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Witness:	Kenneth M. Roberts
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Case No.:	ER-2010-____
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2010-____

DIRECT TESTIMONY

OF

KENNETH M. ROBERTS

ON BEHALF OF

KCP&L GREATER MISSOURI OPERATIONS COMPANY

Kansas City, Missouri
June 2010

"[redacted]**" Designates "Highly Confidential" Information Has Been Removed.**
Certain Schedules Attached To This Testimony Designated "(HC)" Have Been Removed
Pursuant To 4 CSR 240-2.135.

DIRECT TESTIMONY

OF

KENNETH M. ROBERTS

Case No. ER-2010-____

Q: Please state your name and business address.

A: My name is Kenneth M. Roberts. My business address is 233 South Wacker Drive, Suite 6600, Chicago, Illinois 60606.

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

A: I am an equity partner, co-chair of the Construction Law Group and a member of the executive committee of the law firm Schiff Hardin, LLP ("Schiff").

Q: Please describe your education, experience and employment history.

A: I received my undergraduate degree, a Bachelor of General Studies, with honors, concentrations in Business, Political Science, and Rhetorical Studies, in 1982 and my juris doctor with distinction in 1985 from the University of Iowa. I have also attended the Kellogg Management Institute, Kellogg Graduate School of Management of Northwestern University (1999-2000) and The University of Chicago's Graduate School of Business Management Institute (2007). During the fall of 2008, I was a co-instructor on a project finance course (focusing on risk analysis) at Northwestern University's Graduate Engineering program. I am admitted to practice law in Illinois and Missouri, as well as before the United States District Courts for the Northern and Central Districts of Illinois and the Western District of Missouri.

My legal practice is concentrated in the field of construction law, procurement, Project Controls and corporate governance in which I provide independent "eyes and ears" to corporate boards and senior management, particularly on behalf of owners in the energy industry, as to the status of large capital improvement projects. I have handled matters in Brazil, Canada, Texas, Missouri, Kansas, New Jersey, Nevada, Pennsylvania, Massachusetts, Maryland, Alaska, Florida, Illinois, Indiana, and Ohio. I engage in a range of services from preparation and negotiation of contracts, project controls monitoring and advice during on-going projects, negotiation of change orders and contract additions, alternative dispute resolution through mediation and arbitration, and when necessary, litigation. I also consult on a daily and ongoing basis with energy companies' procurement and risk management departments concerning every aspect of planned or ongoing construction projects and outages. The work I have performed for energy companies involves all elements of power plant construction and technology, including construction of air quality control systems ("AQCS"), low NO_x burners, heat recovery steam generators ("HRSG"s), selective catalyst reduction ("SCR") systems, precipitators, nuclear waste disposal and storage, coal handling systems, steam generators, gas and steam turbines, boilers, control systems, and other operational and environmental equipment.

I also have an extensive background of representing owners, contractors and architect/engineers in multi-faceted, complex disputes involving: delays, disruption and losses of efficiency; breaches of contracts for performance, scope of work and payment; and complex multi-party insurance coverage issues. I work with and manage a team that has extensive experience providing project controls (for tracking budget and schedule) for owners and architect/engineers on a national basis and work daily with the owner's project managers at the construction site.

Q: Have you previously testified in a proceeding at the Missouri Public Service Commission or before any other utility regulatory agency?

A: Yes. I have previously filed testimony in KCP&L's last rate case, Case No. ER-2009-0089 ("0089 Docket") and in Case No. ER-2009-0090. I have also filed testimony before the Kansas Corporation Commission in Docket Nos.09-KCPE-246-RTS and 10-KCPE-415-RTS.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is: (1) to discuss the tools KCP&L implemented to make prudent management decisions during the planning and construction of the Iatan Unit 2 Project; (2) to provide a description of the market factors impacting the planning, design and construction of Iatan Unit 2; and (3) to identify the effectiveness of KCP&L's Project Controls for the Iatan Unit 2 Project and how those tools assisted in the prudent management of the project.

Q: Please describe the services you and Schiff's Construction Group are performing on behalf of Kansas City Power & Light Company ("KCP&L" or the "Company")?

A: KCP&L engaged Schiff: (i) to help the Company develop project control procedures to monitor the cost and schedule ("Project Controls") for the infrastructure projects contained in the Company's Comprehensive Energy Plan ("CEP"); (ii) to monitor the CEP's progress and costs, including the review and management of change order requests; (iii) to negotiate contracts with vendors related to the CEP; and (iv) to resolve disputes with vendors that might arise on CEP projects.

Q: What is the method in which you provide information to KCP&L regarding the CEP Projects?

A: Under my direction, Schiff has reported to KCP&L's Executive Oversight Committee and to senior management from time to time during the course of the planning and construction of KCP&L's CEP Projects. Such reports have been in both oral and written format. These reports generally include a summary of Schiff's independent view of the CEP projects' schedule, budget, and procurement status and identification of key issues that have the potential to affect or have affected progress. These reports also generally include metrics that Schiff has developed to independently verify the CEP Projects' then-current status.

Q: Have you reviewed the prudence standard as discussed by Company witness Dr. Kris R. Nielsen in his rebuttal testimony in the 0089 Docket?

A: Yes, I have.

Q: Do you agree with Dr. Nielsen's analysis of the prudence standard as it is applied in Missouri for purposes of determining whether KCP&L was prudent in the construction of the Iatan Unit 1 project?

A: Yes. In particular, I agree with Dr. Nielsen that in determining whether KCP&L's decisions throughout the course of the Iatan Unit 1 project were prudent, such evaluation should be based upon whether the decision-making process was sound. The following aspects of Dr. Nielsen's testimony are those which are critical in evaluating the prudence of the decisions of KCP&L's senior management and project management throughout the Iatan Unit 1 project:

- <u>Data development</u> – What information was available; were management systems and procedures organized and implemented to produce information to enable analysis; was the data reliable; what was the timeliness of the data to the decision?

- Information Flow – To whom and when was data transmitted; what data was communicated; in what format was the information made available?
- Analysis – What does the information mean; what alternatives were identified or, where possible, what benefits and impacts are projected; how does the decision mesh with project and corporate needs?
- Decision – What decision was made; when was the decision made; how was the decision made; was the decision reviewed as assumptions and circumstances changed?

Q: Do you believe this prudence standard as applied in the 0089 Docket to Iatan Unit 1 should be applicable to Iatan Unit 2 in this case?

A: Yes.

Q: How did KCP&L apply the prudence standard with respect to decision-making for the Project?

A: KCP&L put the proper tools in place to allow KCP&L to make prudent management decisions.

Q: In describing KCP&L's management decisions, you will be referencing "Executive Management" and "Senior Management." Please define "Executive Management" and "Senior Management" within the KCP&L organization.

A: As Company witness William Downey testifies, "Executive Management" consists of the Chairman, the President, and Chief Operating Officer ("COO"), the Chief Financial Officer ("CFO"), and the Executive Vice Presidents of KCP&L. "Senior Management" consists of those same individuals plus the Company's other Vice Presidents.

Q: Have you considered the impact of KCP&L's management decisions on the construction of Iatan Unit 2?

A: Yes.

Q: Does applying the prudence standard guarantee that decisions made during the course of a project will yield an optimal outcome?

A: No. On large, complex construction projects, not all management decisions, including those that were made prudently, appear to be perfect in hindsight. However, under the applicable prudence standard, management decisions cannot be judged in hindsight, based solely on the outcome or evaluated in light of information or events arising only after the decision was made. Instead, the standard for prudence is focused on the decision-making process.

Q: What project management tools did KCP&L utilize to assist in the decision-making process for the Iatan Unit 2 Project?

A: KCP&L implemented the various governance considerations, management procedures, and cost control protocols (including Project Controls) based upon the Comprehensive Energy Plan Construction Projects Construction Cost Control System ("Cost Control System"). The Cost Control System is attached to Company witness Steve Jones' testimony as Schedule SJ2010-1.

Q: How did you become familiar with the Cost Control System document?

A: KCP&L asked Schiff to review it and to help develop portions of it.

Q: What are "Project Controls"?

A: As defined by the Cost Control System document "Project Controls" include the systems developed by KCP&L "to monitor, control, and report the schedule, cost, and other relevant information for the respective CEP Projects. The CEP Projects will be managed in accordance with control budgets and baseline schedules that are established at the start of each Project." Based upon my experience, this definition encompasses a baseline of project controls that is standard in the industry.

Q: What "Project Controls" are in place for the Iatan Project?

A: The Project Controls contemplated by the Cost Control System and used on the Iatan Unit 2 Project include: (i) development of a detailed, integrated and baselined project schedule; (ii) earned value tracking of contractors; (iii) development of a Control Budget Estimate that would be reforecast as necessary to track trends and contingency; and (iv) the development of commercial terms and conditions for the major procurements; and (v) early development and enforcement of the Change Management procedure. In addition to the Project Controls suite set forth in the Cost Control System, KCP&L has developed the following for Iatan Units 1 and 2:

- A robust Notice and Notification Procedure that is vigorously enforced by KCP&L. (See Direct Testimony of Company witness Steven Jones.)
- KCP&L's project team has developed user-friendly reporting tools for earned value, budget status, safety and project status that meets industry standard, and those tools as well as Schiff's independent overview and reports from KCP&L's Internal Audit are provided to KCP&L's Senior

Management on an on-going basis.

Q: Was the Cost Control System ever submitted to Missouri Public Service Commission ("MPSC") Staff for its review?

A: Yes. It is my understanding that the Cost Control System was presented to MPSC Staff on or about July 17, 2006.

Q: Do you believe the guidelines discussed in the Cost Control System were adequate for KCP&L to manage the Iatan Unit 2 Project?

A: Yes. Additionally, throughout the course of the Iatan Unit 2 project, the guidelines set forth in the Cost Control System have been refined and modified in practice to fit considerations specific for Iatan Unit 2.

Q: Based upon your experience, is the quality and accuracy of the data that is provided to KCP&L's Senior Management based on the various tools outlined in the Cost Control System within industry standards?

A: Yes, in fact, I would consider it to be in conformance with industry best practices.

Q: To whom within KCP&L is this data provided?

A: In addition to the project team, as Company witness William Downey testifies, there are currently monthly meetings of the Executive Oversight Committee ("EOC"), at which such data is supplied to Senior Management. There are also weekly meetings on-site with sub-groups of KCP&L's Senior Management that focus on commercial and regulatory issues at which this data is reviewed and discussed.

Q: How did these tools help KCP&L's Senior Management make timely decisions regarding Iatan Unit 2?

A: The information that Senior Management received regarding the project allowed it to:

(i) identify the need for a decision; and (ii) make informed and timely decisions throughout the Iatan Project.

Q: Do you believe that the EOC had the right processes in place to receive adequate information to make decisions?

A: Yes.

IATAN SCHEDULE

Q: Let's discuss some of the specific Project Controls tools, starting with the schedule. In establishing and tracking the Iatan Unit 2 Project's schedule and the progress of contractors pursuant to the schedule, did Schiff work with any consultants?

A: Yes. Schiff worked extensively with Jim Wilson of Jim Wilson & Associates. Schiff has worked with Mr. Wilson and his firm for over twenty years. Mr. Wilson has testified in numerous courts, arbitrations, and other proceedings regarding all aspects of project controls. His area of expertise includes, but is not limited to, scheduling; monitoring and evaluating the progress of contractors pursuant to the schedule; and evaluating the causation, responsibility, and durations of schedule impacts during construction. Mr. Wilson's resume is attached as Schedule KMR2010-1.

Q: What is a "baseline schedule?"

A: A baseline schedule is an important project tool. As defined in the Cost Control System: "a baseline schedule sets forth all planned work for the Project, including all engineering, procurement, and construction activities, along with associated man-hours required to perform each task in the schedule. The [b]aseline [s]chedule will identify the intended duration of the work, the resources required for performance, the logical relationships of the work and other scheduling tools."

Q: **Based upon your experience, what is the importance of a baseline schedule?**

A: A baseline schedule is important because it allows the project participants to compare the actual progress with the planned performance over time, establishing performance trends and identifying areas of potential difficulty. A baseline schedule also is important in establishing the basis for cost estimates, though it does not necessarily indicate that the project's definition is sufficiently mature for a highly accurate or predictive cost estimate. Having a baseline schedule allowed for the establishment of an earned value system that KCP&L deployed on the Iatan Project, which I will be discussing a little later.

Q: **When is the baseline schedule typically established for a project?**

A: The baseline schedule is typically established at a point in a project where design engineering is mature enough for all of the performing contractors to prepare and integrate a work plan based upon the known project definition. Such a baseline schedule needs to be sufficiently detailed to depict the effort needed to execute the work. That does not mean that a baseline schedule reflects a fully designed and scoped project; rather, the baseline often includes placeholders for information not known at that time. The level of detail in the baseline schedule is intended to reflect the level of maturity of the design at that time.

Q: **How was the baseline schedule for Iatan Unit 2 developed and managed by KCP&L?**

A: Company witness Brent Davis testifies regarding the development of the schedule for the Iatan Unit 2 Project. The integrated baseline schedule for the Iatan Project was developed with input from ALSTOM, Burns & McDonnell and the early balance of plant contractors such as Kissick (foundations), ASI (material handling) and Pullman (chimney) and baselined in April 2007. The process for establishing this baseline schedule involved a detailed review of ALSTOM's schedule and the schedule initially developed by Burns & McDonnell to optimize the balance of plant design and included appropriate placeholders for all construction work that had not been procured as of that time. This was the operative schedule for the Iatan Project until the Revised Unit 2 Schedule was issued in June 2009.

Q: What is earned value?

A: KCP&L's Cost Control System provides a definition for earned value that is commensurate with my experience. The Cost Control System states that: "earned value . . . is an industry-standard measurement of cost and schedule progress as compared to the Project's original plan" and the results of the comparison are then expressed in the form of ratios over time. As work is completed, man-hours are "earned" and compared against the original plan for both the amount of work completed and its timeliness. The ratio of earned hours to planned hours is known as the Schedule Performance Index ("SPI"). Cost Performance Index ("CPI") is the ratio of a contractor's actual, or expended, man-hours as compared to the hours it has earned. This is a measure of the contractor's productivity.

As an example of SPI and CPI, if a scheduled task was planned to take 100 man-hours over a one week period, and the contractor earns 100 hours for the week, its SPI would equal 1.0. However, if the contractor earns 20 hours less than its plan, it will have an SPI of 0.80. If the same contractor spends 100 man-hours to earn 100 hours in that week, its CPI is 1.0. If it expends 120 hours and earns 100 man-hours, its CPI will be only 0.80. In other words, it cost more money than planned. These indices can be further reduced into percentages: in the hypothetical above, the contractor who has an SPI of 0.80 is 20 percent behind schedule for the period measured, and if its CPI was 0.80, it had a 20 percent loss of efficiency/productivity. With these indices, an SPI of 1.0 or greater means that the contractor has maintained or bettered its planned pace, and for CPI an index of 1.0 or better means that the contractor is working productively.

Q: How is earned value utilized in the construction industry?

A: In Schiff's experience, earned value has been heavily utilized by sophisticated owners, contractors and engineering firms for at least the last 20 years. Ultimately, earned value is a tool that allows those who use it to gauge schedule compliance and productivity. Depending on how it is used and the level of detail inherent to the particular application, earned value is used to examine progress on a project at both a macro and a micro level.

Contractors use earned value to track the work necessary to meet their schedule commitments, and also use earned value to identify productivity issues. Earned value is a tool that assists contractors in understanding where they are either efficient or inefficient in their work. Engineering firms also use earned value to track scheduled work in ways that are often similar to how contractors use it. From an owner's standpoint, earned value has become a popular and effective way for owners to understand and control both schedule and budget for large, complex projects. It is a method that allows one to summarize many hundreds or even thousands of detailed schedule activities into simple time and cost indices. Additionally, owners use earned value to implement any contractual rights they may have to direct the contractor to submit a "recovery plan," accelerate the contractor's work or to ensure that the contractor pays for its own productivity losses.

Q: **How does earned value help control costs on a project?**

A: One way earned value helps to control costs is to allow the owner to track the contractors' productivity in their performance of the work. The data generated by an earned value system allows the project team to drill down to find the root cause to mitigate adverse trends. In addition, using earned value to track schedule performance allows the project team to forecast the work's completion.

Q: **What information is needed in order to track earned value on a project?**

A: Earned value relies on all contractors having a man-loaded baseline schedule, which identifies all of the project's activities and associated man-hours needed to complete those activities. Tracking earned value also requires that the contractors report their status and provide visibility to their earned and actual hours as required by the systems in place.

Q: **For the Iatan Unit 2 Project, how does KCP&L obtain the information needed for tracking earned value?**

A: For the Iatan Project, the contractors report their earned and actual hours on a weekly basis, as required by the contracts. KCP&L's Project Controls group maintains the integrated level 3 detailed schedule to which the contractors each provide their weekly updates. The Cost Control System refers to the required data and metrics needed for the Iatan Project's earned value tracking and how the data is used.

Q: **How does Schiff typically track earned value for a project such as Iatan Unit 2?**

A: When Schiff is responsible for tracking, recording and reporting earned value, we generally identify a weekly SPI/CPI, a five-week average SPI/CPI and a cumulative SPI/CPI for each contractor and a project as a whole, as well as cumulative and weekly percent complete. The cumulative SPI/CPI will identify the overall project's status. The five-week averages identify trends, and both in our experience and the industry at-large, a five-week period for recording progress gives a fairly accurate read of the current pace of the work. In addition, we will often identify and forecast a target number of hours that a contractor needs to achieve or earn in order to keep pace with the projected schedule. Over the course of lengthy, complex projects, contractors will often ramp up or ramp down their forces in order to achieve the level of earned value production necessary to meet schedule and not expend more resources than needed. Earned value can be used to determine whether a contractor is behind or ahead of schedule, as well as how many man-hours a contractor is ahead or behind.

Q: **How did KCP&L track earned value for the Iatan Project?**

A: KCP&L, along with Project Controls oversight from Schiff, utilized the methods for tracking earned value as described above and applied that methodology to the Iatan Project. Attached is Schedule KMR2010-2 which is an earned value chart that Schiff prepared for the Iatan Project. This chart **[redacted]** This chart shows a series of vertical lines that are color-coded; the blue bars represent the contractor's planned hours, plotted over time; the yellow bars show the contractor's earned hours as compared over time to the planned hours; and the red bars show the actual hours that contractor expended over time. The grouping of vertical bars shows the planned, earned and actual progress broken into monthly increments. The hatched lines in the monthly bars further break the planned, earned and actual man-hours into weekly segments. This way, someone analyzing the data in the chart could readily identify and compare the contractor's planned, earned and actual hours on weekly or monthly basis. In addition, this chart shows a cumulative percent complete on a planned, earned and actual basis over time.

The earned value systems that have been established for the Iatan Project have identified when contractors have fallen behind schedule and in which areas the contractors' performance has lagged. By quantifying the number of hours behind schedule, the Project team is able to identify ways to improve performance, remove impediments, foster jobsite coordination and/or hold the contractors accountable for establishing a recovery plan.

Q: Are there other ways in which KCP&L has tracked progress on the Iatan Project?

A: Yes. KCP&L has also tracked the progress to the schedule itself to insure that the contractors are not just performing work but also the work necessary to move the Project along. All construction projects involve performing work in a logical sequence, and a project as complex as Iatan Unit 2 requires the contractors to maintain that logical sequence or there could be coordination difficulties in the field. In addition, as Company witness Daniel Meyer testifies, KCP&L has been tracking the Iatan Project's cost performance against the Control Budget.

Q: How committed is KCP&L to the implementation of effective project controls on the Iatan Project?

A: KCP&L was extremely committed to utilizing effective project controls on the Project, even more than many of our other clients. As an example, KCP&L negotiated robust project controls into the ALSTOM contract. Typically, owners view EPC fixed-price contracts as 'turnkey' projects, and do not require, nor do the contractors offer, much data to be provided with respect to the contractor's performance. Originally, during the bid process ALSTOM stated that it would give KCP&L a schedule, but it would not comply with all of KCP&L's requirements, including resource loading the schedule so that it could be subject to an earned value analysis. Throughout the course of the contract negotiations, KCP&L refused to yield on the earned value system for construction of the Iatan Project. Ultimately, ALSTOM relented, and agreed that its construction activities would be man-loaded and subject to earned value tracking by KCP&L. This has been an invaluable tool to KCP&L throughout ALSTOM's performance on Iatan Unit 2 because it (along with the other project controls previously described): 1) has given KCP&L an opportunity to status ALSTOM's performance on the project at various points; 2) identified areas of concern as well as track the progress on critical milestones; 3) identified areas of rework by ALSTOM; 4) identified productivity issues; and 5) allowed KCP&L to resolve commercial disputes with ALSTOM as the Project progressed. Additionally, having an earned value system has allowed KCP&L to identify ALSTOM's capabilities for completing the work and to forecast its future performance based upon the size and skill of its labor force.

Q: How has KCP&L's Senior Management used earned value and other Project Controls implemented on the Iatan Project to make decisions?

A: KCP&L's Senior Management's decision-making has been prudent in large part because of the quality of the information it receives from the Project team on a regular basis. With respect to earned value, in Schiff's experience, once Senior Management is educated regarding how to look at a project from an earned value perspective, it becomes a very effective tool for them to understand and quickly gain access to data necessary for managing a project. Earned value allows the Project team and the contractors to reduce a very complex construction project into something that can be readily seen and easily understood. By utilizing this tool, KCP&L's Senior Management was able to understand where problems were with the Iatan Project's major contractors and were able to develop appropriate problem-solving strategies utilizing that information. In addition, the other key metrics provided regularly to Senior Management regarding schedule progress by the contractors in meeting key milestones, quality and safety statistics and changes in scope and budget have been critical in providing the information necessary upon which it has made prudent decisions.

Q: To whom is the earned value data provided?

A: The information Schiff prepares is provided to KCP&L's Senior Management. In addition, the Project team provides additional project controls analysis to Senior Management.

Q: Has the earned value data and analysis of that data provided to KCP&L's Senior Management been timely?

A: Yes.

Q: Is the earned value data sufficient to keep KCP&L's Project team and Senior Management informed to make decisions as necessary?

A: Yes.

COST CONTROL

Q: Please describe the specific cost controls that KCP&L has implemented for the Iatan Unit 2 Project.

A: The cost controls used by KCP&L's Project team and Senior Management follow the guidelines established in the Cost Control System. The Project team regularly reported to Senior Management using the Control Budget as a basis for tracking the Iatan Unit 2 Project's costs and contingency. The Control Budget included tracking of: (i) costs committed to date; (ii) actual costs paid to date; (iii) change orders to date; (iv) expected cost at completion based on current forecasts of the Iatan 2 Project's costs; (v) contract amounts with vendors under contract; and (vi) identification of functional groups (*e.g.*, engineering, project management, procurement, oversight) costs. The reports provided to Senior Management also identify variances to the Project's approved Control Budget Estimate, as well as assessments of cash flow.

Q: In your opinion, is the quality and accuracy of the data that is provided to KCP&L's Senior Management through these various sources within industry standards?

A: Yes.

Q: To whom is this data provided?

A: In addition to the Project team, as Company witness William Downey testifies, there are currently monthly meetings of the EOC and other regular meetings at which such information is supplied to Senior Management. There are also weekly meetings on-site of a subgroup of Senior Management that focuses on commercial and regulatory issues, at which weekly updates are provided.

Q: Is the data provided to KCP&L's Senior Management timely?

A: Yes.

Q: Is the data that is provided to KCP&L's Senior Management on a regular basis sufficient to keep management informed to make decisions as they occur?

A: Yes.

Q: What is a Control Budget Estimate?

A: The Cost Control System defines a "Control Budget" as a tool that details the expected cost of the work on the Project and includes appropriate contingency.

Q: What is the Control Budget Estimate for the Unit 2 Project?

A: The Control Budget Estimate was the **[redacted]** estimate of costs for the Iatan Unit 2 Project that was approved by the KCP&L Board of Directors in December 2006 and which was used by the Project team to initially set the budget and manage the Iatan Project's costs.

Q: How was the Control Budget Estimate developed?

A: The development of the Control Budget Estimate for Iatan Unit 2 is discussed in detail in the testimony of Company witness Daniel Meyer.

Q: Who is Daniel Meyer?

A: Mr. Meyer is a consultant retained by Schiff with an expertise in cost engineering for large, complex construction projects. Mr. Meyer works very closely on all aspects of cost issues with the Schiff team.

Q: Have you read Mr. Meyer's testimony?

A: Yes, I have.

Q: Does Mr. Meyer's testimony comport with your understanding of the work that he performed for Schiff?

A: Yes.

Q: Did members of Schiff work closely with Mr. Meyer, attend the same meetings and review the same documents referenced in Mr. Meyer's Testimony?

A: Yes.

Q: Do you agree with Mr. Meyer's description of those events and documents?

A: Yes.

Q: What are your opinions with respect to the statements made by Mr. Meyer in his testimony?

A: Mr. Meyer's testimony comports with my understanding of the events that have occurred on the Iatan Unit 2 Project, and we share the same opinions and analysis with respect to those events.

Q: Why did KCP&L reforecast the project's estimate at completion ("EAC")?

A: I agree with the testimony of Company witness Daniel Meyer that "it is a widespread industry practice to periodically reforecast project cost, and those who do so are generally regarded as prudent. From a cost management perspective, it is good practice to examine and update estimates and reforecast costs. In its simplest sense, a cost reforecast is an exercise that parties in the industry go through at logical points in a project to revisit the budget and the efficacy of the budget amounts." (Meyer Direct Testimony at 6 ll. 1-6). From a corporate governance perspective, KCP&L's Senior Management has an obligation to its shareholders and customers to manage costs on the Iatan Project, which would include reforecasting the Project's Control Budget when facts and circumstances result in changes to earlier assumptions.

Q: Was the Executive Oversight Committee aware that the CBE for the Project would periodically be reforecasted?

A: To the best of my knowledge, it was known and acknowledged at the time that the Control Budget Estimate was presented to the Executive Oversight Committee that there would be a time at which it would be appropriate to reforecast the Iatan Project's expected cost (the "Cost Reforecast").

Q: How many times has the CBE been reforecasted?

A: To date, KCP&L has performed three separate Cost Reforecasts of the CBE.

Q: In your opinion, does the mere fact that the Control Budget number for the Iatan Unit 2 Project increased as a result of the reforecast establish imprudence on the part of KCP&L?

A: No.

Q: Why not?

A: Because increases in costs on a project over time such as the Iatan Unit 2 Project are not evidence of imprudence. As discussed above, the prudency standard cannot be judged in hindsight or simply on the results of a decision. In order for there to be a determination of prudence, each decision should be evaluated based upon the decision-making process, not on the results of the decision itself. Therefore, the simple fact that Iatan Unit 2 has experienced some cost increases does not indicate that KCP&L has acted in an imprudent manner. In fact, a decision, when reviewed in hindsight, may ultimately be viewed to have been the wrong decision, though that decision was prudent at the time it was made. Furthermore, there have been factors outside of KCP&L's control that have caused some of the Project's cost increases. These include contractor performance as well as market-driven cost increases.

Q: What do you mean by "contractor performance"?

A: KCP&L had some coordination responsibilities with respect to all of the contractors on site. Ultimately, however, KCP&L did not manage or direct the contractor's means, methods or procedures or the day-to-day activities of the craft labor. This was done by the individual contractors themselves.

Q: What actions did KCP&L take relative to contractor performance?

A: KCP&L took appropriate measures to incentivize the contractors to meet their respective contractual dates, monitored the contractor's performance through the Project Controls tools discussed above, and KCP&L's executive management engaged in executive-level discussions with the contractors to ensure the timely resolution of commercial disputes at the least cost possible. Beyond these measures, however, KCP&L was limited in ensuring that the contractors administered their contractual duties to ensure timely completion of the Project.

Q: Can you please elaborate on the market-driven cost increases?

