 80% below 1990 levels by 2050	yes	
Connecticut	1990 levels by 2010; 10% below 1990 levels by 2020; 75-85% below 2001 levels in the long term		yes
Delaware			yes
Florida	2000 levels by 2017, 1990 levels by 2025, and 80 percent below 1990 levels by 2050		
Hawaii	1990 levels by 2020		
Illinois	1990 levels by 2020; 60% below 1990 levels by 2050		
Maine	1990 levels by 2010; 10% below 1990 levels by 2020; 75-80% below 2003 levels in the long term		yes
Maryland			yes
Massachusetts	1990 levels by 2010; 10% below 1990 levels by 2020; 75-85% below 1990 levels in the long term		yes
Minnesota	15% by 2015, 30% by 2025, 80% by 2050		
New Hampshire	1990 levels by 2010; 10% below 1990 levels by 2020; 75-85% below 2001 levels in the long term		yes
New Jersey	1990 levels by 2020; 80% below 2006 levels by 2050		yes
New Mexico	2000 levels by 2012; 10% below 2000 levels by 2020; 75% below 2000 levels by 2050	yes	
New York	5% below 1990 levels by 2010; 10% below 1990 levels by 2020		yes
Oregon	Stabilize by 2010; 10% below 1990 levels by 2020; 75% below 1990 levels by 2050	yes	
Rhode Island	1990 levels by 2010; 10% below 1990 levels by 2020; 75-80% below 2001 levels in the long term		yes
Utah		yes	
Vermont	1990 levels by 2010; 10% below 1990 levels by 2020; 75-85% below 2001 levels in the long term		yes
Washington	1990 levels by 2020; 25% below 1990 levels by 2035; 50% below 1990 levels by 2050	yes	

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

A. Yes. A summer 2006 poll by Zogby International showed that an overwhelming majority of Americans are more convinced that global warming is happening than they were even two years ago. In addition, Americans also are connecting intense weather events like Hurricane Katrina and heat waves to global warming.[33] Indeed, the poll found that 74% of all respondents, including 87% of Democrats, 56% of Republicans and 82% of Independents, believe that we are experiencing the effects of global warming.

The poll also indicated that there is strong support for measures to require major industries to reduce their greenhouse gas emissions to improve the environment without harming the economy – 72% of likely voters agreed such measures should be taken.[34]

Other recent polls reported similar results. For example, a recent Stanford University/Associated Press poll found that 84 percent of Americans believe that global warming is occurring, with 52 percent expecting the world's natural environment to be in worse shape in ten years than it is now.[35] Eighty-four percent of Americans want a great deal or a lot to be done to help the environment during the next year by President Bush, the Congress, American businesses and/or the American public. This represents ninety-two percent of Democrats and seventy-seven percent of Republicans.

At the same time, according to a recent public opinion survey for the Massachusetts Institute of Technology, Americans now rank climate change as the country's most pressing environmental problem—a dramatic shift from three

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

34 Id.

35 *The Second Annual "America's Report Card on the Environment" Survey by the Woods Institute for the Environment at Stanford University in collaboration with The Associated Press,* September 25, 2007. http://woods.stanford.edu/docs/surveys/2006_ClimatePoll.pdf.

years ago, when they ranked climate change sixth out of 10 environmental concerns.[36] Almost three-quarters of the respondents felt the government should do more to deal with global warming, and individuals were willing to spend their own money to help.

Q. What CO_2 prices has IPL used in its modeling of the proposed SGS Unit 4 Project?

A. IPL did not assume any annual carbon or CO2 emissions cost for the base case of its 2007 Electric Resource Plan although it did prepare two sensitivity analyses assuming what it calls low CO_2 and high CO_2 emissions allowance prices.[37]

Q. Is it prudent and reasonable to assume no CO_2 emissions allowance prices in the Reference Case Analysis?

A. No. It is not prudent to project that there will be no regulation of greenhouse gas emissions at any point over the next thirty or more years. As I have discussed above and Alliant Energy has acknowledged, federal regulation of greenhouse gas emissions is highly likely in the near future. States also have started to take actions to reduce greenhouse gas emissions both on their own and as part of regional initiatives. Given all of its public statements and [redacted] about the likelihood, [redacted], of mandating requirements for reducing greenhouse gas emissions and that the time for action is now, I find it very hard to accept that IPL believes that this is a reasonable scenario on which to base decisions about future generation alternatives.

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36 *MIT Carbon Sequestration Initiative, 2006 Survey,* http://sequestration.mit.edu/research/survey2006.html

37 IPL Response to OCA DR No. 16, IPL Response to OCA DR. No. 15 and IPL Response to OCA DR. No. 19, Attachment A, page 47 of 55.

Q. Does IPL discuss in its Application what its total greenhouse gas emissions will be if its adds SGS Unit 4 to its generation mix, as it proposes?

A. Not really. All that IPL does is to compare the projected CO2, methane and Nitrous Oxide emissions from the proposed supercritical SGS Unit 4 against a hypothetical comparable sub critical unit.[38] However, this comparison does reveal that SGS Unit 4 would emit 5.935 million tons of CO_2 into the atmosphere each year.

Q. Have you seen any projections of what IPL's future total annual CO_2 emissions would be under the Company's base case IRP which is based on the assumption that there will be no regulation of greenhouse gas emissions?

A. Yes. As shown in Figures 2 and 3 below, IPL's annual CO_2 emissions would [redacted] percent 2008 and 2020 if the Company's completes it Resource Plan that includes the addition of SGS Unit 4 in 2013. Total Alliant Energy CO_2 emissions would [redacted] percent during the same period.

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[38] Table 1.6.6-1, at page 37 of IPL's Application for A Generating Facility Siting Certificate.

Figure 2: **Future IPL CO2 Emissions Under Current IRP including SGS Unit 4[39] [CONFIDENTIAL]**

[39] Source: IPL's Confidential Response to OCA DR. No. 76, Attachment A.

Figure 3: Future Alliant Energy CO_2 Emissions Under Current IRP including SGS Unit 4[40] [CONFIDENTIAL]

Q. How do these future IPL and Alliant emissions levels compare to the emissions target levels in the bills that have been introduced in the current U.S. Congress?

A. Alliant Energy has compared its projected CO_2 emissions with the emissions levels that would be mandated by six of the current bills in Congress. As shown in Figure 4 below, Alliant's CO_2 emissions under its preferred Resource Plan that includes SGS Unit 4 would be [redacted]

40 Source: IPL's Confidential Response to OCA DR. No. 76, Attachment A.

Figure 4: Future Alliant Energy CO_2 Emissions Versus National Proposals[41] [CONFIDENTIAL]

Q. Is IPL aware that carbon costs are becoming a more significant factor in resource planning?

A. Yes. A March 2007 presentation for Alliant Energy's senior management as part of the Company's Strategic Planning Process 2008 summarized the risks and considerations related to the goal of building [redacted] This presentation contained the following observations:

[redacted]

[redacted]

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41 Source: *Climate Change Strategy*, presentation at Alliant Energy's Strategic Planning Committee Meeting, May 31, 2007. Provided in IPL's Confidential Response to OCA DR. No. 21, Attachment A, at page 157 of 212.

[redacted][42]

Q. What CO_2 prices did IPL assume in its low and high CO_2 sensitivities?

A. IPL's low and high CO2 price forecasts are presented in Table 3 below:

Table 3: IPL CO_2 Price Forecasts

	IPL Low CO_2 Prices Nom$	IPL Low CO_2 Prices 2005$	IPL High CO_2 Prices Nom$	IPL High CO_2 Prices 2005$
2010	$8.00	$7.1	$15.00	$13.26
2011	$8.46	$7.3	$16.28	$14.03
2012	$8.95	$7.5	$17.66	$14.86
2013	$9.47	$7.8	$19.16	$15.72
2014	$10.02	$8.0	$20.79	$16.65
2015	$10.61	$8.3	$22.55	$17.62
2016	$11.22	$8.6	$24.47	$18.65
2017	$11.87	$8.8	$26.55	$19.74
2018	$12.56	$9.1	$28.81	$20.90
2019	$13.29	$9.4	$31.26	$22.12
2020	$14.06	$9.7	$33.91	$23.42
2021	$14.87	$10.0	$36.80	$24.79
2022	$15.74	$10.3	$39.93	$26.24
2023	$16.65	$10.7	$43.32	$27.77
2024	$17.62	$11.0	$47.00	$29.40
2025	$18.64	$11.4	$51.00	$31.12
2026	$19.72	$11.7	$55.33	$32.94
2027	$20.86	$12.1	$60.03	$34.87
2028	$22.07	$12.5	$65.14	$36.91
2029	$23.35	$12.9	$70.67	$39.07
2030	$24.71	$13.3	$76.68	$41.36

Q. What happens to these price forecasts after 2030?

A. The Company's low CO_2 forecast would continue to increase at 5.3 percent per year. IPL's high CO_2 price forecast would continue to increase at 8.5 percent per year.

[42] Id, at page 12 of 24.

Q. How did IPL develop its low and high CO_2 price forecasts?

A. IPL has said that its low CO_2 price forecast is based on a 2003 MIT analysis of Senate Bill 139, the original McCain-Lieberman climate change legislation.[43] The Company also has said that its high CO_2 price forecast is similarly based on a 2003 analysis of the same legislation by the Energy Information Administration of the U.S. Department of Energy.[44]

Q. Is it reasonable and prudent to base current CO_2 price forecasts on just these two analyses of a single piece of proposed legislation that was introduced in Congress back in 2003?

A. No. As I will discuss below, we looked at the results of these same two analyses when we developed our Synapse CO_2 price forecasts in the spring of 2006. However, we also considered the results of another eight analyses of both the 2003 McCain-Lieberman bill and of other proposed climate change legislation that had been introduced in Congress between 2003 and 2006.[45] Thus, we examined a much wider range of inputs when we developed our CO_2 price forecasts. We believe that it is necessary to do so because of the uncertainties associated with the design, timing and implementation of federal greenhouse gas regulations. IPL, in contrast, has based its projected CO_2 prices on optimistic scenarios involving a single bill.

As I also will discuss in detail below, we also have continued to re-evaluate the reasonableness of our CO_2 price forecasts in light of the proposed climate change legislation that is being considered in the current Congress.

[43] IPL Response to OCA DR. No. 19, Attachment A, at page 47 of 55.
[44] Id.
[45] See the discussion in Exhibit___DAS-1, Schedule C, beginning at page 41 of 63.

Q. How do the emissions targets assumed by IPL in its base CO_2 forecast compare to the emissions target levels in the bills that have been introduced in the current U.S. Congress?

A. The emissions levels considered in the 2003 McCain-Lieberman legislation (Senate Bill S. 139), on which IPL bases it CO_2 price forecasts, are significantly less stringent (that is, higher) than would be required under the great majority of the bills currently under consideration in Congress.

[redacted]

Table 4: Targets in Current National Climate Change[46] [CONFIDENTIAL]

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46 Source: IPL's Confidential Response to OCA DR. No. 21, Attachment A. page 116 of 212.

Thus, IPL's projected range of CO_2 prices is not consistent with the full range of emissions reductions that Congress is currently considering.

