Q. Please state your name and business address.

A. My name is Thomas Sanzillo. My business address is 150 East 49th Street, New York, New York, 10017.

Q. By whom are you employed and in what capacity?

A. I am currently a Senior Associate at TR Rose Associates. In this position, I spend most of my time providing policy and financial advice to clients.

Q. What is your experience and educational background?

A. For the past twenty-five years I have served in a number of government finance positions in the City and State of New York. Most recently, I completed four years as the First Deputy Comptroller for the State of New York. The State Comptroller is the equivalent of the chief financial officer, and the first deputy is a constitutional officer charged with all operational responsibilities of the Comptroller’s office. The staff of the Comptroller’s Office is 2400 employees, mostly accountants, auditors, investment and budget analysts, attorneys, claims administrators, procurement experts and support personnel.

In this capacity, I supervised the New York State Common Retirement Fund. The Fund is a $150 billion global fund with investments across a broad set of asset classes. The Fund has considerable holdings in the energy industry.

The Comptroller also serves as the Chief Procurement Officer reviewing and approving 44,000 contracts worth $85 billion annually. These contracts cover all aspects of government operations including master service agreements between public utilities and private energy companies, power plants, debt instruments for public utilities and other contracts for the operation of energy functions of the state and its public authorities.
The Comptroller supervises the design, fieldwork, report preparation and recommendations for some 400 audits annually of state and local government and public authorities. Audits and reviews during my tenure have been conducted on power plant construction cost controls, management and operation of the New York Power Authority in a changing deregulated market, the rate setting mechanism used by the Long Island Power Authority, the budget and procurement practices of public utilities, demand side efficiency programs and internal controls and contracting processes of state research and development agencies.

In addition to these reviews, other policy work resulted in a published report on New York’s deregulation effort: restructuring of the industry, new challenges for the Public Service Commission, creation of a statewide power pool and the impact on local property tax assessments and collections.

The job also requires review and approval of a debt portfolio for local and state governments of over $200 billion – including approximately $20 billion in energy related authority debt. This includes the review, approval and monitoring of the largest public plant and the purchase of it by the publicly owned Long Island Power Authority. I hold a Bachelor of Arts degree in Politics from the University of California at Santa Cruz.

Q. Have you testified in prior Iowa Utilities Board (IUB) regulatory proceedings or other state or federal utility regulatory proceedings?

A. I testified before the IUB in Docket No. GCU-07-1.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of Community Energy Solutions, Iowa Environmental Council, Iowa Farmers Union, Iowa Renewable Energy Association, and Physicians for
Social Responsibility Iowa Chapter (intervenors). Intervenors as a group represent thousands of Iowa residents, farmers, renewable energy producers, healthcare providers, and electricity consumers who will be directly affected by construction of a new dirty coal plant at a time when coal is an increasingly risky and expensive fuel source and better alternatives are readily available. Damages they may suffer include diminution of the value of the state’s existing renewable energy generation facilities, diminished investment in energy efficiency, damage to the development of new renewable energy generation facilities, displacement of renewable energy from the grid, increase in retail electricity rates, damage to air and water quality, increased fuel costs due to inefficient ethanol refining processes, civil rights violations of minority communities targeted by the highly polluting coal industry, damage to Iowa’s ecosystem and agricultural economy from the increasing impacts of global warming, violation of state energy policy, and future damage to electricity consumers who will pay the eventual cost of carbon regulation.

Q. Has IPL established that the SGS Unit 4 plant is the best alternative to meet the service needs of its customers?

A. No. The load forecast presentation submitted with this rate request demonstrates that the coal plant is an inappropriate alternative. Mr. Hillberry describes IPL’s forecast model: “The peak and energy models are developed based on regressions of historical per customer data with weather, economic and indicator variables. Then forecasted values are inserted into the model to predict future values. Finally any large known adjustments are made to the data.”
Mr. Hillberry’s model is not based on historical per customer data. The critical assumption that IPL’s load growth will be upwards of 40 MW per year over the long run is unsubstantiated. According to the Application, Section 2.2.1 Need for SGS Unit 4:

The last base load plant built in Iowa, of which IPL owns a share, was the Louisa Generating Station (LGS), which was placed in service in 1983. IPL’s share of LGS is only 28 MW. Thus, IPL has gone more than 25 years without adding a significant amount of owned base load generation. In the intervening period, IPL’s customer load increased an estimated 750 MW, and is expected to grow approximately another 190 MW by 2013.†

Based on this statement, IPL’s twenty-five year historical performance average is 30 MW load growth per year. There is no substantiation for the aggressive modeling used by IPL to justify this plant. Evidence presented to the board shows that Iowa’s population remains flat and even declines in the out-years of the load forecast that serves as the core justification for this plant.