A: The overall rising costs of power plant construction have been confirmed by other utilities attempting to build projects during the relevant time period. For example, in June 2008, Wisconsin Power and Light Company ("WPL") filed testimony of Charles J. Hookham, who was the Vice President of Power Projects for HDR|Cummins & Barnard, Inc. (Schedule KMR2010-3, Direct Testimony of Charles J. Hookham on behalf of Wisconsin Power & Light Company in Public Service Commission of Wisconsin Docket No. 6680-CE-170, June 12, 2008 ("WPL Testimony"), at page 20). WPL was seeking regulatory approval to begin construction on a 300 MW circulating fluidized bed unit that was projected to cost $3,506/kW (in early 2008 dollars). (WPL Testimony at p. 20-21). Mr. Hookham testified that from 2006 through 2008, WPL's cost estimate for the construction costs of this unit had increased by 40 percent. (WPL Testimony at p. 14). WPL had similarly estimated that the cost of building a new supercritical coal plant also would exceed $3,500/kW. In support of its new cost estimates, WPL presented testimony that noted that "EPC [Engineering, Procurement and Construction] pricing for other non-IGCC, primarily coal-fired generating projects under construction or in the planning stages have similarly increased with many projects falling in the $2,500 to $3,800/kW range, without AFUDC or uncommon owner's costs (e.g., major railway additions.)." (WPL Testimony at p. 21).

In April 2008, Duke Energy Indiana, Inc. announced an 18 percent increase in the estimated cost of its proposed Edwardsport IGCC coal plant from the previous year. (Schedule KMR2010-4, Petition of Duke Energy Indiana, Inc. before the Indiana Utility Regulatory Commission Cause No. 43114 IGCC-1, filed on May 1, 2008 ("Duke May 2008 Petition"), at p. 3). Duke indicated that higher than expected costs had been experienced when the Company actually began final procurement of equipment for the plant. Duke also said that "the increase in the cost estimate is driven by factors outside the Company's control, including unprecedented global competition for commodities, engineered equipment and materials, and increased labor costs." (Duke May 2008 Petition at pp. 3-4). Duke also noted in its Petition to the Indiana Utility Regulatory Commission that this projected increase in cost "is consistent with other recent power plant project cost increases across the country." (Duke May 2008 Petition at p. 7.) Project costs continued to increase and in November 2009, when the project was approximately 44% complete, Duke Energy Indiana, Inc. forecasted an additional 6.4% cost increase. (Schedule KMR2010-5, Petition of Duke Energy Indiana, Inc. before the Indiana Utility Regulatory Commission Cause No. 43114 IGCC-4, filed on November 24, 2009 ("Duke November 2009 Petition"), at p. 3).

Q: Do you have any other industry examples?

A: Another example of a significant cost increase is Duke Energy Carolinas' Cliffside Project. (Schedule KMR2010-6, July 2008 Synapse Energy Economics, Inc. Article, Coal-Fired Power Plant Construction Costs, by David Schissel, Allison Smith and Rachel Wilson ("Synapse Article"), pp. 1-2). The original project consisted of two units. The original 2006 cost estimate for the two-unit project was approximately $2 billion. Less than one year after completing the original cost estimate, Duke announced an approximately 47 percent (or an additional $1 billion) increase in the cost of the project. (Synapse Article at pp. 1-2). The applicable state regulatory Commission denied the permit application prompting Duke to downsize the project to a single unit. Duke revised its project estimate and announced that the cost of the remaining single unit would be approximately $1.53 billion, not including AFUDC. In May 2007, Duke announced that the costs increased by another 20 percent. As a result, the estimated cost of the one 825 MW unit at Cliffside is projected to cost $1.8 billion (excluding AFUDC) which is almost as much as Duke estimated for a two unit plant only two years before. (Synapse Article at pp. 1-2).

Q: What are some of the reasons for these market-wide increases?

A: The increases in construction costs in 2006-2008 were due, in large part, to a significant increase in the worldwide demand for power plant design and construction resources, commodities and equipment. This worldwide competition was driven mainly by huge demands for power plants in China and India, 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, and by the competition for resources from the petroleum refining industry.

Construction industry literature and publications from that time are filled with reports and information on the continuing increases in power plant and commodity costs. For example, a May 15, 2008 story in The Wall Street Journal noted that "relentless increases in the price of steel are halting or slowing major construction projects world-wide and investments in shipbuilding and oil-and-gas exploration." (Schedule KMR2010-7, The Wall Street Journal, Fast-Rising Steel Prices Set Back Big Projects, Robert Guy Matthews, May 15, 2008 ("May 15, 2008 The Wall Street Journal" p. 1)). The same article also reported that "steel prices are up 40% to 50% since December [2007], and industry executives say they haven't hit their peak" and that cost increases "are part of a broader surge in raw-materials prices and tight supplies and soaring global demand, fueled in part by the rapid industrialization of China, India and other developing nations." (May 15, 2008 The Wall Street Journal p. 1). Similarly, Cambridge Energy Research Associates ("CERA"), a leader in analyzing utility project cost data, stated in February 2008 that prices in the power industry rose by 27 percent in 2007, and 19 percent in just the last six months of 2007. CERA's Power Capital Costs Index shows that costs have risen 130 percent since 2000 and were poised to rise higher in 2008. (Schedule KMR2010-8, CERA Press Release, May 27, 2008). Stated another way, this means that a new power plant that cost $1 billion in 2000 would cost $2.3 billion in 2008.

Additionally, from 2005 to 2008, competition for large EPC contractors capable of performing large projects was increasing. This competition was studied by the Edison Foundation, who found that the composite backlog of Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. increased by 37 percent from 2005 to 2006, the same time that Iatan's initial major contracts were bid and negotiated. (Schedule KMR2010-9, Article, Rising Utility Construction Costs: Sources and Impacts, for the Edison Foundation by Mark W. Chupka, Gregory Basheda, September 2007, ("Edison Foundation Article") at p. 23). The article concluded, "This significant increase in the annual backlog of infrastructure projects at EPC firms is consistent with the data showing an increased worldwide demand for infrastructure projects in general and also utility generation, transmission, and distribution projects." (Edison Foundation Article at p. 23). Other major vendors were also at capacity during the time that Iatan Unit 2 was being constructed. The four major stack vendors each had backlogs stretching to 2011. (Schedule KMR2010-10, Final Report, Analysis of MOD and LADCO's FGD and SCR Capacity and Cost Assumptions in the Evaluation of Proposed EGU 1 and EGU 2 Emissions Controls, James Marchetti and J. Edward Cichanowicz, January 19, 2007 ("LADCO Report") p. 14). This scarcity led to higher prices and longer lead times.

Finally, the global, national and regional competition for resources had a profound impact on the availability and cost of labor. Company witnesses Daniel Meyer and Brent Davis provide testimony regarding the information on labor availability that KCP&L was utilizing to make important strategic decisions in 2006-2008.

Q: What was the potential impact on KCP&L's contracting strategy for the Project as a result of the increased industry demand and these market-wide increases?

A: In addition to longer lead times on equipment and a shortage of available and qualified labor, during this time period there was a significant shift in the amount of risk that contractors were willing to take on. As a result of the increase in demand for their work, it was increasingly more difficult to find contractors who were willing to bid on, let alone enter into fixed-price contracts or take any pricing risk on labor or materials. One way utilities sought to control costs was by securing fixed-price contracts for their power plant construction projects, and this was effective assuming that such contracts were adequately managed. However, for the period of time of the Iatan Unit 2 Project's development, the market for obtaining fixed-price contracts for new power plant projects was severely constrained. (Synapse Article at p. 4). For example, in a recent regulatory proceeding, a witness for the Appalachian Power Company, a subsidiary of American Electric Power testified before the West Virginia Public Service Commission that Appalachian Power Company's project had difficulty obtaining fixed price contracts due to the "the rapid escalation of key commodity prices in the [Engineering, Procurement and Construction] industry. In such a situation, no contractor is willing to assume this risk for a multi-year project. Even if a contractor was willing to do so, its estimated price for the project would reflect this risk and the resulting price estimate would be much higher." (Synapse Article at p. 4).

Q: What action did KCP&L take to mitigate the impact of these market conditions on the construction of Iatan Unit 2?

A: Despite the constrained market for fixed-price contracts, KCP&L was able to pursue an aggressive procurement schedule which allowed it to obtain fixed-price contracts on almost all of its major equipment. Additionally, KCP&L entered into what I believe is one of the last, if not the last, large fixed-price EPC contracts for probably close to three years. KCP&L mitigated significant risk on the Iatan Unit 2 Project by entering into a fixed-price agreement for the single largest contract on the Project.

Q: In your opinion, what other ways did KCP&L prudently manage the Iatan Unit 2 Project?

A: Two other key examples of KCP&L's prudence in its management of Iatan Unit 2 are the projects' major procurements and processes developed for change order and claim notices from the contractors.

Q: How did KCP&L manage the major procurements for Iatan Unit 2?

A: Most notably: (i) KCP&L developed and adhered to a schedule of major procurement packages that allowed the Iatan Project to maintain progress at a critical stage; (ii) KCP&L utilized its Procurement Plan to purchase materials and services in a highly competitive market in a timely manner and generally within the Control Budget Estimate; and (iii) the terms and conditions that KCP&L has utilized in the Iatan Unit 2 Project's contracts have been very effective at holding the contractors and suppliers accountable to their obligations. In addition, the processes that have been put in place by KCP&L have been very effective at controlling costs and helping to advance the Iatan Project's schedule to date. Based upon our experience, failure of an owner to timely procure materials, equipment or services in order to support the Project's schedule can cause large impacts to the other contractors and will subject the owner to major delay claims. While there were occasional issues with the delivery of equipment through no fault of KCP&L,

impacts to the Project of late deliveries were very minimal.

Q: How did KCP&L implement systems for tracking performance and monitoring contractor change orders?

A: KCP&L developed processes and procedures to monitor changes to the contractors' contracts as the major construction activities were just getting started. These processes and procedures included the following:

- The Change Management procedure was in place early (3Q 2006), just about the time construction at the site was beginning.
- The contracts for all major procurements had change order controls consistent with Cost Control System document.
- As testified by Mr. Jones, KCP&L has implemented and rigorously enforces its Notice and Notification Procedures. By doing so, KCP&L has eliminated numerous potential frivolous claims by contractors on site, as well as managed contractor claims.

Q: How do these processes compare with your experience on other Projects?

A: I believe that KCP&L's Change Management Procedure and other associated processes comport with industry best practices.

Q: Please describe the Change Management Procedure as you understand it.

A: The Change Management Procedure identifies the requirements for processing contractor change orders. In particular, the process focuses on documenting the reasons behind the changes in order to establish trends for increased costs that will allow the Owner to either predict future costs or institute measures that can mitigate adverse trends.

Q: Who on the KCP&L project team is responsible for reviewing and vetting claims received from the Iatan Unit 2 Project's contractors?

A: KCP&L has established various "commercial teams" made up of project management, procurement, construction and legal personnel that reviews and resolves contractor claims and helped to control contractor costs. The handling of contractor claims by the commercial team ensures that contractor claims are processed in a timely and global manner, so that commercial disputes do not spiral out of control impacting the contractor's performance on the Project.

Q: What is the Notice and Notification Procedure?

A: This procedure is tied to the Change Management Procedure. In general, this procedure requires that contractors must submit any commercial claim in a formal written letter to a specified individual or individuals. In return, KCP&L will submit its own commercial correspondence to a single point of contact identified by the contractor. The purpose of this process is to create an expectation of timely, formal notification from the contractor of any commercial claims. The benefits of the Notice and Notification Procedure include KCP&L's ability to document and track open issues with contractors, which ensures thoughtful and strategic resolutions of disputes. It also makes it less likely that a contractor will submit a large claim at the end of the project that is a surprise to the Owner. Waiting until the end of the Project to submit a large claim is a common tactic for contractors because it is harder for the owner to properly evaluate and respond to such claims.

Q: How successful has KCP&L been regarding cost management on Iatan Unit 2?

A: In my opinion, the project management tools put in place by KCP&L have worked quite well to monitor and manage the costs and schedule challenges imposed by a particularly challenging market environment. As intended, the Project Controls have worked to timely notify KCP&L of future cost and scheduling issues in a manner that has allowed the Company to be proactive in addressing those issues, and thereby minimizing, mitigating and/or in some cases eliminating their impact on the Iatan Unit 2 Project.

Q: Is the fact that costs have increased an indication that KCP&L's management of the Project was imprudent?

A: No. While the original Control Budget Estimate has been exceeded, in my opinion the Project Controls in place have allowed KCP&L to mitigate those cost impacts in a prudent and cost-effective manner. I believe that the cost of the Iatan Unit 2 Project would have been significantly higher if KCP&L had not implemented the processes and Project Controls tools I have previously discussed.

A key reason for the project team's success has been its management of changes to the ALSTOM contract. To date, ALSTOM's estimate at completion is approximately **[redacted]** This increase to a fixed-price contract is well within industry standards.

Q: Does that conclude your testimony?

A: Yes, it does.

HIGHLY CONFIDENTIAL

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of KCP&L Greater Missouri Operations Company to Modify Its Electric Tariffs to Effectuate a Rate Increase	)))	Docket No. ER-2010-____

AFFIDAVIT OF KENNETH M. ROBERTS

STATE OF ILLINOIS)
) ss
COUNTY OF COOK)

Kenneth M. Roberts, being first duly sworn on his oath, states:

1. My name is Kenneth M. Roberts. I am a partner with the firm of Schiff Hardin LLP. Kansas City Power & Light Company engaged the services of Schiff Hardin LLP to provide certain services in connection with the company Comprehensive Energy Plan construction projects.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of KCP&L Greater Missouri Operations Company consisting of thirty-one (31) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Kenneth M. Roberts
Kenneth M. Roberts

Subscribed and sworn before me this 20th day of May, 2010.

Joanne M Smith
Notary Public

My commission expires: 7-23-12

OFFICIAL SEAL
JOANNE M. SMITH
Notary Public - State of Illinois
My Commission Expires Jul 23, 2012

JIM E. WILSON

Jim E. Wilson, President of J. Wilson & Associates, Incorporated, has field and consulting experience in the design and construction industry since 1975. Mr. Wilson is an expert in the preparation and analysis of design and construction claims. He has provided this service for Owners, Contractors, Architects and Engineers from both a defense and a plaintiff's perspective. He has repeatedly analyzed the claimed delay effect of changed scope of work, delayed access and design drawings (errors and omissions) effect on construction status.

Mr. Wilson has provided expert testimony in State and Federal Courts, Arbitrations, before the Armed Services Board of Contract Appeals, Mediations and Depositions. He has experience in a wide range of construction projects that includes power plants, hospitals, industrial, water and sewage treatment plants, multiple housing projects, office towers, ship building and rapid transit systems. He has prepared and defended delay claims and provided construction management services on both private and government projects; *e.g.:* Northern Indiana Power Services Company (NIPSCo), Commonwealth Edison Utility Corporation (Mid-West Generation), the Chicago Housing Authority, the City of Chicago Rapid Transit System and Black and Veatch Engineers, International. Mr. Wilson has also provided on-site construction management services for ComEd, NIPSCo, Constellation Energy and Ontario Power Generation (OPG) of Canada during their more critical power plant outage periods.

Mr. Wilson's experience includes the review of contracts, specifications, and design drawing addendum and revisions, change order analysis and construction management. Previously, Mr. Wilson was a Cost and Scheduling Engineer with Daniel International Corporation's Power Division (Fluor-Daniel). He was President of Wilson, Gudgel, Kopmeyer Consulting and a Senior Consultant and manager of Wagner-Hohns-Inglis, Inc. regional office CPM scheduling department.

Mr. Wilson has lectured nationally on the topics of CPM Scheduling and Construction Delay Claims. The most recent lectures were for the Kansas Bar Association; Federal Publications' Practical Illinois Construction Law Seminars; Chicago Kent School of Law of Illinois and the American Association of Cost Engineers. Mr. Wilson has been an Adjunct Instructor at Central Missouri State University and the University of Kansas, and was a previous member of NAIT's National College Accreditation Board for five (5) years and is currently on the Advisory Committee of Central Missouri State University. Mr. Wilson is an active member of the American Arbitration Association and has served several times as an Arbitrator panelist on complex and multi-party disputes.

EDUCATION	Bachelor of Science in Building Construction Technology Central Missouri State University, 1975; Associate of Science in Architectural Design Central Missouri State University, 1973
PROFESSIONAL ASSOCIATIONS	American Arbitration Association American Association of Cost Engineers National Association of Industrial Technology

SPEAKER

Chicago Kent School of Law of Illinois
Institute of Technology, Chicago, Illinois, 1984, 1985 & 1986
"Construction Claims"

Federal Publications
Practical Illinois Construction Law

Kansas Bar Association
Construction Law

Society of Manufacturing Engineers,
Kansas City, Missouri, "Planning & Scheduling"

American Society of Cost Engineers,
"Delay Claim Analysis"

UNIVERSITY CLASSES & ADVISORY COMMITTEES

Adjunct Instructor, Central Missouri State University,
Construction Scheduling, M F & C 4000

Adjunct Instructor, University of Kansas,
Construction Scheduling, ARCE 650

Advisory Committee, Central Missouri State University,
Construction Engineering Department, 1991 to 1995

Advisory Committee, Pittsburgh State University,
Construction Management Department, 1990-1995

National Association of Industrial Technology
College Accreditation Board, 1988 to 1992

SCHEDULE KMR2010-2

THIS DOCUMENT CONTAINS HIGHLY CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Power and Light Company for Issuance of a Certificate of Public Convenience and Necessity for Construction and Placement in Operation of an Approximately 300 MW Coal-Fired Baseload Facility and an Application for Approval of Fixed Financial Parameters and Capital Cost Rate-Making Principles for the Baseload Facility.	Docket No. 6680-CE-170

DIRECT TESTIMONY OF CHARLES J. HOOKHAM ON BEHALF OF WISCONSIN POWER AND LIGHT COMPANY

I. INTRODUCTION AND CREDENTIALS

Q. Please state your name and business address.

A. My name is Charles J. Hookham. My business address is HDR | Cummins & Barnard, Inc., 5405 Data Court, Ann Arbor, Michigan, 48108.

Q. By whom are you employed and what is your position?

A. I am employed by HDR | Cummins & Barnard, Inc. (HDR|CB) as Vice President (VP) of Power Projects.

Q. Please describe your duties and responsibilities in that position.

A. Currently as VP, I am primarily focused on execution of a number of our Owner Engineering assignments and design work for industrial and utility clients, in addition to managing HDR|CB's project management group. This includes leading the Owner Engineering assignments for two major projects for Wisconsin Power and Light Company: the Wisconsin Baseload Project as further defined herein, and the Clean Air Compliance Project, which addresses air quality control additions at existing fossil generating plants. I am also participating in other Owner's Engineering assignments on domestic coal-fired new generation and air quality control system (AQCS) projects for E.ON U.S., Nevada Power/Sierra Pacific, Consumers Energy Company, Constellation, and We Energies. Also, I am managing miscellaneous design and consulting efforts on power generation projects including those for We Energies in Milwaukee and DTE Energy, Consumers Energy Company, and Holland Board of Public Works in Michigan.

Q. Please describe your educational background and business experience.

A. I received a Bachelors of Science Degree in Civil Engineering from the University of Illinois-Urbana/Champaign in 1981 and Masters in Business Administration from Eastern Michigan University in 1991. In addition, I have taken graduate level courses in engineering and technology from a number of institutions, primarily focused on boiler operations, energy efficiency, renewable energy, and pollution control technologies. I am a registered professional engineer in 3 states and am certified with the National Council of Examiners for Engineering and Surveying. Additionally, I am a member of the American Society of Civil Engineers (ASCE) presently serving as Past-Chair of ASCE's Energy Division executive committee as well as being a Senior Member of the Association of Energy Engineers (AEE).

I began my career with the architect/engineer construction company Bechtel Power Corporation as a civil/structural engineer with a broad range of assignments in the design, construction and startup of utility power plants. This included design of the coal-fired 2x600 MW Belle River Power Plant. I subsequently spent 8 years with an international consulting engineering firm, Multiple Dynamics Corporation, with primary assignment of being Manager of Utilities and Industrial Projects. I managed and was responsible for staff expertise in key power plant systems as well as cogeneration and nuclear and fossil generation projects including Enrico Fermi II, Monticello, and Santa Maria de Garona plants and many others throughout the world. I progressed to partner status before leaving MDC. Subsequently, I worked for Black & Veatch Corporation for approximately 14 years, managing a variety of design, engineer/procure/construct (EPC), and consulting engineering projects in the international power generation field and achieving the responsibilities associated with being Associate Vice President and officer. In 2006, I left Black & Veatch and joined HDR|CB as a VP and member of the Executive Committee, and have been significantly involved in power generation project development and engineering projects on behalf of public utilities, power developers, municipalities, as well as large industrial and institutional clients since that time.

Q. Have you previously provided verbal or written testimony in a public utility proceeding?

A. I was recently involved in the preparation of research and testimony related to Florida Power & Light's Glades Power Park project and needs study in 2006/2007 and am currently participating in technical assessment of a rate case request of The Detroit Edison Company in Michigan. The Glades testimonial work included opining on the overall capital cost for the two-unit ultra-supercritical pulverized coal-fired generating station project and reasonableness thereof, factoring in major equipment procurement, EPC contracting strategy, and power generation and electrical transmission system conceptual design. The Detroit Edison rate case effort includes analysis of cost and prudency of air quality control improvements being undertaken on its fossil generating units. Cummins & Barnard also testified several years ago in support of the Elm Road

Generating Station needs assessment and its contracting strategy, in Wisconsin on behalf of We Energies.

Q. Are you sponsoring any Exhibits in this case?

A. Yes. I am sponsoring two exhibits. Exhibit ____ (CJH-1) is my current curriculum vitae. Exhibit _____ (CJH-2) contains the following Schedules:

Schedule 1	Barge Traffic Study and Conceptual Layout
Schedule 2	Renewable Resource Fuel Options, Properties, and Conceptual Site Layout, NED 3 Project
Schedule 3	Greenhouse Gas Emissions White Paper, NED 3
Schedule 4	Carbon Dioxide Capture and Sequestration White Paper, NED 3

II. PURPOSE

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

A. The purpose of my testimony is to set forth my opinions to a reasonable degree of engineering certainty with regard to the following issues:

(1) suitability of circulating fluidized bed (CFB) technology for use in the NED 3 Project;

(2) the estimated capital costs for the preferred NED 3 and alternate COL 3 Projects;

(3) expanded barge unloading facilities and traffic study;

(4) capabilities and site layout for the NED 3 CFB boiler to combust renewable resource fuels and conceptual layout;

(5) the forecasted greenhouse (CO_2, N_2O and CH_4) gas emission levels for NED 3 and COL 3; and

(6) the design measures and suitability of NED 3 to allow capture and sequestration of carbon dioxide (CO_2) in the future.

Q. What are the qualifications of HDR|CB and yourself in offering this independent engineering testimony?

A. HDR|CB is very active in the present coal and renewable resource-fired electric power project market, serving as Owner's Engineer on multiple projects in various states of development, bidding and construction and as design engineer on numerous other assignments. Key representative and active projects include:

- We Energies Elm Road Generating Station – Two x 615 MW supercritical pulverized coal (SCPC) units presently under construction in Wisconsin, with commercial operating dates (COD) set for 2009 and 2010.
- We Energies Port Washington Generating Station – Conversion of generating station in Wisconsin from coal-fired to natural gas-fired generation, serving as Owner's Engineer.
- E. ON U.S. Trimble County Unit 2 – 750 MW SCPC unit presently under construction in Kentucky, with the EPC contract finalized and issued July 2006 with a COD in 2010.
- UAMP/IPA Intermountain Power Plant Unit 3 – 900 MW SCPC project in Utah, currently in the EPC bidding phase with a tentative COD of April, 2012 (currently delayed).
- Nevada Power Ely Energy Center – 2 x 750 MW SCPC in development stage, with HDR|CB currently working on finalizing contracting approach and design

development/bid documents for major equipment and EPC contracting (currently delayed, COD dates in 2013).

- Owner's Engineer assignments examining new coal, gas, and renewable resource fuel-fired generation opportunities, including gasification, in various states including Idaho, Michigan, Florida, and Minnesota.
- Owner's Engineer assignments, including target-priced EPC contract development, on five large Air Quality Control System (AQCS) retrofit projects on existing coal-fired units including the South Oak Creek project in Wisconsin and multiple renewable resource/biomass power generating stations.
- Engineer, with procurement and construction management responsibility for the 36 MW Rapid River Renewable Biomass Power Plant in Michigan; this project also employs a fluidized bed boiler, biomass firing, and carbon dioxide capture.

Personally, I have been involved in the development, design, procurement, construction, and startup phases of power generating plants since the inception of my career. I have worked on many projects involving barge and marine materials transport design and rehabilitation; fossil boiler improvement, alternative fuels/combustion, and pollution control upgrades; and major project capital cost estimation. I am also currently involved in HDR|CB's analysis of criteria pollutants, greenhouse gas emissions, and carbon capture and sequestration (CCS) options for a number of new and existing client facilities.

Collectively, the experience of HDR|CB, including myself and staff assigned to the WPL and other owner's engineer assignments, is comprehensive, very active in the current power generation field, unbiased, and cognizant of the needs for new power generation in Wisconsin. Our study of the NED 3 project in particular has found many positive attributes for the State of Wisconsin including ability to minimize costs for future power supply, removal of constraints in the high voltage power grid, and utilization of local indigenous renewable resource fuel products as a portion of the fuel supply.

III. SUITABILITY OF CFB TECHNOLOGY FOR NED 3

Q. Was HDR | Cummins & Barnard or yourself involved in WPL's initial site analysis, integrated resource planning, or generation options studies?

A. No. However, subsequent to be selected as Owner's Engineer earlier in 2007, HDR|CB has had the opportunity to be involved in many siting issues, technology selection decisions, and cost evaluations for the NED 3 Project. HDR|CB also previously acquired significant experience in technology and site selection for new coal-fired and other generation, including 300 MW class CFB boilers.

Q. Please provide your opinion regarding the selection of CFB boiler technology for NED 3.

A. HDR|CB has examined the NED site, currently housing two 100 MW nominal coal-fired generating units, relative to the addition of a nominal 300 MW CFB generating unit. The topography and site area were definitely found conducive to adding the new generating unit and sufficient property was identified for expanded coal, petcoke, and limestone storage. The 300 MW CFB unit size was judged to be at the upper limit of what solid fuel-fired generation technology could be placed on the NED site given that additional space for expansion is limited. Attractive features of the NED site include site adjacency to the Mississippi River (for construction equipment and fuel deliveries), existing

Burlington Northern Santa Fe (BNSF) main rail line, and county highway, existing infrastructure and operating staff, and transmission line access for the 300 MW generation with expanded transmission import benefit. As explained in this testimony and others, the NED site is also situated in an area where renewable resource fuel products are grown and may be combusted in a CFB boiler; the aforementioned and currently planned transportation access via rail and road also benefit the supply of renewable resource fuel from remote locations.

Q. What makes CFB technology an appropriate choice for NED 3?

A. None of the other coal-fired generating technologies, such as pulverized coal or integrated gasification combined cycle (IGCC), were viewed to offer the benefits of CFB technology. Space limitations, 300 MW size, and reliability concerns are significant constraints for the utilization of IGCC technology. CFB technology also better matches the existing NED Units 1 and 2 cyclone boilers in terms of expected base fuel supply type and size (blend of Powder River Basin (PRB) coal and petroleum coke; non-pulverized), and a CFB offers the significant opportunity to combust and develop the Wisconsin market for renewable resource fuels (RRFs, also termed “biomass”). Finally, the CFB technology, with WPL’s chosen design, may allow future CO_2 capture with less of a unit performance impact from capture equipment demands when compared to other PC or IGCC technologies. *See* discussion below.

Constraints associated with IGCC technology were noted in the testimony of Mr. Kevin Vesperman, as well as in the IGCC Technology Summary prepared by Black & Veatch Corporation (B & V) and submitted as Volume 1, Appendix D of the original CPCN Application and the B & V June 2007 IGCC Technology Study Update submitted with Mr. Vesperman's testimony. As 300 MW of baseload generation is needed by WPL in calendar year 2012 to 2013 timing, IGCC is not a viable solution given concerns with capital cost, reliability, space needs, overall project timeline, and unit availability concerns given industry experience.

IV. PROJECT CAPITAL COSTS

Q. Are you presently involved in any major electric generation projects and contracting strategy or capital cost development?