Q. By how much would IPL and Alliant Energy have to reduce their CO_2 emissions to reach 1990 levels by 2020?

A. Alliant has estimated that IPL would have to reduce its projected base case CO_2 emissions [redacted].[47] Alliant Energy would have to [redacted].[48]

Q. Is IPL's "high" CO_2 price a reasonable high end of a range of CO_2 price forecasts?

A. No. Although the forecast is far more reasonable than the Company's low CO_2 price forecast, it still is too low to be considered the high end of a reasonable range of possible future CO_2 emissions allowance prices. In particular, IPL's high CO_2 price forecast does not reflect the emissions allowance prices that could result from a number of the bills that have been introduced in Congress which propose very significant emissions reductions.

Q. Has Synapse developed a carbon price forecast that would assist the Board in evaluating the proposed SGS Unit 4?

A. Yes. Synapse's forecast of future carbon dioxide emissions prices are presented in Figure 5 below.

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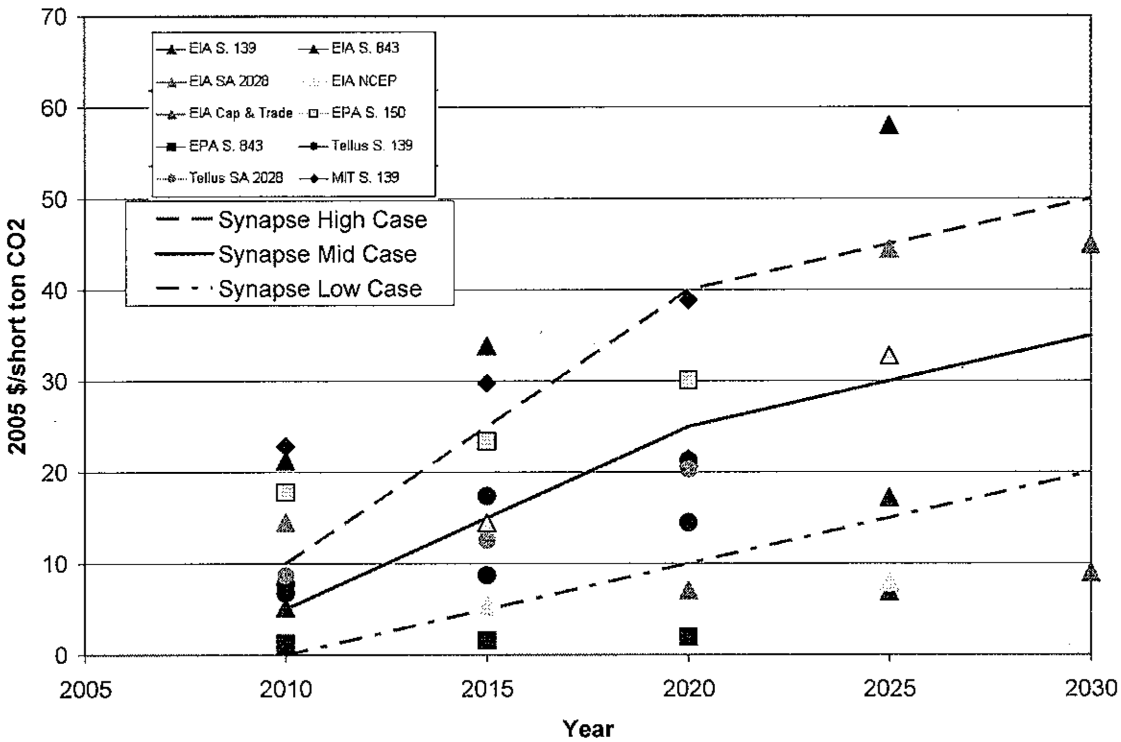
[47] IPL Confidential Response to OCA DR. No. 21, Attachment A, at pages 58 and 65 of 212.
[48] IPL Confidential Response to OCA DR. No. 21, Attachment A, at page 56 of 212.

Figure 5. Synapse Carbon Dioxide Prices



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

A. Synapse's forecast, levelized[49] over 20 years, 2011 – 2030, is provided in Table 4 below.

Table 5: Synapse's Levelized Carbon Price Forecast (2005\$/ton of CO_2)

Low Case	Mid Case	High Case
$8.23	$19.83	$31.43

Q. When were the Synapse CO_2 emission allowance price forecasts shown in Figure 5 developed?

A. The Synapse CO_2 emission allowance price forecasts were developed in the Spring of 2006.

Q. What have you assumed for the trajectory of CO_2 prices after 2030?

A. For the purposes of the OCA's EGEAS modeling in this case, we have conservatively assumed that CO_2 prices will increase at only the overall rate of inflation after 2030, that is, they will not increase in constant 2005 dollars.

Q. How were these CO_2 price forecasts developed?

A. The basis for the Synapse CO_2 price forecasts is described in detail in Exhibit___DAS-1, Schedule C, starting on page 41 of 63.

In general, the price forecasts were based, in part, on the results of economic analyses of individual bills that had been submitted in the 108th and 109th Congresses. We also considered the likely impacts of state, regional and international actions, the potential for offsets and credits, and the likely future trajectories of both emissions constraints and technological programs.

Q. Are the Synapse CO_2 price forecasts shown in Figure 5 based on any independent modeling?

A. Yes. Although Synapse did not perform any new modeling to develop our CO_2 price forecasts, our CO_2 price forecasts were based on the results of independent modeling prepared at the Massachusetts Institute of Technology ("MIT"), the Energy Information Administration of the Department of Energy ("EIA"), Tellus, and the U.S. Environmental Protection Agency ("EPA").[50]

In fact, two of the studies on which we relied when we developed the Synapse CO_2 price forecasts are the same MIT and EPA assessments of the 2003 McCain Lieberman bill which IPL has taken its low and high CO_2 prices.

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[49] A value that is "levelized" is the present value of the total cost converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).

[50] See Table 6.2 on page 42 of 63 of Exhibit___DAS-1, Schedule C.

Q. Do the triangles, squares, circles and diamond shapes in Figure 5 above reflect the results of all of the scenarios examined in the MIT, EIA, EPA and Tellus analyses upon which Synapse relied?

A. As a general rule, Synapse focused our attention either on the modeler's primary scenario or on the presented high and low scenarios to bracket the range of results.

For example, the blue triangles in Figure 5 represent the results from EIA's modeling of the 2003 McCain Lieberman bill, S.139. Synapse used the results from EIA's primary case which reflected the bill's provisions that allowed: (a) allowance banking; (b) use of up to 15 percent offsets in Phase 1 (2010-2015) and up to 10 percent offsets in Phase II (2016 and later years). The S.139 case also assumed commercial availability of advanced nuclear plants and of geological carbon sequestration technologies in the electric power industry.

Similarly, the blue diamonds in Figure 5 represent the results from MIT's modeling of the same 2003 McCain Lieberman bill, S.139. MIT examined 14 scenarios which considered the impact of factors such as the tightening of the cap in Phase II, allowance banking, availability of outside credits, and assumptions about GDP and emissions growth. Synapse included the results from Scenario 7 which included allowance banking and zero-cost credits, which effectively relaxed the cap by 15% and 10% in Phase I and Phase II, respectively. Synapse selected this scenario as the closest to the S.139 legislative proposal since it assumed that the cap was tightened in a second phase, as in Senate Bill 139.

At the same time, some of the studies only included a single scenario representing the specific features of the legislative proposal being analyzed. For example, SA 2028, the Amended McCain Lieberman bill set the emissions cap at constant 2000 levels and allowed for 15 percent of the carbon emission reductions to be met through offsets from non-covered sectors, carbon sequestration and qualified international sources. EIA presented one scenario in its table for this policy. The results from this scenario are presented in the green triangles in Figure 5.

Q. Do you believe that technological improvements and policy designs will reduce the cost of CO_2 emissions?

A. Yes. Exhibit___DAS-1, Schedule C identifies a number of factors that will affect projected allowance prices. These factors include: the base case emissions forecast; whether there are complimentary policies such as aggressive investments in energy efficiency and renewable energy independent of the emissions allowance market; the policy implementation timeline; the reduction targets in a proposal; program flexibility involving the inclusion of offsets (perhaps international) and allowance banking; technological progress; and emissions co-benefits.[51] In particular, Synapse anticipates that technological innovation will temper allowance prices in the out years of our forecast.

Q. Could carbon capture and sequestration be a technological innovation that might temper or even put a ceiling on CO_2 emissions allowance prices?

A. Yes.

Q. Does IPL see carbon capture technology as a currently commercially viable way to mitigate CO_2 emissions from pulverized coal plants like SGS Unit 4?

A. No. As I noted earlier, IPL has concluded that "commercially-available back-end CO2 emissions control technologies do not currently exist."[52]

Q. Do you agree with this assessment?

A. Yes. I agree with this view of the current status of carbon capture and sequestration technology although I would note that there is some experience with the piping of CO_2 gas for enhanced oil recovery and industrial use in certain geographical areas.

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[51] Exhibit___DAS-1, Schedule C, at pages 46 to 49 of 63.
[52] IPL Response to OCA DR. No. 44.

Q. Is there any consensus when carbon capture and sequestration technology will become commercially viable for plants like SGS Unit 4?

A. No. I have seen estimates that carbon capture and sequestration technology may be proven and commercially viable from as early as 2015 to 2030 or later. For example, the February 2007 *Future of Coal* study from the Massachusetts Institute of Technology:

> Many years of development and demonstration will be required to prepare for its successful, large scale adoption in the U.S. and elsewhere. A rushed attempt at CCS [carbon capture and sequestration] implementation in the face of urgent climate concerns could lead to excess cost and heightened local environmental concerns, potentially lead to long delays in implementation of this important option.[53]

Q. What are the currently estimated costs for carbon capture and sequestration at pulverized coal facilities?

A. Hope has been expressed concerning potential technological improvements and learning curve effects that might reduce the estimated cost of carbon capture and sequestration. However, I have seen recent studies by objective sources that estimate that the cost of carbon capture and sequestration could increase the cost of producing electricity at coal-fired power plants by 60-80 percent, on a $/MWh basis. For example, a very recent study by the National Energy Technology Laboratory ("NETL") projects that the cost of carbon capture and sequestration would be $68/ton of CO_2 avoided, in 2007 dollars, for pulverized coal plants.[54] This translates in to $65/ton of CO_2 avoided, in 2005 dollars.

The March 2007 "Future of Coal Study" from the Massachusetts Institute of Technology estimated that the cost of carbon capture and sequestration would be

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53 *The Future of Coal, Options for a Carbon-Constrained World, an Interdisciplinary MIT Study*, February 2007, at page 15. Available at http://web.mit.edu/coal/.

54 *Cost and Performance Baseline for Fossil Energy Plants*, National Energy Technology Laboratory, Revised August 2007, at page 27. Available at http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf

about $28/ton although it also acknowledged that there was uncertainty in that figure.[55] The tables in that study also indicated significantly higher costs for carbon capture for pulverized coal facilities, in the range of about $40/ton and higher.[56]

However, even when the technology for CO_2 capture matures, there will always be significant regional variations in the cost of storage due to the proximity and quality of storage sites.