According to the U.S. Census Bureau’s Population Division, Iowa’s population is projected to grow a total of only 1 percent annually between 2000 and 2030, placing Iowa 48th in the nation in projected population growth and well below the 29.2 percent population increase projected for the national as a whole over that period. From 2010 to 2030, the out-year of the Census Bureau projection, Iowa’s population is actually projected to experience a net decline of 1.8 percent, or approximately 55,000 residents.‡

A careful reading of IPL’s Table 2.2.1-1 shows the following.¶ The model forecasts slow growth through 2009.¶ IPL anticipates growth in Internal Demand of only 12 MW for the two-year period 2007-2009. This is approximately 2/10 ths of one percent of growth on an annual basis. These projections actually reflect the relatively flat economic projections for the State through 2009.

† Interstate Power and Light, Application RPU-08-1, Section 2.2.1 Need for SGS Unit 4, March 31, 2008 p. 12.
‡ Sanzillo, Rebuttal Testimony, Docket No. GCU-07-1 (attached as Exhibit TS-2).
¶ IPL Application, Op Cit.
¶ Kitchen Testimony, Exhibit (BRK-1), Schedule A (March 13, 2008).
The IPL model then shows aggressive growth thereafter – a 61 MW increase in 2010; 54 MW increase in 2011; 53 MW increase in 2012 and 54 MW in 2013. The average increase through 2022 is 45 MW annually. These aggressive demand assumptions are made by IPL during a period when Iowa’s population is projected to decline.

Another way to view IPL’s presentation is look at the last decade of “Firm Peak”. Mr. Hillberry states: “Firm peak is what IPL is required to serve.”

In response to OCA Data Request No. 49, Mr. Hillberry submitted a table that charts IPL’s “Firm Peak” from 1998-2007. During the decade covered by the chart, the Firm Peak rose from 2,657 MW to 2,813 MW --- an increase of 156 MW. This represents an annual growth rate of one-half of one percent (0.05). IPL’s assumed future growth rate of net internal demand for this application is 1.4%.

Had either a one decade scenario looking backward been used, or a two decade scenario looking backward been used, neither justifies the 40 MW annual growth projected by IPL.

Furthermore, there are clearly large, known losses of industrial customers from the IPL base. These adjustments are not in the current plan.

In its most recent Annual Report, “Building on Our Commitment” IPL makes the following disclosure:

**Ethanol and BioFuel Production** – A number of previously announced plants in Alliant Energy’s service territory have not begun construction, which is reflective of a national slowdown in the construction of ethanol production facilities… Alliant Energy is currently unable to estimate the impacts new ethanol and

---

5 Hillberry Direct Testimony at 3.
6 Hillberry Response to OCA Data Request 49, Attachment A (attached as Exhibit TS-3).
7 Kitchen Testimony (March 13, 2008) at 5-6.
biodiesel production facilities in its service territory will have on its future financial condition or results of operations.

Professor Daniel M. Otto in his testimony and appended report: “Economic Importance of Securing Reliable Electric Energy for Iowa” stresses the importance of a new baseload generation for the expansion of ethanol and industrial production. My testimony and Dr. Harl’s in the earlier proceeding point out weaknesses in this area of the State’s economy.

From my rebuttal testimony (Docket GCU-07-01):

Second, when addressing the contribution that wind and ethanol are making to the economy of Iowa, he does not explain why the manufacturing sector as a whole has remained flat and is expected to decline in 2008, or what impact this will have on projected energy demand. Because IPL’s largest customer base is the manufacturing sector, Dr. Otto’s failure to put wind and ethanol into this broader context weakens his case. If Dr. Otto is correct, and wind and ethanol are indeed the critical building blocks for Iowa’s manufacturing future, then it is only fair to ask for quantifiable evidence showing that ethanol and wind development create a demand for electricity that both offsets projected losses in the traditional manufacturing base and uses electricity in a manner that simulates the need for new capacity. (emphasis added).