A. Yes. As previously noted, I was involved in preparing supporting reports and testimony on behalf of the validity and reasonableness of FP&L's Glades Project (a 2x980 MW ultra-supercritical pulverized coal generating project proposed in Florida) with Mr. Bill Damon of our firm (HDR|CB). This assignment required scrutiny and validation of project costs in today's volatile marketplace. This research involved compilation of a database of costs for in-house and external power generating plants. Our scope of work for that assignment and our current engagement by WPL have involved project cost estimating, EPC contract development, major equipment selection/cost assessment, technical and commercial bid review, and related tasks. I am also familiar with project cost estimation and development engineering efforts for other active coal-fired electric generation and AQCS retrofit projects within HDR|CB. HDR|CB's clients for these projects include Nevada Power, IPA/UAMP, Consumers Energy, Constellation, and FirstEnergy, among others.

I have also managed the development of firm price estimates and feasibility studies for other CFB boiler additions at existing generating plants, including several Midwestern projects involving renewable resource fuel firing in CFB boilers. I am also directing the design of the Rapid River Renewable Energy project and worked on conceptual development of another 70 MW coal and biomass-fired CFB project, both located in the State of Michigan.

Q. Please summarize the history of previous WPL project cost estimates, and the evolution to the most current cost estimates for both the NED 3 and COL 3 projects.

A. WPL originally employed another architect/engineer for the preparation of capital cost estimates for the two projects, with results reported in the Certificate for Public Convenience and Necessity (CPCN) Application first submitted to the Public Service Commission in February, 2007. For the NED 3 project, WPL also employed two independent architect/engineers in addition to the original as a means of assessing project capital costs in late 2006 and early 2007. HDR|CB also was requested to prepare a cost estimate independent from these three other estimates in April, 2007 to allow comparison and to establish an overall view of capital cost estimate accuracy (see following testimony). After accounting for escalation and market conditions, the NED 3 and COL 3 cost estimates prepared by HDR|CB earlier in 2007 were found to be within 5% of the cost estimates prepared by the other firm(s). A third estimate for the NED 3 project completed by another engineering firm was also found to be within 5% of these two estimates, providing some confidence that the original estimated costs were reasonably accurate.

After selecting an EPC Contractor in Spring 2008, via the process described later in this testimony, preliminary/conceptual design was undertaken and equipment specifications were prepared and issued for bid to gain better understanding of current-day costs for larger components of the NED 3 project. The EPC Contractor was also chartered to prepare a cost estimate for the NED 3 project on the basis of these new inputs and quantities derived from conceptual design on an "open-book" basis; the purpose of this effort was to gain further confidence and a more current basis for project costs given that market conditions were changing. The latest costs reported by this EPC Contractor are included in this testimony.

Q. What constitutes the current total installed project cost estimate for the NED 3 and COL 3 Projects?

A. NED 3 and COL 3 would be built on the existing NED and COL sites, respectively, so the primary costs for each project are focused on those associated with installing new generating equipment and interfacing utilities adjacent to and within an operating plant as opposed to a new, "green field", setting.

NED 3

The NED 3 project involves installing a third nominal 300 MW generating unit at the NED site currently housing two, 100 MW units; initial WPL studies indicated that this 300 MW unit size was the maximum sustainable on the NED site. The overall installed cost for the NED 3 Project includes several major cost components:

- Power plant costs, including those for direct major equipment (circulating fluidized bed boiler, steam turbine/generator (ST/G) and air quality control system (AQCS)), balance-of-plant equipment and commodities, site work and improvements, engineering, construction, and startup/commissioning, and other indirect construction costs (including construction supervision and management) estimated on an EPC basis with Owner involvement.

- Transmission and other off-site interconnection costs, including those for high voltage transmission line (grid) modification and interconnection of the NED 3 generator step-up transformer to the grid, and off site rail and highway modifications adjacent to the project site, with Owner involvement.
- Owner's costs, including internal manpower and external consultant costs directly associated with project permitting and project development and future costs associated with project execution (e.g., insurance, project management, initial fuel and materials net of revenues from initial generation, tax, and others). An allowance for funds used during construction (AFUDC) was not included in the NED 3 cost estimate.

<u>COL 3</u>

The alternate COL 3 project involves installing a third nominal 300 MW generating unit at the COL site currently housing two, 500 MW units. The overall installed cost estimate for the COL 3 Project was similarly prepared, with major components consisting of a 300 MW subcritical pulverized coal-fired boiler and generating equipment, ST/G, AQCS, direct/indirect costs involved in design, procurement, and construction, and Owner's costs; there were no associated off-site construction costs included. As the COL 3 project was characterized with a different boiler, the resulting plant configuration, major equipment, and capital cost estimate were different than utilized in the NED 3 estimate. In addition, the COL 3 project did not go through preliminary engineering in 2007/2008. The resulting COL 3 cost estimate prepared by the EPC Contractor thus depended heavily on prior projects of similar scale and configuration.

Cost estimates prepared by the EPC Contractor were established based on an EPC contracting strategy, as further described in this testimony.

Summary

The following table summarizes project costs in early 2008 dollars, assuming a summer, 2013 in-service date for each. These estimates were generated in early 2008 and reflect significant recent changes (cost increases and schedule extensions) in the construction marketplace as a whole, driven by commodity and manufactured equipment cost increases and labor shortages and cost increases; as a result, WPL is presently pursuing further validating these capital cost estimates, re-examining industry/marketplace changes, and examining adjustments to the individual project's scope:

Cost Item	**NED 3**	**COL 3**
Power Plant	$ 977,952,000	$ 991,387,995
Owner's Costs	$ 165,114,000	$ 161,940,226
Total	$1,143,066,000	$1,153,328,221

These values include escalation but do not include AFUDC or other pre-certification and financing costs

In its October, 2007 response to the Public Service Commission's request for updated project cost data, WPL, with my assistance, advised that total project cost estimates for NED 3 and COL 3 had increased from those on the original date of notification to then present-day status by 5 to 7 percent and 8 to 10 percent, respectively. The basis for these increases included market-based material and labor escalation and necessary project scope changes subsequent to the original estimates being completed. The associated AFUDC for each project was also expected to have similar percent growth. WPL and its EPC Contractor were developing a more detailed cost estimate for the NED 3 project at that time and, accordingly, WPL stated that the previously cited cost estimates were subject to future change as the development of more firm pricing information continued. However, the estimated costs for new power generating plants in general, and the NED 3 and COL 3 projects specifically, rose significantly from predicted levels in early 2007 and October, 2007 forecasts to current-day 2008 estimates in the table above, without significant changes in project scope. The tabulated costs represent an increase of between 38 and 40 percent over year-of-occurrence costs submitted in the original CPCN application.

Q. What was the source of the cost increases in this short time period, and were such increases directly related to changes in these Projects?

A. Within the last several years, the costs of domestic industrial construction have increased sharply. For projects such as power generating plants, which include large fabricated equipment and components comprised of copper and highly sought metals and alloys, cost increases have been magnified even further. A February, 2008 publication from IHS and Cambridge Energy Research Associates (CERA) indicated that power generation construction costs increased 43 percent over the last three years, 27 percent over the prior 12 months, and 19 percent in the most recent six months. These increases have been witnessed in all forms of new power generation and large modification projects (such as air quality control system additions), including those fired on other fuels and renewable energy projects. Further increases subsequent to February, 2008 were also witnessed in published commodity indices and quoted manufactured equipment costs. The NED 3 and COL 3 project cost estimates completed by the EPC Contractor also included increases in engineering costs and expected craft labor costs associated with both shortages of skilled craft and labor transportation costs due to the distant location of both project sites from local population centers.

The 40% cost increase for NED 3 on an escalated basis from the cost estimate included in the original CPCN document primarily covers increased scope to support the handling and firing of renewable resource fuels, further rail relocation and wet land avoidance issues, and particularly market/industry impacts on the installed cost of major items and commodities. In particular, the purchase cost for certain equipment, such as transformers, increased significantly, as did the purchase cost for copper and stainless steel fabricated materials (e.g., cable, pipe). For COL 3, the cost increases encompass the installed cost for additional scope (required pollution control equipment and a zero liquid discharge (ZLD) wastewater treatment system) as well as the same market impacts and purchase cost increases in major commodities. Thus, the bulk of the cost increases since the original CPCN Application submittal have come from equipment, material, and labor escalation which have similarly affected all new power generation projects and industrial construction in general. As indicated, these approximate increases are subject to change as the development of more firm pricing information continues in parallel with preliminary engineering design and final scope definition.

In summary, recent-year capital cost increases for new power generation have not been specifically attributable to coal-fired generation such as NED 3 and COL 3, but have affected all forms of construction and particularly those such as power generating plants which contain significant fabricated equipment. Many power industry and construction trade publications anticipate further growth in capital construction costs for

2008 and beyond; in response, WPL is actively reviewing and validating the NED 3 and COL 3 project scopes and capital cost estimates.

It is important to note that such cost increases are not limited to the United States. Large demand for new power generation in Europe, India, China, and other developing countries has placed an elevated demand on the limited number of material/equipment suppliers that provide equipment globally and this has resulted in upward pricing pressure. Increased demand has also lengthened project schedules due to longer manufacturing cycles, further increasing project costs and the uncertainties associated with such until actual purchases are made for a specific project.

Q. Please describe your understanding of the overall contracting approach that is being pursued by WPL, and whether such had any impact on the cost estimates prepared for each project and recent increases.

A. <u>NED 3</u>.

Both HDR|CB and WPL pursued both major equipment and EPC cost estimates from multiple parties during project development, using what HDR|CB terms as a "hybrid EPC" contracting strategy. This strategy involved the solicitation of major equipment costs directly by the Owner, and estimation of balance of project costs through solicitation of pricing for a defined work scope from experienced EPC contractors via a detailed request for proposal (RFP) basis. The RFP was also used to select and contract with the Washington Group International (WGI, now URS-Washington Division, or URS-WD) as the EPC Contractor in May, 2007. WPL subsequently proceeded with further defining the scope of work and NED 3 conceptual design on an open-book basis with WGI, to establish a more detailed overall project cost estimate and a target price EPC contract and schedule from which to execute the work.

Based on the efficient, power generation thermal cycle and major equipment requirements established by WPL for NED 3, a planned competitive solicitation, negotiation, and award process will be conducted by WPL to secure the major equipment contracts (CFB boiler, ST/G, AQCS, other major equipment). Preliminary budgetary pricing has been received from prospective vendors and was used in the most current NED 3 capital cost estimate by the EPC Contractor. Major equipment competitive bidding will be completed in parallel with the CPCN review process, such that contract awards can be placed immediately after the CPCN is awarded to WPL and full notice to proceed is granted from WPL to the EPC Contractor.

With respect to transmission and railroad interconnection, WPL initiated discussions with the American Transmission Company LLC (ATC) and Burlington Northern Santa Fe Railway (BNSF) to establish necessary costs for needed off-site interconnection construction. For substation expansion and transmission work, ATC completed preliminary high-voltage transmission line definition, conceptual design, and verification of the design basis with state and federal transmission regulations. This conceptual design served as the basis from which cost estimates for the electrical interconnection were developed. Modification of the existing BNSF main line and creation of off-site industrial tracks were similarly defined by BNSF's preferred engineering firm and formed the basis for off-site construction costs. Sitework for the rail improvements and highway adjustment were similarly derived from conceptual designs, leading up to an on-site ladder track arrangement.

In summary, the NED 3 project costs have been collaboratively estimated on an EPC target price and open-book basis, with continued refinement of the cost estimate underway. As the NED 3 project configuration is not similar to other generating plants in the United States and abroad, the approach being taken to refine capital costs after conceptual design and bidding process for major equipment with an experienced EPC contractor is considered imperative to increasing cost certainty.

COL 3.

As a result of the state of project development, less information was available from which to base estimation of capital costs for the COL 3 project. In early 2007, HDR|CB obtained pricing for major equipment (pulverized coal boiler island) and utilized its data base for defining installed costs for the bulk of the other equipment, engineering, construction, and startup/commissioning work. HDR|CB also completed a brief labor analysis to establish expected costs for construction craft labor, and such efforts allowed preparation of a cost estimate for COL 3. WPL has not pursued securing an EPC Contractor or more refined pricing for this alternate project at this juncture. However, WPL employed the same EPC contractor (WGI) selected for the NED 3 project to update the COL 3 estimate from previous efforts with results included in the previous table. There are no current efforts underway to further refine the COL 3 cost estimate, as there is with the NED 3 project.

Q. Would adoption of another contracting strategy, such as a competitively bid lump sum turnkey (LSTK) strategy, have yielded a lower or more accurate estimate of the power plant costs or greater control in the future over actual costs incurred?

A. No. As stated, resource constraints and current activity levels within the ranks of experienced EPC contractors and major equipment manufacturers and forecast uncertainties for material and labor escalation coupled with the timeline of the WPL project was not supportive of a competitive LSTK strategy. Even if the schedule supported a competitive LSTK bid process, the ability to secure an adequate number of qualified EPC contractors would be a significant challenge in today's market, and we do not believe such would have yielded a more accurate estimate of costs. Combining the resources of WPL and an experienced EPC contractor to establish EPC pricing on an open book basis, in parallel to confirming major equipment pricing, has produced an updated cost estimate with even higher accuracy than possible through LSTK contracting approach. The hybrid target price contracting approach is commonly used today to incent the EPC contractor to perform, with all payments to contractor based on earned value and actual costs incurred. The EPC contractor is encouraged to finish under the target price and is partially exposed to cost overruns.

The large increases in estimated costs for either project have thus far not been found to be a result of the WPL contracting strategy. In fact, experience has shown that utilization of an EPC contractor experienced with the generation technology and in possession of actual installed costs increases estimation accuracy.

Q. What are the forecasted industry trends for major equipment and power plant pricing?

A. Calendar year 2007 industry pricing forecasts for major equipment and labor pricing trended significantly upward following the initial development of project cost estimates in 2006 and early 2007. These increases were the result of the heavy commitment of space within major manufacturer's production schedules, combined global demand for equipment for both new plants and existing plant retrofits, limited number of qualified manufacturers, and continued escalation of key commodity materials such as high alloy steel. The extended outlook for 2008 calls for continued escalation in prices for certain commodities and equipment such as copper and manufactured turbine and air quality control equipment, with other key commodity prices, such as for lumber and carbon steel, expected to stay reasonably flat or to possibly even decrease. Long-term projections for 2009 and 2010, when significant WPL procurements are forecasted to take place, call for continued slight upward escalation of prices. This is being addressed in continued refinement and validation efforts by WPL. A contracting strategy wherein the equipment design requirements are established to match thermal cycle and emission limits, followed by a competitive bid process for selecting a manufacturer, and negotiating and confirming pricing is considered to be a "least-cost" approach, particularly for projects having a commercial operating date (COD) extended into late 2013. This approach will reduce exposure to potential price escalation, provides greater assurance that the equipment will be available in accordance with the project schedule, and reduces uncertainties associated with the COD and associated AFUDC costs.

Q. Are the capital costs estimated for NED 3 and COL 3 consistent with those for other <u>current</u> major coal-fired power generating stations in the United States?

A. The overall EPC price estimated for the NED 3 Project reported herein without AFUDC is $1,143 million, or $3,506/kW at nominal 326 MW of output, including shared construction associated with NED Unit 1 and 2 upgrades. The overall EPC price estimated for the COL 3 project reported herein without AFUDC is $1,153 million, or

$3,537/kW at 326 MW nominal output. EPC pricing for other non-IGCC, primarily coal-fired generating projects under construction or in the planning stages have similarly increased with many projects falling in the $2,500 to $3,800/kW range, without AFUDC or uncommon owner's costs (e.g., major railway additions). Although project-specific differences can impact the accuracy and correlation of project-to-project comparison, the NED 3 and COL 3 project cost estimates are at the higher end of this range, primarily as a result of lower generating output compared to other baseload projects (e.g., WPL cost estimates are higher due to lower economies of scale). As the NED 3 and COL 3 costs have accounted for many recent-year escalation effects witnessed in power and heavy industrial construction, the costs are in-line with market and reasonable estimates of the current year-of-occurrence-based project costs. It is noted that, because each generation project has different attributes and capabilities, comparison of the merits between specific power generating projects on a simple dollars per kilowatt basis is not a suitable approach.

Q. What are your specific conclusions regarding the reasonableness of the commercial basis and EPC pricing established for the NED 3 and COL 3 Projects?

A. The process employed by WPL to-date to obtain cost estimates for NED 3 and COL 3 involved multiple efforts by architect/engineers and consultants highly experienced in power plant construction. Through multiple different estimation procedures, all based on limited conceptual design, WPL received cost estimates in 2007 from these parties that were reasonably close in total dollars. HDR|CB's estimates completed several months afterwards in mid 2007 were slightly higher in total cost as they reflected continued material and labor escalations that took place in the interim period. In particular, HDR|CB noted that the cost of procured equipment and alloy materials had sharply increased. As a result, and to establish a more accurate cost base for project execution, WPL contracted with WGI (now URS-WD), an experienced EPC contractor, on an "open book" basis to increase NED 3 project design detail and furnish an EPC-based cost estimate. WPL participated in development and final review of this cost estimation with values reported herein. As reported earlier in testimony, market forces have further increased the estimated cost of both the NED 3 or COL 3 projects. In response, WPL is conducting additional cost reviews, validation efforts with major suppliers, and examining application of value engineering to first ensure that the design basis and project scope meet utility requirements for the project and secondly to confirm that costs are valid and free from excess redundancy or contingency. It is anticipated that the ultimate cost estimates for the two projects will be lower after these actions are completed, and that such costs will be reported to the Public Service Commission at that time.

Through HDR|CB cost estimation and conceptual design basis checks, and review of current cost basis, our conclusion is that WPL has acted prudently in obtaining cost estimates for NED 3 and COL 3 projects and that the values set forth above represents early 2008 market conditions. Other market forces, such as the limited number of CFB boiler manufacturers and their heavy workload and continued material and labor escalation, have a significant bearing on final costs. As a result, HDR|CB concludes that the efforts taken to date by WPL for securing project cost estimates through use of an EPC contractor and additional conceptual engineering have produced an accurate portrayal of project costs. Further scope and cost validation efforts are underway to establish final estimate values and to reduce uncertainty.

Q. What are the major uncertainties in the cost estimates for NED 3 and COL 3 Projects included herein? For NED 3, how are such uncertainties being mitigated?

A. From HDR|CB's active involvement in other coal-generating projects, the following list identifies cost factors having the greatest degree of uncertainty within the NED 3 and COL 3 capital cost estimates; these factors are common to any new power generation project estimate:

- Construction labor costs, and particularly any premiums needed to overcome a predicted labor shortfall due to the location of the project remote from a large population center (productivity also becomes a concern, and forced overtime is a significant cost); mitigative efforts taken in the cost estimates included adding a per diem on top of published wage rates to characterize rates anticipated in the future;
- Delivered costs for major equipment given the relatively small number of capable and experienced suppliers, including those for the boilers and air quality control systems, and their current excessive backlog effect on cost and schedule; evaluations completed against cost estimates provided by the suppliers were completed to estimate costs at the future time of procurement; challenges with moving large equipment to a remote site also adds cost and uncertainty;
- Availability and cost for highly engineered equipment, particularly that containing materials/commodities of high demand (e.g., copper, alloy steels); consideration

was made in the project schedule to support early procurement of this equipment to reduce the potential for future cost and schedule impacts;

- Availability and cost of critical project commodities, including cable and cable tray, structural and alloy steels, certain piping types, and miscellaneous electrical components; consideration was made in the project schedule to support early procurement of these critical commodities to reduce the potential for future cost and schedule impacts.

Uncertainty was reduced via development of open book estimates of equipment and commodities, establishing preliminary costs for equipment through a formal bidding process, and early scope definition to remove excessive redundancy. However, until the project is approved and procurements can be completed, all procurements are subject to market-driven escalation in price and future availability risk. Any deferral of construction to a later time period would only serve to further increase costs. Similarly, switching to a different fuel source, such as natural gas, would not reduce the impacts of future cost increases since the labor and equipment cost increases are power generation industry-wide trends.

V. BARGE UNLOADING FACILITIES

Q. Please briefly summarize the existing NED barge unloading facilities and their ability to support current and future material handling needs.

A. The current NED barge unloader is a mechanical clam shell type, rated for 600 tons per hour (tph) material flow and with actual unloading capacity of 500 tph. This capacity has proven to be marginally acceptable for offloading coal and petroleum coke for the current NED Units 1 and 2 only, and for offloading a fleet of 6 to 9 barges in a reasonable time without incurring demurrage costs for excessive unloading time. The single unloader was installed with the original plant in 1959 and has recently begun to require more frequent and significant maintenance attention.

Q. Does the existing unloader have the capacity to allow unloading of fuels and limestone for NED Units 1 and 2 and NED 3?

A. No. This unloading capacity and slow clam shell-based unloading operations will not sustain the total unloading capacity needed for unloading fuel for all three units during the 8-month river shipping season. The needed unloading capacity for fuel only is a minimum of 3,000 tph. There are also concerns with the long-term reliability of this existing unloader if solely used for supporting increased usage for NED 3. Limestone will be shipped to site using alternate modes (rail or truck).

Q. Are there any technical or environmental issues that may restrict expansion of barge unloading capabilities?

A. From a technical perspective, additional unloading capacity can be achieved through expanding the capacity of the existing unloader by replacing it with a higher capacity unloader or adding a second unloader to provide redundancy against the existing unloader thus allowing parallel unloading of two barges at one time. Due to potential impact to mussels in the area where a second unloader would be constructed, however, WPL is proposing only the replacement of the existing barge unloader to achieve the needed fuel unloading capacity. *See* discussion in the testimony of Ms. Dunn.

From an environmental perspective, expansion of barge unloading capacity by replacing the existing unloader will not require significant new construction in the Mississippi River (the “River”). As illustrated in Exhibit (CJH-2), Schedule 1, in-river construction activities associated with replacing the existing unloader would consist of removal of the existing unloader, demolishing the existing concrete foundation cap in/above the existing cofferdam, installing new piles inside and outside the cofferdam and new foundation cap construction. The in-river work area will be approximately 0.57 acres in size. All in-river construction would be preceded by efforts to relocate mussels from the area to a more conducive habitat and construction of a silt curtain (silt fence around the perimeter of the construction will keep fish and other aquatic life out of the construction area and possible harm, and keep any sedimentation created by construction within the barrier, thus minimizing any environmental impacts). Dredging is limited to an area in the vicinity of the existing unloader cofferdam (less than 200 cubic yards of recovered dredge material would be placed as fill on the NED site).

In the proposed area of unloader construction, the only aquatic life of specific interest that is projected to be affected by construction and future operations are freshwater mussels. WPL has conducted a number of surveys to establish the extent and population of mussels in front of NED and in the vicinity of the proposed barge unloader. Conclusions from these surveys are discussed in the testimony of Ms. Heidi Dunn.

Q. Will expanded barge-delivered fuel associated with both the existing NED Units 1 and 2 and new Unit 3 create any additional barge traffic in front of NED during use of the replaced (or second) barge unloader?

A. HDR|CB completed a barge traffic study (Exhibit ___ (CJH-2), Schedule 1) to define the extents and use of either a replacement of the existing unloader or construction of a second unloader and the engineering impacts to the river in front of NED from increased traffic and unloader operations. A mussel assessment was also completed by Ecological

Specialists, Inc. (ESI) for this same purpose, as discussed in the testimony of Ms. Heidi Dunn. Consensus from these documents included the following conclusions:

- Traffic patterns associated with an increased number of barge tows (towboat, pushing six to nine barges lashed together) carrying coal and pet coke to the site would follow/use current-day shipping channels, patterns, and barge staging areas;
- Barge traffic will increase from 550 to approximately 1500 barges (or from 72 to approximately 188 round-trip fleets) per eight-month shipping season). The number of additional tug tows associated with increased fuel/limestone deliveries through River Pool 11 was checked against historical commercial traffic. Using the combined NED Units 1, 2, and 3 fuel demand and number of fleets noted previously, a comparison was made to calendar year 2000 to 2006 statistics on river traffic through Pool 11 as recorded by the U.S. Army Corp of Engineers. The total number of fleets for the combined NED fuel supply was added to the number of commercial vessels through Pool 11 in 2006 and this sum was found to be less than the total commercial shipping volumes seen through the pool in the 2000 to 2004 time period. This indicates that increased fleets associated with NED 3 fuel delivery are not significant compared to historical pool usage;
- The number of barges per tug (e.g., tow) would not change, thus maintaining the same effective turbulence and river effects as are currently imposed in each fleet and individual barge movement; the river bottom in front of NED appears to be typically granular soils with limited silt and fines, so turbulence and soil re-suspension coupled with deposition downstream is not projected to be a concern;

- Pool 11 is not a heavily traveled body of water, given its remote location from large population centers and river terminals; the added barge fleets and traffic patterns associated with NED 3 fuel demands are not expected to have any safety or congestion impacts on commercial or navigational vessels in the Pool. This conclusion was corroborated with multiple fleeting services who operate in this segment of the Upper Mississippi River;

As a result, the traffic study concluded that the increased tows associated with NED 3 would not create a significant impact on other Pool 11 traffic.

Q. What are your conclusions relative to expanded barge unloading facilities at NED?

A. Replacing the existing unloader will provide the capability of supporting 100 percent of annual NED fuel supply needs after NED 3 operations begin. Having additional barge unloading capacity is a needed hedge against increasing transportation costs and potential constraints associated with alternative rail delivery. Having both the ability to unload fuel by multiple transportation modes will reduce the likelihood of future transportation cost increases or delivery restrictions. A cantilevered continuous bucket elevator (CBE) design of nominal 3,000 tph capacity represents a suitable fit from an operability perspective.

VI. RENEWABLE RESOURCE FUELS COMBUSTION IN THE NED 3 BOILER AND SITE LAYOUT FOR HANDLING

Q. Describe the inherent "fuel flexibility" capability of the NED 3 CFB boiler?

A. CFB boilers are well-known for their flexibility to burn fuels ranging from coals, waste products such as those from the ethanol industry, and other process waste products (such as tire-derived fuel and petroleum coke) to renewable resource fuels with reduced efforts applied to fuel preparation (e.g., no pulverizing required). CFB technology has commonly been used where additional electric generation is needed and an opportunity fuel source (low cost, plentiful supply) is available. For NED 3, petroleum coke, Illinois bituminous coal and renewable resource products from the indigenous area around NED represent this opportunity fuel. In addition, currently low-cost and low-sulfur PRB coal remains a primary fuel of choice for NED 3. This boiler is not designed to combust solid wastes such as tire derived fuel, refuse, or animal waste products.

Q. Will the NED 3 CFB boiler have the ability to combust renewable resource fuels, and how effective is such combustion in terms of power generation capability and environmental factors?

A. Yes. As included in testimony by Mr. Bill Johnson and Professors Fontenbery and Deller, WPL is actively involved in developing a renewable resource fuels market as a supply source for NED 3. NED 3 will be designed to have the capability of combusting most renewable resource fuels that are available or can be effectively grown in the indigenous area. Certain products, such as certain straws and hays, will possess chloride or alkali levels that may not be safely combusted in a CFB boiler for long periods, and these will be avoided via use of fuel specifications and sampling procedures. In addition, lighter density agricultural residues such as corn stover and switchgrass will require a densification step to allow reasonable handling. The NED 3 boiler will also be able to fire both waste woods and switch grass, both of which typically have dry heat contents approaching that of PRB coal, to reduce the impacts of their addition on net power produced by NED 3 when supplied at higher feed rates. It is critical to maintain a reasonable balance of renewable resource fuels and carbon-based fuels so as to maximize unit efficiency and minimize exhaust gas emissions.

Q. What is the co-burn percentage for combusting renewable resource fuels in the NED 3 CFB boiler?

A. Twenty percent of the total heat input in the NED 3 boiler will be supplied by burning renewable resource fuels. It will take some time to achieve this heat input percentage, so WPL will begin by supplying10 percent of total heat input by burning RRFs one year after NED 3 reaches commercial operation delivery (COD) and increase to the 20% contribution five (5) years after NED 3 reaches COD.