Q. Have you seen any Company estimates of what it would cost to add carbon capture and sequestration technologies to the proposed SGS Unit 4?

A. No. IPL has only provided some generic estimates of the cost of employing carbon capture and sequestration technologies to coal plants. For example, the Company has cited [redacted].[57] Using data from the February 2007 MIT Future of Coal Study, the Company has estimated that [redacted]

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[55] *The Future of Coal, Options for a Carbon-Constrained World,* Massachusetts Institute of Technology, March 2007, at page xi. Available at http://web.mit.edu/coal/.
[56] Id, at page 19.
[57] IPL Response to OCA DR No. 97, Attachment A, at page 10.
[58] IPL Response to OCA DR No. 97, Attachment B, at page 1.
[59] IPL Response to OCA DR No. 97, Attachment C, at page 1.

Q. Does IPL reflect any costs associated with employing carbon capture and sequestration technologies in any of its economic analyses of SGS Unit 4?

A. No.

Q. Has IPL included any carbon capture and sequestration equipment or features in the current design or cost estimate for SGS Unit 4?

A. No. The Company has said that at this time no specific equipment has been included in the design of SGS Unit 4 exclusively for the purpose of carbon capture and sequestration.[60] However, some design features have been made for other reasons that IPL contends will make carbon capture less expensive.[61] According to the Company, other design features may also be feasible. IPL has committed to developing a white paper to study this issue in more depth and to evaluate the options that are available.[62]

Q. Has IPL reflected in its economic analyses any of the performance penalties that can be expected to be experienced as a result of the addition and use of carbon capture and sequestration technologies at SGS Unit 4?

A. No. Recent studies, such as the 2007 study by the National Energy Technology Laboratory, project that the output of a coal plant could be reduced by between 10 percent and 29 percent as a result of the addition of carbon capture and sequestration technologies. However, IPL has not included any such performance penalties in any of the economic analyses we have reviewed. In fact, IPL has not made any specific assessments of the performance penalties associated with the addition of carbon capture and sequestration equipment to the proposed unit.[63] All that IPL could do is to refer to a generic, and confidential, EPRI study of "Updated Cost and Performance Estimates for Clean Coal Technologies including CO2 Capture – 2006." However, the Company has not used in its analyses any of

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60 IPL Response to OCA DR. No. 180.
61 IPL Responses to OCA DR. No. 180 and OCA DR. No. 181.
62 IPL Response to OCA DR. No. 181.

the available information from that study, or from any of the public studies that have been released in recent years on the costs and performance penalties associated with the addition of carbon capture and sequestration technologies.

Q. Do the Synapse CO_2 price forecasts reflect the potential for the inclusion of domestic offsets and, perhaps, international offsets in U.S. carbon regulation policy?

A. Yes. Even the Synapse high CO_2 price forecast is consistent with, and in some cases lower than, the results of studies that assume the use of some levels of offsets to meet mandated emission limits. For example, as shown in Figure 6 the highest price scenarios in the years 2015, 2020 and 2025 were taken from the EIA and MIT modeling of the original and the amended McCain-Lieberman proposals. Each of the prices for these scenarios shown in Figure 5 reflects the allowed use of offsets.

Q. How do the Synapse CO_2 price forecasts compare to the CO_2 prices used by IPL in its recent analyses of the proposed SGS Unit 4?

A. The Synapse and IPL CO_2 price forecasts are shown in Figure 6 below. As this Figure demonstrates, IPL's high CO_2 price forecast is similar to our mid-forecast.

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[63] IPL Response to OCA DR. No. 35.

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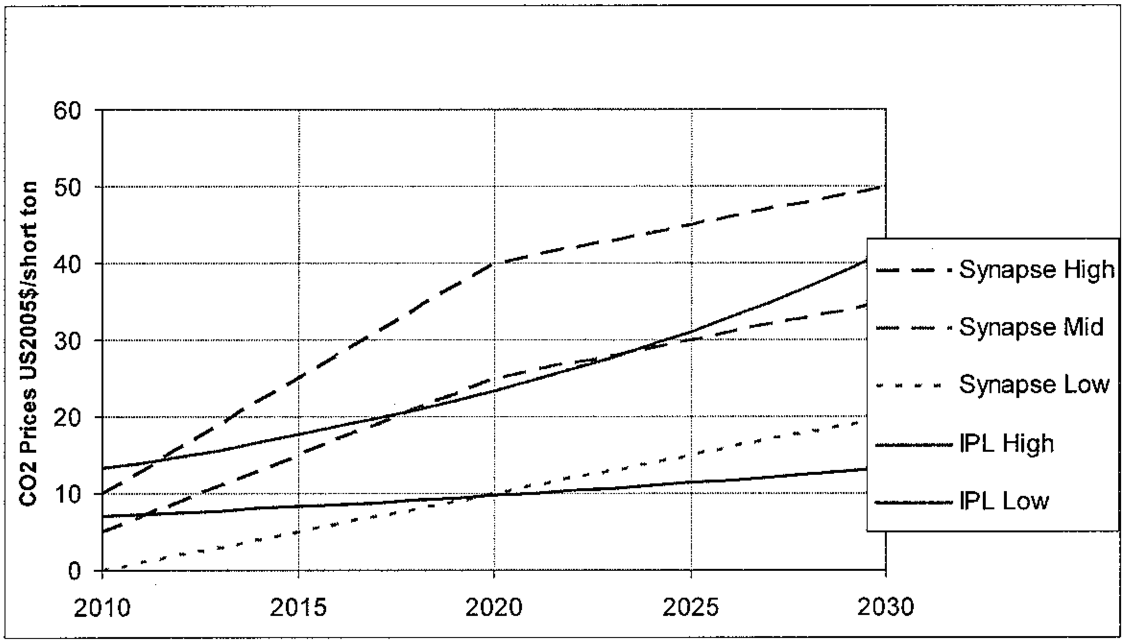
Figure 6: Synapse and IPL CO_2 Price Forecasts



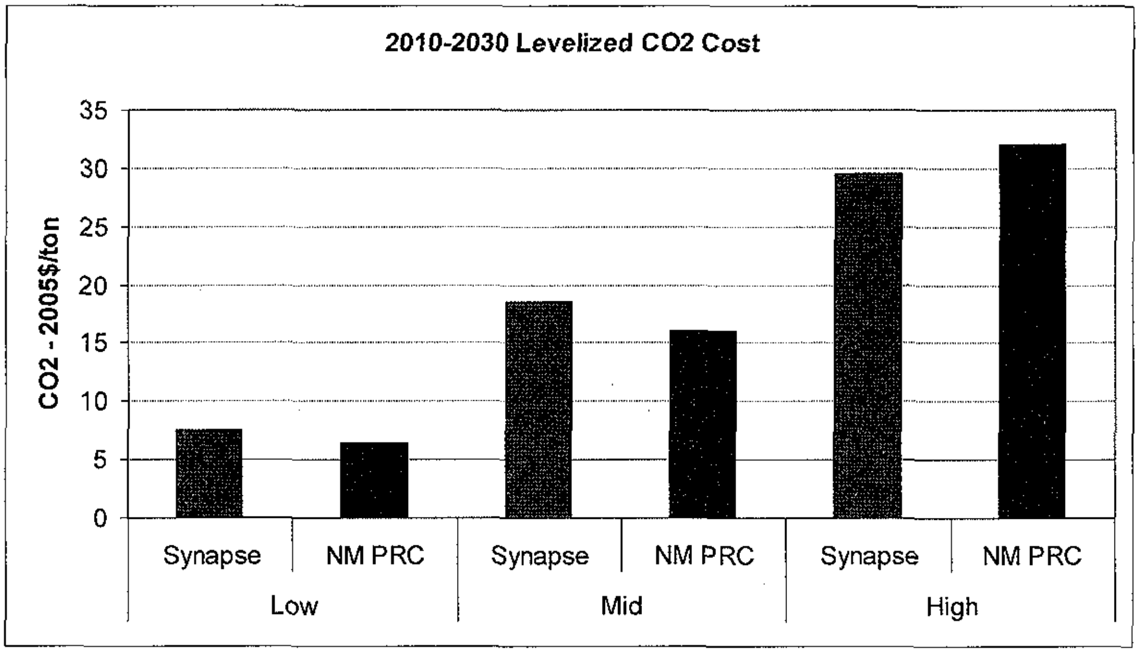
Q. Have you seen any recent independent forecasts of future CO_2 emissions prices that are similar to the Synapse forecast?

A. Yes. The Synapse CO_2 emissions allowance price forecasts compare favorably to recent forecasts of future CO_2 prices used in resource planning analyses.

For example, last June the New Mexico Public Regulation Commission ordered that utilities should consider a range of CO_2 prices in their resource planning.[64] This range runs from $8 to $40 per metric ton, beginning in 2010 and increasing at the overall 2.5 percent rate of inflation. This range includes significantly higher CO_2 prices than the low and high CO_2 prices used by IPL in its analyses of SGS Unit 4. Figure 7 below shows that the New Mexico Commission's CO_2 prices are extremely close to the Synapse price forecasts on a levelized basis.

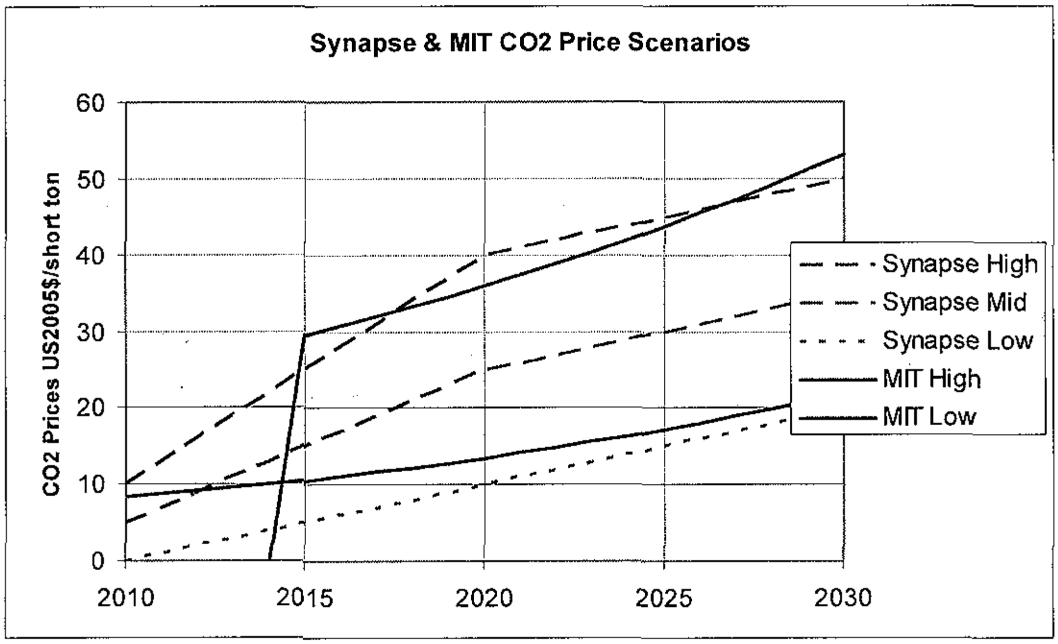
[64] A copy of this Order is included as Exhibit___DAS-1, Schedule D.