In the short term, IPL’s data shows a weakening of demand. In the longer term, the data shows a strengthening of demand, but there are known losses that are not quantified.

Mr. Hillberry’s statements that (1) the need for the plant is derived from historical per customer usage and (2) large known adjustments are reflected in the data, are not confirmed by a review of the record.

Q. Besides there being a weakening in demand, are there other factors that should be considered when reviewing the justification for the plant?

---

9 Otto, Daniel, Economic Importance of Securing Reliable Electric Energy for Iowa, March 2008 (Exhibit DMO-1, Schedule B).
10 Sanzillo Rebuttal Testimony, Op Cit, at 14-15 (see Exhibit TS-2).
A. Yes, IPL’s Internal Demand figure for 2007 of 3,326 MW is without foundation. Its derivation is artificial. An appropriate, independently verifiable figure is 3,085 MW, which represents the booked peak amount for 2007.  

IPL’s usage of this inflated base number for Internal Demand is wrongly carried forward throughout their analysis.

If the base is 3,085 MW and then combined with IPL’s own short-term assumption of 30 MW growth per year for the period 2007-2013, the “Net Internal Demand” for 2013 is (3,235 MW – 455 Interruptible Demand and Control Management), or 2,780 MW. This gives the IPL system a surplus of 293 MW (2,780MW x 15% Reserve – 3,489 MW Capacity) in 2013, not a deficit of 80 MW.

Even if one concedes that IPL’s “deficit” is 80 MW, it is first a shortfall in IPL’s electricity reserve. The reserve is a supplemental supply resource used in the event of disruptions in the existing system. The deficit is not one that poses an imminent threat to the reliability of the supply of electricity to Iowans.

Second, why has IPL applied for 432 MW’s of additional capacity if the need is only 80 MW?

Q. Would you be more specific about the methodological problem with IPL’s approach?

A. Yes. Mr. Hillberry states:

The IPL firm peak shown in the filing is adjusted upward based on 2.19% diversity between the former IES Utilities and Interstate Power Company (IPC).  

---

11 Mr. Hilberry’s Direct Testimony of March 27, 2008 demonstrates quite clearly that ‘firm peak’ is a contrived number. He explains how he gets from this “Firm Peak” to “Internal Demand” and then to “Net Internal Demand”. My method follows the same course, however the base, or firm peak is 3085 MW for 2007, not the estimated 3,326 contained in the IPL presentation.
territories and the interruptible load is added to arrive at Internal Demand listed on Line 1 of Mr. Kitchen’s Exhibit BRK-1 Schedule A.\textsuperscript{12}

In order for Internal Demand to rise by 40 MW per year as projected by IPL --- firm peak (which is derived from book peak) must rise by that amount or more. The other methodological adjustments described by Mr. Hillberry only confuse this fact. (Nothing in the data or Mr. Hillberry’s presentation implies that changes in the “Interruptible” load are the source of the projected growth). There is no historical basis for either the “book peak” or the “firm peak” to rise by 40 MW over a period of years. Therefore, the only other way this is achieved is through statistical contrivance.

Q. Has IPL demonstrated that this plant is reasonable in comparison to other feasible alternatives?

A. No. The need for the plant has dwindled since IPL made its initial application in Docket GCU-07-01. In addition, IPL’s record of achievement in energy efficiency makes it a far superior investment to meet the purported 80 MW need identified in the rate proposal.

The original plan estimated that IPL’s demand would increase by 50 MW annually\textsuperscript{13}. Then, IPL adjusted this downward to 40 MW annually. IPL has still not explained why this adjustment was necessary. Because IPL has not explained what changed, --- in the underlying needs of IPL’s customers or in the forecasting model --- it is difficult to understand the decision.

IPL has submitted information that establishes a 25-year average load growth of 30 MW per year. IPL's long-term forecast assumes that demand will grow by an annual average

\textsuperscript{12} Hillberry Direct Testimony at 5.
\textsuperscript{13} See Sanzillo, \textit{Op Cit}, at 9 (see Exhibit TS-2).
of 40 MW’s. This assumption drives IPL to project unrealistically large annual increases in electricity use in the out-years.

IPL is showing very slow growth in the short term, and potential losses in its industrial customer base.

IPL has lowered its reserve margin from 18% to 15% from its earlier filing. This reduces the capacity requirement by approximately 100 MW.

IPL’s analysis of the situation cites a deficit in the reserve margin of 80 MW by 2013.

