STATE OF IOWA
IOWA UTILITIES BOARD

In Re:		
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Interstate Power and Light	**)**	**Docket No. SPU-05-15**
Company and FPL Energy	**)**	
Duane Arnold, LLC	**)**	

Direct Testimony of
Ezra D. Hausman, Ph.D.
Synapse Energy Economics, Inc.

On Behalf of the
Iowa Office of Consumer Advocate

REDACTED VERSION

September 28, 2005

Q. Please state your name, position and business address.

A. My name is Dr. Ezra D. Hausman. I am a Senior Associate with Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

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

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

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.

Q. Please summarize your educational background and recent work experience.

A. I graduated from Wesleyan University with a Bachelor of Arts Degree in 1986. In 1990, I received a Master of Science Degree in Civil Engineering from Tufts University. In 1994, I received a Master of Science Degree in Applied Physics from Harvard University, and in 1997 I received a Ph.D. from Harvard University's Department of Earth and Planetary Science, with a focus on Atmospheric Chemistry.

Since 1998 I have worked as a consultant in the electric power industry, performing a wide range of market analysis, price forecasting and asset valuation studies for clients in both the public and private sector. These studies have included long-range price forecasting studies for a number of purposes, including analysis of proposed capacity investments, contract valuation and liquidation studies, market power studies, market transition cost/benefit studies and market design support. I have assisted in the preparation of testimony in a wide range of civil and regulatory cases. In addition to performing these studies for clients, I have spoken and led several seminars on electricity pricing and hedging

transmission cost risk in electricity markets. I have also published peer-reviewed papers on the topics of pricing of losses in electricity markets, and on the dynamics of the California price spikes during the winter of 2000-2001.

Prior to accepting my current position with Synapse, I was employed as a Senior Associate with Tabors, Caramanis and Associates (TCA) of Cambridge, MA from 1998 until 2004, and subsequently for Charles River Associates (CRA) when the latter acquired TCA.

A copy of my current resume is attached as Exhibit___EDH-1, Schedule A.

Q. Have you previously submitted testimony before this Commission?

A. No, I have not.

Q. What is the purpose of your testimony?

A. Synapse was asked by the Iowa Office of Consumer Advocate (OCA) to assist in estimating of the cost of replacement base load electricity for the period 2014 through 2034, to represent the case in which the Duane Arnold Energy Center (DAEC) were to retire in 2014 at the conclusion of its current NRC license period. This testimony presents our price forecast analyses for that period, which is detailed in Exhibit__EDH-1, Schedule B.

Q. What is the basis of your forecast?

A. With the retirement of DAEC, IPL is expected to require new generating capacity on an ongoing basis by and during the forecast period 2014-2034. The only way any investor would develop new capacity is if they could recover the all-in costs (capital plus operating expenses) of such a new plant. However, if the price were expected to be much higher than that required to cover these costs, more capacity would enter the market and bring the price down. Thus, our forecast of the price of electricity is based on the per-MW hour, all-in cost of the type of base load plant that we consider most likely to be built during this period.

Q. What is the generating technology on which you base this forecast, and why?

A. We believe that the most likely base load plant to be built during this period is a coal burning, Integrated Gasification Combined Cycle (IGCC) generating unit. After several years in which most new power plants built in the United States were powered by natural gas, the gas supply and pipeline infrastructure nationwide are significantly stressed and the price of gas has risen significantly in the last few years. Coal, on the other hand, is available in seemingly unlimited supply domestically, although there may be some transportation limitations that I will address later in my testimony. In addition, the newer IGCC technology promises much greater efficiency than traditional coal plants, with significant reductions in emissions of pollutants such as NO_x, SO_2 and mercury. Finally, many people believe that IGCC technology will offer opportunities for the capture and permanent sequestration of CO_2 gas, which is a major contributor to the problems of global warming and climate change. Because limitations on CO_2 emissions are considered extremely likely in the coming decade or two, investors in power plants will prefer to keep their options open for eventual control of these emissions.

For all of these reasons, we believe that an IGCC plant is the most likely technology for investments in base load generating capacity for the study period, and we base our forecast on the per-MW hour, all-in costs of such a plant.