Figure 7: CO_2 Price Scenarios – Synapse & 2007 NM Public Regulation Commission



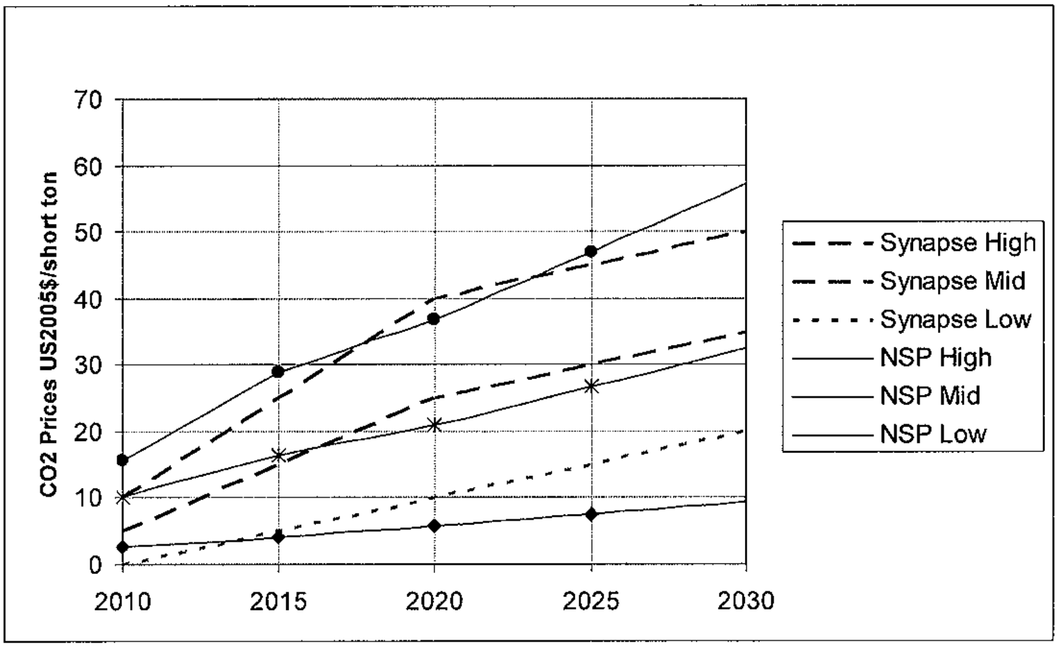
Similarly, the recent MIT study on *The Future of Coal* contained a set of assumptions about high and low future CO_2 emission allowance price. Figure 8 below shows that the CO_2 price trajectories in the MIT study are very close to the high and low Synapse forecasts.

Figure 8: **CO_2 Price Scenarios – Synapse & MIT March 2007 Future of Coal Study**



At the same time, in its recently completed Integrated Resource Planning process, Nova Scotia Power used CO_2 prices that were developed by Natsource. Figure 9 below shows that the CO2 prices used by Nova Scotia Power are very similar to the Synapse price forecasts.

Figure 9: CO_2 Price Scenarios – Synapse & Nova Scotia Power IRP



Q. Do you believe that the Synapse CO_2 price forecasts remain valid despite being based, in part, on analyses from 2003-2005 which examined legislation that was proposed in past Congresses?

A. Yes. Synapse believes it is important for the Commission to rely on the most current information available about future CO_2 emission allowance prices, as long as that information is objective and credible. The analyses upon which Synapse relied when we developed our CO_2 price forecasts were the most recent analyses and technical information available when Synapse developed its CO_2 price forecasts in the Spring of 2006. However, new information shows that our CO_2 prices remain valid even though the original bills that comprised part of the basis for the forecasts expired at the end of the Congress in which they were introduced.

Most importantly, many of the new greenhouse gas regulation bills that have been introduced in Congress are significantly more stringent than the bills that were being considered prior to the spring of 2006. As I will discuss below, the increased stringency of current bills can be expected to lead to higher CO_2

emission allowance prices. The higher forecast natural gas prices that are being forecast today, as compared to the natural gas price forecasts from 2003 or 2004, also can be expected to lead to higher CO_2 emissions allowance prices.

Q. Do the Synapse carbon price forecasts presented in Figures 5 through 9 reflect the emission reduction targets in the bills that have been introduced in the current Congress?

A. No. Synapse developed our price forecasts late last spring and relied upon bills that had been introduced in Congress through that time. The bills that have been introduced in the current US Congress generally would mandate much more substantial reductions in greenhouse gas emissions than the bills that we considered when we developed our carbon price forecasts. Consequently, we believe that our forecasts are conservative but consistent with the climate change legislation that has been introduced in the current Congress.

Q. Have you seen any analyses of the CO_2 prices that would be required to achieve the much deeper reductions in CO_2 emissions that would be mandated under the bills currently under consideration in Congress?

A. Yes. An *Assessment of U.S. Cap-and-Trade Proposals* was issued last spring by the MIT Joint Program on the Science and Policy of Global Change.[65] This *Assessment* evaluated the impact of the greenhouse gas regulation bills that are being considered in the current Congress.

Twenty nine scenarios were modeled in the *Assessment*. These scenarios reflected differences in such factors as emission reduction targets (that is, reduce CO_2 emissions 80% from 1990 levels by 2050, reduce CO_2 emissions 50% from 1990 levels by 2050, or stabilize CO_2 emissions at 2008 levels), whether banking of allowances would be allowed, whether international trading of allowances would be allowed, whether only developed countries or the U.S. would pursue

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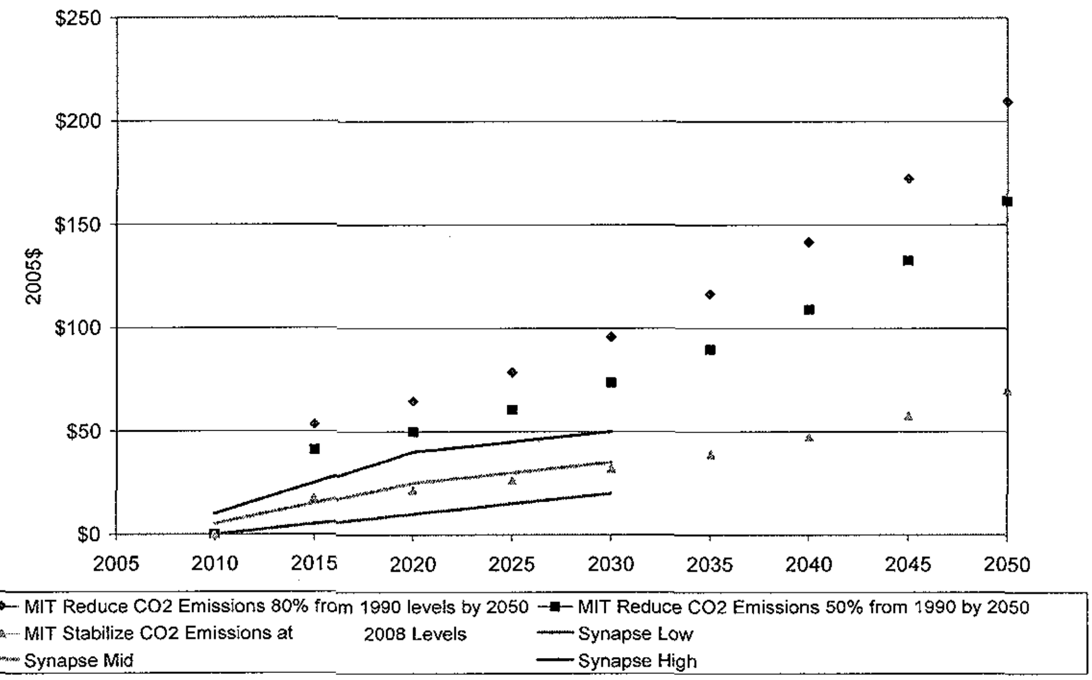
[65] Available at http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt146.pdf.

greenhouse gas reductions, whether there would be safety valve prices adopted as part of greenhouse gas regulations, and other factors.[66]

In general, the ranges of the projected CO_2 prices in these scenarios were higher than the range of CO_2 prices in the Synapse forecast. For example, twelve of the 29 scenarios modeled by MIT projected higher CO_2 prices in 2020 than the high Synapse forecast. Fourteen of the 29 scenarios (almost half) projected higher CO_2 prices in 2030 than the high Synapse forecast.

Figure 10 below compares the three Core Scenarios in the MIT *Assessment* with the Synapse CO_2 price forecasts.

Figure 10: CO_2 Price Scenarios – Synapse and Core Scenarios in April 2007 MIT *Assessment of U.S. Cap-and-Trade Proposals*

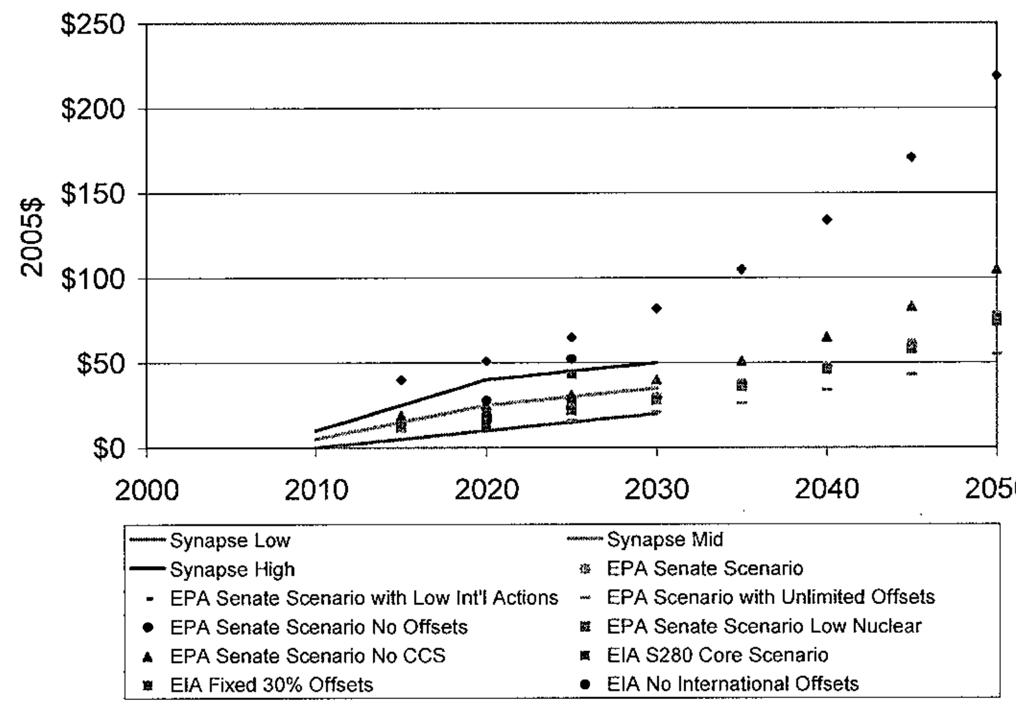


[66] The scenarios examined in the MIT *Assessment of U.S. Cap-and-Trade Proposals* are listed in Exhibit___DAS-1, Schedule E.