We project a surplus. Even IPL now acknowledges that the need for the plant has diminished since the filing of Docket- GCU-07-01 only last year.

At the same time the need for the plant has diminished for other reasons, IPL has been pursuing a program of energy efficiency. According to IPL:

Figure 2.1-1 clearly demonstrates that IPL has achieved its Board-approved energy savings goals in each of the last five years. Moreover, the amount by which IPL has exceeded the budget and still passed its goals is diminishing. Accordingly, IPL has saved approximately 509 MW of electricity over the last five years.

The preliminary figures for 2007 alone were 118 MW.

Other companies that have demonstrated success in the energy efficiency area see it as a beginning from which even greater achievement is possible.

For example, the most recent annual report from Pacific Gas and Electric states:

Equally important, we are taking actions in the meantime to prepare our company and our customers for the future. This includes continuing to aggressively drive advances in energy efficiency and extending our renewable energy commitments.

This leadership has put PG&E in a strong position. Last year, Innovest Strategic Value Advisors, a top evaluator of investor risk and value related to sustainability

---

14 IPL Application, *Op Cit.* Table 2.2.1-1, Line 14b.
issues, issued a report that ranked PG&E environmental leadership (EcoValue index) is the top 25 percent of all utilities in its peer group.

Through energy efficiency, we plan to meet 50 percent or more of the growth in energy demand in our service area over the next ten years.

A recent investor presentation by Melissa Lavinson, PGE Director of Federal Environmental Affairs and Corporate Responsibility, April 30, 2008 discussed PGE’s performance and forward-looking goals.

PGE’s Energy Efficient Investments

- Over the past thirty years, our customer energy efficiency programs have:
  - Saved enough electricity to power 18 million homes;
  - Avoided the need to build approximately 24 power plants;
  - Prevented more than 125 million tons of carbon dioxide emissions from being emitted into the atmosphere.

PGE’s program goals over the next 10 years are to reduce load by 2500 MW and develop a Demand Response Program that reduces peak electricity demand by 5%.

It is clear that the potential for additional energy efficiency savings would eliminate even IPL’s purported 80 MW deficit, and then some. A robust energy efficiency program represents a far superior alternative than a new coal plant. In addition, it would save consumers money as well. On the other hand, an expense of nearly $2 billion for a new coal plant will necessarily divert investment from expanded energy efficiency and requires consumers to bear the burden of paying for through higher electricity prices. The California model described above has an aggressive energy efficiency program with the explicit objective, of avoiding expensive new investment in generation.

Q. Do the costs for the construction of this plant fit the reasonableness criteria?

---

A. No. Cost assumptions of this plant are at best speculative. According to IPL, the construction cost of the plant will be at least $3,544 kW. At this level, it is arguably the most expensive coal fired power plant in the country. A recent study documented the cost of the AMP-Ohio plant at cost of the Meigs County Plant at $3,475 kW with financing. A recent article in the Wall Street Journal, “Costs to Build Power Plants Pressure Rates”, May 27, 2008, describes the most recent report by the Cambridge Energy Research Energy Associates, Inc. The article states that the costs of coal-fired power plants have risen by 78% since 2000. If anything, the index likely minimizes the rising cost of building power plants because it doesn’t factor in financing costs, and it doesn’t include fuel costs. But as prices for coal, natural gas and uranium have risen, they have put added pressure on the operating costs of many companies, and those increases are pushing up electricity prices, too. The upshot, Ms. Scott said (director of Cost and Technology at CERA), is that prudent utility regulators should make sure they are basing future decisions on data that are updated frequently, because even calculations less than a year old can be dangerously out of date. The article continues:

The analysis is of interest because it is difficult to get solid cost data until after plants have been built. Even then, data aren’t always available.

The final cost of this plant cannot be projected with any certainty, however it would not be a stretch to see final construction costs in the range of $4,000 kW, or approximately 15-25% higher.

---

17 R.W. Beck, American Municipal Power Generating Station Initial Project Feasibility Study Update: January 2008. The report page 7 (attached as Exhibit TS-6) places the cost at $3.391 billion for a 960 MW plant. These plants are roughly at the same stage of the process. The status of the planning process of a plant is critical to assessing its current cost in the current market. It is very likely that both plants will see a higher final cost than those projected in this document. See: Wall Street Journal Article below.