Q. What data sources did you use to produce this forecast?

A. The primary source for the capital and operating costs of IGCC generating technology, as well as for fuel costs, is the Annual Energy Outlook (AEO) published by the Department of Energy's Energy Information Administration (EIA). The AEO fuel forecasts go out to the year 2025. However, because coal is produced domestically and almost always purchased under long-term contract, it has historically not exhibited the degree of price volatility seen in other fuels such as natural gas and oil. Thus we believe that it is reasonable, for a baseline

forecast, to extend the AEO forecast trend (essentially flat in real terms) throughout the forecast period.

Another significant factor in the cost of thermal generation is the cost of air emissions allowances, or alternatively emission control technology. For these costs we use the cost projections distributed with EPA's Clean Air Mercury Rule (CAMR) in March, 2005. Again, these projections do not cover the full forecast period, so we assume a linear extension of the CAIR trend to 2034. Expected costs associated with mercury emissions are too small to materially affect these forecast results and are neglected.

Q. What sources did you use to forecast the price of CO_2 emissions?

A. The price of CO_2 emissions we used are based upon extensive research performed by Synapse staff, who reviewed a range of sources to explore likely carbon emissions costs over the coming decades. The results of this research have been submitted as an exhibit with Mr. Schlissel's testimony, as Exhibit__DAS-1, Schedule _F. Based on this research, Synapse staff produced "high", "mid" and "low" case projections of carbon emissions prices through the forecast period, which are included in Exhibit__EDH-1, Schedule B._2__. The prices used in our forecast are represented by the "mid" case.

Q. Do these CO_2 emissions prices reflect existing carbon emissions regulations?

A. No. At this time there are no federal, state or regional regulations governing CO_2 emissions in Iowa. There is, however, overwhelming consensus in the scientific community that CO_2 emissions from human activity, including electric power generation using fossil fuels, are affecting and will continue to affect the climate of the Earth in ways that will be socially and economically disruptive to human societies. Modeling studies have consistently shown that these effects will become increasingly severe as the concentration of CO_2 in the atmosphere increases. As a result, most industrialized as well as developing nations are taking

steps to reduce their emissions of CO_2 into the atmosphere. An example of this activity is the Kyoto Protocol, to which the United States is not a signatory.

However, it is all but inevitable that the United States will institute some form of CO_2 emissions limitation in the near future in response to this overwhelming scientific consensus, and in response to the observable and potential disruptive effects of global warming. In fact, as detailed in Mr. Schlissel's testimony, many US States and regional bodies have already begun to explore or institute emissions limitations and costs. For example, in December 2004 the California Public Utilities Commission directed utilities to consider carbon emission allowance prices of between $8 and $25 per ton in their long range planning.[1] It is not unusual in environmental regulation for the States to take the lead, and for the federal government to come in afterwards with standardized federal regulations. This seems to be occurring in the case of CO_2 regulation.

Q. How confident are you of your prediction of carbon emissions prices?

A. I do not know what the price of CO_2 emissions allowances will be 10 or 20 years in the future, nor do I know when federally mandated emissions limits will come into effect and impose those costs on the electric sector, nor what form those regulations will take. What I can say with confidence is that such regulations and costs are extremely likely to come into effect during this period. It would be unrealistic, misleading and inconsistent with the generally anticipated future economics of the electric sector to assume that these costs will be zero.

[1] *http://www.cpuc.ca.gov/Published/Agenda_decision/42314-07.htm*

Q. If the carbon prices you have forecast were actually to be paid by generators for every ton of CO_2 produced, this would be extremely burdensome and perhaps fatal to the coal industry, for example. Can you comment on why you think it is politically or economically realistic to expect this kind of cost to be implemented?