Q. Is renewable resource fuel handling infrastructure being incorporated as part of the site layout?

A. Yes. Conceptual design to-date has included provisions for renewable resource fuels receipt, handling, and forwarding to the CFB boiler, as illustrated in Exhibit ____ (CJH-2), Schedule 2. It is anticipated that the material handling infrastructure will be capable of handling a maximum of 460,000 tons of 5,500 Btu/lb renewable resource fuel per year to allow co-burning of 20% renewable resource fuel by heat input. Final design must consider the ability to complete a number of processing steps off-site by an aggregator, given limited site space available at NED. This practice of using an aggregator is common to the renewable resource fuel-based power generating industry. Utilization of pelleted fuel, as defined in Exhibit ______ (CJH-2), Schedule 2, provides additional flexibility and increased ability to combust renewable resource fuels. *See* Testimony of Bill Johnson also.

Q. Why won't NED 3 co-burn more renewable resource fuels (say to 100% of total heat input)?

A. Experience has been gained world-wide with 100 percent renewable resource fuels combustion in a CFB boiler, but typically on boiler sizes of far smaller than 300 MW. The largest CFB built to combust 100 percent renewable resource fuels is the Alholmens Station in Finland, which has demonstrated 100 percent firing on dense wood materials for an extended period in a 250 MW nominal unit. Yet, experience has shown that significant loss in generation occurs with elevated biomass as well as reductions in efficiency. Most domestic power plants that combust 100 percent renewable resource fuels are often powered by stoker-fired boilers versus CFB technology, are of scale of less than 50 MW in net output, and burn a narrowly defined band of waste products (e.g., wood chips). The 20 percent NED 3 co-burn level essentially equates to a 60 to 65 MW 100% renewable resource fuel-powered unit, and appropriate handling, processing, and preparing equipment scaled from similar plants will be required to facilitate said flow rate to NED 3. Sufficient operating experience exists at this flow rate to justify 20% RRF firing in a CFB boiler at NED 3.

Q. Which renewable resource materials have been considered as fuels for Unit 3 and are such available?

A. WPL has considered both woody biomass products including forest residues, tree trimmings, wood chips, waste wood (e.g., demolished wood structures) and other wood-based products, herbaceous agricultural crop remains including stalks and stover, and energy crops including poplar and willow tree limbs/bark and switch grass in conceptual design. These biomass products are generally available in the southwestern Wisconsin area, as further illustrated in the testimony of Mr. Bill Johnson. Specific chemical and physical limits for these products will be established with the boiler manufacturer to avoid boiler damage and limitations on service life.

WPL will configure the material handling and processing systems to handle this diverse fuel flow on-site. Certain handling limitations may further define suitable fuels in the design process. Consideration is being given to both mechanical and pneumatic delivery systems; such cannot be fully designed until more information is available concerning the indigenous materials that may be supplied to NED and the capabilities of local aggregators. *See* Exhibit _____ (CJH-2), Schedule 2 and Testimony of Mr. Bill Johnson for further discussion on fuels and their availability.

Q. Does firing renewable resource fuels reduce the emissions of greenhouse gases (GHGs) from the CFB boiler, including carbon dioxide and nitrous oxide?

A. Yes. HDR|CB has evaluated the reduction in CO_2, nitrous oxide (N_2O) and methane (CH_4) associated with utilization of renewable resource fuels. *See* Exhibit ____ (CJH-2), Schedule 3. Although GHGs are still generated during the firing of renewable resource fuels, it is generally accepted that such GHGs are mostly offset by photosynthesis, plant growth, and sequestration of said renewable resources during their planting/life cycle, and do not contribute to the overall carbon footprint of the power generating unit. This near net-zero emission also must include the contributions of GHGs in harvesting, processing, and transporting the material to the boiler, but that is generally offset against the same extraction and transportation emissions that would have been associated with the coal or pet coke that otherwise would have been combusted.

Combusting renewable resource fuels also provides the co-benefit of reducing overall sulfur, nitrogen oxide (NO_x), and mercury emissions from the NED 3 boiler, as renewable resource fuels typically contain less sulfur, nitrogen, and mercury than any of the carbon-based fuels proposed for NED 3 and less limestone addition to the boiler is needed.

Q. Can a pulverized coal boiler such as that proposed for COL 3 also burn renewable resource fuels?

A. Yes. However, fuel preparation requirements, including the need for pulverization, reduce the amount of proven capability of renewable resource fuels and fuel types considerably. Most experience with pulverized coal-fired boilers has involved dry woody biomass fed through the pulverizers with coal at rates up to 5 percent heat content contribution. There are other documented cases involving renewable resource fuel feeds of less than 10% contribution with separate burners or feed points from those used for coal combustion, but such experience is limited. These experiences include Interstate Power and Light Company's pneumatic supply of biomass (switch grass) to the Ottumwa Generating Station and boiler combustion via two separate burners.

Q. Does sufficient space exist at the NED site for renewable resource fuels handling?

A. Physical layouts prepared to-date show that sufficient space exists to support a renewable resource fuels feed, with approximately 2 to 5-days storage to reside on site. See Exhibit _____ (CJH-2), Schedule 2. One or more aggregators will be secured and an off-site aggregator facility with proper space for drying, shaping, pelleting, and collection and physical fuel testing (fuel specification compliance) will be established to support frequent deliveries to the site via truck and short train transport.

At present, limited on-site processing (weighing, reject processing, in-pile drying) at NED is planned, with balance of processing to be completed off-site by the aggregator (the size of renewable resource fuels particles will be controlled by the specific type of material and handling system employed).

Q. What is your opinion as to the ability of NED 3 to co-burn renewable resource products to reduce environmental impacts?

A. As previously indicated, CFB boilers offer proven capability to utilize renewable resource fuels in combination with carbon fuels versus other combustion technologies. A CFB boiler also has the ability to efficiently generate steam sufficient to nominally produce 300 MW of power using 20 percent resource fuels contribution, and this has the advantage of reducing the amount of incremental CO_2 and other GHGs emitted to the atmosphere. CFB boilers are also considered to be "clean coal technology" by the U.S. Department of Energy given reduced emission of criteria pollutants. Burning renewable resource fuel also has the benefits of further reducing CO_2 in the atmosphere by means of in-field sequestration, as discussed in Mr. Vesperman's testimony and attached exhibits. A 20% co-burn forecast is consistent with other large CFB designs wherein renewable resource opportunity fuels have been considered. WPL is committed to the renewable resource fuels co-burn design, has designed material handling infrastructure and is developing the supply market to ensure its success. The renewable resource fuels firing capabilities of NED 3 contribute directly to the State of Wisconsin's Renewable Portfolio Standard (RPS) and utilize the State's major supply of untapped renewable resource reserves, reducing the State's dependency on importation of coal and other fuel. Creating a renewable resource fuel supply chain also benefits Wisconsin's economy by opening up other crops that may profitably be harvested, processed and sold.

V. GREENHOUSE GASES AND CARBON CAPTURE

Q. What is the expected generation of GHG emissions from NED 3 and COL 3?

A. Combustion of carbon-based fuels (coal, pet coke) in the CFB boiler at NED 3 will produce CO_2, N_2O and CH_4 in varying amounts, depending on the fuel, combustion temperature, sorbent flow, and combustion air quality to a lesser degree. These same GHG emissions will be produced at COL 3 in comparable overall amounts. While CFB's lower combustion temperature in the range of 1500 to 1700 degrees F (when compared to over 2,000 degrees F in pulverized coal boilers) is suitable for minimizing NO_X emissions which are a criteria pollutant, N_2O is generated at an elevated level above what would be generated at higher combustion temperatures. HDR|CB has prepared a white paper analyzing and estimating the overall GHG emissions for both NED 3 and COL 3. *See* Exhibit _____ (CJH-2), Schedule 3. The estimated annual CO_2, N_2O and CH_4 emissions and the carbon equivalent emissions are described in Schedule 3. Based on a fuel blend of 80% Wyoming Powder River Basin coal and 20% pet coke (i.e. not considering the 20% RRFs co-burn), the carbon equivalency emissions for NED 3 are 2,985,000 tons annually compared to 2,723,000 tons with 10 percent wood co-fire and 2,420,000 tons with 20 percent wood co-fire. How those GHG emissions are more than offset by the 20% RRFs co-burn and WPL's carbon reduction plan is described in Mr. Bauer's testimony.

Q. Are these GHG emission forecasts the same as those included in the CPCN Application?

A. No. The annual emissions were estimated in the CPCN Applications at maximum permitted heat input using the EPA AP-42 emission factor data, wherein emissions are estimated using a single rate for the emission multiplied by fuel flow. Based on HDR|CB's research, the EPA AP-42 emission factors for certain GHGs, such as N_2O, are founded on limited data from actual experience and are general rather than source specific. Given the small overall volumetric component of non-CO_2 GHGs in the exhaust flow (less than 0.1 percent of volumetric and mass flow), N_2O and methane measurement is also extremely difficult. HDR|CB's analysis of expected GHGs from NED 3 and COL 3 utilized both EPA AP-42 factors as well as those recently published by researchers and boiler manufacturers based on continued testing. Emissions were calculated for a number of different fuel cases for both the NED 3 and COL 3 projects, as described above and in the GHG white paper. *See* Exhibit **____** (CJH-2), Schedule 3. Although the actual emission levels will not be known until after the boiler is operating, it is our opinion that the emission levels set forth in Schedule 3 are more accurate indicators of future emissions from NED 3 and COL 3 than those derived generally by using the EPA AP-42 emission factor data.

Q. How do the GHG emissions from NED 3 with 20% RRFs co-burn compare with either COL 3 with 4% RRFs co-burn or a supercritical pulverized coal (SCPC) unit with 10% RRFs co-burn?

A. As shown in Table 5-2 of Exhibit ___ (CJH-2), Schedule 3, the equivalent CO_2 emissions from NED 3 when firing 20% RRFs are significantly lower than COL 3 when firing 4% biomass if N_2O emissions are maintained at the lower end of what has been proven available in CFB boiler technology. Also depicted in Table 5-2 is a comparison of the equivalent CO_2 emissions from NED 3 with those from an SCPC power plant utilizing 10 percent biomass. It was assumed that the SCPC plant is a 650 MW plant with main steam conditions of 3,700 psia and 1,100°F and a reheat steam temperature of 1,100°F and that 326 MW of the power is purchased by WPL with associated emissions. The NED 3 unit with a CFB boiler has similar equivalent CO_2 emissions when utilizing 20 percent biomass to that of the SCPC option utilizing 10 percent biomass.

Q. What design steps has WPL undertaken to reduce GHG emissions?

A. As indicated, WPL has designed material handling and is developing the market for co-burning renewable resource fuels. As explained earlier, this reduces the incremental addition of GHG emissions to the atmosphere when compared with burning the carbon-based fuels that are replaced by the renewable resource fuels. WPL will also optimize boiler combustion methods and consider adjustments to other contributory effects (e.g., ammonia-based selective non-catalytic reduction will be used for NO_x control versus urea-based control that has been shown to increase N_2O formation) after start-up to establish a prudent combustion temperature wherein both criteria pollutants (primary) and GHGs are minimized and necessary reagents for emission control are minimized.

Q. What has WPL done in the conceptual design of NED 3 to allow for carbon capture when sequestration becomes viable for a Wisconsin unit?

A. HDR|CB has prepared a white paper analyzing the carbon capture technologies that may be available at NED 3. Exhibit _____ (CJH-2), Schedule 4. To prepare in advance for full carbon capture implementation, WPL is taking prudent engineering design steps now that will reduce future retrofitting costs. There is room on-site for the necessary carbon capture retrofit equipment. Utilizing good engineering practices, WPL will be installing a transformer and generator (rated above the current anticipated gross MW output) and larger last stage steam turbine blades that have some margin and may potentially allow increased gross power production to offset increased consumption from capture equipment. WPL is also preserving space on-site to potentially add additional steam generating capacity and capture/compression equipment for the same reasons. The CFB technology lends itself to this type of approach because of the deployment of external heat exchangers. With these engineering steps and space allocations, the future steps and costs for retrofitting for carbon capture will be reduced.

Sequestration is being assessed by a number of research bodies and partnerships in the Midwestern states. However, there are many technical, regulatory, safety, and legal uncertainties associated with using underground, geologic repositories such as salt caverns, abandoned oil/gas wells and reefs, and similar formations for long-term CO_2 storage.

Q. Is NED 3's CFB technology well suited for carbon capture?

A. Yes. Both pre-combustion (*e.g.*, oxy-fuel firing) or post-combustion (*e.g.*, chilled ammonia, electrocatalytic reduction/absorption, amine scrubbing) technologies as currently conceptualized can be retrofitted to a CFB unit, as discussed in Exhibit _____ (CJH-2), Schedule 4. Amine-based CO_2 capture has already been applied to two CFB installations in the United States, although for only approximately 10% of the total exhaust/flue gas flow. These installations are the AES Shady Point units in Oklahoma and the AES Warrior Run unit in Pennsylvania. The Shady Point station is a 4 X 80 MW plant using CFB technology and includes a monoethanol amine (MEA) scrubbing system to scrub roughly 10% of the flue gas to produce flue grade CO_2 for dry ice production used in preparing freeze dried chickens. This unit went into operation in the late 80's. In the early 90's, similar technology was deployed at the AES Warrior Run (200 MW CFB-based unit) to produce food-grade CO_2 for use in carbonated beverages.

However, the capture of CO_2 takes energy. This energy typically comes from the electrical output of the unit from which the CO_2 is captured, or from steam removed from the generation process to provide heat or motive force for carbon capture equipment. The CO_2 that is "produced" must then be liquefied and compressed so that it can be put in a pipeline and sent for downstream process use or sequestration. The only exceptions are those capture technologies that are able to produce CO_2 at pressure. At the present time, the chilled ammonia process is the only capture technology that proposes to regenerate the CO_2 at substantial pressure. The chilled ammonia absorption and regeneration step also requires energy input. As indicated, these carbon capture technologies are discussed in Exhibit _____ (CJH-2), Schedule 4.

The requirement for the energy and steam to power and operate the carbon capture technology "derates" the generating output from the unit. Each of the carbon capture technologies has some amount of derate. It would, of course, be desirable to retain the net generating output from the unit even after the derate effect to power the CO_2 capture system. The CFB technology appears to offer good potential in this regard. As indicated, with the provisions made to add heat transfer surface at a later time, there is potential that more steam may be generated in a CFB boiler such that it can be used to offset increased demands from capture equipment, thus minimizing impacts so that the net generated output approximates the unit nameplate capacity without carbon capture. In a recent study done by Alstom Power for the U.S. Department of Energy, the derate effect from oxy-fuel firing and modifications to support such were further analyzed on CFB technology, and the Alstom Report illustrates certain measures to reduce carbon capture "derate" effect on CFB units which will be considered in project design. *See* Exhibit ____ (CJH-2), Schedule 4.

Thus, with the steps WPL is taking in the design of NED 3, and future equipment additions including increased heat transfer surface, it is anticipated that the power output of NED 3 may be maintainable in the 260 to 300 MW range even after carbon capture. The capture retrofit cost is considerably less expensive on a dollar/kW basis when the output of NED 3 is maintained as high as possible.

Q. Have capital costs been allocated for future CO_2 capture and sequestration?

A. Adequate space has been preserved for pre- and post-combustion capture equipment based on information available to the industry today. At the present time, it is not possible to select with certainty what commercially proven and economically viable capture technology will be best at the time carbon capture and sequestration becomes viable for NED 3. As such, no future capital costs for carbon capture equipment have been included in the overall project capital cost estimate (see previous). The costs for the higher capacity transformer and generator and the longer last-stage turbine blades are, however, included in the cost estimates.

Q. What is your opinion about the feasibility of carbon capture for NED 3?

A. The NED 3 CFB boiler will be adaptable to pre- or post-combustion carbon capture technologies. However, sequestration is not currently a viable option for a Wisconsin facility and, until it becomes viable (i.e, there is some place to dispose of the captured CO_2), carbon capture is not practical. *See* Exhibit ____ (CJH-2), Schedule 4. Since it is unknown when sequestration will become viable for NED 3, it is uncertain which carbon capture technology will be most effective and commercially available. Based on current studies, however, it appears that CFB technology is equally or better suited for carbon capture than other coal-fired technologies because of the potential ability to increase steam production and gross power generated in association with capture equipment addition. WPL is taking prudent engineering steps now by installing slightly higher rated transformer and generator and longer last stage steam turbine blades and allocating space for additional heat exchangers that will result in NED 3 being "carbon capture ready" at the appropriate time. These measures will reduce the impacts of said retrofit, without committing capital early on uncertain capture technologies. The site layout for the space allocation for additional heat exchanger units is included with Exhibit ____ (CJH-2), Schedule 4.

VIII. CONCLUSIONS

Q. Please summarize your testimony.

A. It is my opinion that the selection of CFB boiler technology for NED 3 is prudent given its significant fuel flexibility and ability to combust renewable resource fuels at a greater contribution than in other power generating cycles. NED's location on the Mississippi River, adjacent to a BNSF main rail line and on County Highway VV, provides significant fuels delivery options, and the on-site substation provides the means to distribute the generated power to the 161 kV grid. The power generating cycle selected has high efficiency, which reduces the amount of fuel required and maximizes power output. With an increased barge unloading capacity and industrial rail lines adjacent to the BNSF main rail line, WPL will have the ability to select the most economic fuel delivery option, and to avoid congestion and constraint issues which affect most other generators.

I also completed a review of the estimated capital costs of the NED 3 and COL 3 Projects to determine whether such costs were reasonable in magnitude, comparable to market conditions, and consistent with industry estimating practices. Through these project reviews, I concluded that the estimated costs developed by WPL and its consultants for both projects in 2008 dollars are reasonable and competitive in today's marketplace. The cost per kW of generation for the 300 MW CFB is at the higher range for other new coal-fired generating plants, primarily as a result of scale effects as the largest commercial sub-critical CFB boilers can produce only 300 MW nominal compared to approximately 1,000 MW for an ultra supercritical PC boiler. However, the many benefits illustrated previously with respect to NED 3's CFB technology remain very attractive. Verification of project costs is continuing.

NED 3 will co-burn 20 percent renewable resource fuels five (5) years after NED 3 reaches COD, and is closely located to sources for both woody and herbaceous materials in southwest Wisconsin. In addition, NED will have the ability to receive fuel from truck, rail, and barge sources, which minimizes transportation risks and costs associated with fuel supply. Renewable resource fuels is an important contribution towards the State of Wisconsin's Renewable Portfolio Standards, and NED 3 offers many advantages over other forms of generation in this regard due to the higher compatibility of CFB technology to renewable resource fuels when compared to other coal-fired technologies. WPL is actively pursuing renewable resource supply chains and opportunities as part of its development of NED 3.

NED 3 is being developed as "carbon capture ready", with physical space allocation and equipment sizing designed for future deployment of carbon dioxide capture equipment should such be commercially demonstrated and viable sequestration options become available. The State of Wisconsin has few sequestration options, but NED's location in the southwest corner may support piped disposal to hosts in other states to the west or south.   NED 3 CFB technology may provide advantages to maintain close to nameplate output despite increased power/steam demand for carbon capture when compared to other generation technologies such as pulverized coal.

NED 3 possesses many attractive features, including improved transmission import capability, fuel flexibility, efficiency, pollution control and impact on environment. It is my opinion that the addition of NED 3 to WPL's generation portfolio is prudent and in the public interest.

Q. Does this conclude your direct testimony?

A. Yes.

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INDIANA UTILITY REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. (1) SEEKING AUTHORITY TO REFLECT COSTS INCURRED FOR THE EDWARDSPORT INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY ("IGCC PROJECT") PROPERTY UNDER CONSTRUCTION IN ITS RATES AND AUTHORITY TO RECOVER EXTERNAL COSTS THROUGH ITS INTEGRATED COAL GASIFICATION COMBINED CYCLE GENERATING FACILITY COST RECOVERY ADJUSTMENT, STANDARD CONTRACT RIDER NO. 61 PURSUANT TO IND. CODE SECTIONS 8-1-8.8-11 AND -12; (2) SEEKING AN EXPEDITED APPROVAL OF AN UPDATED COST ESTIMATE FOR THE IGCC PROJECT, INCLUDING APPROVAL OF AN ONGOING REVIEW PROGRESS REPORT PURSUANT TO IND. CODE 8-1-8.7; AND (3) SEEKING APPROVAL OF AND COST RECOVERY ASSOCIATED WITH THE STUDY OF CARBON CAPTURE, SEQUESTRATION AND/OR ENHANCED OIL RECOVERY FOR THE IGCC PROJECT PURSUANT TO AN ALTERNATIVE REGULATORY PLAN UNDER IND. CODE § 8-1-2.5-6	CAUSE NO. 43114 IGCC-1

VERIFIED PETITION

TO THE INDIANA UTILITY REGULATORY COMMISSION:

Duke Energy Indiana, Inc. ("Petitioner", "Company" or "Duke Energy Indiana") respectfully represents and shows to the Indiana Utility Regulatory Commission ("Commission") that:

1. **Petitioner's Corporate and Regulated Status.** Petitioner is an Indiana corporation with its principal office in the Town of Plainfield, Hendricks County, Indiana. Its address is 1000 East Main Street, Plainfield, Indiana 46168. It has the corporate power and

authority, among others, to engage, and it is engaged, in the business of supplying electric utility service to the public in the State of Indiana. Accordingly, Petitioner is a "public utility" within the meaning of that term as used in the Indiana Public Service Commission Act, as amended, Ind. Code § 8-1-2-1, and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana, including Ind. Code § 8-1-2-1 *et seq*. Duke Energy Indiana is also an energy utility as defined by Ind. Code § 8-1-2.5-2. As of April 3, 2006, Petitioner is a second tier wholly-owned subsidiary of Duke Energy Corporation.

2. Petitioner's Electric Utility Service. Petitioner owns, operates, manages and controls plants, properties and equipment used and useful for the production, transmission, distribution and furnishing of electric utility service to the public in the State of Indiana. Duke Energy Indiana directly supplies electric energy to over 780,000 customers located in 69 counties in the central, north central and southern parts of the State of Indiana. Petitioner also sells electric energy for resale to municipal utilities, Wabash Valley Power Association, Inc., Indiana Municipal Power Agency and to other public utilities that in turn supply electric utility service to numerous customers in areas not served directly by Petitioner.

3. Petitioner's Electric Generating Properties. Petitioner's electric generating properties currently consist of: (1) steam capacity located at five stations comprised of nineteen coal-fired generating units supplied by nineteen coal-fired boilers and one oil-fired boiler; (2) combined cycle capacity located at one station comprised of three natural gas-fired combustion turbines ("CT") and two steam turbine-generators; (3) a run-of-river hydroelectric generation facility comprised of three units; (4) peaking capacity consisting of seven oil-fired diesels located at two stations, eight oil-fired CT units located at two stations, and sixteen natural gas-fired CTs, one of which has oil back-up.

4. **The Purpose of this Proceeding.** In its November 20, 2007 Order in Cause Nos. 43114 and 43114-S1 (the "Order"), the Commission issued certificates of public convenience and necessity and clean coal technology ("CPCNs") authorizing Petitioner to construct the 630 megawatt Edwardsport IGCC Project ("IGCC Project"). The Order approved Petitioner's estimated construction cost for the IGCC Project of $1.985 billion and Petitioner's proposed Standard Contract Rider No. 61 ("IGCC Rider"), which provides for the timely recovery of costs in connection with the IGCC Project. The Commission also directed Petitioner to file semi-annual IGCC Rider and Ongoing Review Progress Report proceedings. Finally, the Order directed Petitioner to initiate a proceeding within six months of the date of the Order with proposals for the study of partial CO_2 capture, sequestration and/or enhanced oil recovery at the IGCC Project.

The purpose of this proceeding is: (1) to notify the Commission and the parties that the estimated cost of constructing the IGCC Project has increased by approximately 18%—from $1.985 billion to $2.350 billion; (2) to demonstrate that such increase is warranted and should be approved by the Commission as the revised estimated construction cost for the IGCC Project; (3) to request recovery under the IGCC Rider of external costs and the actual costs of the IGCC Project through February 29, 2008; (4) to seek expedited approval—as more fully set forth in paragraph 5 below—of the revised estimated construction cost for the IGCC Project; and (5) to request approval of proposals to study partial CO_2 capture, sequestration and/or enhanced oil recovery at the IGCC Project, and associated cost recovery.

5. **Request for Expedited Determination on Cost Estimate Update.** The Company respectfully requests expedited proceedings related to the cost estimate update. As discussed in more detail below, the increase in the cost estimate is driven by factors outside the

Company's control, including unprecedented global competition for commodities, engineered equipment and materials, and increased labor costs. Petitioner believes and is prepared to show that the increase in the estimate is warranted. Expedited treatment is necessary and appropriate because the committed costs the Company has already incurred through April 2008 (approximately $180 million), to lock in pricing and preserve schedule, are significant. Moreover, in order to keep the IGCC Project on course, Petitioner will be required to substantially ramp up its financial commitments from this point forward. The Company anticipates the commitment of approximately $40 to $50 million per month through the balance of the year in order to meet the projected in-service date. *See* Attachment 1 for a breakdown of the estimated expenditures for the Edwardsport IGCC Project by month for the next twelve months. It is in the interests of Petitioner, its customers, shareholders, and all stakeholders to resolve the matters in this proceeding as expeditiously as possible.

6. <u>Edwardsport IGCC Project Status.</u> Since receiving approval of the CPCNs for the Edwardsport IGCC Project the Company has taken major steps toward construction of the Project. In November 2007, the Company began the process of finalizing contract terms with its principal vendors on the IGCC Project, General Electric Company ("GE") and Bechtel Corporation ("Bechtel"). In December 2007, Duke Energy Indiana signed a definitive contract with GE to furnish engineered equipment for the Project. GE immediately began fabrication of several major components, including the radiant syngas cooler which was the longest lead time for any piece of equipment for the Project. GE has also selected a vendor for the Air Separation Unit ("ASU"), securing the availability of the ASU. Since signing the contract, GE has been moving rapidly to begin fabrication of major proprietary equipment and to secure other equipment components from third party vendors.

In April 2008, Duke Energy Indiana finalized a commercial term sheet with Bechtel outlining the framework of an Engineering, Procurement, and Construction Management agreement. In May 2008, the Company plans to sign a Limited Notice to Proceed Agreement allowing Bechtel to begin work on the IGCC Project while negotiations proceed on a definitive agreement.

At the Project site, grouting of the underground mine tunnels has been completed, the temporary project offices have been erected, preparation of the site to accept the deep injection well drill rig is complete, and the contract for deep well installation has been awarded. Bids have been solicited from contractors for the site preparation scope of work. Sargent & Lundy is continuing detailed design of peripheral systems not in Bechtel's scope. With their assistance, the Company has awarded the coal handling equipment contract and is nearing the awarding of the warehouse buildings contract. Negotiations are nearing completion for the drilling and installation of the raw water collector wells. Through the remainder of 2008 and going forward, work on the Project will continue at an accelerated pace in order to meet the expected 2012 in-service date. Attachment 1 to this Verified Petition demonstrates the most current anticipated cash flows for the project for the next twelve months.

7. **Specific Relief Sought By This Petition.** As discussed above, Petitioner seeks: (1) Commission authorization to reflect the actual expenditures through February 29, 2008 for the IGCC Project under construction in its retail electric rates and authorization to recover external costs via its Standard Contract Rider No. 61; (2) expedited approval of an updated cost estimate for the IGCC Project including approval of an ongoing review progress report concerning the IGCC Project; and (3) approval of and assurance of cost recovery for

studies regarding potential partial carbon capture, sequestration and/or enhanced oil recovery for the IGCC Project.

(a). **<u>IGCC Rider</u>.** Pursuant to Ind. Code § 8-1-8.8-12 and consistent with 170 I.A.C. § 4-1-18, Petitioner hereby requests that the Commission, for ratemaking purposes, authorize the addition of the actual expenditures for its IGCC Project made through February 29, 2008 to the value of Petitioner's property. Petitioner further requests that the Commission approve and authorize the requested rate adjustment allowing Petitioner to earn a return on said amount, in addition to the return on the value of its used and useful utility property and on its construction work in progress investment previously approved by the Commission. Petitioner also requests, consistent with the CPCN Order, recovery of external costs, other than IRP costs, via the IGCC Rider.

(b). **<u>Approval of Updated Cost Estimate for the IGCC Project and Ongoing Review Progress Report ("Progress Report")</u>.** Under the CPCN statutes and ongoing review provisions, once a CPCN is granted, absent extraordinary circumstances specified in the statute, the utility shall recover through rates the actual costs the utility has incurred in reliance on the CPCN. Ind. Code § 8-1-8.5-6.5.