18 Attached as Exhibit TS-7.

19 Id.
Q. Do the cost projections of fuel for this plant meet the reasonableness criteria?

A. No. This estimate is unrealistic.

Arch Coal, the second largest producer of coal in the United States, has seen a 73% increase in the price of PRB coal over the last year. Peabody Energy reports a rise in PRB prices of 155% since the beginning of 2007. Arch Coal attributes the rise in prices to rising export demand on eastern basin coal that is results in greater use of PRB coal from states east of the Mississippi.

Peabody Energy foresees these demand pressures continuing “over the next several decades.”

Recent dramatic increases in the price of Central Appalachian, Northern Appalachian and Illinois Basin Coal have set new ceilings for the per ton cost of coal. According to the Energy Information Agency, one year ago (the week of June 20, 2007) Central Appalachian coal sold on the spot market for $44.60, this week June 20, 2008 the price is $117.60, Northern Appalachian Coal was $45.15 per ton, this week June 20, 2008 the price is $118.00.

One analyst covering coal price quotes Steven Leer, CEO of Arch Coal:

We certainly expect it (an increase in PRB prices) to happen. We have tracked pricing in previous run-ups. What we see is that every price increase starts in

---

20 Arch Coal, 8K Filing, June 19, 2008, slide 22 (attached as Exhibit TS-8).
21 Vic Svec, Senior President for Investor Relations and Corporate Governance, Peabody Energy, The New BTU, Basic and Industrial Conference, June 3, 2008 (attached as Exhibit TS-9).
22 Arch Coal, Op Cit, slides: 6,7, 11,12,14 and 15 (see Exhibit TS-8).
23 Peabody Energy, Op Cit, slide 17 (see Exhibit TS-9).
Central Appalachia moves to Northern Appalachia, moves to the Western bituminous region and then to PRB. Each increase that has occurred since 2001 has seen the spike much higher than the previous one and the valley much higher than the previous one."

The futures price of PRB coal for 2011 on June 26, 2008 is $22.15 per ton. For IPL’s estimate to be correct prices for PRB would have to rise an anemic 10% from 2011-13. This is highly unlikely.

Given the market changes that are occurring in the coal industry, the more likely scenario is an annual 20% rise in prices from 2011-2013. The consequence of this trend would be a per ton price for coal closer to $35 (if not higher), not the $24 per ton that IPL assumes.

Mr. Hillberry provides data from the Energy Information Administration (EIA), Energy Outlook 2007. The title of the subsection to the Energy Outlook is “Fuel Costs Drop from Recent Highs, then Increase Gradually”. The report then goes on to state: “Coal prices to the electric power sector remain relatively low, peaking at $1.71 per million BTU in 2010, falling to $1.69 per million BTU in 2018, and remaining at that level through 2030.”

A recent study by the Western Resource Advocates offers some insight into the forecasting models developed by EIA.

Inherent in the risk associated with fuel price changes is the inability to reliably project future fossil fuel prices. The Energy Information Administration conducted a review of its forecasts and found that, for long-term forecasts made from 1982 through 2006, the average absolute error (comparing forecasted prices and actual prices) for coal prices paid by electrical generating plants was about

---

26 Id. at 3.
27 Hillberry Response to OCA Data Request No. 54, Attachment B, at 7 (attached as Exhibit TS-12).
47% and that natural gas wellhead prices was about 64% --- both enormous forecasting errors.

Q. Has IPL taken into consideration the potential costs of addressing a new system for curbing greenhouse gas?

A. No. The cost will be greater, and IPL carries the cost a separate potential future charge. IPL’s analysis concludes that implementation of CO2 capture technology could add as much as $5.54 Mwh to $6.81Mwh to the cost of electricity.

Mr. Guelker summarizes the current issues facing IPL with regard to the future cost of carbon:

Contrary to the media’s portrayal, the significant debate over greenhouse gas emissions certainty versus price certainty in carbon policy development stems from the lack of technology solutions currently available for greenhouse gas emissions control (especially CO2 emissions from fossil fuel combustion). As a result, carbon allowance markets have the potential to be highly volatile and thus, more costly for regulated companies to use to manage their carbon profiles. Given the many uncertainties, it is impossible to predict the cost impacts to IPL’s customers, although in general terms IPL acknowledges that the potential for this cost to be significant.