Q. Have you compared the Synapse CO_2 emissions allowance price forecasts to any other assessments of current bills in Congress?

A. Yes. Both EPA and the Energy Information Agency (EIA) of the Department of Energy have analyzed the impact of the current version of the McCain-Lieberman legislation (Senate Bill 280).[67] Figure 11 below shows that the Synapse CO_2 price forecasts are consistent with the range of scenarios examined in the EPA and EIA assessments:

Figure 11: Synapse CO_2 Price Forecasts and Results of EPA and EIA Assessment of Current McCain Lieberman Legislation

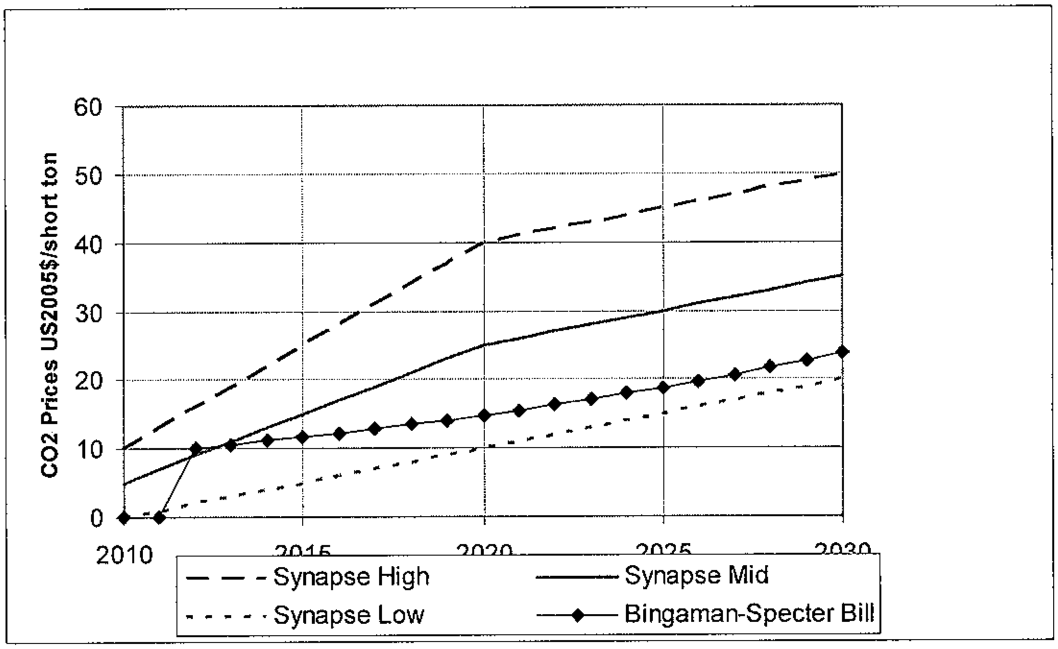


67 *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007,* Energy Information Administration, July 2007 and *EPA Analysis of the Climate Stewardship and Innovation Act of 2007, S. 280 in 110th Congress*, July 16, 2007. These reports are available at http://tonto.eia.doe.gov/FTPROOT/service/sroiaf(2007)04.pdf and http://www.eia.doe.gov/oiaf/servicerpt/csia/index.html.

Q. How do the Synapse CO_2 forecasts compare to the safety valve prices in the bill introduced by Senators Bingaman and Specter?

A. As shown in Figure 12 below, the safety valve prices in the legislation introduced by Senators Bingaman and Specter fall between the Synapse mid and low forecasts.

Figure 12: Synapse CO_2 Price Forecasts and Safety Valve Prices in Bingaman-Specter Legislation in 110th Congress



Q. Would it be reasonable to assume that a new supercritical coal-fired plant like SGS Unit 4 will be grandfathered under federal climate change legislation or will be favored with the provision of extra CO_2 emission allowance allocations that could mitigate or offset the impact of CO_2 regulations?

A. No. It is unclear what provisions for grandfathering existing coal plants, if any, will be adopted as part of future greenhouse gas legislation. At the same time, it is unrealistic to expect that many or all of the new coal-fired plants currently being proposed will be grandfathered because of the substantial reductions in CO_2

emissions from current levels that have to be made by 2050 just to stabilize atmospheric concentrations of CO_2 at 450 ppm to 550 ppm.

Meeting these goals will require either a reduction in dependence on coal for electricity generation or a very large investment in conversion of the current coal generating fleet in the U.S. The only realistic way either of these is going to happen is with a large marginal cost on greenhouse gas emissions such as a CO_2 tax or higher emissions allowance prices. It is not reasonable to expect that a new supercritical coal plant, like SGS Unit 4, which will substantially increase the emissions of CO_2 into the atmosphere, will receive significant emission allowances under any U.S. carbon regulation plan.

For example, the National Commission on Energy Policy has recently recommended that "new coal plants built without [carbon capture and sequestration] not be "grandfathered" (i.e., awarded free allowances) in any future regulatory program to limit greenhouse gas emissions."[68] A report of an interdisciplinary study at the Massachusetts Institute of Technology on *The Future of Coal* similarly noted that:

> There is the possibility of a perverse incentive for increased early investment in coal-fired power plants without capture, whether SCPC or IGCC, in the expectation that the emissions from these plants would potentially be "grandfathered" by the grant of free CO2 allowances as part of future carbon emissions regulations and that (in unregulated markets) they would also benefit from the increase in electricity prices that will accompany a carbon control regime. Congress should act to close this "grandfathering" loophole before it becomes a problem.[69]

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68 *Energy Policy Recommendations to the President and the 110th Congress*, National Commission on Energy Policy, April 2007, at page 21. Available at http://energycommission.org/files/contentFiles/NCEP_Recommendations_April_2007_4656f9759c345.pdf.

69 *The Future of Coal, Options for a Carbon-Constrained World, an Interdisciplinary MIT Study*, March 2007, at page (xiv). Available at http://web.mit.edu/coal/.

Additionally, it has been proposed in Congress that new coal-fired plants would be required to actually have carbon capture and sequestration technology. For example, a bill by Massachusetts Senator Kerry's bill limit CO_2 emissions from new coal-fired facilities to 285 lbs/MWh. New coal-fired facilities would be defined as those that begin construction on or after April 26, 2007 and would certainly include the proposed Hempstead Project.

Q. What are you recommendations concerning the CO_2 prices that the Commission should use in evaluating IPL's proposed SGS Unit 4?

A. Given the uncertainty associated with the legislation that eventually will be passed by Congress, we believe that the Commission should use the wide range of forecasts of CO_2 prices shown in Figure 4 above to evaluate the relative economics of the proposed Repowering Project.

Q. How much additional CO_2 would SGS Unit 4 emit into the atmosphere?

A. SGS Unit 4 can be expected to emit approximately five million tons of CO_2 annually.[70]

Q. What would be the annual costs of greenhouse gas regulations to IPL and its ratepayers under the Synapse CO_2 price forecasts if the Company proceeds with its proposed SGS Unit 4?

A. The range of the incremental annual, levelized cost to the Company and its ratepayers from greenhouse gas regulations would be:

Synapse Low CO_2 Case: 2.75 million tons of CO_2 · 8.23 dollars/ton = 23 million dollars

Synapse Mid CO_2 Case: 2.75 million tons of CO_2 · 19.83 dollars/ton = 55 million dollars

Synapse High CO_2 Case: 2.75 million tons of CO_2 · 31.43 dollars/ton = 86 million dollars

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70 This reflects an 90 percent average annual capacity factor and projected CO_2 emissions of 1991 lbs/MWh.

Q. Has IPL examined the impact that federal regulation of greenhouse gas emissions could have on its customers electric rates?

A. An April 2007 presentation to the Company's senior management on *New Generation Support Strategy Update* did look at the impact that $15 and $29/ton CO_2 taxes would have on customers. This analysis [redacted][71]

4. IPL Has Not Adequately Considered The Risk Of Further Increases In The Estimated Cost Of The SGS Unit 4 Project

Q. What is the currently estimated cost for SGS Unit 4?

A. The currently estimated cost of SGS Unit 4, without AFUCD or any other financing costs, is [redacted].[72]

Q. Is it reasonable to expect that the actual cost of the project will be higher than IPL now estimates?

A. Yes. The costs of building power plants have soared in recent years as a result of the worldwide demand for power plant design and construction resources and commodities. There is no reason to expect that plant costs will not continue to rise during the years when the detailed engineering, procurement and construction of SGS Unit 4 will be underway. This is especially true given the very early stage of the engineering and procurement for the project.

For example, Duke Energy Carolinas' originally estimated cost for the two unit coal-fired Cliffside Project was approximately $2 billion. In the fall of 2006, Duke announced that the cost of the project had increased by approximately 47 percent ($1 billion). After the project had been downsized because the North

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[71] IPL's Confidential Response to OCA DR. No. 21, Attachment A, at page 69 of 212.
[72] IPL Confidential Response to OCA DR. No. 183, Attachment A, page 1 of 1.

Carolina Utilities Commission refused to granted a permit for two units, Duke announced that the cost of that single unit would be about $1.53 billion, not including financing costs. In late May 2007, Duke announced that the cost of building that single unit had increased by about another 20 percent. As a result, the estimated cost of the one unit that Duke is building at Cliffside is now $1.8 billion exclusive of financing costs. Thus, the single Cliffside unit is now expected to cost almost as much as Duke originally estimated for a two unit plant.

Q. Did Duke explain to the North Carolina Utilities Commission the reasons for the skyrocketing cost of the Cliffside Project?

A. Yes. In testimony filed at the North Carolina Utilities Commission on November 29, 2006, Duke Energy Carolinas emphasized that the competition for resources had had a significant impact on the costs of building new power plants. This testimony was presented to explain the approximate 47 percent ($1 billion) increase in the estimated cost of Duke Energy Carolinas' proposed coal-fired Cliffside Project that the Company announced in October 2006.

For example, Duke Energy Carolinas explained that:

> The costs of new power plants have escalated very rapidly. This effect appears to be broad based affecting many types of power plants to some degree. One key steel price index has doubled over the last twelve months alone. This reflects global trends as steel is traded internationally and there is international competition among power plant suppliers. Higher steel and other input prices broadly affects power plant capital costs. A key driving force is a very large boom in U.S. demand for coal power plants which in turn has resulted from unexpectedly strong U.S. electricity demand growth and high natural gas prices. Most integrated U.S. utilities have decided to pursue coal power plants as a key component of their capacity expansion plan. In addition, many foreign companies are also expected to add large amounts of new coal power plant capacity. This global boom is straining supply. Since coal power plant equipment suppliers and bidders also supply other types of

> plants, there is a spill over effect to other types of electric generating plants such as combined cycle plants.[73]

Duke further noted that the actual coal power plant capital costs as reported by plants already under construction exceed government estimates of capital costs by "a wide margin (i.e., 35 to 40 percent). Additionally, current announced power plants appear to face another increase in costs (i.e., approximately 40 percent addition."[74] Thus, according to Duke, new coal-fired power plant capital costs had increased approximately 90 to 100 percent since 2002.