As discussed above, the Company is requesting the Commission revise the approved estimated construction cost for the IGCC Project. The primary reasons for this increased cost estimate are: (1) higher than anticipated contract costs from our major vendors driven in large part by the worldwide demand for engineering and construction services and for construction commodities such as steel and concrete; (2) higher than expected inflationary increases on major pieces of equipment, many of which are only available from overseas firms, also driven by worldwide increases in demand for such equipment; and (3) higher than average expected inflation over the course of the construction period, expected to be reflected in contractors' costs, labor costs, and other equipment costs.

This projected increase has been driven by factors outside of the Company's control, and is consistent with other recent power plant project cost increases across the country. As major high cost / long lead-time items have now been contracted for, the risk of future price increases has been reduced. Under the Company's contracting approach, additional portions of the project costs will be fixed over time as they are purchased. However, some components will remain cost reimbursable throughout the project because the Company could not secure a complete fixed cost set of contracts on reasonable terms.

Despite this projected cost increase, Petitioner believes that continuation of this project remains in the public interest. When completed, this plant will be one of the cleanest and most efficient coal-fired power plants in the nation, producing significantly fewer regulated air emissions than existing coal-fired plants. Additionally, this plant will use Midwestern coal, a domestic resource that is not only abundant, but is lower cost and less subject to price volatility than alternative fuels such as natural gas.

As this Commission has already found, Duke Energy Indiana has a significant need for more baseload capacity to meet its customers' electricity requirements. If the Company were not to pursue the IGCC Project, the alternative option would be to rely more on natural-gas fired power plants for baseload needs. Natural gas is a more costly fuel source than coal, and natural gas prices and supplies are more volatile and unpredictable, especially out in the future. Increasing reliance by electric utilities on natural gas may also drive up the cost of natural gas for industrial consumers as well as residential and commercial heating customers. For these reasons, Duke Energy Indiana does not believe natural-gas fired power plants are a reasonable substitute for this baseload coal plant.

Another strong basis for this project is the importance of developing clean coal technologies, such as IGCC and the potential for carbon capture and sequestration, to be able to continue to use Midwestern coal while at the same time addressing inevitable climate change regulations.

Additionally, the construction of the IGCC Project will help modernize the Company's generating fleet (the average age of Duke Energy Indiana's coal fleet is almost 45 years old). This is important in terms of continuing to be able to provide a reliable supply of electricity while at the same time preparing for the retirement of some older and smaller coal units that are not cost effective to retrofit with modern environmental controls. No new major coal plants have been built in Indiana for over 20 years, and new plants are needed if plentiful Midwestern coal is to remain a viable energy resource.

Finally, the IGCC Project has received support in the form of future tax incentives from the federal, state and local governments to develop this advanced clean coal technology. Duke Energy Indiana has qualified for a combination of federal, state and local tax credits and offsets totaling over $460 million for the IGCC project. These tax incentives will help reduce the cost impact of the IGCC Project on customers.

Of course, the Company recognizes that the revised construction estimate will have an impact on customers' rates. The estimated average customer rate impact resulting from the cost increase amount is an incremental increase of approximately 2%, for a total of approximately 18%, in the peak rate impact year, 2013. This projected increase impacts the overall cost-effectiveness of the IGCC Project, especially in the shorter-term, and may make alternatives such as natural gas-fired plants more attractive in the short term.

However, for all the reasons stated above, Petitioner believes the IGCC Project remains the best option for its customers—particularly given the steps the Company has already taken to commit capital and reduce future price uncertainty. With contracts in place and construction already underway, the construction costs to the Company and its customers from the IGCC Project are accruing on an ongoing basis. It is not prudent or appropriate to delay incurrence of these costs while this proceeding is pending. Indeed, in some instances, it is not possible to delay incurrence of costs while this proceeding is pending.

Delay would create other problems as well – such as redeployment of the outside engineering experts assigned to the IGCC Project, demobilization and remobilization costs, loss of place in line for major pieces of equipment, a significant delay of in-service date, increased financing costs, and other inefficiencies. In addition, if the IGCC Project is delayed it would cause additional increases in the final capital cost and could cause the Company to lose its federal tax credit incentives of $133.5 million, which provide a large benefit to customers.

Accordingly, receiving a prompt decision on this proposed updated cost estimate is very important for both the Company and its customers, and therefore, Duke Energy Indiana requests an expedited schedule as set forth below.

(c). **Approval and Cost Recovery for Carbon Capture and Sequestration ("CCS") and/or Enhanced Oil Recovery ("EOR") Studies**. Pursuant to the Commission's November 20, 2007 Order, Duke Energy Indiana seeks a determination of the appropriateness and cost recovery of various proposed CCS and EOR studies under an Alternative Regulatory Plan pursuant to Ind. Code § 8-1-2.5-6. By this Verified Petition, Duke

Energy Indiana elects to be subject to Ind. Code § 8-1-2.5-6. The Company's alternative regulatory plan will be detailed in its prefiled case-in-chief testimony. Duke Energy Indiana requests to recover the costs of these proposed studies through Standard Contract Rider No. 61, the IGCC Rider, or alternatively, the Company proposes to defer these research and development costs for future recovery pursuant to Ind. Code § 8-1-2-6.1(c) and 170 I.A.C. § 4-6-17.

(i). Carbon Capture. The Company is considering two studies related to carbon capture scenarios. First, the Electric Power Research Institute ("EPRI") is conducting a pre-feasibility study by its Coal Fleet Consultants that will address three capture scenarios (15%-18%, 50%, and 90%), all under the same normal operating conditions. This study will consist of process modeling of the GE process data for the base IGCC plant with a critical analysis of the process and performance impacts on plant design when retrofitting with CO_2 capture equipment and a high level estimate of the cost impacts for each CO_2 capture scenario. This study should provide valuable information on the costs and impacts of different levels of CO_2 capture.

Additionally, the Company is investigating studies to be performed by GE drawing from GE's own IGCC reference plant design CO_2 capture work. GE would adapt its reference plant 15% to 18% CO_2 removal feasibility study case and its 50% to 60% CO_2 removal feasibility study case to the Edwardsport IGCC Project design, providing feasibility study detail on the proposed plant impacts and costs associated with CO_2 capture under these scenarios and at varying operating conditions. The Company is also investigating a more comprehensive capture FEED Study proposal. Further details on the estimated costs and timing of these potential studies will be provided in the Company's testimony.

(ii). Carbon Sequestration. Duke Energy Indiana is pursuing several carbon sequestration funding and study opportunities. As discussed in the CPCN proceeding, Duke Energy Indiana has applied to host a Phase III, large scale demonstration project through the U.S. Department of Energy ("DOE") Regional Partnership program using CO_2 captured from the Edwardsport IGCC Project. If chosen, it is anticipated that some funding would be provided by DOE over a ten year period for site characterization, permitting, operation and migration monitoring providing important data about potential geologic sequestration into deep saline aquifers. If chosen, this would be the only project to have an IGCC plant as the source of the CO_2, and could potentially be the largest demonstration project with twice as much CO_2 being captured compared to the other Phase III projects that have already been awarded. DOE has not announced funding for all of the projects yet and it is unknown when and if the funding for the proposed project at Edwardsport will become available.

The Company is also pursuing funding for carbon capture and sequestration as part of the DOE's plan to restructure FutureGen. The DOE hopes to gain early commercial experience validating clean coal technologies through multiple demonstrations of CCS technology in commercially operated IGCC electric power plants under actual industrial settings. The revised approach focuses on multiple early-commercial technology demonstrations in lieu of the one research and development plant approach of FutureGen. Duke Energy Indiana has responded to the DOE's request for information by outlining the Edwardsport IGCC Project and the Company's plans for studying the feasibility of CCS application. DOE intends to issue a competitive Funding Opportunity Announcement in the summer of 2008 and expects to evaluate proposals and announce selections by the end of December 2008.

Given the uncertainty of these federal study and funding opportunities, the Company is also investigating an independent carbon sequestration study to examine the process of taking captured CO_2 and utilizing the carbon sequestration form of geological storage. Duke Energy Indiana would work with an expert consulting group to investigate, at or near the Edwardsport site, the five stages of sequestration – Site Characterization, Permitting, Operations Performance, Closure, and Post Closure. More details on the costs and timing of these potential funding opportunities and the independent study proposal will be provided in Duke Energy Indiana's testimony.

(iii). Enhanced Oil Recovery ("EOR"). One potential commercial opportunity for captured CO_2 is its use in EOR. Under this scenario, CO_2 would be injected through multiple wells into an oil reservoir with the goal of recovering incremental oil from mature oil fields that have undergone primary oil recovery (recovery through oil pressure) and are being flooded with water for secondary recovery (this CO_2 injection process is sometimes referred to as an "EOR flood"). In an EOR CO_2 flood or tertiary recovery, part of the CO_2 injected into the oil reservoir migrates upward along with the recovered oil, but is separated and recycled back for reuse. Once the reservoir is depleted of oil, the well sealing process is technically believed to permanently sequester the CO_2 used in the EOR process.

Duke Energy Indiana is investigating different EOR opportunities, including working directly with oil companies to establish the feasibility of EOR in the Illinois Basin and entering into a CO_2 off take agreement with a CO_2 marketer which has the responsibility to recruit interested oil companies and establish the EOR feasibility. An EOR study would be performed in two phases. Phase I would include screening and geologic characterization of potential oil fields, determining infrastructure needs for the EOR flood, developing the business economics, structuring an arrangement with an oil company, and screening for EOR pilots. If Phase I proves promising, then Phase II of the study would finalize the number and location of EOR pilots, and execute pilot EOR floods, to help establish the viability of EOR in this area. Duke Energy Indiana will provide more details on the costs and timing of potential EOR studies in its testimony.

8. **Applicable Statutes and Regulations**. Petitioner considers that Ind. Code § 8-1-2-42(a), Ind. Code § 8-1-2-6.1(c), Ind. Code 8-1-2.5 *et seq.*, Ind. Code 8-1-8.5 *et seq.*, Ind. Code 8-1-8.7 *et seq.* and Ind. Code 8-1-8.8 *et seq.*, 170 I.A.C. §§ 4-6-1, 4-6-17 among others, are or may be applicable to the subject matter of this proceeding.

9. **Petitioner's Counsel.** Kelley A. Karn and J. William DuMond at 1000 East Main Street, Plainfield, Indiana 46168, and James R. Pope and Elizabeth A. Herriman, Baker & Daniels LLP, Suite 2700, 300 North Meridian Street, Indianapolis, Indiana 46204 are counsel for Petitioner in this matter, and are duly authorized to accept service of papers in this Cause on behalf of Petitioner.

10. **Request for Expedited Prehearing Conference, the Appointment of Commission Testimonial Staff and an Expedited Procedural Schedule.** As explained above, given the magnitude of construction costs contemplated over the next several months, the Company respectfully requests the Commission to expeditiously set this matter for a prehearing conference as soon as reasonably possible. Further, the Company requests that the Commission encourage collaborative procedures designed to lead to a prompt and constructive outcome, including the appointment of Commission testimonial staff.

Given the urgency, the Company proposes a procedural schedule which may reasonably allow for a Commission Order in this proceeding no later than the beginning of August 2008:

- Duke Energy Indiana case-in-chief testimony on or before May 15
- Prehearing conference on or before May 26
- OUCC and Intervenors testimony on or before June 10
- Duke Energy rebuttal testimony on or before June 23
- Hearing on or before week of July 7
- Simultaneous proposed orders on July 18
- Expected Order on or before July 30

WHEREFORE, Petitioner respectfully requests that the Commission make such investigation and hold such hearings as it may deem necessary and advisable in this Cause, and thereafter make and enter an Order: (a) adding to the valuation of Petitioner's utility property the actual costs incurred through February 29, 2008 of the IGCC Project for ratemaking purposes and authorizing recovery of external costs via Petitioner's Standard Contract Rider No. 61; (b) expeditiously approving Petitioner's updated cost estimate for the IGCC Project and its ongoing review progress report related to its IGCC Project; (c) approving Petitioner moving forward with, and approving cost recovery for, studies relating to carbon capture, sequestration, and/or enhanced oil recovery at the IGCC Project; and (d) granting Petitioner such other and further relief in the premises as may be appropriate and proper.

Dated as of the 1st of May, 2008.

DUKE ENERGY INDIANA, INC.

By: ________________________________
Jim Stanley, President Duke Energy Indiana, Inc.

By: Kelley A K ________________________________
Counsel for Duke Energy Indiana, Inc.

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Facsimile: (317) 237-1000

VERIFICATION

STATE OF INDIANA)
) SS
COUNTY OF HENDRICKS)

Jim Stanley, being first duly sworn, deposes and says that he is President, Duke Energy Indiana, Inc., that he has read and executed the foregoing Verified Petition and is acquainted with the facts therein stated, and that the statements therein contained are true to the best of his information, knowledge and belief.

Jim Stanley

Before me, a Notary Public, in and for said County and State, personally appeared Jim Stanley, who acknowledged the execution of the foregoing document to be his voluntary act and deed.

Dated this 1ST day of May, 2008.

Lana J. Horner
Notary Public

My Commission Expires: 4/19/2015

My County of Residence: HENDRICKS

Edwardsport IGCC Cash Flow Projection - May, 2008

Time Period	Projected Monthly Cash Flow (without AFUDC)	Projected Monthly AFUDC	Projected Cummulative Cash Flow (without AFUDC)	Projected Cummulative AFUDC	Projected Cummulative Cash Flow (with AFUDC)	Equipment and Contractor Termination Cost (Estimate)	Projected Total Committed Cost
Previous Cost	$ 132,136,728	$ 2,774,948	$ 132,136,728	$ 2,774,948	$ 134,911,676		
Mar-08	$ 14,552,182	881,564	$ 146,688,910	$ 3,656,512	$ 150,345,422	$ 22,126,251	$ 172,471,673
Apr-08	$ 15,774,135	981,041	$ 162,463,045	$ 4,637,553	$ 167,100,598	$ 23,626,251	$ 190,726,849
May-08	$ 48,674,807	1,186,916	$ 211,137,853	$ 5,824,469	$ 216,962,322	$ 24,596,884	$ 241,559,206
Jun-08	$ 50,947,164	1,503,103	$ 262,085,017	$ 7,327,572	$ 269,412,589	$ 29,538,149	$ 298,950,738
Jul-08	$ 41,020,206	1,267,195	$ 303,105,223	$ 8,594,767	$ 311,699,990	$ 30,479,413	$ 342,179,403
Aug-08	$ 23,131,976	1,473,923	$ 326,237,198	$ 10,068,690	$ 336,305,888	$ 31,420,678	$ 367,726,566
Sep-08	$ 52,308,349	1,716,926	$ 378,545,547	$ 11,785,616	$ 390,331,163	$ 33,773,841	$ 424,105,004
Oct-08	$ 35,080,321	1,998,476	$ 413,625,868	$ 13,784,092	$ 427,409,960	$ 36,597,636	$ 464,007,596
Nov-08	$ 54,352,497	2,288,108	$ 467,978,365	$ 16,072,200	$ 484,050,565	$ 37,127,004	$ 521,177,569
Dec-08	$ 40,714,571	2,597,003	$ 508,692,936	$ 18,669,203	$ 527,362,139	$ 34,773,841	$ 562,135,980
Jan-09	$ 57,663,254	1,778,043	$ 566,356,190	$ 20,447,246	$ 586,803,436	$ 33,420,678	$ 620,224,114
Feb-09	$ 43,895,804	2,103,900	$ 610,251,994	$ 22,551,146	$ 632,803,140	$ 30,596,883	$ 663,400,023
Mar-09	$ 44,324,009	2,390,426	$ 654,576,003	$ 24,941,572	$ 679,517,575	$ 27,773,088	$ 707,290,663
Apr-09	$ 53,039,938	2,707,075	$ 707,615,941	$ 27,648,647	$ 735,264,588	$ 23,949,294	$ 759,213,882

Attachment 1

CERTIFICATE OF SERVICE

The undersigned hereby certifies that copies of the foregoing Petition were delivered or mailed, postage prepaid, in the United States Mail, this 1st day of May 2008, to the following:

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COPY

FILED

NOV 24 2009

INDIANA UTILITY REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. SEEKING (1) APPROVAL OF AN ONGOING REVIEW PROGRESS REPORT PURSUANT TO IND. CODE §§8-1-8.5 AND 8-1-8.7; (2) AUTHORITY TO REFLECT COSTS INCURRED FOR THE EDWARDSPORT INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY ("IGCC PROJECT") PROPERTY UNDER CONSTRUCTION IN ITS RATES AND AUTHORITY TO RECOVER APPLICABLE RELATED COSTS THROUGH ITS INTEGRATED COAL GASIFICATION COMBINED CYCLE GENERATING FACILITY COST RECOVERY ADJUSTMENT, STANDARD CONTRACT RIDER NO. 61 PURSUANT TO IND. CODE §§8-1-8.8-11 AND -12; AND (3) ESTABLISHMENT A SUBDOCKET PROCEEDING TO REVIEW THE COST ESTIMATE FOR THE IGCC PROJECT	)	**CAUSE NO. 43114 IGCC-4**

VERIFIED PETITION AND MOTION FOR SUBDOCKET PROCEEDING

TO THE INDIANA UTILITY REGULATORY COMMISSION:

Duke Energy Indiana, Inc. ("Petitioner", "Company" or "Duke Energy Indiana") respectfully represents and shows to the Indiana Utility Regulatory Commission ("Commission") that:

1. **Petitioner's Corporate and Regulated Status.** Petitioner is an Indiana corporation with its principal office in the Town of Plainfield, Hendricks County, Indiana. Its address is 1000 East Main Street, Plainfield, Indiana 46168. It has the corporate power and authority, among others, to engage, and it is engaged, in the business of supplying electric utility service to the public in the State of Indiana. Accordingly, Petitioner is a "public utility" within

the meaning of that term as used in the Indiana Public Service Commission Act, as amended, Ind. Code § 8-1-2-1, and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana, including Ind. Code § 8-1-2-1 *et seq*. As of April 3, 2006, Petitioner is a second tier wholly-owned subsidiary of Duke Energy Corporation.

2. **Petitioner's Electric Utility Service.** Petitioner owns, operates, manages and controls plants, properties and equipment used and useful for the production, transmission, distribution and furnishing of electric utility service to the public in the State of Indiana. Duke Energy Indiana directly supplies electric energy to approximately 775,000 customers located in 69 counties in the central, north central and southern parts of the State of Indiana. Petitioner also sells electric energy for resale to municipal utilities, Wabash Valley Power Association, Inc., Indiana Municipal Power Agency and to other public utilities that in turn supply electric utility service to numerous customers in areas not served directly by Petitioner.

3. **Petitioner's Electric Generating Properties.** Petitioner's electric generating properties currently consist of: (1) steam capacity located at five stations comprised of nineteen coal-fired generating units[1] supplied by nineteen coal-fired boilers and one oil-fired boiler; (2) combined cycle capacity located at one station comprised of three natural gas-fired combustion turbines ("CT") and two steam turbine-generators; (3) a run-of-river hydroelectric generation facility comprised of three units; (4) peaking capacity consisting of seven oil-fired diesels located at two stations, eight oil-fired CT units located at two stations, and sixteen natural gas-fired CTs, one of which has oil back-up.

[1] Pursuant to the New Source Review ("NSR") remedy order ("remedy order"), issued on May 29, 2009, Wabash River Units 2, 3, and 5 were shut down, effective September 30, 2009, pending a decision on appeal of the remedy order. Therefore, although Petitioner's generating properties consist of nineteen coal-fired-boilers, only sixteen of those coal-fired boilers are in service at this time.

4. **Request for Establishment of a Subdocket Proceeding to Review Cost Estimate for the IGCC Project.** The Edwardsport IGCC Project has made considerable progress in the six months since our previous filing. Construction is proceeding at an expected pace and the total project is approximately 44% complete. Yet, despite Petitioner's best efforts to rigorously manage the Edwardsport IGCC Project, we have experienced design modifications and scope growth above what was anticipated from the preliminary engineering design, adding capital costs to the Project. We are currently forecasting that the additional capital cost items will use the remaining contingency and escalation amounts in the current $2.35 billion cost estimate and add approximately $150 million, or about 6.4%, to the estimated cost of the Project. The Company is in the process of determining how this increase in capital costs will impact the total Project cost estimate, including the impact associated with additional contingency. Over the next few months, we will be examining items such as craft labor estimates, final engineering, procurement and start-up estimates to better understand the potential cost increases and how much additional contingency will be needed to complete the Project.

Petitioner is not requesting approval of an increased estimate in this semi-annual update proceeding, and there are no amounts included in this proceeding associated with the increased capital costs. Rather, Petitioner respectfully requests the establishment of a subdocket proceeding in which Petitioner will present additional evidence regarding an updated estimated cost of the Project and in which a more comprehensive review of the Project can occur. In a few months, we will be in a position where engineering for the Project will be essentially final, we will have more experience with construction on-site, and we will have an updated Integrated Resource Plan. These factors will help the Commission and the parties make a better decision regarding the updated cost estimate.

In its case-in-chief filing in such subdocket, Petitioner proposes to present evidence concerning the nature and extent of the cost pressures impacting the Project, a revised cost estimate for the Project using the most up-to-date information, and analyses using Petitioner's most recent Integrated Resource Plan. Additionally, Petitioner will present evidence of its efforts to manage the Project and the actions it has taken and will continue to take to contain the costs. Petitioner proposes that such testimony will be available for prefiling in the March 2010 timeframe. A subdocket proceeding will allow for a more detailed review on a somewhat extended procedural schedule, while allowing the semi-annual tracker proceedings to occur on a regular, more summary schedule. Petitioner proposes that the procedural schedules for the IGCC-4 tracker proceeding and the proposed subdocket proceeding be established in a prehearing conference to be set in this Cause.

5. Purpose of this Proceeding. In its November 20, 2007 Order in Cause Nos. 43114 and 43114-S1 (the "CPCN Order"), the Commission issued certificates of public convenience and necessity and clean coal technology ("CPCNs") authorizing Petitioner to construct an integrated gasification combined cycle plant in Knox County, Indiana near the location of the Company's existing Edwardsport generating station ("IGCC Project" or "Project"). The CPCN Order approved Petitioner's estimated construction cost for the IGCC Project (as presented at the hearing in June, 2007) of $1.985 billion and Petitioner's proposed Standard Contract Rider No. 61 ("IGCC Rider"), which provides for the timely recovery of costs in connection with the IGCC Project. The Commission also directed Petitioner to file semi-annual IGCC Rider and ongoing review progress report proceedings.

On May 1, 2008, Petitioner filed its first semi-annual IGCC Rider and ongoing review progress report proceeding, designated as Cause No. 43114 IGCC-1. In that proceeding, Petitioner requested and received approval on January 7, 2009 ("IGCC-1 Order") of: (1) its updated construction cost estimate of $2.350 billion and ongoing review progress report; (2) the timely recovery of construction and operating costs through the IGCC Rider reflecting actual expenditures through February 29, 2008; and (3) studies related to carbon capture at the IGCC Project and cost recovery, consistent with the order, for such studies. The IGCC-1 Order also requires Petitioner to include certain scheduling and other Project information in its ongoing IGCC progress review filings.

On November 3, 2008, Petitioner filed its second semi-annual IGCC Rider and ongoing review progress report proceeding, designated as Cause No. 43114 IGCC-2. In that proceeding, Petitioner requested and received approval on May 13, 2009 ("IGCC-2 Order") of: (1) its updated ongoing progress report for the IGCC Project, and (2) recovery under the IGCC Rider of the additional actual costs of the Project through September 30, 2008, and for certain external costs. The IGCC-2 order further specified the information Petitioner is to include in testimony or exhibits in support of its ongoing IGCC progress review filings.

On May 1, 2009, Petitioner filed its third semi-annual IGCC Rider and ongoing review progress report proceeding, designated as Cause No. 43114 IGCC-3. In that proceeding, Petitioner requested approval of: (1) the Company's updated ongoing progress report for the IGCC Project, and (2) recovery under the IGCC Rider of the additional actual costs of the Project through March 31, 2009, and for certain external costs. A hearing was held on Cause No. 43114 IGCC-3 on August 26, 2009. No decision has been issued in Cause No. 43114 IGCC-3 as of the date this Verified Petition is being filed.

The purpose of this fourth semi-annual IGCC Rider request and ongoing review progress report proceeding is to (1) request approval of the Company's updated ongoing progress report for the IGCC Project; (2) request recovery under the IGCC Rider of the additional actual costs of the Project through September 30, 2009, and for certain other applicable related costs; and (3) also request the establishment of a subdocket proceeding to provide a further review of the cost estimate for the IGCC Project.

6. <u>Edwardsport IGCC Project Status</u>. As of the end of October 2009, the engineering work for the Project is nearly 84% complete, procurement progress (including delivery of equipment and materials) is approximately 53% complete, and construction is 28% complete. Taking all these phases of the Project into account, the Project overall is approximately 44% complete.

Regarding the procurement aspect of the Project, 97% of engineered equipment orders have been placed, 96% of structural steel has been released for fabrication, and 77% of piping fabrication drawings have been released. Thousands of tons of structural steel and thousands of pipe spools have been delivered to the site. The liquid nitrogen tanks in the Air Separation Unit have been received and set on their foundations. The heat recovery steam generator ("HRSG") casings have been delivered to the site and some of the internal tube bundles have also been delivered. All sections of the radiant syngas cooler ("RSC") vessels have been delivered to the site. Many tanks, pumps, heat exchangers, compressors, chillers, and other equipment have also been delivered to the site.

At the Project site, concrete foundations are complete on most critical areas such as the gasification tower, HRSGs, gas turbines. The steam turbine pedestal is also nearing completion. As a whole, concrete work is now 46% complete and is progressing at a rate of 2% to 3% per week. Underground utility conduit and piping installation is approximately 90% complete and structural steel erection has been started, along with above-ground piping installation and tank construction. Other important construction work underway includes the cooling tower basin, water treatment foundations and tanks, the above ground pipe racks, the final assembly of the RSC vessel sections, and the transmission interconnecting switchyard. Contracts have been awarded or are in the final stages of award for all mechanical construction work and equipment erection as well as some electrical work.

The Project master schedule, as of the end of October 2009 is projecting an in-service date of July 8, 2012.

Unfortunately, as the Project moves out of the engineering phase and into full construction, certain factors, including design development growth and scope growth, have impacted the Project cost as discussed above. The Project team is working to mitigate the magnitude of the cost increase, and Duke Energy Indiana is not requesting approval of a specific Project cost estimate increase at this time in this proceeding. Rather, Petitioner is requesting the establishment of a subdocket proceeding wherein a more comprehensive review of the Project, and specifically the cost estimate of the Project, can be undertaken, as discussed above.

In its June 3, 2008 docket entry in Cause No. 43114 IGCC-1, the Commission ordered Petitioner to retain the services of Black & Veatch Corporation ("Black & Veatch") to serve as the Commission contractor for active and continuing independent oversight of the Project. Pursuant to such docket entry, Duke Energy Indiana and Black & Veatch executed an Independent Engineering Services Agreement and other necessary forms on July 31, 2008. Duke Energy Indiana continues to provide Black & Veatch with access to Project information on an ongoing basis. Black & Veatch personnel regularly visit the Project site and attend Project meetings with Petitioner, GE and Bechtel. Members of the Commission staff also regularly visit the Project site and attend Project meetings. It has been, and continues to be, Duke Energy's practice to cooperate openly with Black & Veatch and Commission staff about the Edwardsport IGCC Project engineering and construction process and its challenges.

7. **Specific Relief Sought By This Petition in This Proceeding.** Petitioner seeks: (1) approval of the Company's ongoing progress report concerning the IGCC Project; (2) Commission authorization to reflect the additional actual expenditures through September 30, 2009 for the IGCC Project under construction in its retail electric rates and authorization to recover certain other applicable related costs via the IGCC Rider consistent with the Commission's prior decisions in the CPCN Order and subsequent update cases; and (3) establishment of a subdocket proceeding for the purposes of further review of the IGCC Project, including the cost estimate.

(a). Approval of Ongoing Progress Report. Pursuant to Ind. Code § 8-1-8.5-6 and §8-1-8.7-7, Petitioner requests Commission approval of its ongoing progress report (as provided in this Verified Petition and Petitioner's testimony).