A Bechtel Power report prepared for the purposes of assessing the SGS Unit 4 technology states:

To clarify this analysis Mr. Vesperman of IPL adds:

---

29 Guelker Direct Testimony at 14.
30 Bechtel Power Corporation, Study of CO2 Capture Capable Design Concepts For Sutherland Generating Station Unit, December 2007 (Exhibit KDV-1, Confidential Schedule G).
It is estimated to cost between $20,000,000 and $25,000,000 per year or a cost between $5.44 and $6.81 MwHr (net after derate). \(^{31}\)

One study by Synapse Energy Economics arrives at approximately the same costs as Bechtel\(^{32}\). Synapse adds the following caveat:

Most importantly, as can be seen from Figure 2, the Synapse CO2 price forecasts are substantially lower than a number of the other recent price projections. Thus, the annual CO2 costs would be even higher if Figure 4 had reflected these other CO2 price forecasts.

The Synapse report refers to the fact that its per ton CO2 cost estimate is lower than the Environmental Protection Agency (EPA) and Massachusetts Institute of Technology (MIT). EPA and MIT prepared their CO2 cost analyses in 2007. The Synapse figure is based on data available in 2006.

Mr. Guelker states in several places in his testimony that a new greenhouse gas emissions policy will take years to implement. Any delay is imprudent.

Questions on what the anticipated greenhouse gas emissions policy may or may not be, including its impact on the proposed construction of SGS Unit 4, will not be answered in the near term by the passage of any single piece of legislation and regulation. No single piece of legislation or regulation will provide the certainty or clarity needed to predict the future including the resulting CO2 emissions prices in a carbon-constrained world.\(^{33}\)

A recent decision on an air permit on a coal plant proposed for Early County, Georgia points to both the urgency for federal legislation, and the current inability to set a firm price on any new technology.

A New York Times account of the case states:

Judge Moore said in her decision that the permit would have to require “best available control technology” for all emissions that could be regulated, including

---

\(^{31}\) Vesperman Direct Testimony at 17.


\(^{33}\) Guelker Direct Testimony at 13.
carbon dioxide. But Mr. Vogt (project manager for LS Power Group and Dynegy) said that in contrast to pollutants like soot, nitrogen, oxides and sulfur dioxide, there was no commercially available carbon-control technology, nor a government-set limit on emissions.

“There simply are no regulations out there to tell us what we would have to do,” he said. “The E.P.A. is wrestling with this right now, as is Congress.”

Q. Are there any other cost factors that IPL has not taken into consideration?

A. Yes. According to the Agreement between Corn Belt, CIPCO and IPL the project as a whole may face additional environmental costs.

Whether or not actual financing is secured from RUS, the longstanding relationship between the two organizations and RUS may require RUS’ approval of their participation with this plant. What, if any, environmental actions would be required is unknown. The agency has recently instituted a moratorium on future financing of coal-fired plants. (A more detailed discussion on the RUS moratorium is contained near the end of this testimony). Any alternative financing secured by CIPCO or Corn Belt will be more expensive than RUS.

Q. Does the Return on Equity recommendation of 12.55% by IPL meet the reasonableness criteria?

---

35 Agreement between Interstate Power and Light, Corn Belt Cooperative and CIPCO, Section 10.8, November 27, 2007, p. 42 (Confidential Figure 1.1-1).
A. This extraordinary request reflects IPL’s concern with financial risks associated with constructing a coal-fired power plant in this environment. The company has decided to place the risk for the plant on the ratepayers, in order to protect the short-term interests of its shareholders. Given the speculative nature of the assumptions used to prepare this rate proposal it is surprising that the request was for only 12.55%.

If the Board proposes a set of principles for this plant, a substantially reduced ROE, which more reasonably balances the risks, would be prudent.

According to a recent Alliant presentation, 12.55 % represents the highest request of any new generation project currently under review. The latest ROE approval was 10.7%.

Q. If IPL’s estimates are aggregated and compared to an alternative estimate and then to IPL’s current cents per kwh revenue received from residential customers, is SGS Unit 4 a sound investment for Iowa’s consumers?  
A. No. The presentation lacks a simplified one page version of what this plant could mean to consumers. According to Alliant Energy’s Annual Report, the company receives 7.93 cents per kilowatt for electricity sold to retail customers across the entire AES operation.  