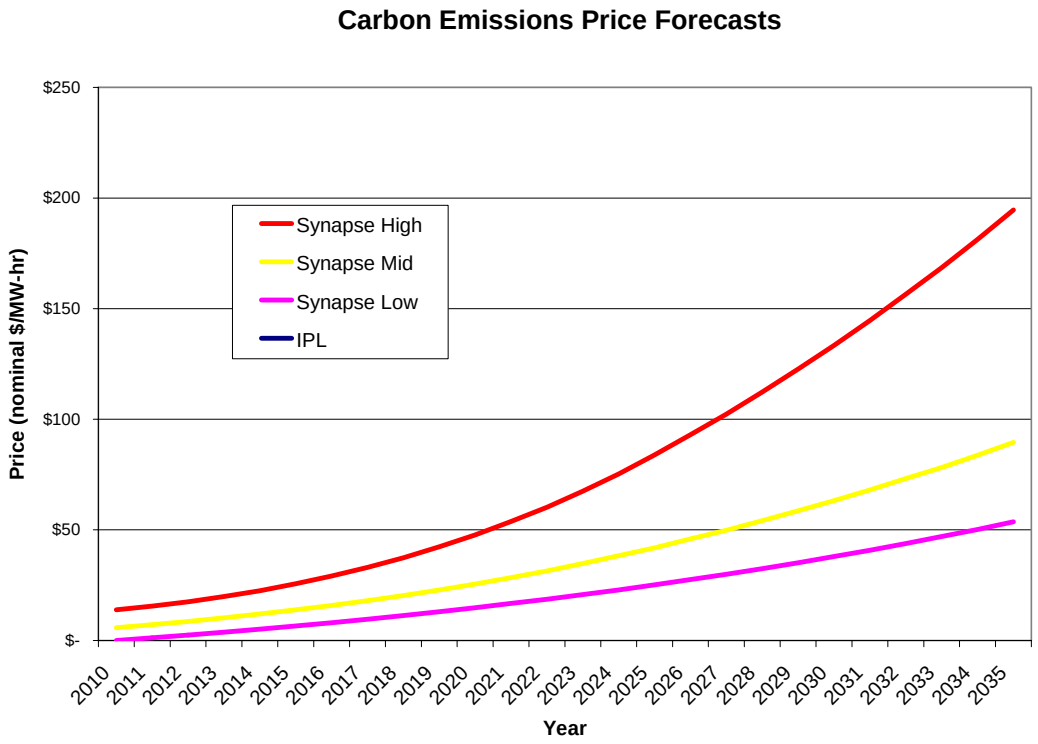
A. The prices I have forecast would not be as burdensome as they might seem at first glance, because they only affect the shadow price, or marginal cost, of each incremental unit of CO_2 emissions. A responsible policy can and would be devised to create the necessary incentives to reduce emissions by imposing this marginal cost, whilst minimizing the overall financial impact on the coal industry. For example, many of the emissions allowances would probably be allocated to existing coal-fired generating facilities, so they could continue to operate and use the allowances with minimal impact on their operational profits. However, they would incur an opportunity cost for every allowance they used, which is the shadow price of carbon emissions. If there were a more productive or efficient use of the allowances, they could sell them at this price instead of using them to produce electricity. This is the point of a cap-and-trade system, and it has worked very well in regulating other pollutants. The goal is not to impose a large new cost on industry, but to align the economic incentives with the social benefits of reducing pollution.

Once the caps were in place, however, new allowances would not be created for new coal plants. They would have to either purchase allowances on the market, or find some way to neutralize their carbon emissions, for example through sequestration or offsets. If new technology were able to produce power with lower per-MWh carbon emissions, the allowances would flow through the market from less efficient units to more efficient ones. Again, this would be the whole point of this sort of regulation.

Q. Has IPL produced any forecasts of CO_2 emissions prices, and if so, how do they compare with the prices you have used?

A. [REDACTED]

The following chart shows IPLs emissions price forecast (converted into nominal dollars) compared to the "low", "mid" and "high" cases produces by Synapse:



Q. In your opinion, are IPL's emissions price projections reasonable?

A. [REDACTED]

As economies continue to grow and the threat of global climate change becomes increasingly obvious, I expect three factors to drive up carbon emissions prices.

First, I believe that emissions limitations will become increasingly restrictive. Second, the cheapest and easiest ways to reduce carbon emissions, such as self-funding energy conservation and the most attractive investments in renewable energy, as well as simple offsets, will be exhausted in the early years of emissions limitations. In later years, it will become increasingly difficult and expensive to implement incremental reductions. Third, as technology improves and more economic value can be extracted from each unit of carbon emissions, the market will place a higher value on each emission allowance. At this point it will no longer be economical to use the allowances for low-value emissions such as inefficient generating technologies. Once again, this is exactly the point of this sort of regulation.