(b). IGCC Rider. Pursuant to Ind. Code § 8-1-8.8-12 and consistent with 170 I.A.C. §4-6-1 *et seq.*, Petitioner hereby requests that the Commission, for ratemaking purposes, authorize the addition of the actual expenditures for its IGCC Project made through September 30, 2009 to the value of Petitioner's property. Petitioner further requests that the Commission approve and authorize the requested rate adjustment allowing Petitioner to earn a return on said amount, in addition to the return on the value of its used and useful utility property and on its construction work in progress investment previously approved by the Commission. Petitioner also requests recovery of certain other applicable costs via the IGCC Rider, including Black & Veatch costs, depreciation, and the external costs previously approved for recovery by the Commission. These requests will be supported in testimony filed on behalf of Petitioner.

8. **Applicable Statutes and Regulations.** Petitioner considers that Ind. Code § 8-1-2-42(a), Ind. Code § 8-1-2-6.1(c), Ind. Code § 8-1-8.5 *et seq.*, Ind. Code § 8-1-8.7 *et seq.* and Ind. Code § 8-1-8.8 *et seq.*, 170 I.A.C. §4-6-1 *et seq.* among others, are or may be applicable to the subject matter of this proceeding.

9. **Petitioner's Counsel.** Kelley A. Karn and J. William DuMond at 1000 East Main Street, Plainfield, Indiana 46168 are counsel for Petitioner in this matter, and are duly authorized to accept service of papers in this Cause on behalf of Petitioner.

10. **Request for Prehearing Conference.** Petitioner respectfully requests the Commission to expeditiously convene a prehearing conference wherein the procedural schedule for this proceeding, and (if its request for a subdocket is granted) for the subdocket proceeding, may be established.

WHEREFORE, Petitioner respectfully requests that the Commission make such investigation and hold such hearings as it may deem necessary and advisable in this Cause, and thereafter make and enter an Order: (a) approving Petitioner's ongoing progress report related to its IGCC Project; (b) adding to the valuation of Petitioner's utility property the actual costs incurred through September 30, 2009 of the IGCC Project for ratemaking purposes and authorizing recovery of certain other applicable costs via Petitioner's IGCC Rider; and (c) establishment of a subdocket proceeding for the purposes of further review of the IGCC Project, including the cost estimate; (d) granting Petitioner such other and further relief in the premises as may be appropriate and proper.

Dated as of the 24th of November, 2009.

DUKE ENERGY INDIANA, INC.

By: ______________________________
Jim Stanley, President Duke Energy Indiana, Inc.

By: ______________________________
Counsel for Duke Energy Indiana, Inc.

Kelley A. Karn, Atty. No. 22417-29
J. William DuMond, Atty. No. 4634-49
Duke Energy Business Services LLC
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Telephone: (317) 838-2461
Fax: (317) 838-1842

VERIFICATION

STATE OF INDIANA)
) SS
COUNTY OF HENDRICKS)

Jim Stanley, being first duly sworn, deposes and says that he is President, Duke Energy Indiana, Inc., that he has read and executed the foregoing Verified Petition and is acquainted with the facts therein stated, and that the statements therein contained are true to the best of his information, knowledge and belief.

Jim Stanley

Before me, a Notary Public, in and for said County and State, personally appeared Jim Stanley, who acknowledged the execution of the foregoing document to be his voluntary act and deed.

Dated this 24 day of November, 2009.

Notary Public LANA J. HORNER

My Commission Expires: 4/19/2015

My County of Residence: HENDRICKS

CERTIFICATE OF SERVICE

The undersigned hereby certifies that copies of the foregoing Petition were delivered or mailed, postage prepaid, in the United States Mail, this 24th day of November 2009, to the following:

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By: Kelley A K
Counsel for Duke Energy Indiana, Inc.

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Synapse
Energy Economics, Inc.

Coal-Fired Power Plant Construction Costs

July 2008

AUTHORS
David Schlissel, Allison Smith and Rachel Wilson

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Schedule KMR2010-6

Introduction

Construction cost estimates for new coal-fired power plants are very uncertain and have increased significantly in recent years. The industry is using terms like "soaring," "skyrocketing," and "staggering" to describe the cost increases being experienced by coal plant construction projects. In fact, the estimated costs of building new coal plants have reached $3,500 per kW, without financing costs, and are still expected to increase further. This would mean a cost of well over $2 billion for a new 600 MW coal plant when financing costs are included. These cost increases have been driven by a worldwide competition for power plant design and construction resources, commodities, equipment and manufacturing capacity. Moreover, there is little reason to expect that this worldwide competition will end anytime in the foreseeable future.

Cost Estimates for Proposed Coal-Fired Power Plants

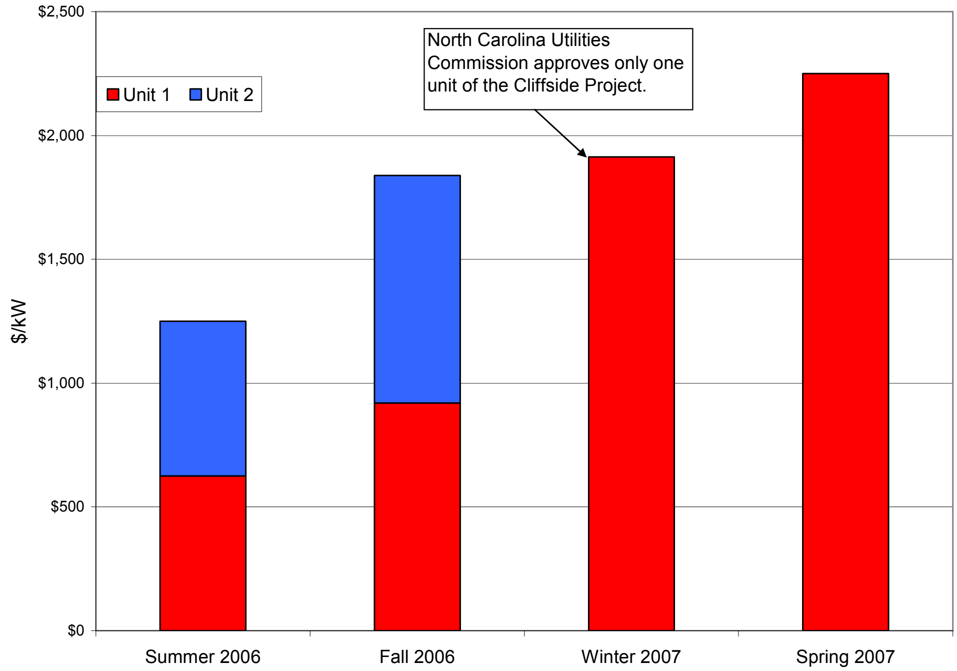
As recently as 2005, companies were saying that proposed coal-fired power plants would cost as little as $1,500/kW to $1,800/kW. However, the estimated construction costs of new coal plants have risen significantly since then.

The following examples illustrate the cost increases that proposed projects experienced in the past two or three years:

- Duke Energy Carolinas' summer 2006 cost estimate for the two unit 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 Carolina Utilities Commission refused to grant a permit for two units, Duke announced that the cost of the remaining single unit would be about $1.53 billion, not including financing costs. In late May 2007, Duke announced that the cost of building the single Cliffside unit had increased by yet another 20 percent. As a result, the estimate 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 estimated for a two unit plant only two years ago in the summer of 2006.

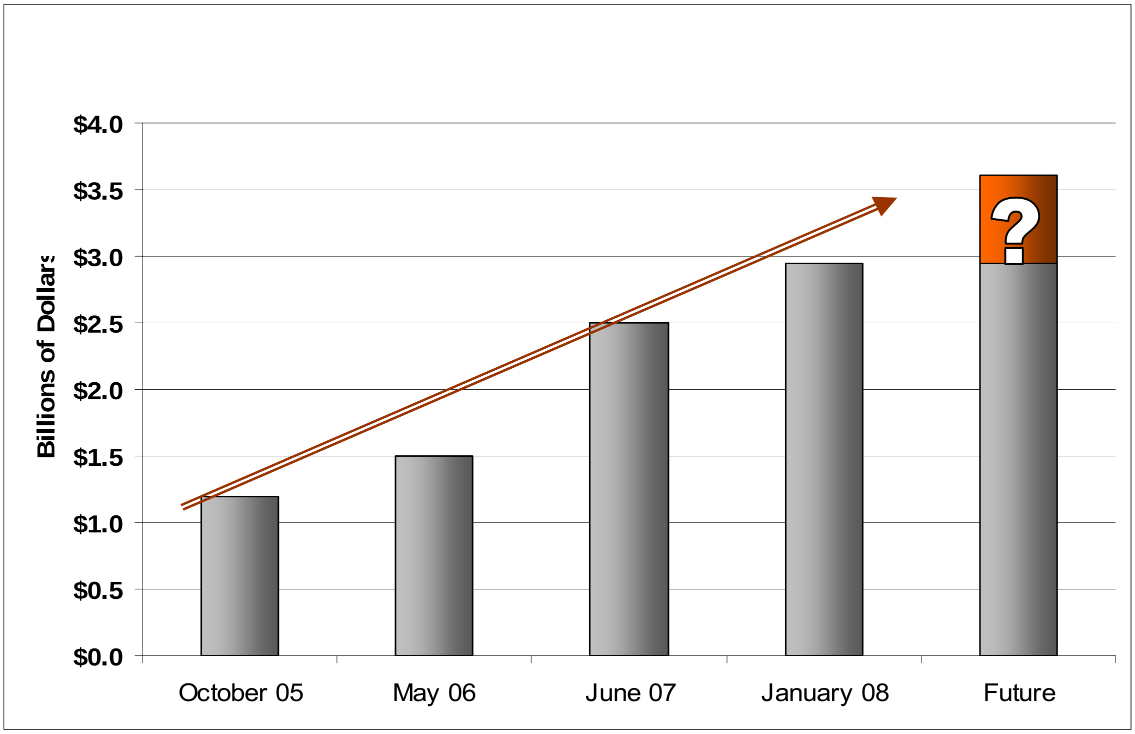
The increases in the estimated cost of the Cliffside Project are presented in Figure 1 below.

Figure 1: Duke Energy Carolinas Cliffside Project Cost Increases 2006-2007 ($/kW)



- As shown in Figure 2 below, the estimated cost of AMP-Ohio's proposed 960 MW coal-fired power plant project nearly doubled between May 2006 and January 2008. The estimated cost increased by 15 percent in just the six months between June 2007 and January 2008. The estimated cost of the 960 MW plant is currently estimated at nearly $3 billion, without any financing costs. This represents a construction cost of more than $3,100 per kW. And the available evidence suggests that plant costs will continue to rise.

Figure 2: AMP-Ohio AMPGS Cost Increases 2005-2008 ($)



- In mid-June 2008, Wisconsin Power & Light ("WPL") announced a nearly 40 percent increase in the estimated cost of its proposed 300 MW Nelson Dewey 3 coal-fired power plant. The previous estimate had been prepared in late 2006. The estimated cost for this Circulating Fluid Bed plant is above $3,500/kW, in early 2008 dollars. The company has similarly estimated that the cost of building a new supercritical coal plant also would exceed $3,500/kW. In support of its new cost estimates, WPL presented testimony that noted that "EPC [Engineering, Procurement and Construction] pricing for other non-IGCC, primarily coal-fired generating projects under construction or in the planning stages have similarly increased with many projects falling in the $2,500 to $3,800/kW range, without AFUDC or uncommon owner's costs (e.g., major railway additions.)."[1]
- In April 2008, Duke Energy Indiana announced an 18 percent increase in the estimated cost of its proposed Edwardsport coal plant just since the spring of 2007. Duke said that "the increase in the cost estimate is driven by factors outside the Company's control, including unprecedented global competition for commodities, engineered equipment and materials, and increased labor costs."[2] Duke noted in its Petition to the Indiana Utility Regulatory Commission that this

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1 Direct Testimony of Charles J. Hookham on behalf on Wisconsin Power & Light Company in Public Service Commission of Wisconsin Docket No. 6680-CE-170, June 2008, at page 21.

2 Verified Petition in Indiana Utility Regulatory Commission Cause No. 43114 IGCC-1, filed on May 1, 2008, at pages 3-4

> projected increase in cost “is consistent with other recent power plant project cost increases across the country.”[3]

Nor are coal-fired power plants that are under construction immune to further cost increases. For example, Kansas City Power & Light just announced a 15 percent price increase for the Iatan 2 power plant that has been under construction for several years and is scheduled to be completed by 2010. This shows that one cannot assume that the cost of a plant will be fixed when construction begins.

Indeed, in the past utilities were able to secure fixed-price contracts for their power plant construction projects. However, it is not possible to obtain fixed-price contracts for new power plant projects in the present environment. The reasons for this change in circumstances has been explained as follows by a witness for the Appalachian Power Company, a subsidiary of American Electric Power in testimony before the West Virginia Public Service Commission:

> Company witness Renchek discusses in his testimony the rapid escalation of key commodity prices in the [Engineering, Procurement and Construction] industry. **In such a situation, no contractor is willing to assume this risk for a multi-year project.** Even if a contractor was willing to do so, its estimated price for the project would reflect this risk and the resulting price estimate would be much higher.[4] [Emphasis added.]

A fall 2007 assessment of AMP-Ohio’s proposed coal-fired power plant similarly noted that the reviewing engineers from Burns and Roe Enterprises:

> agree that the fixed price turnkey EPC contract is a reasonable approach to executing the project. However, the viability of obtaining a contract of this type is not certain. The high cost of the EPC contract, in excess of $2 billion, significantly reduces the number of potential contractors even when teaming of engineers, constructors and equipment suppliers is taken into account. Recent experience on large U.S. coal projects indicates that the major EPC Contractors are not willing to fix price the entire project cost. This is the result of volatile costs for materials (alloy pipe, steel, copper, concrete) as well as a very tight construction labor market. When asked to fix the price, several EPC Contractors have commented that they are willing to do so, but the amount of money to be added to cover potential risks of a cost overrun would make the project uneconomical.[5]

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3 Id, at page 7.

4 Ibid, at page 16, lines 16-20.

5 *Consulting Engineer’s Report for the American Municipal Power Generating Station located in Meigs County, Ohio*, for the Division of Cleveland Public Power, Burns and Roe Enterprises, Inc., October 16, 2007, at page 11-1.

In fact, rising commodity prices and increasing construction cost risks have been responsible, at least in part, for the cancellation or delay of more than fifty proposed coal-fired power plants since mid-2006. The following examples are illustrative of the factors and risks which have contributed to these cancellations and delays:

- Tenaska Energy cancelled plans to build a coal-fired power plant in Oklahoma in 2007 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."[6]

- 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 of 20 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."[7] As a result, Westar Energy 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 company also explained that:

  > most major engineering firms and equipment manufacturers of coal-fueled power plant equipment are at full production capacity and yet are not indicating any plans to significantly increase their production capability. As a result, fewer manufacturers and suppliers are bidding on new projects and equipment prices have escalated and become unpredictable.[8]

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6 Available at www.swtimes.com/articles/2007/07/09/news/news02.prt.

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

8 Id.

The increases in construction costs being experienced by proposed coal-fired power plants are due, in large part, to a significant increase in the worldwide demand for power plant design and construction resources, commodities and equipment. This worldwide competition is driven mainly by huge demands for power plants in China and India, 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, and by the competition for resources from the petroleum refining industry.

The limited capacity of EPC firms and equipment manufacturers also has contributed to rising power plant construction costs. This has meant fewer bidders for work, higher prices, earlier payment schedules and longer delivery times. The demand for and cost of both on-site construction labor and skilled manufacturing labor also have escalated significantly in recent years.

In addition, the planned construction of new nuclear power plants is expected to compete for limited power plant design and construction resources, manufacturing capacity and commodities.

It is reasonable to expect that the factors that have led to skyrocketing power plant construction costs in recent years will lead to further increases in costs and construction delays in the five or more years before the projects are scheduled to be completed. For example, a May 15, 2008 story in the Wall Street Journal noted that “escalating steel prices are halting and slowing major construction projects worldwide and limiting shipbuilding and oil and gas exploration.” The same article noted that “Steel prices are up 40 percent to 50 percent since December, and industry executives say they have not reached a peak” and “raw materials prices have surged in the past year, fueled in part because of the rapid industrialization of China, India and other developing nations.”

Indeed, there is no reason to expect that the worldwide competition for resources or the existing supply constraints and bottlenecks affecting coal-fired plant construction costs will clear anytime in the foreseeable future.

The Virginia State Corporation Commission denied the request of Appalachian Power Company to build a coal-fired power plant in West Virginia. The Commission found that the proposal was neither “reasonable” nor “prudent.” In its order denying the request to build the new coal-fired power plant, the Virginia Commission also found that the Company’s cost estimate for the project was not credible and that the Company had not updated its cost estimate since November 2006. The Commission further noted that the Company (“APCo”) will not obtain actual or firm prices for components of the project until after receiving regulatory approval.[9] The Virginia Commission Final Order included the following language concerning risk: “Indeed APCo has no fixed price contract for any appreciable portion of the total construction costs; there are no meaningful price or performance guarantees or controls for this project at this time. This represents an extraordinary risk that we cannot allow the ratepayers of Virginia in [Appalachian Power

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9 April 14, 2008 Final Order of the Virginia State Corporation Commission in Case No. PUE-2007-00068, at page 5.

Company's] service territory to assume." This is the very same "extraordinary" risk that the customers and ratepayers of investor-owned companies and publicly-owned utilities building new coal-fired power plants are being asked to assume because there are no fixed prices or contracts for the projects.

Finally, there is no currently commercially available technology for post-combustion capture of carbon dioxide from pulverized coal power plants. Moreover, it is estimated that such technology may not be commercially available until 2020 or 2030, if then. However, it is expected that the addition of carbon capture and sequestration technology will greatly increase the cost of generating power at coal-fired power. In fact, a number of independent sources agree, as illustrated in Table 1 below, that adding and operating CCS equipment will raise the cost of generating electricity at new coal-fired power plants by perhaps as much as 60% to 80%.

Table 1: Projected Increase in the Cost of Generating Power Due to Carbon Capture and Sequestration

Source	Projected Increase in Cost of Electricity from Addition of CCS
Duke Energy Indiana[10]	68%
MIT Future of Coal Report[11]	61%
Edison Electric Institute[12]	75%
National Energy Technology Laboratory[13]	81%

10 Testimony of James E. Rogers in Indiana Utility Regulatory Commission Cause No. 43114, Joint Petitioners' Exhibit No. 1, at page 13, lines 6-11.

11 *The Future of Coal*, *Options for a Carbon-Constrained World*, Massachusetts Institute of Technology, 2007, at page 19.

12 Letter to Hon. Edward J. Markey, Chairman, Select Committee on Energy Independence and Global Warming, from Thomas R. Kuhn, Edison Electric Institute, September 21, 2007, at page 4.

13 *Cost and Performance Baseline for Fossil Energy Plants*, *Revised August 2007,* DOE/NETL – 2007/1281, at page 17.

THE WALL STREET JOURNAL.
WSJ.com

MAY 15, 2008

Fast-Rising Steel Prices Set Back Big Projects

ArcelorMittal's Net Rises but Shipyards, Builders Feel Pinch

By ROBERT GUY MATTHEWS

Relentless increases in the price of steel are halting or slowing major construction projects world-wide and investments in shipbuilding and oil-and-gas exploration, setting the stage for a potential backlash against steelmakers.

Lakshmi N. Mittal

In Turkey, a construction association said this week it will begin a 15-day strike in eigh cities Thursday to press steelmakers to cut their prices, which have more than doubled locally since late last year.

In New Delhi, India, an ambitious bridge project has been put on hold because of steel related cost overruns, and contractors are postponing or reining in construction of much-needed housing for the poor, prompting the Indian government to freeze steel prices for the next three months.

Venezuela, aiming to control prices, renationalized its largest steelmaker and is limitin exports. Oil executives in the U.S., meanwhile, say costly steel is threatening their energy exploration efforts.

Globally, steel prices are up 40% to 50% since December, and industry executives say they haven't hit their peak. On Wednesday, ArcelorMittal, the world's largest steelmaker by volume, boosted prices by €120 ($186), or 20%, a metric ton in Europe, citing increases in its own costs -- from iron ore to energy and transportation.

"We have not yet seen that prices have peaked, what we have seen is the cos increasing every month," said ArcelorMittal Chief Executive Lakshmi Mittal on a conference call with reporters.

Iron-ore prices have risen 71% this year. Two other crucial steelmaking ingredients, coking coal and scrap steel, ha doubled in price. The run-ups are part of a broader surge in raw-materials prices amid tight supplies and soaring global demand, fueled in part by the rapid industrialization of China, India and other developing nations.

ArcelorMittal said Wednesday that its earnings grew 5.4% to $2.37 billion in the first quarter from $2.25 billion a year earlier. Both sales and shipments grew sharply as the Luxembourg-based company sold more steel in emergin markets.

The world's voracious appetite for steel shows little sign of easing. In Turkey, a new shipyard, once completed, will

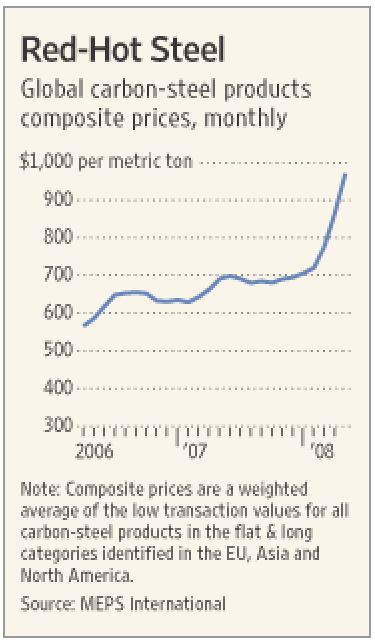
Schedule KMR2010-7

Associated Press

A ladle skims slag off of iron before it is poured into the basic oxygen furnace to be converted to steel.

need 100,000 tons of steel a year. And demand in the U.S. is rising, despite a sluggish economy.

While still in a position of pricing power, steelmakers are concerned that over time, their high prices will affect sales. "There will be impact on demand, and that is not a good development for the steel industry," said Aditya Mittal, chief financial officer of ArcelorMittal, on a separate conference call.



As a result, steelmakers are taking steps to cut their costs. To shield themselves from higher raw-material prices, more of them are acquiring their own iron-ore and coal mines or deposits, as well as producers of scrap steel. Nippon Steel Corp. and other Japanese steelmakers announced this month that they would accelerate cost-cutting efforts, which could include layoffs and developing cheaper steel substitutes.

The industry is also consolidating, which should allow producers to become more efficient and gain economies of scale that could ultimately result in more pricing stability and fewer, larger players. In recent months, India's Tata Steel Ltd. and Essar Steel Holdings Ltd. have made major acquisitions, as have Russia's Evraz Group SA and Sweden's SSAB Svenskt Stl AB. Even so, the world's top-five steelmakers still account for just 18% of the world's steel supplies.

Some steelmakers also are experimenting with ways to make their products less expensive, in an effort to keep customers from switching to less-expensive substitutes like aluminum or high-strength plastics. Finnish stainless-steel maker Outokumpu Oyj, which makes steel for appliances, has come up with a way to reduce the nickel content of its stainless steel to make it cheaper.

But until such changes take hold, steel prices will likley continue to increase.

Builders recently warned officials in Turkey, which rests in an earthquake zone, that rising steel prices have prompted some contractors to use cheaper, inferior-grade steel, threatening the quality of their buildings.

Some nations, meanwhile, are hoarding steel by erecting export barriers. Last week, India imposed a 15% duty on exported steel. Countries that don't make enough of the metal are slashing import taxes in an effort to attract more. Last month, Iran announced it was lowering its import tax on rebar steel, used in new buildings and roads, to 9% from 20%.

The impact of high steel prices is rippling through industries from shipbuilding to energy exploration. Shipbuilders, who buy vast quantities of high-end plate steel are getting hammered, and analysts say steel-supply problems are slowing the pace of construction, especially at smaller shipyards like South Korea's Daewoo Shipbuilding & Marine Engineering Co.

In April, an executive of Royal Dutch Shell PLC told a House committee that steel, which is needed to make drilling equipment and pipelines, and other raw-material costs were hampering efforts to find new energy sources. These costs "are a major challenge for oil and gas companies and are contributing to the delays and postponements of many projects," according to Cambridge Energy Research Associates, a leading energy-research company.

Cellphone users could eventually feel the pinch. Eric Steinmann, development manager at wireless carrier NTCH Inc., which operates under the Clear Talk brand, says steel costs for each of the about 100 cellphone tower poles his company builds annually doubled to about $30,000 last year.

Robert Griggs, owner of Missouri-based Trinity Products Inc., a maker of steel pipes, tubes and rebar for bridges, said he tells his customers he can only guarantee prices for two weeks. Last year, it took six months for steel prices to rise $100 a ton, he said. Now, prices are moving that much in a month.

Shifting to lower cost materials isn't an easy option for steel buyers, either. It takes years to retool auto and appliance stamping and dye machines, currently engineered for steel products. Also the cost of alternatives, such as aluminum and certain plastics, is increasing.

Write to Robert Guy Matthews at robertguy.matthews@wsj.com

Printed in The Wall Street Journal, page B1

Construction Costs for New Power Plants Continue to Escalate: IHS CERA Power Capital Costs Index

May 27, 2008

Costs have risen 130% since 2000; poised to rise higher in the coming year

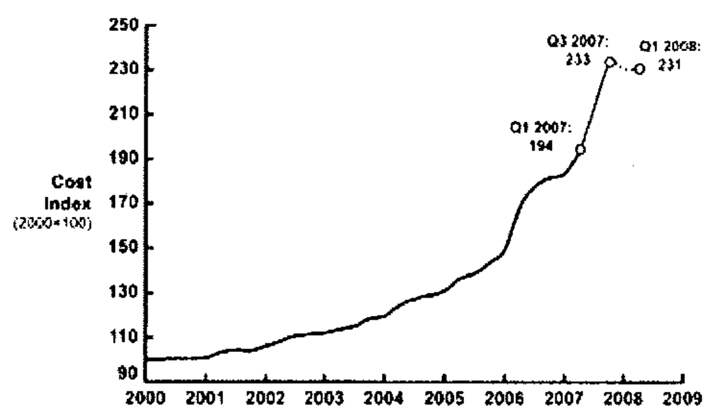
Press Release

CAMBRIDGE, MA (May 27, 2008) – The costs of building new power plants have more than doubled since 2000, according to the most recent IHS CERA Power Capital Costs Index (PCCI). The latest IHS CERA PCCI shows that the cost of new power plant construction in North America has risen 130 percent in the last eight years. A majority of this cost increase has occurred since 2005, with the index rising 69 percent since then.

The IHS CERA PCCI – which tracks the costs of building coal, gas, wind and nuclear power plants indexed to the year 2000 – is a proprietary measure of project cost inflation similar in concept to the Consumer Price Index (CPI). The IHS CERA PCCI now registers 231 index points, indicating a power plant that cost $1 billion in 2000 would, on average, cost $2.31 billion today.

The latest IHS CERA PCCI indicates a one percent drop in the first quarter of 2008. However, the miniscule drop in the index does not signal a change in the long-term factors that have been driving up costs. The decrease was driven solely by one narrow factor—an easing of nuclear equipment costs as a result of market volatility which has been driven by high global demand. Recent results of the IHS CERA PCCI show that the costs for all other power plants, such as those powered by coal, gas and wind, continued to rise.

IHS/CERA Power Capital Costs Index (PCCI)



Source: Cambridge Energy Research Associates

Wind has shown the largest increase at six percent since the third quarter of 2007 and 108 percent since 2000 in response to increased demand for wind turbines which has pushed up equipment costs and time to deliver, and is compounded with increasing labor and construction costs.

- Gas has increased by three percent since the third quarter of 2007 and 92 percent since 2000. This has been driven by manufacturers' response to increased demand for gas turbine costs, as costs increase and lead times continue to extend for equipment delivery. Additional escalation can be attributed to continued increases in labor, engineering and construction costs.
- Coal has increased in cost by 2.3 percent since the third quarter of 2007 and 78 percent since 2000. Strong international demand for boilers has sustained high cost levels. There has also been high demand for scrubbers in the United States as clean air provisions push utilities to retrofit their coal facilities in order to comply with the 2010 regulations.