Q. Have other coal-fired plant projects experienced similar cost increases?

A. Yes. A large number of projects have announced significant construction cost increases over the past few years. For example, the cost of Westar's proposed coal-fired plant in Kansas, originally estimated at $1 billion, increased by 20 percent to 40 percent, over just 18 months. This prompted Westar's Chief Executive to warn: "When equipment and construction cost estimates grow by $200 million to $400 million in 18 months, it's necessary to proceed with caution."[75] As a result, the company has suspended site selection for the coal-plant and is considering other options, including building a natural gas plant, to meet growing electricity demand.

The estimated cost of the now-cancelled Taylor Energy Center in Florida increased by 25 percent, $400 million, in just 17 months between November 2005 and March 2007. The estimated cost of the Big Stone II coal-fired power plant project in South Dakota has increased by about 60 percent since the project was

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73 Direct Testimony of Judah Rose for Duke Energy Carolinas, North Carolina Utilities Commission Docket No. E-7, SUB 790, at page 4, lines 2-14. Mr. Rose's testimony is available on the North Carolina Utilities Commission website. Available at http://ncuc.commerce.state.nc.us/cgi-bin/fldrdocs.ndm/INPUT?compdesc=DUKE%20ENERGY%20CAROLINAS%2C%20LLC&docketdesc=&comptype=E&docknumb=7&Search=Search&suffix1=&subnumb=790&suffix2=&parm1=000123542&parm2=01/09/2007&parm3=WBAAAA90070B.

74 Ibid, at page 6, lines 5-9, and page 12, lines 11-16.

75 Available at http://www.westarenergy.com/corp_com/corpcomm.nsf/F6BE1277A768F0E4862572690055581C/$file/122806%20coal%20plant%20final2.pdf

first announced. Finally, the estimated cost of the Little Gypsy Repowering Project (gas to coal) increased by 55 percent between announcement of the project in April 2007 and the filing of a request for a license to build in July 2007.

Q. What are the sources of the worldwide competition for power plant design and construction resources, commodities and equipment?

A. The worldwide competition is driven mainly by huge demands for power plants in China and India and by a rapidly increasing demand for power plants and power plant pollution control modifications in the United States required to meet SO_2 and NO_x emissions standards. The demand for labor and resource to rebuild the Gulf Coast area after Hurricanes Katrina and Rita hit in 2005 also has contributed to rising costs for construction labor and materials.

Q. Is it commonly accepted that domestic United States and worldwide competition for power plant design and construction resources, commodities and manufacturing have led to these significant increases in power plant construction costs in recent years?

A. Yes. A wide range of energy, construction and financial industry studies have identified the worldwide competition for power plant resources as the driving force for the skyrocketing construction costs.

For example, a June 2007 report by Standard & Poor's, *Increasing Construction Costs Could Hamper U.S. Utilities' Plan to Build New Power Generation*, has noted that:

> As a result of declining reserve margins in some U.S. regions ... brought about by a sustained growth of the economy, the domestic power industry is in the midst of an expansion. Standing in the way are capital costs of new generation that have risen substantially over the past three years. Cost pressures have been caused by demands of global infrastructure expansion. In the domestic power industry, cost pressures have arisen from higher demand for pollution control equipment, expansion of the transmission grid, and new generation. While the industry has experienced buildout cycles in the past, what makes the current environment different is

> the supply-side resource challenges faced by the construction industry. A confluence of resource limitations have contributed, which Standard & Poors' Rating Services broadly classifies under the following categories
>
> - Global demand for commodities
> - Material and equipment supply
> - Relative inexperience of new labor force, and
> - Contractor availability
>
> The power industry has seen capital costs for new generation climb by more than 50% in the past three years, with more than 70% of this increase resulting from engineering, procurement and construction (EPC) costs. Continuing demand, both domestic and international, for EPC services will likely keep costs at elevated levels. As a result, it is possible that with declining reserve margins, utilities could end up building generation at a time when labor and materials shortages cause capital costs to rise, well north of $2,500 per kW for supercritical coal plants and approaching $1,000 per kW for combined-cycle gas turbines (CCGT). In a separate yet key point, as capital costs rise, energy efficiency and demand side management already important from a climate change perspective, become even more crucial as any reduction in demand will mean lower requirements for new capacity.[76]

More recently, the president of the Siemens Power Generation Group told the New York Times that "There's real sticker shock out there."[77] He also estimated that in the last 18 months, the price of a coal-fired power plant has risen 25 to 30 percent.

A September 2007 report on *Rising Utility Construction Costs* prepared by the Brattle Group for the EDISON Foundation similarly concluded that:

> Construction costs for electric utility investments have risen sharply over the past several years, due to factors beyond the industry's control. Increased prices for material and manufactured components, rising wages, and a tighter market for construction

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76 *Increasing Construction Costs Could Hamper U.S. Utilities' Plans to Build New Power Generation*, Standard & Poor's Rating Services, June 12, 2007, at page 1. A copy of this report is included in Exhibit___DAS-1, Schedule F.

77 "Costs Surge for Building Power Plants, *New York Times*, July 10, 2007.

project management services have contributed to an across-the-board increase in the costs of investing in utility infrastructure. These higher costs show no immediate signs of abating.[78]

The report further found that:

- Dramatically increased raw materials prices (e.g., steel, cement) have increased construction cost directly and indirectly through the higher cost of manufactured components common in utility infrastructure projects. These cost increases have primarily been due to high global demand for commodities and manufactured goods, higher production and transportation costs (in part owing to high fuel prices), and a weakening U.S. dollar.

- Increased labor costs are a smaller contributor to increased utility construction costs, although that contribution may rise in the future as large construction projects across the country raise the demand for specialized and skilled labor over current or project supply. There also is a growing backlog of project contracts at large engineering, procurement and construction (EPC) firms, and construction management bids have begun to rise as a result. Although it is not possible to quantify the impact on future project bids by EPC, it is reasonable to assume that bids will become less cost-competitive as new construction projects are added to the queue.

- The price increases experienced over the past several years have affected all electric sector investment costs. In the generation sector, all technologies have experienced substantial cost increases in the past three years, from coal plants to windpower projects…. As a result of these cost increases, the levelized capital cost component of baseload coal and nuclear plants has risen by $20/MWh or more – substantially narrowing coal's overall cost advantages over natural gas-fired combined-cycle plants – and thus limiting some of the cost-reduction benefits expected from expanding the solid-fuel fleet.

- The rapid increases experienced in utility construction costs have raised the price of recently completed infrastructure projects, but the impact has been mitigated somewhat to the extent that construction or materials acquisition preceded the most recent price increases. The impact of rising costs has a more dramatic impact on the estimated cost of proposed utility infrastructure projects, which fully incorporates recent price trends. This has raised significant concerns that the next wave of utility investments

78 *Rising Utility Construction Costs: Sources and Impacts*, prepared by The Brattle Group for the EDISON Foundation, September 2007, at page 31. A copy of this report is attached as Exhibit___DAS-1, Schedule G.

> may be imperiled by the high cost environment. These rising construction costs have also motivated utilities and regulators to more actively pursue energy efficiency and demand response initiatives to reduce the future rate impacts on consumers.[79]

Q. Is it reasonable to expect that these same factors will lead to construction delays as well as rising costs?

A. Yes.

Q. Does the current SGS Unit 4 cost estimate include a contingency to reflect possible future cost increases?

A. Yes. It appears that the current SGS Unit 4 construction cost estimate includes a [redacted] contingency which would be about [redacted] percent of the estimate, far below the double digit annual escalation experienced by other coal-fired power plant construction projects in recent years.

Q. What is the current status of contracting and procurement for SGS Unit 4?

A. Basically, it appears that none of the major contracts for SGS Unit 4 have been finalized. IPL has indicated that it does not expect to give even a limited notice to proceed to its Engineering, Procurement and Construction ("EPC") contractor until December 2007, with a full notice to proceed not expected until July 2008. Similarly, the full notices to proceed with procurement of the steam turbine generator, steam generator and air quality control system are not expected to be issued until July 2008. The current estimated start for construction is October 2008.[80]

The extremely early status of contracting and procurement render the project very susceptible to cost increases and construction delays.

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79 Id, at pages 1-3.
80 IPL Response to OCA DR No. 24.

Q. Has the Company recognized the risks associated with rising power plant construction costs?

A. Yes. Internal Alliant Energy presentations reflect the risks associated with building new power plants in the current environment. For example, a February 2, 2007 presentation to Alliant Energy's Board of Directors concerning the proposed Nelson Dewey #3 coal plant noted that the U.S. Department of Energy current forecasts the "largest coal generation capacity installation in 40 years."[81] The same presentation also listed the risks associated with pursuing that project:

[redacted]

Q. Did IPL reflect the potential for higher capital costs in its recent 2007 Resource Plan modeling for SGS Unit 4?

A. No. The Company used the same plant capital cost in its base case modeling and the two CO_2 price sensitivity scenarios.

Q. Did IPL reflect the potential for a schedule delay as a result of the increased competition for power plant design and construction resources, commodities and manufacturing capacity?

A. No.

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81 IPL's Confidential Response to OCA DR. No. 60, Attachment B, at page 6 of 12.

82 Id, at page 8 of 12.

Q. Is it your testimony that IPL should change its current cost estimate for SGS Unit 4?

A. Not necessarily. However, in order to evaluate the risks of continuing with the proposed project, IPL should have prepared sensitivity studies that examined the relative economics of SGS Unit 4 against alternatives assuming that the capital cost of the project is substantially higher than the Company now estimates. For example, IPL should have prepared sensitivity analyses that reflected capital costs 20 percent and 40 percent higher than its current estimated cost for SGS Unit 4. It is not unreasonable to expect such additional cost increases at SGS Unit 4 in light of the industry-wide experience and the expectation that worldwide demand will continue to be a driving force for rising prices.

Q. Have you seen any such capital cost sensitivity analyses that have been prepared by IPL?

A. Not in this proceeding. However, IPL did prepare a higher capital cost sensitivity analysis as part of its 2005 Resource Plan modeling. In that sensitivity, IPL assumed a capital cost for a coal-fired power plant that was approximately 32 percent higher than the base case capital cost.

Q. Is it reasonable to expect that these same current market conditions also will lead to increases in the estimated costs of other supply-side alternatives such as natural gas-fired or wind facilities?

A. Yes.

Q. What impact would higher coal-plant capital costs have on the relative economics of energy efficiency as compared to SGS Unit 4?

A. I have seen no evidence that the same worldwide demand for power plant resources has led to significant increase in the costs of energy efficiency measures. Therefore, it is reasonable to expect that higher coal-plant capital costs increase the relative economics and attractiveness of energy efficiency.

Q. Have you seen any evidence that potential participants in SGS Unit 4 are very concerned about the potential for increasing plant construction costs?

A. [redacted][83]

Q. What was IPL's response to this demand?

A. [redacted]"[84]

Q. Have you seen any subsequent correspondence between IPL and CIPCO or Corn Belt, or any other potential co-owners of SGS Unit 4, that addresses this issue?