For all of these reasons, I think an upward trending emissions price is a more reasonable expectation than IPL's [REDACTED].

Q. Has IPL used these and other pollutant emissions prices in their EGEAS price forecast modeling?

A. IPL has not used their own or any other emissions price forecasts in their EGEAS modeling, as far as I can tell. They justify this on the grounds that the regulatory environment is not yet settled. However, this is equivalent to assuming that the cost of emissions will be zero throughout the forecast period, which makes no sense. Since they anticipate, as we do, that there will be a cost associated with these emissions, these costs should not be ignored in their long range planning analyses.

Q. The AEO, which you use as a source of your underlying data, also forecasts long-range electricity prices. Why do your electricity price forecasts differ from those of the AEO?

A. The primary reason our forecasts differ from those of the AEO is that our forecasts include projected costs of carbon emissions, which those of the AEO do not. The AEO as a matter of policy does not consider regulations which are

neither existing nor pending at the time of their analysis. Implicit in the AEO approach is that the price of CO_2 emissions will be zero throughout the forecast period. As discussed above, I believe there is very little chance that this will be the case.

Q. In calculating the cost of SO_2 and NOx emissions, did you make an assumption about the number of emissions permits held by the owner of the hypothetical IGCC plant?

A. I did not make an assumption in this area, because it does not affect the outcome of the electricity price forecast. Emissions allowances are part of a cap-and-trade system, which means that allowances can be purchased at the market price for any level of emissions. Conversely, emission allowances that are not used can be either sold or banked for later use, so they retain their value. Thus a competitive supplier of electricity will be indifferent, in pricing an offer, to the number of emissions allowances already held. The opportunity cost is equal to the market price of the allowance, so the market price forecast treats these costs equally.

Q. What if the owner were a regulated utility such as Alliant's subsidiary, Interstate Power and Light Company (IPL), would this logic still hold?

A. The case is slightly more complex for a regulated utility, because IPL for example may not be allowed to include the opportunity cost of "allowances not used" in rate base. However, if we look at the particular case of a coal burning plant that would be built to replace Duane Arnold's output, even if it were owned by IPL, the logic does hold. The reason for this is that new plants in Iowa with construction beginning after 2008 will not be allocated any allowances, so they would have to purchase additional allowances for all emissions from such a plant, and every one they use will have to be replaced in the market. Even if they have emissions permits for other plants which were constructed prior to this time, every incremental ton of pollutants that comes from the new plant will require the purchase and retirement of an emissions allowance.

Q. How are capacity factor and capacity revenues taken into account in your price forecasts?

A. The price forecasts I have presented in Exhibit__EDH-1, Schedule B represent the amount of revenue a new IGCC coal plant would expect to earn, operating at an 85% capacity factor, on each megawatt-hour of energy produced. Depending on the structure of the specific electricity market, some of this money might be earned through the electricity market and some in the capacity market. There is no way of knowing what the particular structure of the market affecting the DAEC area will be during the twenty year forecast period. However, from the standpoint of analyzing the economics of future power plants this difference is not important, and in fact the same split would apply to any base load plant.

Q. Do you consider your price forecasts to represent an upper bound, a lower bound, or an expected value for actual electricity prices?

A. I would consider this forecast to be a lower bound on the price of electricity during the forecast period. There are a large number of factors which could make the actual price higher, including stricter emissions rules, higher fuel prices, higher fuel transportation prices, unexpected load growth, and the exercise of market power by generators. I am particularly concerned that the coal prices underlying this forecast are low. If one or more new coal plants are built in this region, it will add significantly to the load on the existing coal delivery infrastructure from the Powder River Basin area (the source of the coal) to the Midwest US. This transportation corridor is already very heavily utilized, including the South Powder River Basin Joint Line (SPRBL) which may be the most intensively trafficked rail line in the world. Although domestic coal appears to be in abundant supply and inexpensive to extract, the need for additional transportation infrastructure may well make it impossible for new coal-burning plants to obtain fuel at as low a price as the AEO forecasts. Because of this and the other factors mentioned above, it is entirely possible that the actual price of electricity during the study period will be higher than the price I have forecast.

Q. Does this conclude your testimony?

A. Yes, it does.