---

36 Hanley Exhibit, Interstate Power and Light, Authorized Returns on Common Equity and Common Equity Ratios for Electric Operations of Electric and Combination Electric and Gas Companies for the Twelve Months Ended December 2007, Exhibit (FJH-1), Schedule 9, Page 2 of 7.
37 Alliant Energy Services, Baird Marketing (June 20, 2008) slide 20 (attached as Exhibit TS-16).
38 AES, Annual Report, Op Cit, p. F-87 (see Exhibit TS-4).
Table 1 above provides a simplified version of the many complex calculations that are part of this rate proposal. In the absence of a commitment by IPL of a fixed capital structure, the Annual Capital Charge in the Table assumes a 12%, 30 fixed financing instrument, similar to that found in a number of the IPL estimating models. Other than that one calculation, the column "IPL Estimate and Capital Charge" reflects IPL’s assumption found throughout the application, testimony and exhibits.

[Confidential Table 1 redacted]
The "Trend Estimate" is based on data derived from the proposal and those external sources used to prepare this testimony. The conclusions drawn from reviewing these numbers are as follows:

Using IPL’s current assumptions (as adjusted), this plant could produce electricity at a cost of 7.75 cents per kwh without CO2 Capture. An amount just under the 7.93 cents per kwh AES received as revenue from residential customers in 2007.

Using IPL’s estimate (as adjusted), plus CO2 costs, the cost of electricity rises to 14.56 cents per kwh ---- an 84% cost above the 7.93 cents per kwh.

Using the Trend Estimate without CO2, the cost of electricity could be 9.28 cents per kwh --- a 17% cost above the 7.93 cents per kwh.

Using the Trend Estimate with CO2 costs, the cost of electricity could be 16.09 cents per kwh ----- a 101% cost above the 7.93 per kwh.

The risk is that this plant will add to IPL and the State’s electricity grid a new facility that requires customer payments to effectively double in order to pay for it. This would place strong upward pressure on rates and the price to customers, as this 432 MW’s of additional capacity would constitute 14 percent of all capacity in 2014, the first full year of operation.

Q. Has IPL addressed the cumulative risk that it is confronting?

No. There are four distinct problems with IPL’s presentation. The cost of construction is high, and likely to go higher. The regulatory outcome on the issue of greenhouse gas
could double the cost of electricity from this plant. The price of coal is high and expected to rise. Finally, the demand for electricity is not as strong as IPL has stated.

Mr. Hanley hints at the cumulative risk when he quotes both Moody’s and Standard and Poors:\footnote{Hanley, Frank, Response to OCA Data Request 31 (May 13, 2008) (attached as Exhibit TS-17).}

From Moody’s:

Rising concerns about the causes and consequences of climate change will carry major implications for the U.S. electric utility sector. Potential new limits on emissions of greenhouse gases, primarily carbon dioxide, are likely in the next several years. New rules are likely to force the industry to spend billions of dollars on compliance. The timing and form of any federal legislation that would establish these caps is unknown.

Future costs related to greenhouse gases would come on top of the significant capital many utilities are already investing to reduce emissions of mercury, nitrogen oxide and sulfur dioxide. While EPA-mandated rules relating to these pollutants are being challenged in the federal court system, many utilities foresee remediation costs that significantly exceed the agency’s original estimates.

Given the magnitude of these potential nondiscretionary environmental-related costs and the fact that electricity prices are rising throughout the country, electric utilities could face a daunting challenge in obtaining timely recovery of these costs through their respective regulatory rate-setting authorities. While Moody’s believes that most commissions are likely to grant timely recovery of prudently incurred mandated environmental costs, the resulting increase in electricity prices may make recovery of other operating costs and capital investments more challenging. Such a scenario could cause negative rating actions within the sector.

From Standard and Poors (still quoting Mr. Hanley):

Among the risks are that CO2 compliance costs could spiral out of control, those costs could be up for rate recovery at the same time that other expenses are rising, and the costs could then get “crowded out” if regulators try to ease customer rate shock. Any disallowance would not necessarily be explicit, since it is difficult and legally suspect to keep prudent, legislatively mandated costs out of rates. The real risk to credit quality is the prospect that CO2 compliance costs will be the proverbial straw that leads to harsh regulatory responses such as a disallowance or deferral because of cost pressures tied to commodity prices, more capital spending for basic reliability needs on the transmission and distribution system, and added
construction costs for new generation to meet rising demand…. Clearly, the pursuit of a cooler planet will leave utilities sweating over the risk to their credit quality.