A. No. IPL has said that there is no additional correspondence that is related to this provision.

5. Adding SGS Unit 4 Would Reduce, Not Increase, the Diversity in IPL's Generation Supply

Q. Is supply diversity an issue that the Commission should consider as it evaluates IPL's proposed SGS Unit 4?

A. Yes. I think supply diversity is a very important consideration. Reducing the Company's current heavy dependence on fossil-fired generation, especially coal-fired power, and moving towards greater use of renewable resources and energy efficiency, should be a major goal given the threat posed by global climate change

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[83] IPL Confidential Response to OCA DR. No. 7, Attachment A, page 128 of 579.
[84] IPL Confidential Response to OCA DR. No. 51A.

and the inevitability of federal regulation of greenhouse gas emissions in the near future. Building SGS Unit 4 would be a major step in the wrong direction.

Q. What would be the Company's energy supply mix under its proposed Resource Plan that includes SGS Unit 4?

A. As shown in Figures 13 and 14 below, IPL's generation supply which is already very heavily dependent on coal and other CO_2 emitting fossil fuels [redacted] with the Company's base resource plan that includes SGS Unit 4. In fact, [redacted] of the energy supplied by IPL in the year 2022 would be generated at coal-fired facilities. The data for this figure were taken from IPL's base case EGEAS model for the year 2022.

PUBLIC VERSION

Figure 13: IPL Energy Supply Mix in 2007 [CONFIDENTIAL]

Figure 14: IPL Energy Supply Mix in 2022 [CONFIDENTIAL]

Thus, under its base case 2007 Resource Plan, IPL's dependence on coal-fired generation would [redacted] percent in 2007 [redacted] percent in 2022.

Q. Why is considering a company's generation mix the appropriate way to evaluate its fuel diversity?

A. Because the issue of fuel diversity is a matter of the amount of each type of fuel that the company burns, and the cost consequences of burning that fuel. Simply looking at its capacity mix does not offer any information about the utilization of that capacity.

Q. Is fuel diversity a broader issue than merely deciding whether to build a coal- or gas-fired generating unit?

A. Yes, it should be. Implementing demand side management and energy efficiency programs and building or buying power from non- or low-carbon emitting renewable resource facilities also would increase a company's supply diversity. Investments in demand side management and renewable resources would provide real benefits in terms of supply diversity by reducing IPL's dependency on coal, oil and gas.

6. IPL's Modeling Analyses Do Not Show that SGS Unit 4 Would Be the Lowest Cost and the Lowest Risk Option for the Company's Ratepayers

Q. Is it IPL's position that the construction of SGS Unit 4 will provide greater economic benefits than any other options available to the Company?

A. No. The Company has said that the language of Code Section 476.53 does not require that a utility choose the option that provides the "greatest economic benefits."[85] The Company goes on to state that "An option that provides the "greatest economic benefits" would not necessarily also adequately balance

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[85] IPL Response to OCA DR. No. 90.a.

environmental concerns. That said, IPL believes that it has chosen a prudent option that will balance economic with environmental benefits, as supported by its Application."[86]

Q. Does the Company provide any evidence of a balancing the economic and environmental benefits of available options that shows that SGS Unit 4 is a prudent option?

A. No. The Company's Application and supporting testimony and exhibits do not provide any comparative balancing of the environmental and economic benefits and costs of SGS Unit 4 and other available options. Instead, IPL merely makes a number of claims about the environmental benefits of the SGS Unit 4 project, while completely ignoring the plain fact that the plant, if built, will be emitting approximately 5 million tons of additional CO_2 into the atmosphere each year for a 40 to 60 year operating life. The Company does not compare the relative environmental benefits of building SGS Unit 4 as a supercritical coal-fired power plant to the benefits of undertaking non-carbon emitting options such as energy efficiency and wind resources, in conjunction with the addition of some new gas capacity, if needed.

Q. What evidence does IPL provide to show the relative economic benefits of SGS Unit 4 as compared to other available options?

A. The only evidence that IPL provides in its Application and supporting testimony and exhibits in support of the economic benefits of SGS Unit 4 is to say that the EGEAS model picked the plant in the Company's most recent 2007 resource planning analyses.[87] It does not show the amount by which the cost of the resource plan with SGS Unit 4 is lower than the costs of other reasonable resource plans without the plant. Indeed, IPL witness Kitchen does not even state that SGS Unit 4 is the most economic option for meeting IPL's capacity and energy needs.

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86 Id.
87 See the Direct Testimony of Brent R. Kitchen.

Instead, his testimony is limited to saying that "In its evaluation, IPL concluded a coal-fired generating unit met the overall economic flexibility to meet IPL's demand and energy requirements in the 2013 timeframe."

Q. Mr. Kitchen testifies that IPL considers a wide of future resource alternatives in its resource planning using the EGEAS model:

> **IPL evaluates its customers' capacity and energy needs using the Electric Generation Expansion Analysis System (EGEAS). By using EGEAS, all combinations of existing resources and future resource alternatives are considered when determining the most reasonable expansion plan. IPL evaluates many different resource alternative, both traditional and nontraditional, including purchased power agreements (market, short- and long-term), simple cycle gas turbines, combined cycle gas turbines, coal technologies, renewable resources (wind, biomass, biogas and ethanol-fueled generation) and demand-side management (load management and conservation) resources.[88]**

Have you seen any evidence that IPL considered such a wide range of alternatives in the 2007 Resource Plan modeling that it cites in support of SGS Unit 4?

A. No. The Company only prepared three EGEAS scenarios in its 2007 Resource Plan modeling. These were a base case scenario in which IPL determined that SGS Unit 4 was the preferred generation resource to add in 2013 and the two CO_2 price sensitivities. In all three of these scenarios, the Company only allowed the model to select from a limited range of [redacted] possible alternatives: [redacted]. No load management programs or energy efficiency investments were made available to the model. Nor do we see where the model had the option of selecting biomass or ethanol-fueled generation. Thus, there was no way that the EGEAS model could select these alternatives even if they were, in fact, lower cost options. In addition, as Mr. Drunsic and Mr. Fagan explain, IPL limited the amount of wind generation that the model could select, even if adding more wind beyond that needed to meet its reserve margin requirement would provide an economic advantage.

Q. Are there any other flaws or limitations in the 2007 Resource Plan modeling that the Company uses to justify the selection of SGS Unit 4?

Yes. There are a number of flaws that bias the analysis in favor of the coal-fired SGS Unit 4 project:

- As OCA witness Parker explains, IPL failed to allow the model to select any additional energy efficiency to meet its projected capacity and energy needs.
- As I explain in Section 4 above, IPL did not use a reasonable range of CO_2 emissions allowance prices in its 2007 Resource Plan modeling.
- As OCA witness Drunsic explains, IPL set the maximum number of so-called "superfluous units" that the model could select at two (that is, the model was set at SU=2). This unreasonably limited the amount of wind capacity that the model could add in early years beyond that needed to meet the chosen system reserve margin, even if adding more wind resources would result in lower cost plans.
- As OCA witness Fagan explains, IPL assumed an unnecessarily high, and unsupported, 18 percent reserve margin.
- As OCA witness Fagan explains, IPL unreasonably limited the total amount of new wind that IPL can add through the year 2022.
- As I explain in Section 5 above, IPL failed to reflect the very real risk that power plant capital costs could increase significantly above the figures assumed in its 2007 EGEAS modeling.
- IPL assumed that its new coal unit could operate at an extremely high capacity for all of the years of the study period.

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[88] Id, at page 3, line 21, to page 4, line 6.

Q. At what capacity factor(s) does SGS Unit 4 operate in IPL's 2007 Resource Plan modeling?

A. The coal-fired power plant added in 2013 in IPL's base case, that is, SGS Unit 4, operates at a [redacted] percent average annual capacity factor.

Q. Is it reasonable to expect that SGS Unit 4 will be able to operate at this average annual capacity factor over a projected 40 to 60 year service life?

A. No. It is very optimistic to assume that a plant that has not yet started commercial operations or, indeed, is not even under construction, will achieve such a high capacity factor in every year of an expected 40 to 60 year service life, especially during the plant's early immature "breaking-in" years of operation.

Q. What has been the recent operating performance of supercritical coal-fired power plants of the same size as SGS Unit 4?

A. According to data provided by IPL, coal-fired power plants sized between 600-799 MW, achieved an average 75.75 percent net capacity factor during the years 2001-2005.[89] These same units achieved an 87 percent availability factor and an 84.44 percent equivalent availability factor (which reflects deratings) during the same five year period.

Q. Isn't it reasonable to expect that a new supercritical unit like SGS Unit 4 will be able to perform better than the older units operating today?

A. Yes. It is reasonable to expect some improvement in performance from a new power plant <u>after</u> it completes an initial breaking-in period. However, expecting SGS Unit 4 to operate at an average annual [redacted] percent capacity factor for its entire 40 to 60 year service life still is not reasonable.

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[89] IPL Response to OCA DR. No.114, Attachment A.

Q. What capacity factors does Black & Veatch assume for 600 MW supercritical coal-fired power plants in its 2007 Power Station Characterization Study for Alliant Energy?

A. Black & Veatch assumes that the average net generation of a 600 MW supercritical coal-fired unit would be 4,470,000 MWh.[90] This translates into an 85 percent average annual capacity factor. This is slightly lower than the average 87.8 percent annual capacity factors that Black & Veatch projects for 500 MW and 750 MW coal-fired supercritical power plants in the 2003 and 2005 Power Station Characterization Studies it prepared for Alliant Energy.[91]

Black & Veatch also assumes an [redacted] percent average annual capacity factor for a 600 MW supercritical coal-fired power plant in its March 2007 Site Evaluation Study – Coal Technology, prepared for Alliant Energy.[92]

Q. What capacity factors do other companies assume for their proposed coal-fired power plants?

A. Much of the projected operating performance information we have seen for other coal-fired power plants is confidential. However, the owners of the proposed Big Stone II coal-fired power plant in South Dakota have publicly assumed an 88 percent average annual capacity factor for that unit. Entergy Louisiana has publicly assumed an 85 percent capacity in its reference case analyses for its proposed repowering of its natural-gas fired Little Gypsy Unit 3 as a coal-fired power plant.

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90 IPL's Response to OCA DR. No. 12, Attachment C, at page 97 of 212.
91 IPL's Response to OCA DR. No. 12, Attachment A, at page 71 of 117, and Attachment B, at page 75 of 157.
92 IPL's Confidential Response to OCA DR. No. 1, Attachment A, page 48 of 56.

Q. Are there any factors, besides imprudent management or normal maintenance, that could result in the plant's failing to achieve an assumed [redacted] percent capacity factor?

A. Yes. The primary source of fuel for SGS Unit 4 is planned to be Wyoming's Power River Basin. ("PRB") New coal-fired facilities, like SGS Unit 4, may be subject to some of the same production and coal-deliverability problems that occurred in 2005 and 2006 and that plagued existing coal-fired units throughout the Midwest that depend on coal supplies from the Powder River Basin. Such problems could adversely affect the reliability of SGS Unit 4 and its ability to operate at a consistently high average annual capacity factor.

Q. Could such production and deliverability problems also affect the prices of the coal that would be burned at SGS Unit 4?