"While the index has shown a small drop in the past six months, there are no signs that this is the start of a downward trend," said Candida Scott, CERA senior director of cost and technology. "The

Schedule KMR2010-8

fundamentals that have driven costs upward for the past eight years—supply constraints, increasing wages and rising materials costs—remain in place and will continue during 2008."

Additional factors, such as rising prices for commodities such as steel, nickel and copper, could soon drive costs up further, added Paul Bachmuth, CERA associate director of capital cost power.

"Renegotiated prices for iron ore contracts and supply disruptions of coking coal raise serious concern for cost increases in steel in excess of 50 percent in 2008 if all costs are passed through to the end consumer," Bachmuth said. "Combined with the escalating cost of diesel impacting transportation for all materials, the power industry is set to see costs rise higher in 2008."

"Timely decisions on fuel choice—what type of power plants to build and when to build them—are critical to keep the lights on, limit power price increases and manage carbon emissions," added Jone-Lin Wang, CERA managing director of global power group. "Understanding what's driving the dramatic cost escalation will go a long way toward making efficient decisions,"

Continuing Pressures

Demand for new power generation facilities remains high worldwide, leading to continued tightness in equipment markets. Cost increases, supply issues and longer delivery times are exacerbated as manufacturers struggle to keep up with demand. The weakening U.S. dollar also increases the costs of global procurement for equipment and materials.

The number of engineers in the workforce is also declining as older workers retire and are not being replaced. The resulting shortages in plant design teams add additional delays to construction schedules. The current increase in construction for nuclear power generation and the dearth of experienced nuclear engineers in North America has been a key driver behind cost escalation.

Recent cancellations of proposed coal plants in the United States due to uncertainty over environmental regulations has provided some slowing in cost increases in the U.S. coal industry. However, international competition for coal boilers, particularly in Southeast Asia, is keeping the equipment order books very active.

Concerns over a looming U.S. recession and subsequent cut backs in residential construction have offered little relaxation to power construction. The residential slump does not free up the skilled workers required in the power industry and there is no overlap of the specialist metals and equipment required.

Energy Industry Capital Costs

The IHS CERA PCCI complements the IHS CERA Upstream Capital Costs Index (UCCI) and IHS CERA Downstream Capital Cost Index (DCCI) which measures the cost of construction of new oil and gas production projects such as platforms and pipelines and construction of new refineries and petrochemical plants. Both indices demonstrate the dramatic impact rapidly rising costs are having on the energy industry.

####

About the IHS CERA Power Capital Costs Index (PCCI)

The IHS CERA PCCI tracks the costs of equipment, facilities, materials and personnel (both skilled and unskilled) used in the construction of a geographically diversified portfolio of more than 30 power generation construction projects throughout North America. It is similar to the consumer price index (CPI) in that it provides a clear, transparent benchmark tool for tracking and forecasting a complex and dynamic environment. The IHS CERA PCCI can be tracked on the IHS Index Web Site at www.ihsindexes.com. The IHS CERA PCCI is a work product of CERA's Capital Costs Analysis Forum for Power (CCAF-P) in partnership with PowerAdvocate. For information on the Capital Costs Analysis Forum for Power , contact Candida Scott at cscott@cera.com.

About CERA (www.cera.com)

Cambridge Energy Research Associates (CERA), an IHS company, is a leading advisor to energy companies, consumers, financial institutions, technology providers and governments. CERA (www.cera.com) delivers strategic knowledge and independent analysis on energy markets, geopolitics, industry trends, and strategy. CERA is based in Cambridge, MA, and has offices in Bangkok, Beijing, Calgary, Dubai, Johannesburg, Mexico City, Moscow, Mumbai, Oslo, Paris, Rio de Janeiro, San Francisco, Tokyo and Washington, DC.

About IHS (www.ihs.com)

IHS (NYSE: IHS) is a leading global source of critical information and insight for customers in a broad range of industries. Our customer product and service solutions span four major areas of information: energy, product lifecycle management, environmental and security. By focusing on our customers first, we deliver data and expertise that enable innovative and successful decision-making. Customers range from governments and multinational companies to smaller companies and technical professionals in more than 180 countries. IHS has been in business since 1959 and employs more than 3,500 people in 35 locations around the world.

Rising Utility Construction Costs:

Sources and Impacts

Prepared by:

Marc W. Chupka
Gregory Basheda

The Brattle Group

Prepared for:

The EDISON FOUNDATION

SEPTEMBER 2007

Schedule KMR2010-9

The Edison Foundation is a nonprofit organization dedicated to bringing the benefits of electricity to families, businesses, and industries worldwide.

Furthering Thomas Alva Edison's spirit of invention, the Foundation works to encourage a greater understanding of the production, delivery, and use of electric power to foster economic progress; to ensure a safe and clean environment; and to improve the quality of life for all people.

The Edison Foundation provides knowledge, insight, and leadership to achieve its goals through research, conferences, grants, and other outreach activities.

The Brattle Group

The Brattle Group provides consulting services and expert testimony in economics, finance, and regulation to corporations, law firms, and public agencies worldwide. Our principals are internationally recognized experts, and we have strong partnerships with leading academics and highly credentialed industry specialists around the world.

The Brattle Group has offices in Cambridge, Massachusetts; San Francisco; Washington, D.C.; Brussels; and London.

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Table of Contents

Introduction and Executive Summary

In *Why Are Electricity Prices Increasing? An Industry-Wide Perspective* (June 2006), *The Brattle Group* identified fuel and purchased-power cost increases as the primary driver of the electricity rate increases that consumers currently are facing. That report also noted that utilities are once again entering an infrastructure expansion phase, with significant investments in new baseload generating capacity, expansion of the bulk transmission system, distribution system enhancements, and new environmental controls. The report concluded that the industry could make the needed investments cost-effectively under a generally supportive rate environment.

The rate increase pressures arising from elevated fuel and purchased power prices continue. However, another major cost driver that was not explored in the previous work also will impact electric rates, namely, the substantial increases in the costs of building utility infrastructure projects. Some of the factors underlying these construction cost trends are straightforward—such as sharp increases in materials cost—while others are complex, and sometimes less transparent in their impact. Moreover, the recent rise in many utility construction cost components follows roughly a decade of relatively stable (or even declining) real construction costs, adding to the "sticker shock" that utilities experience when obtaining cost estimates or bids and that state public utility commissions experience during the process of reviewing applications for approvals to proceed with construction. While the full rate impact associated with construction cost increases will not be seen by customers until infrastructure projects are completed, the issue of rising construction costs currently affects industry investment plans and presents new challenges to regulators.

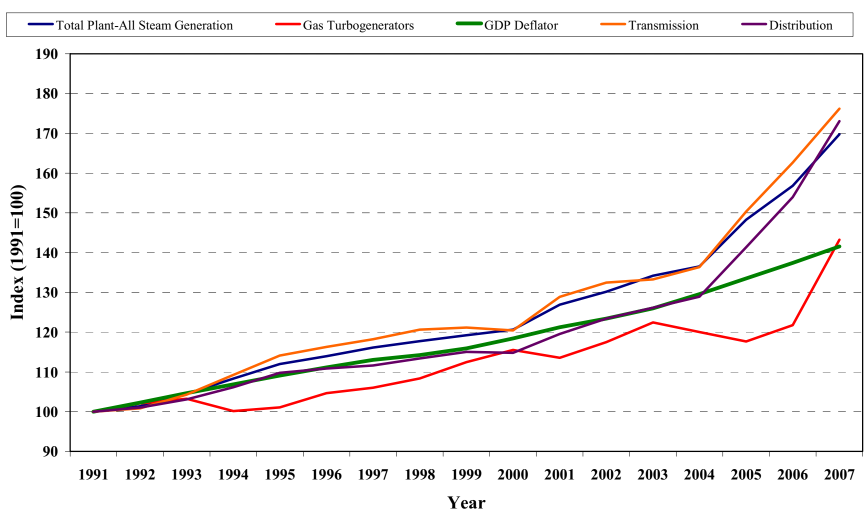
The purpose of this study is to a) document recent increases in the construction cost of utility infrastructure (generation, transmission, and distribution), b) identify the underlying causes of these increases, and c) explain how these increased costs will translate into higher rates that consumers might face as a result of required infrastructure investment. This report also provides a reference for utilities, regulators and the public to understand the issues related to recent construction cost increases. In summary, we find the following:

- 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 projected 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 firms, 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. Large proposed transmission projects have undergone cost revisions, and distribution system equipment costs have been rising rapidly. This is seen in Figure ES-1, which shows recent price trends in generation, transmission and distribution infrastructure costs based on the Handy-Whitman Index© data series, compared with the general price level as measured by the gross domestic product (GDP) deflator over the same time period.[1] As shown in Figure ES-1, infrastructure costs were relatively stable during the 1990s, but have experienced substantial price increases in the past several years. Between January 2004 and January 2007, the costs of steam-generation plant, transmission projects and distribution equipment rose by 25 percent to 35 percent (compared to an 8 percent increase in the GDP deflator). For example, the cost of gas turbines, which was fairly steady in the early part of the decade, increased by 17 percent during the year 2006 alone. 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.

Figure ES-1
National Average Utility Infrastructure Cost Indices



Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indexes for the specified components.

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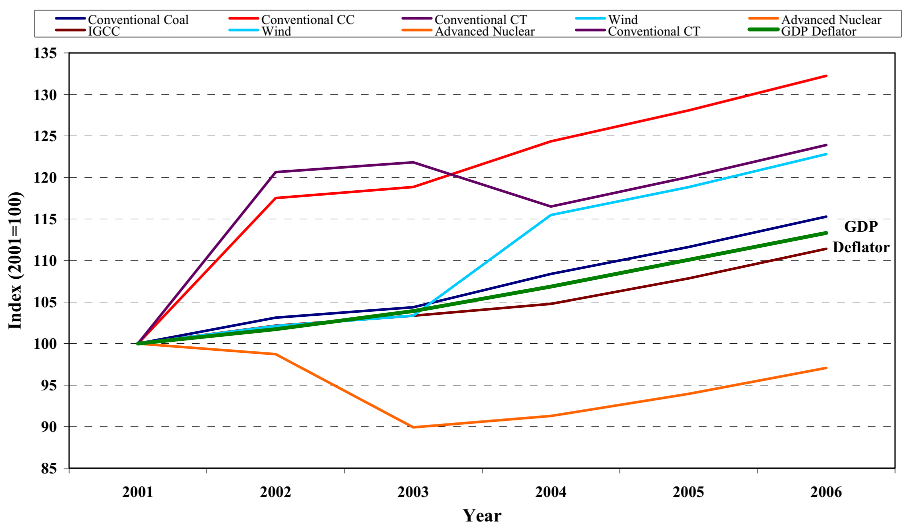
[1] The GDP deflator measures the cost of goods and services purchased by households, industry and government, and as such is a broader price index than the Consumer Price Index (CPI) or Producer Price Index (PPI), which track the costs of goods and services purchased by households and industry, respectively.

- 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 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 in order to reduce the future rate impacts on consumers.
- Despite the overwhelming evidence that construction costs have risen and will be elevated for some time, these increased costs are largely absent from the capital costs specified in the Energy Information Administration's (EIA's) 2007 *Annual Energy Outlook* (AEO). The AEO generation capital cost assumptions since 2001 are shown in Figure ES-2. Since 2004, capital costs of all technologies are assumed to grow at the general price level—a pattern that contradicts the market evidence presented in this report. The growing divergence between the AEO data assumptions and recent cost escalation is now so substantial that the AEO data need to be adjusted to reflect recent cost increases to provide reliable indicators of current or future capital costs.

Figure ES-2
EIA Generation Construction Cost Estimates



Sources: Data collected from the U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

Projected Investment Needs and Recent Infrastructure Cost Increases

Current and Projected U.S. Investment in Electricity Infrastructure

The electric power industry is a very capital-intensive industry. The total value of generation, transmission and distribution infrastructure for regulated electric utilities is roughly $440 billion (property in service, net of accumulated depreciation and amortization), and capital expenditures are expected to exceed $70 billion in 2007.[2] Although the industry as a whole is always investing in capital, the rate of capital expenditures was relatively stable during the 1990s and began to rise near the turn of the century. As shown in *Why Are Electricity Prices Increasing? An Industry-Wide Perspective* (June 2006), utilities anticipate substantial increases in generation, transmission and distribution investment levels over the next two decades. Moreover, the significant need for new electricity infrastructure is a world-wide phenomenon: According to the *World Energy Investment Outlook 2006*, investments by power-sector companies throughout the world will total about $11 trillion dollars by 2030.[3]

Generation

As of December 31, 2005, there were 988 gigawatts (GW) of electric generating capacity in service in the U.S., with the majority of this capacity owned by electric utilities. Close to 400 GW of this total, or 39 percent, consists of natural gas-fired capacity, with coal-based capacity comprising 32 percent, or slightly more than 300 GW, of the U.S. electric generation fleet. Nuclear and hydroelectric plants comprise approximately 10 percent of the electric generation fleet. Approximately 49 percent of energy production is provided by coal plants, with 19 percent provided by nuclear plants. Natural gas-fired plants, which tend to operate as intermediate or peaking plants, also provided about 19 percent of U.S. energy production in 2006.

The need for installed generating capacity is highly correlated with load growth and projected growth in peak demand. According to EIA's most recent projections, U.S. electricity sales are expected to grow at an annual rate of about 1.4 percent through 2030. According to the North American Electric Reliability Corporation (NERC), U.S. non-coincident peak demand is expected to grow by 19 percent (141 GW) from 2006 to 2015. According to EIA, utilities will need to build 258 GW of new generating capacity by 2030 to meet the

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[2] Net property in service figure as of December 31, 2006, derived from Federal Energy Regulatory Commission (FERC) Form 1 data compiled by the Edison Electric Institute (EEI). Gross property is roughly $730 billion, with about $290 billion already depreciated and/or amortized. Annual capital expenditure estimate is derived from a sample of 10K reports surveyed by EEI.

[3] Richard Stavros. "Power Plant Development: Raising the Stakes." *Public Utilities Fortnightly*, May 2007, pp. 36-42.

projected growth in electricity demand and to replace old, inefficient plants that will be retired. EIA further projects that coal-based capacity, that is more capital intensive than natural gas-fired capacity which dominated new capacity additions over the last 15 years, will account for about 54 percent of total capacity additions from 2006 to 2030. Natural gas-fired plants comprise 36 percent of the projected capacity additions in *AEO 2007*. EIA projects that the remaining 10 percent of capacity additions will be provided by renewable generators (6 percent) and nuclear power plants (4 percent). Renewable generators and nuclear power plants, similar to coal-based plants, are capital-intensive technologies with relatively high construction costs but low operating costs.

High-Voltage Transmission

The U.S. and Canadian electric transmission grid includes more than 200,000 miles of high voltage (230 kV and higher) transmission lines that ultimately serve more than 300 million customers. This system was built over the past 100 years, primarily by vertically integrated utilities that generated and transmitted electricity locally for the benefit of their native load customers. Today, 134 control areas or balancing authorities manage electricity operations for local areas and coordinate reliability through the eight regional reliability councils of NERC.

After a long period of decline, transmission investment began a significant upward trend starting in the year 2000. Since the beginning of 2000, the industry has invested more than $37.8 billion in the nation's transmission system. In 2006 alone, investor-owned electric utilities and stand-alone transmission companies invested an historic $6.9 billion in the nation's grid, while the Edison Electric Institute (EEI) estimates that utility transmission investments will increase to $8.0 billion during 2007. A recent EEI survey shows that its members plan to invest $31.5 billion in the transmission system from 2006 to 2009, a nearly 60-percent increase over the amount invested from 2002 to 2005. These increased investments in transmission are prompted in part by the larger scale of base load generation additions that will occur farther from load centers, creating a need for larger and more costly transmission projects than those built over the past 20 years. In addition, new government policies and industry structures will contribute to greater transmission investment. In many parts of the country, transmission planning has been formally regionalized, and power markets create greater price transparency that highlights the value of transmission expansion in some instances.

NERC projects that 12,873 miles of new transmission will be added by 2015, an increase of 6.1 percent in the total miles of installed extra high-voltage (EHV) transmission lines (230 kV and above) in North America over the 2006 to 2015 period. NERC notes that this expansion lags demand growth and expansion of generating resources in most areas. However, NERC's figures do not include several major new transmission projects proposed in the PJM Interconnection LLC, such as the major new lines proposed by American Electric Power, Allegheny Power, and Pepco.

Distribution

While transmission systems move bulk power across wide areas, distribution systems deliver lower-voltage power to retail customers. The distribution system includes poles, as well as metering, billing, and other related infrastructure and software associated with retail sales and customer care functions. Continual investment in distribution facilities is needed, first and foremost, to keep pace with growth in customer demand. In real terms, investment began to increase in the mid-1990s, preceding the corresponding boom in generation. This steady climb in investment in distribution assets shows no sign of diminishing. The need to replace an aging infrastructure, coupled with increased population growth and demand for power quality and customer service, is continuing to motivate utilities to improve their ultimate delivery system to customers.

Continued customer load growth will require continued expansion in distribution system capacity. In 2006, utilities invested about $17.3 billion in upgrading and expanding distribution systems, a 32-percent increase over the investment levels incurred in 2004. EEI projects that distribution investment during 2007 will again exceed $17.0 billion. While much of the recent increase in distribution investment reflects expanding physical infrastructure, a substantial portion of the increased dollar investment reflects the increased input costs of materials and labor to meet current distribution infrastructure needs.

Construction Costs for Recently Completed Generation

The majority of recently constructed plants have been either natural gas-fired or wind power plants. Both have displayed increasing real costs for several years. Since the 1990s, most of the new generating capacity built in the U.S. has been natural gas-fired capacity, either natural gas-fired combined-cycle units or natural gas-fired combustion turbines. Combustion turbine prices recently rose sharply after years of real price decreases, while significant increases in the cost of installed natural gas combined-cycle combustion capacity have emerged during the past several years.

Using commercially available databases and other sources, such as financial reports, press releases and government documents, *The Brattle Group* collected data on the installation cost of natural gas-fired combined-cycle generating plants built in the U.S. during the last major construction cycle, defined as generating plants brought into service between 2000 and 2006. We estimated that the average real construction cost of all natural gas-fired combined-cycle units brought online between 2000 and 2006 was approximately $550/kilowatt (kW) (in 2006 dollars), with a range of costs between $400/kW to approximately $1,000/kW. Statistical analysis confirmed that real installation cost was influenced by plant size, the turbine technology, the NERC region in which the plant was located, and the commercial online date. Notably, we found a positive and statistically significant relationship between a plant's construction cost and its online date, meaning that, everything else equal, the later a plant was brought online, the higher its real installation cost.[4] Figure 1 shows the average yearly installation cost, in *nominal* dollars, as predicted by the regression analysis.[5] This figure shows that the average installation cost of combined-cycle units increased gradually from 2000 to 2003, followed by a fairly significant increase in 2004 and a very significant escalation—more than $300/kW—in 2006. This provides vivid evidence of the recent sharp increase in plant construction costs.

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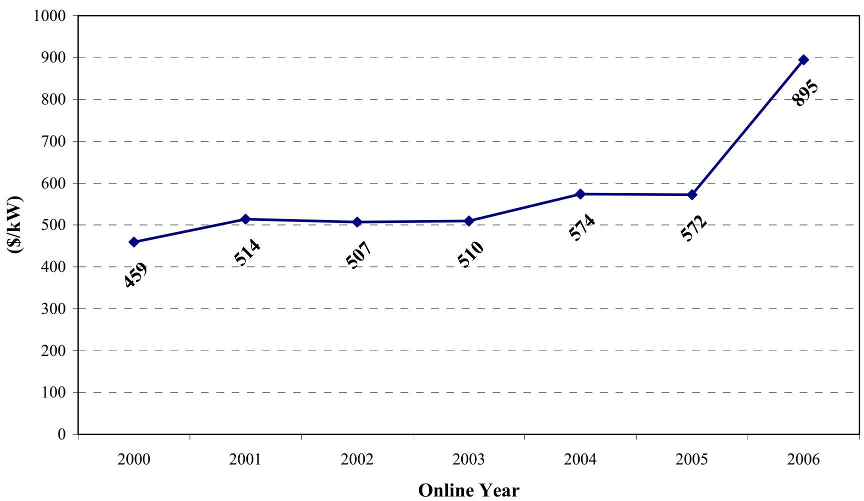
[4] To be precise, we used a "dummy" variable to represent each year in the analysis. The year-specific dummy variables were statistically significant and uniformly positive; *i.e.*, they had an upward impact on installation cost.

[5] The nominal form regression results are discussed here to facilitate comparison with the GDP deflator measure used to compare other price trends in other figures in this report.

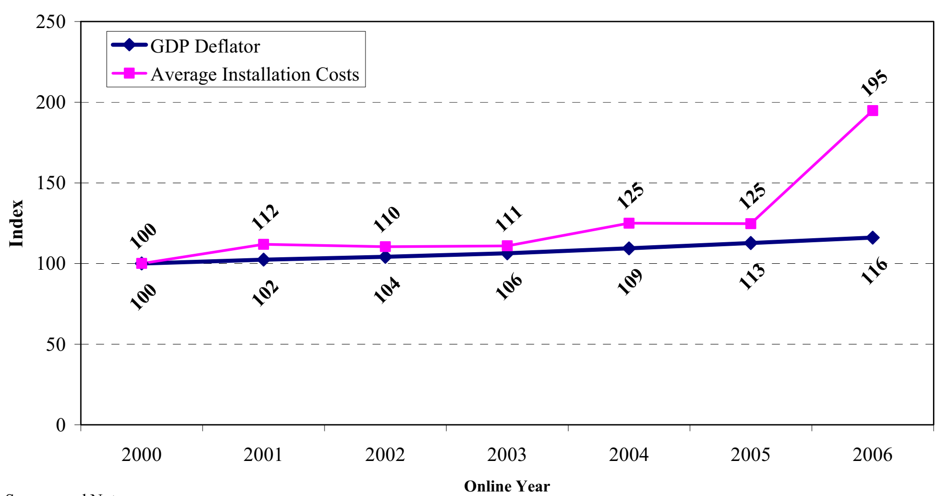
Figure 1
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year ($/kW)



Sources and Notes:
* Data on summer capacity, total installation cost , turbine technology, commercial online date, and zip code for the period 2000-2006 were collected from commercially available databases and other sources such as company websites and 10k reports.

Figure 2 compares the trend in plant installation costs to the GDP deflator, using 2000 as the base year. Over the period of 2000 to 2006, the cumulative increase in the general price level was 16 percent while the cumulative increase in the installation cost of new combined-cycle units was almost 95 percent, with much of this increase occurring in 2006.

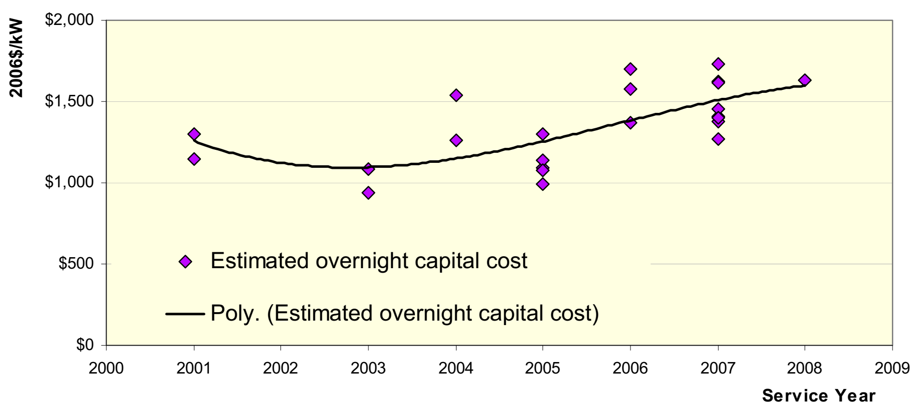
Figure 2
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year (Index Year 2000 = 100)



Sources and Notes:
* Data on summer capacity, total installation cost , turbine technology, commercial online date, and zip code for the period 2000-2006 were collected from commercially available databases and other sources such as company websites and 10k reports.
** GDP Deflator data were collected from the U.S. Bureau of Economic Analysis.

Another major class of generation development during this decade has been wind generation, the costs of which have also increased in recent years. The Northwest Power and Conservation Council (NPCC), a regional planning council that prepares long-term electric resource plans for the Pacific Northwest, issued its most recent review of the cost of wind power in July 2006.[6] The Council found that the cost of new wind projects rose substantially in real terms in the last two years, and was much higher than that assumed in its most recent resource plan. Specifically, the Council found that the levelized lifecycle cost of power for new wind projects rose 50 to 70 percent, with higher construction costs being the principal contributor to this increased cost. According to the Council, the construction cost of wind projects, in real dollars, has increased from about $1150/kW to $1300-$1700/kW in the past few years, with an unweighted average capital cost of wind projects in 2006 at $1,485/kW. Factors contributing to the increase in wind power costs include a weakening dollar, escalation of commodity and energy costs, and increased demand for wind power under renewable portfolio standards established by a growing number of states. The Council notes that commodities used in the manufacture and installation of wind turbines and ancillary equipment, including cement, copper, steel and resin have experienced significant cost increases in recent years. Figure 3 shows real construction costs of wind projects by actual or projected in-service date.

Figure 3
Wind Power Project Capital Costs



Source: The Northwest Power and Conservation Council, "Biennial Review of the Cost of Windpower" July 13, 2006.

These observations were confirmed recently in a May 2007 report by the U.S. Department of Energy (DOE), which found that prices for wind turbines (the primary cost component of installed wind capacity) rose by more than $400/kW between 2002 and 2006, a nearly 60-percent increase.[7] Figure 4 is reproduced from the DOE report (Figure 21) and shows the significant upward trend in turbine prices since 2001.

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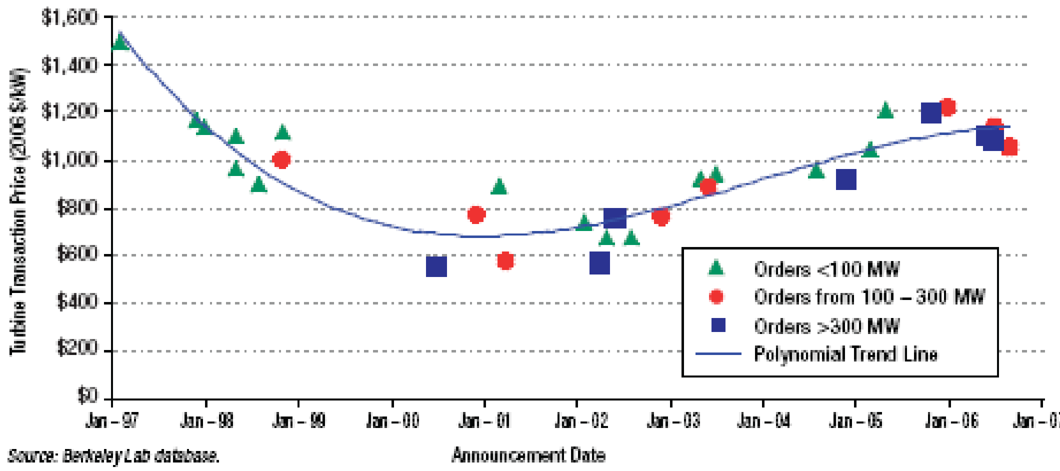
[6] The NPCC planning studies and analyses cover the following four states: Washington, Oregon, Idaho, and Montana. See "Biennial Review of the Cost of Windpower" July 13, 2006, at www.bpa.gov/Energy/N/projects/post2006conservation/doc/Windpower_Cost_Review.doc. This study provides many reasons for windpower cost increases.

[7] See U.S. Department of Energy, *Annual Report on U.S. Wind Power Installation, Cost and Performance Trends: 2006* Figure 21, page 16.

Figure 4
Wind Turbine Prices 1997 - 2007



Rising Projected Construction Costs: Examples and Case Studies

Although recently completed gas-fired and wind-powered capacity has shown steady real cost increases in recent years, the most dramatic cost escalation figures arise from *proposed* utility investments, which fully reflect the recent, sharply rising prices of various components of construction and installation costs. The most visible of these are generation proposals, although several transmission proposals also have undergone substantial upward cost revisions. Distribution-level investments are smaller and less discrete ("lumpy") and thus are not subject to similar ongoing public scrutiny on a project-by-project basis.