In other words, this plant will be a regulatory quagmire for the Iowa Utility Board for the next several decades.

Q. Has IPL demonstrated a sound financial rationale for moving forward with this plant?

A. No. It is clear that with these documents in support of ratemaking principles IPL is attempting to move the extraordinary risk involved with the project from its shareholders onto the ratepayers of Iowa.

One institution, with far greater experience financing coal-fired power plants than IPL has come to a completely different conclusion regarding the degree of risk involved with this proposal. The United States Department of Agriculture, Rural Utility Service has been providing financing for rural electrification projects for over seventy years. Faced with the same economic conditions that IPL faces, it has decided to call a moratorium on any coal fired power plant projects.

On February 19, 2008, the RUS Administrator informed the General Manager of Southern Montana Electric Cooperative, Inc. that it could not move forward with the Highwood Generation Station project. The letter to the cooperative discussed the general issues facing RUS, and informed the cooperative that no further baseload generation loans would be forthcoming at least through 2009. The letter states:

I have been closely and carefully monitoring the developments with the proposed Highwood Generation Station. The inherent risks associated with compounded delays make the situation more problematic as well as increasing the cost of the plant which will be
passed on in the form of higher member rates raise concerns about financial feasibility.

Additionally, as you know, the Agency is precluded from financing base load generation plants in Fiscal Year 2008 and I suspect that will be the situation in Fiscal year 2009. Costs will continue to increase throughout this period.

With all the facts considered: No base load generation loans probably through 2009; continued cost increases further exacerbated by the added time to reach loan approval; the feasibility of the project with extra time and additional cost; and the uncertainty of the litigation now filed compels me to inform you the Agency will not be able to finance the proposed Highwood Station Plant.

Add to the above facts concern exists that approximately 40 percent of Southern Montana’s capacity in the proposed plant is not under contract through the entire term of the proposed financing from the Agency. 40

Disclosure of this application denial and the larger issue of an effective moratorium on new lending have prompted press attention. 41 The Washington Post article states:

Though the last loan for a generating plant was made in 2006, rural cooperatives have applied for $1.2 billion in loans to cover all or part of four more coal-fired plants, including controversial ones in eastern Kentucky and southern Illinois. Two other cooperatives recently shelved their projects and withdrew their RUS loan applications. And last month the RUS informed the Southern Montana Electric Generation and Transmission Cooperative that the agency was rejecting its application for a coal plant loan, citing new agency policy, rising construction costs and the lack of customers for much of the proposed plant’s output…..

The RUS administrator, James M. Andrew, said in the letter that it “is not funding loans for new base load generators until the Agency and the Office of Management and Budget can develop a subsidy rate to

---

40 Letter from Andrew, James M., Administrator, Utilities Program, United States Department of Agriculture to Gregori, Tim, General Manager, Southern Montana Electric Generation and Transmission Cooperatives, Inc. (February 19, 2008) (attached as Exhibit TS-18).
41 Mufson, Steven, Government Suspends Lending for Coal Plants: Risks Cited to Economy, Environment, Washington Post, March 13, 2008. See also Karl Puckett, Rural Utilities explains funding pullout and Coal-fired power plant projects feel heat from rising costs, environmental concerns, Great Falls Tribune, March 4 and 13, 2008, respectively (attached as Exhibit TS-).
reflect the risks associate with the construction of new base load
generation plants.”

An RUS spokesman would not say when the OMB closed the lending
window for baseload plants; the agency gave no hint of the policy
change until its letter to Southern Montana Electric on February 19.

The agency also conceded yesterday that it had not considered
potential costs that could result from climate-change legislation that
most commercial banks, utilities and other businesses consider when
considering energy projects. “Since there is no clear consensus on
what emission standards will be enacted and associated costs,
attempting to make decisions on loans absent a factual base is
speculative at best,” Andrew said.

…..A budget expert who asked not to be identified to protect his
relationship with clients noted that the RUS was also glossing over
the difficulty of passing costs along. Power generation co-ops are
separate from distribution co-ops, which in the past have forced some
generators into bankruptcy, rather than pass along higher costs.

The financial conditions facing RUS projects are the same ones confronting IPL. The
difference is that RUS has decided the assumptions used by its applicants are speculative
and did not meet financial standards. IPL would have the Iowa Utility Board ratify them
as prudent and reasonable.

Q. Does this conclude your prepared direct testimony?

A. Yes