A. Yes.

Q. Hasn't IPL effectively mitigated the risks associated with supply disruptions by requiring that the plant be designed to burn a range of fuel supplies?

A. IPL has mitigated the risk in part, but not fully. There still is a risk of being primarily dependent upon PRB coal because of the rising demand for PRB low sulfur sub-bituminous coal, the substantial investments that will be required to increase the amount of coal that can be transported from the PRB to power plants in the Midwest, and the market power that can be exercised by the small number of railroads that control the rail lines out of the PRB. In addition, there is a risk that the alternative fuel supplies that SGS Unit 4 would burn in place of PRB would, themselves, be unavailable when required or would be more expensive.

Q. Has IPL prepared any sensitivity analyses as part of their recent modeling to determine whether higher than expected coal prices and/or less than optimal plant performance due to coal deliverability problems would affect the overall economics of SGS Unit 4?

A. No. IPL has not prepared any such sensitivity analyses as part of its 2007 Resource Plan modeling that we have seen.

Q. Is it prudent to not even consider the potential for coal supply disruptions or price increases as a risk associated with developing SGS Unit 4?

A. No. Given the serious deliverability problems that have been experienced with coal from the Powder River Basin in 2005 and 2006 and the disputes that have arisen between coal shippers, utilities and the railroads that deliver coal from the Powder River Basin, it is not prudent to ignore this risk when evaluating the economics of proposed coal-fired facilities like SGS Unit 4. Due to disruptions in supplies from the Power River Basin, some utilities were forced to import coal from Columbia in South America or as far away as Indonesia.

Q. Did you undertake any modeling to correct for the flaws and limitations in IPL's 2007 Resource Planning modeling?

A. Yes. With our input, and that of OCA witness Parker, OCA staff has rerun the Company EGEAS modeling to reflect more reasonable assumptions.

Q. What scenarios has the OCA run to examine whether the lowest cost expansion plans selected by the EGEAS model include the proposed SGS Unit 4?

A. The scenarios that OCA witness Shi ran with our inputs are presented in Table 6 below:

1 **Table 6: OCA EGEAS Scenarios**

Scenario[93]	OCA Input Changes
IPL Inputs plus Superfluous Units = 10	Increased the maximum number of superfluous units that the model could select in any one year from 2 to10
IPL Inputs with Increased Wind Availability	Increased the Amount of Available New Wind from a Max. of 800 MW to 1400 MW by 2022
IPL Inputs with Increased Wind Availability and Increased Wind Capacity Credit	(1) Increased Amount of Available New Wind from a Max. of 800 MW to 1400 MW by 2022, and (2) Increased New Wind Capacity Credit from 10% to 15%
IPL Inputs with Low DSM	Allowed the Model to Select up to 286 MW of Load Reductions from Energy Efficiency
IPL Inputs with Low and Mid DSM	Allowed the Model to Select up to 458 MW of Load Reductions from Energy Efficiency
IPL Inputs with Low, Mid, and High DSM	Allowed the Model to Select Up to 608 MW of Load Reduction from Energy Efficiency
IPL Inputs with 20% Higher Power Plant Capital Costs	Increased IPL Capital Costs for all Resources by 20%
IPL Inputs with 40% Higher Power Plant Capital Costs	Increased IPL Capital Costs for all Resources by 40%
IPL Inputs with a 17% Minimum Reserve Margin	Reduced the Minimum Reserve Margin from 18% to 17%
IPL Inputs with a 16% Minimum Reserve Margin	Reduced the Minimum Reserve Margin from 18% to 16%
IPL Inputs with a 15% Minimum Reserve Margin	Reduced the Minimum Reserve Margin from 18% to 15%
IPL Inputs with a 14% Minimum Reserve Margin	Reduced the Minimum Reserve Margin from 18% to 14%

93 The maximum number of superfluous units that the model could select in any one year was increased from two to ten in each of the OCA's EGEAS scenarios, as explained in the Testimony of Michael Drunsic.

IPL Inputs but with Natural Gas Prices Increased by 10%	Increased IPL's Natural Gas Prices by 10% starting in 2010
IPL Inputs with Increased Wind and Low, Mid and High DSM	(1) Increased Amt. of Available New Wind from a Max. of 800 MW to 1400 MW by 2022, and (2) Allowed Up to 608 MW of Load Reduction from Energy Efficiency
IPL Inputs with (1) Increased Wind, (2) Low, Mid and High DSM, (2) 20% Higher Capital Costs %, and (4) 88% New Coal Capacity Factor	(1) Increased Amt. of Available New Wind from a Max. of 800 MW to 1400 MW by 2022; (2) Allowed Up to 608 MW of Load Reduction from Energy Efficiency; (3) Increased Capital Costs for all Resources by 20%; and (4) Increased the Forced Outage Rate for New Coal from 4% to 8.5%

Q. What were the results of the OCA's modeling?

A. The results of our EGEAS modeling, in terms of when a new coal plant is selected, are presented in Table 7 below.

Table 7: Results of OCA EGEAS Scenarios – Year in Which SGS Unit 4 is selected as part of the lowest cost expansion plan

Scenario	CO_2 Price			
	None	IPL Low	IPL High	Synapse High
IPL Base Case Inputs	2013	2013	2013	Not Selected
IPL Inputs except for the maximum number of "superfluous units" increased from two to ten	2013	2019	Not Selected	Not Selected
IPL Inputs with Increased Wind Availability	2013	2019	Not Selected	Not Selected
IPL Inputs with Increased Wind Availability and Increased Wind Capacity Credit	2013	2017	Not Selected	Not Selected
IPL Inputs with Low DSM	2013	2019	Not Selected	Not Selected
IPL Inputs with Low and Mid DSM	2018	2019	Not Selected	Not Selected
IPL Inputs with Low, Mid and High DSM	2018	2019	Not Selected	Not Selected
IPL Inputs with 20% higher Power Plant Capital Costs	2015	2017	Not Selected	Not Selected
IPL Inputs with 40% higher Power Plant Capital Costs	2015	2017	Not Selected	Not Selected
IPL Inputs except for a 17% Minimum Reserve Margin	2013	2018	Not Selected	Not Selected
IPL Inputs except for a 16% Minimum Reserve Margin	2014	2016	Not Selected	Not Selected
IPL Inputs except for a 15% Minimum Reserve Margin	2015	2019	Not Selected	Not Selected
IPL Inputs except for a 14% Minimum Reserve Margin	2015	2018	Not Selected	Not Selected
IPL Inputs plus Natural Gas Prices Increased by 10%	N/A	N/A	2019	Not Selected
IPL Inputs with Increased Wind and Low, Mid and High DSM	2018	Not Selected	Not Selected	Not Selected
IPL Inputs with (1) Increased Wind Availability, (2) Low, Mid and High DSM, (3) 20% higher Capital Costs and (4) An 88% New Coal Capacity Factor	2018	Not Selected	Not Selected	Not Selected

Thus, when IPL's high CO_2 prices was included, the EGEAS model added a new coal plant only as part of the lowest cost plan in one of the scenarios, other than in the Company's flawed base case model run. Even in that case, which assumed ten percent higher natural gas prices, the new coal plant still was not added until 2019, or six years later than IPL proposes to add SGS Unit 4.

As shown in Table 7, when IPL's low CO_2 prices were used, the installation date for the new coal plant in the lowest cost plan was delayed a minimum of between three and six years (that is, 2016 to 2019). These delays occurred in the scenarios which included increased wind availability or increased DSM availability or higher capital costs or the target reserve margins were reduced from 18 percent. When combined sensitivities reflecting increased wind and increased DSM were run, the new coal plant was not selected as part of the lowest cost plan even with the Company's low CO_2 prices.

A new coal plant was not selected in any of the lowest cost plans with the Synapse high CO_2 prices.

Q. Is it possible that natural gas demand could be higher due to CO_2 emission regulations and, as a result, natural gas prices can be expected to be higher than otherwise would be the case?

A. Yes. However, the effect is very complicated and will depend on a number of factors such as how much new natural gas capacity is built as a result of the higher coal-plant operating costs due to the CO_2 emission allowance prices, how much additional DSM and renewable alternatives become economic and are added to the U.S. system, the levels and prices of any incremental natural gas imports, and changes in the dispatching of the electric system. Thus, it is very difficult to determine, at this time, the degree to which natural gas prices might be affected due to CO_2 emission regulations.

Q. Did you ask the OCA to rerun the EGEAS model to reflect some increases in natural gas prices as a result of federal regulation of greenhouse gas emissions?

A. Yes. To illustrate the possible impact of higher natural gas prices as a result of federal regulation of greenhouse gas emissions, the OCA reran the EGEAS model to reflect a ten percent increase in natural gas prices in scenarios with the IPL high CO_2 and the Synapse high CO_2 price forecasts. As shown in Table 7 above, the model still did not add SGS Unit 4 in 2013 even with the increased natural gas prices. In the scenario with IPL's high CO_2 prices, the model added a 350 MW coal unit in 2019. No coal plant was selected in the scenario with Synapse's high CO_2 price forecast and the 10 percent higher natural gas prices.

Q. Did IPL explore whether the need for SGS Unit 4 could be eliminated or deferred if it engaged in joint and integrated planning with WPL?

A. No. Alliant Energy IPL has not conducted joint and integrated planning for both IPL and WPL. Each of Alliant Energy's wholly owned utility subsidiaries conducts integrated planning on an individual utility basis.[94] Therefore, IPL is unable to say that both companies would need to build their proposed coal-fired power plants in Wisconsin and Iowa.[95]

Q. Has Alliant Energy conducted any analysis to determine if significant efficiencies are achievable through joint and integrated electric resource planning between its wholly owned utility subsidiaries?

A. No.[96]

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94 IPL Response to OCA DR. No. 173.
95 IPL Confidential Response to OCA DR. No. 174.
96 IPL Response to OCA DR. No. 175.

Q. Has IPL previously claimed that joint and integrated resource planning between Alliant Energy's wholly owned utility subsidiaries would produce significant efficiencies and benefits for Iowa ratepayers?

A. Yes. The Company made those claims in Board Docket No. 96-6.[97]

Q. IPL has claimed that its 2003 and 2005 Electric Resource Plans also supported the need for a coal-fired resource in the same timeframe as the proposed Sutherland Generating Unit 4. Should the Board rely on the results of these Electric Resource Plans when considering whether to approve the Company's request for permission to build SGS Unit 4?

A. No. Circumstances have changed significantly since the Company prepared its 2003 and 2005 Electric Resource Plans. In particular, IPL's 2005 IRP modeling did not reflect any CO_2 prices and much lower capital costs for the generating alternatives it considered. For example, the coal plant and wind facility capital costs that IPL has used in its [redacted]. For these reasons, the results of the 2005 are obsolete and should not be relied upon.

Q. Does this conclude your testimony?

A. Yes.

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[97] For example, see the Direct Testimony of Glen E. Jablonka in Iowa Utilities Board Docket No. SPU-96-6, at pages 16-22. See also, *IES Industries Inc, Interstate Power Co., and WPL Holdings, Inc,* Docket No. SPU-96-6, IUB Order, dated September 16, 1997, at pages 4 and 8.