Coal-Based Power Plants

Evidence of the significant increase in the construction cost of coal-based power plants can be found in recent applications filed by utilities, such as Duke Energy and Otter Tail Power Company, seeking regulatory approval to build such plants. Otter Tail Power Company leads a consortium of seven Midwestern utilities that are seeking to build a 630-MW coal-based generating unit (Big Stone II) on the site of the existing Big Stone Plant near Milbank, South Dakota. In addition, the developers of Big Stone II seek to build a new high-voltage transmission line to deliver power from Big Stone II and from other sources, including possibly wind and other renewable forms of energy. Initial cost estimates for the power plant were about $1 billion, with an additional $200 million for the transmission line project. However, these cost estimates increased dramatically, largely due to higher costs for construction materials and labor.[8] Based on the most recent design refinements, the project, including transmission, is expected to cost $1.6 billion.

[8] Other factors contributing to the cost increase include design changes made by project participants to increase output and improve the unit's efficiency. For example, the voltage of the proposed transmission line was increased from 230 kV to 345 kV to accommodate more generation.

In June 2006, Duke submitted a filing with the North Carolina Utilities Commission (NCUC) seeking a certificate of public convenience and necessity for the construction of two 800 MW coal-based generating units at the site of the existing Cliffside Steam Station. In its initial application, Duke relied on a May 2005 preliminary cost estimate showing that the two units would cost approximately $2 billion to build. Five months later, Duke submitted a second filing with a significantly revised cost estimate. In its second filing, Duke estimated that the two units would cost approximately $3 billion to build, a 50 percent cost increase. The North Carolina Utilities Commission approved the construction of one 800 MW unit at Cliffside but disapproved the other unit, primarily on the basis that Duke had not made a showing that it needed the capacity to serve projected native load demands. Duke's latest projected cost for building one 800 MW unit at Cliffside is approximately $1.8 billion, or about $2,250/kW. When financing costs, or allowance for funds used during construction (AFUDC), are included, the total cost is estimated to be $2.4 billion (or about $3,000/kW).

Rising construction costs have also led utilities to reconsider expansion plans prior to regulatory actions. In December 2006, Westar Energy announced that it was deferring the consideration of a new 600 MW coal-based generation facility due to significant increases in the estimated construction costs, which increased from $1.0 billion to about $1.4 billion since the plant was first announced in May 2005.

Increased construction costs are also affecting proposed demonstration projects. For example, DOE announced earlier this year that the projected cost for one of its most prominent clean coal demonstration project, FutureGen, had nearly doubled.[9] FutureGen is a clean coal demonstration project being pursued by a public-private partnership involving DOE and an alliance of industrial coal producers and electric utilities. FutureGen is an experimental advanced Integrated Gasification Combined Cycle (IGCC) coal plant project that will aim for near zero emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury, particulates and carbon dioxide (CO_2). Its initial cost was estimated at $950 million. But after re-evaluating the price of construction materials and labor and adjusting for inflation over time, DOE's Office of Fossil Energy announced that the project's price had increased to $1.7 billion.

Transmission Projects

NSTAR, the electric distribution company that serves the Boston metropolitan area, recently built two 345 kV lines from a switching station in Stoughton, Massachusetts, to substations in the Hyde Park section of Boston and to South Boston, respectively. In an August 2004 filing before ISO New England Inc. (ISO-NE), NSTAR indicated that the project would cost $234.2 million. In March 2007, NSTAR informed ISO-NE that estimated project costs had increased by $57.7 million, or almost 25 percent, for a revised total project cost of $292 million. NSTAR stated that the increase is driven by increases in both construction and material costs, with construction bids coming in 24 percent higher than initially estimated. NSTAR further explained that there have been dramatic increases in material costs, with copper costs increasing by 160 percent, core steel by 70 percent, flow-fill concrete by 45 percent, and dielectric fluid (used for cable cooling) by 66 percent.

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[9] U.S. Department of Energy, April 10, 2007, press release available at http://www.fossil.energy.gov/news/techlines/2007/07019-DOE_Signs_FutureGen_Agreement.html

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Another aspect of transmission projects is land requirements, and in many areas of the country land prices have increased substantially in the past few years. In March 2007, the California Public Utilities Commission (CPUC) approved construction of the Southern California Edison (SCE) Company's proposed 25.6-mile, 500 kV transmission line between SCE's existing Antelope and Pardee Substations. SCE initially estimated a cost of $80.3 million for the Antelope-Pardee 500 kV line. However, the company subsequently revised its estimate by updating the anticipated cost of acquiring a right-of-way, reflecting a rise in California's real estate prices. The increased land acquisition costs increased the total estimate for the project to $92.5 million, increasing the estimated costs to more than $3.5 million per mile.

Distribution Equipment

Although most individual distribution projects are small relative to the more visible and public generation and transmission projects, costs have been rising in this sector as well. This is most readily seen in Handy-Whitman Index© price series relating to distribution equipment and components. Several important categories of distribution equipment have experienced sharp price increases over the past three years. For example, the prices of line transformers and pad transformers have increased by 68 percent and 79 percent, respectively, between January 2004 and January 2007, with increases during 2006 alone of 28 percent and 23 percent.[10] The cost of overhead conductors and devices increased over the past three years by 34 percent, and the cost of station equipment rose by 38 percent. These are in contrast to the overall price increases (measured by the GDP deflator) of roughly 8 percent over the past three years.

[10] Handy-Whitman© Bulletin No. 165, average increase of six U.S. regions. Used with permission.

Factors Spurring Rising Construction Costs

Broadly speaking, there are four primary sources of the increase in construction costs: (1) material input costs, including the cost of raw physical inputs, such as steel and cement as well as increased costs of components manufactured from these inputs (*e.g.*, transformers, turbines, pumps); (2) shop and fabrication capacity for manufactured components (relative to current demand); (3) the cost of construction field labor, both unskilled and craft labor; and (4) the market for large construction project management, *i.e.*, the queuing and bidding for projects. This section will discuss each of these factors.

Material Input Costs

Utility construction projects involve large quantities of steel, aluminum and copper (and components manufactured from these metals) as well as cement for foundations, footings and structures. All of these commodities have experienced substantial recent price increases, due to increased domestic and global demands as well as increased energy costs in mineral extraction, processing and transportation. In addition, since many of these materials are traded globally, the recent performance of the U.S. dollar will impact the domestic costs (see box on page 14).

Metals

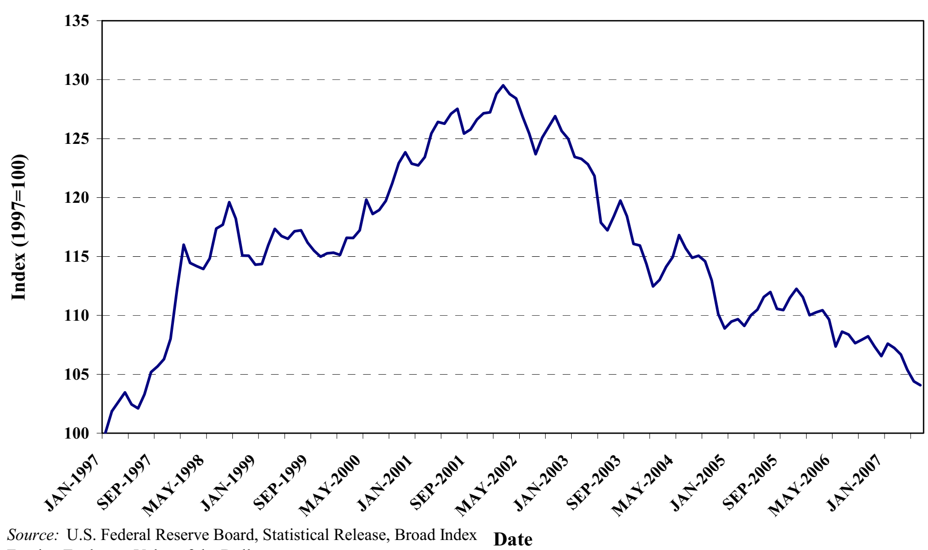
After being relatively stable for many years (and even declining in real terms), the price of various metals, including steel, copper and aluminum, has increased significantly in the last few years. These increases are primarily the result of high global demand and increased production costs (including the impact of high energy prices). A weakening U.S. dollar has also contributed to high domestic prices for imported metals and various component products.

Figure 5 shows price indices for primary inputs into steel production (iron and steel scrap, and iron ore) since 1997. The price of both inputs fell in real terms during the late 1990s, but rose sharply after 2002. Compared to the 20-percent increase in the general inflation rate (GDP deflator) between 1997 and 2006, iron ore prices rose 75 percent and iron and steel scrap prices rose nearly 120 percent. The increase over the last few years was especially sharp—between 2003 and 2006, prices for iron ore rose 60 percent and iron and scrap steel rose 150 percent.

Exchange Rates

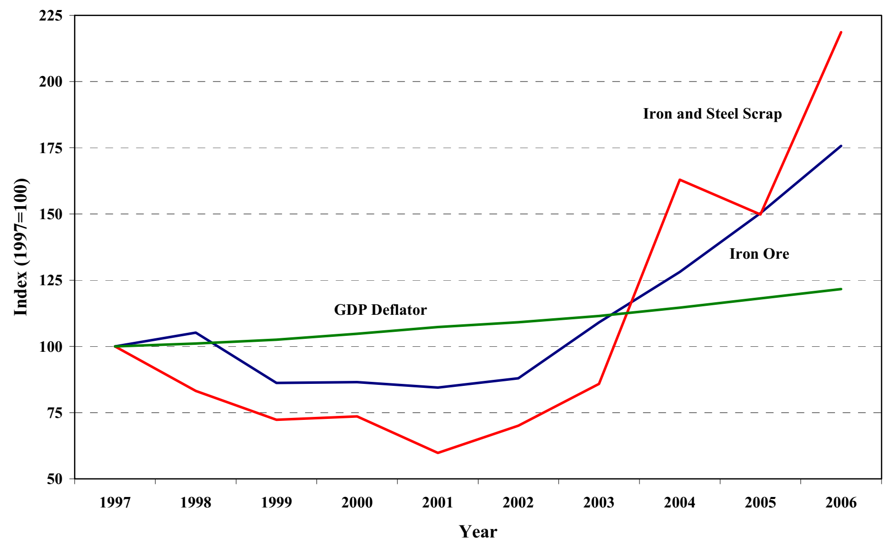
Many of the raw materials involved in utility construction projects (e.g., steel, copper, cement), as well as many major manufactured components of utility infrastructure investments, are globally traded. This means that prices in the U.S. are also affected by exchange rate fluctuations, which have been adverse to the dollar in recent years. The chart below shows trade-weighted exchange rates from 1997. Although the dollar appreciated against other currencies between 1997 and 2001, the graph also clearly shows a substantial erosion of the dollar since the beginning of 2002, losing roughly 20 percent of its value against other major trading partners' currencies. This has had a substantial impact on U.S. material and manufactured component prices, as will be reflected in many of the graphs that follow.

Nominal Broad Dollar Index



Source: U.S. Federal Reserve Board, Statistical Release, Broad Index Foreign Exchange Value of the Dollar.

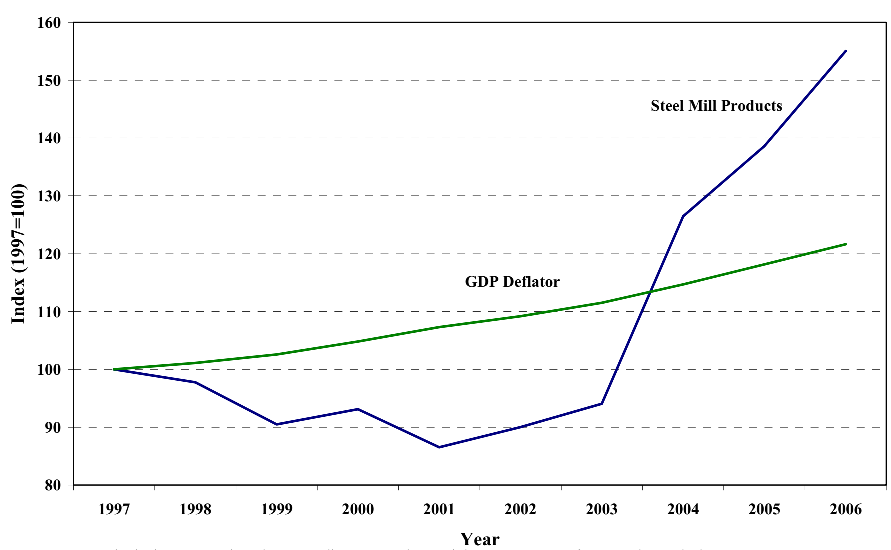
Figure 5
Inputs to Iron and Steel Production Cost Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

The increase in input prices has been reflected in steel mill product prices. Figure 6 compares the trend in steel mill product prices to the general inflation rate (using the GDP deflator) over the past 10 years. Figure 6 shows that the price of steel has increased about 60 percent since 2003.

Figure 6
Steel Mill Products Price Index



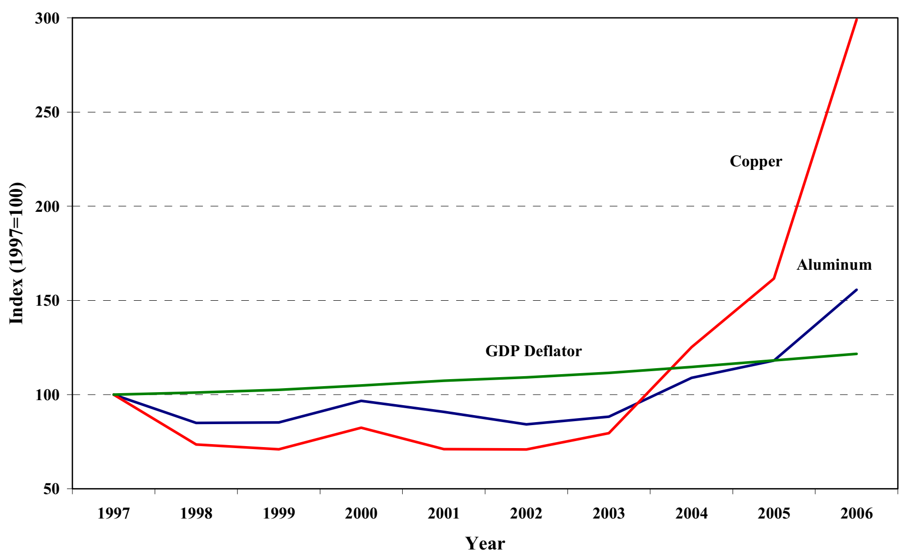
Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Various sources point to the rapid growth of steel production and demand in China as a primary cause of the increases in both steel prices and the prices of steelmaking inputs.[11] China has become both the world's largest steelmaker and steel consumer. In addition, some analysts contend that steel companies have achieved greater pricing power, partly due to ongoing consolidation of the industry, and note that recently increased demand for steel has been driven largely by products used in energy and heavy industry, such as plate and structural steels.

From the perspective of the steel industry, the substantial and at least semi-permanent rise in the price of steel has been justified by the rapid rise in the price of many steelmaking inputs, such as steel scrap, iron ore, coking coal, and natural gas. Today's steel prices remain at historically elevated levels and, based on the underlying causes for high prices described, it appears that iron and steel costs are likely to remain at these high levels at least for the near future.

Other metals important for utility infrastructure display similar price patterns: declining real prices over the first five years or so of the previous 10 years, followed by sharp increases in the last few years. Figure 7 shows that aluminum prices doubled between 2003 and 2006, while copper prices nearly quadrupled over the same period.

Figure 7
Aluminum and Copper Price Indices

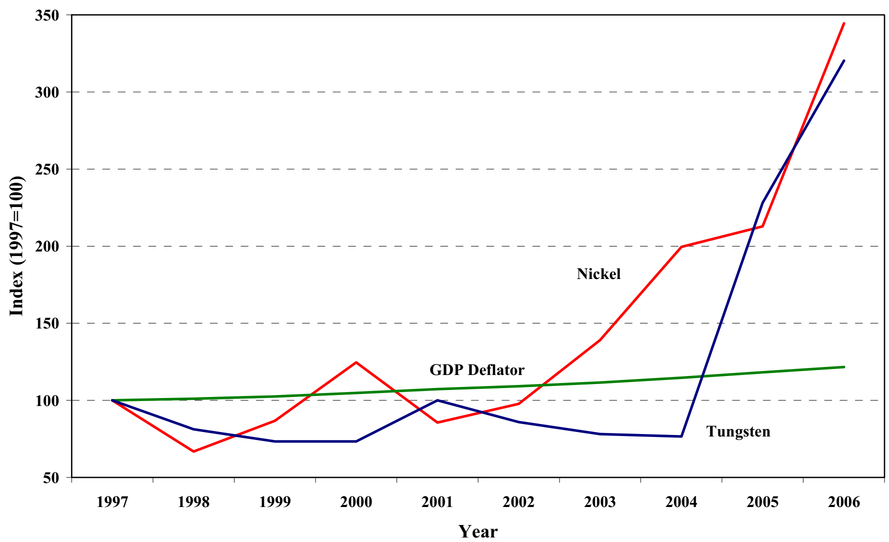


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

[11] See, for example, *Steel: Price and Policy Issues*, CRS Report to Congress, Congressional Research Service, August 31, 2006.

These price increases were also evident in metals that contribute to important steel alloys used broadly in electrical infrastructure, such as nickel and tungsten. The prices of these display similar patterns, as shown in Figure 8.

Figure 8
Nickel and Tungsten Price Indices

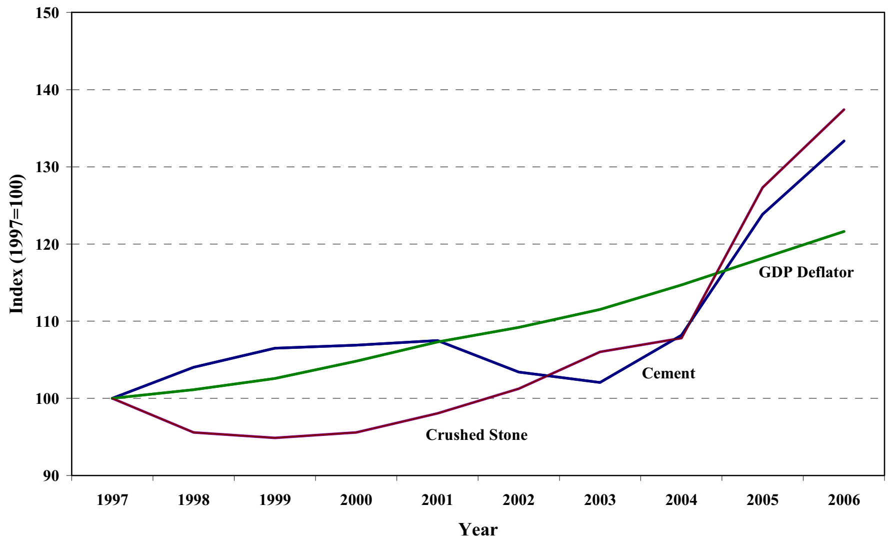


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Cement, Concrete, Stone and Gravel

Large infrastructure projects require huge amounts of cement as well as basic stone materials. The price of cement has also risen substantially in the past few years, for the same reasons cited above for metals. Cement is an energy-intensive commodity that is traded on international markets, and recent price patterns resemble those displayed for metals. In utility construction, cement is often combined with stone and other aggregates for concrete (often reinforced with steel), and there are other site uses for sand, gravel and stone. These materials have also undergone significant price increases, primarily as a result of increased energy costs in extraction and transportation. Figure 9 shows recent price increases for cement and crushed stone. Prices for these materials have increased about 30 percent between 2004 and 2006.

Figure 9
Cement and Crushed Stone Price Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

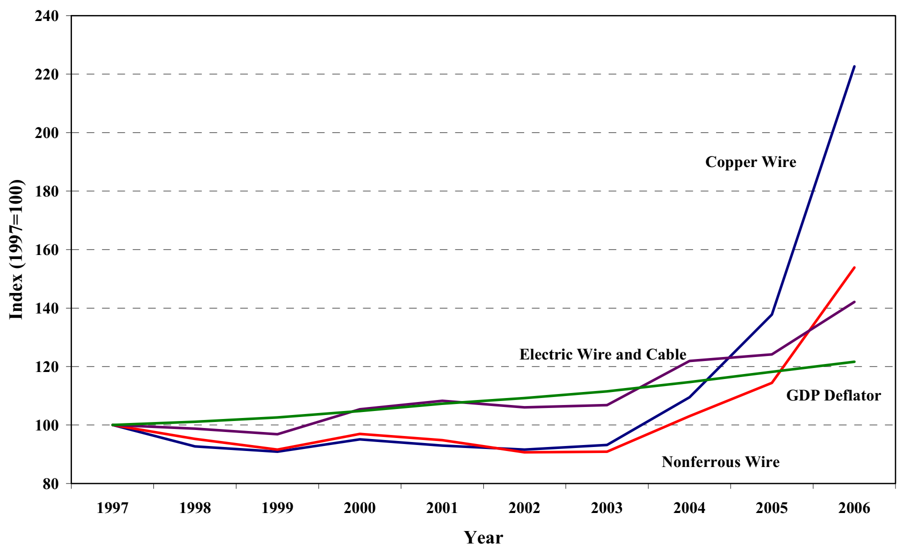
Manufactured Products for Utility Infrastructure

Although large utility construction projects consume substantial amounts of unassembled or semi-finished metal products (*e.g.*, reinforcing bars for concrete, structural steel), many of the components such as conductors, transformers and other equipment are manufactured elsewhere and shipped to the construction site. Available price indices for these components display similar patterns of recent sharp price increases.

Figure 10 shows the increased prices experienced in wire products compared to the inflation rate, according to the U.S. Bureau of Labor Statistics (BLS), highlighting the impact of underlying metal price increases.

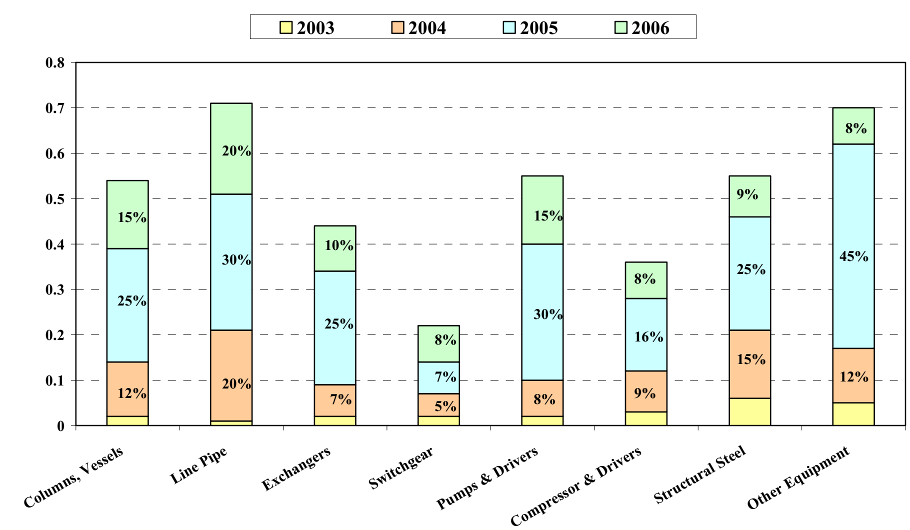
Manufactured components of generating facilities—large pressure vessels, condensers, pumps, valves—have also increased sharply since 2004. Figure 11 shows the yearly increases experienced in key component prices since 2003.

Figure 10
Electric Wire and Cable Price Indices



Sources: The U.S. Bureau of Labor Statistics and the U.S. Bureau of Economic Analysis.

Figure 11
Equipment Price Increases

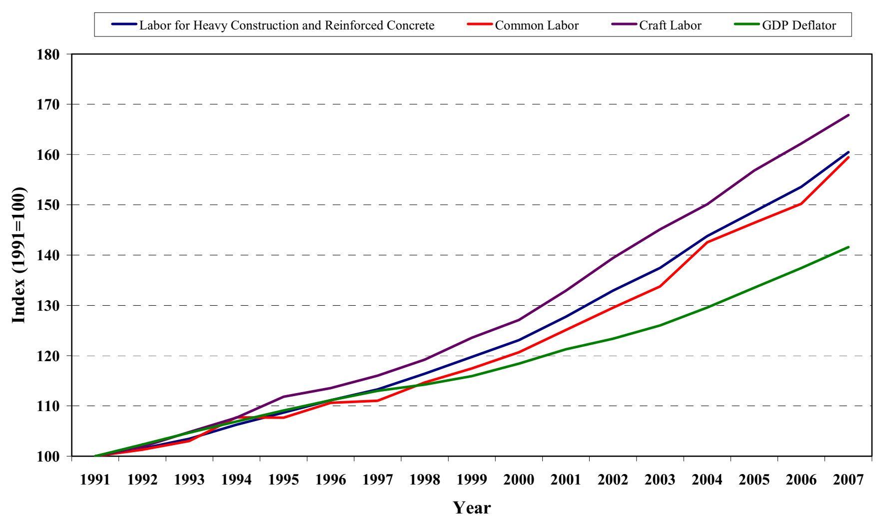


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Labor Costs

A significant component of utility construction costs is labor—both unskilled (common) labor as well as craft labor such as pipefitters and electricians. Labor costs have also increased at rates higher than the general inflation rate, although more steadily since 1997, and recent increases have been less dramatic than for commodities. Figure 12 shows a composite national labor cost index based on simple averages of the regional Handy-Whitman Index© for common and craft labor. Between January 2001 and January 2007, the general inflation rate (measured by the GDP deflator) increased about 15 percent. During the same period, the cost of craft labor and heavy construction labor increased about 26 percent, while common labor increased 27 percent, or almost twice the rate of general inflation.[12] While less severe than commodity cost increases, increased labor costs contributed to the overall construction cost increases because of their substantial share in overall utility infrastructure construction costs.

Figure 12
National Average Labor Costs Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional labor cost indices for the specified types of labor.

Although labor costs have not risen dramatically in recent years, there is growing concern about an emerging gap between demand and supply of skilled construction labor—especially if the anticipated boom in utility construction materializes. In 2002, the Construction Users Roundtable (CURT), surveyed its members and found that recruitment, education, and retention of craft workers continue to be critical issues for the industry.[13] The average age of the current construction skilled workforce is rising rapidly, and high attrition rates in construction are compounding the problem. The industry has always had high attrition at the entry-level positions, but now many workers in the 35-40 year-old age group are leaving the industry for a variety of reasons. The latest projections indicate that, because of attrition and anticipated growth, the construction

[12] These figures represent a simple average of six regional indices, however, local and regional labor markets can vary substantially from these national averages.

[13] *Confronting the Skilled Construction Workforce Shortage*. The Construction Users Roundtable, WP-401, June 2004, p. 1.

industry must recruit 200,000 to 250,000 new craft workers per year to meet future needs. However, both demographics and a poor industry image are working against the construction industry as it tries to address this need.[14]

There also could be a growing gap between the demand and supply of electrical lineworkers who maintain the electric grid and who perform much of the labor for transmission and distribution investments. These workers erect poles and transmission towers and install or repair cables or wires used to carry electricity from power plants to customers. According to a DOE report, demand for such workers is expected to outpace supply over the next decade.[15] The DOE analysis indicates a significant forecasted shortage in the availability of qualified candidates by as many as 10,000 lineworkers, or nearly 20 percent of the current workforce. As of 2005, lineworkers earned a mean hourly wage of $25/hour, or $52,300 per year. The forecast supply shortage will place upward pressure on the wages earned by lineworkers.[16]

Shop and Fabrication Capacity

Many of the components of utility projects—including large components like turbines, condensers, and transformers—are manufactured, often as special orders to coincide with particular construction projects. Because many of these components are not held in large inventories, the overall capacity of their manufacturers can influence the prices obtained and the length of time between order and delivery. The price increases of major manufactured components were shown in Figure 11. While equipment and component prices obviously reflect underlying material costs, some of the price increases of manufactured components and the delivery lags are due to manufacturing capacity constraints that are not readily overcome in the near term.

As shown in Figure 13 and Figure 14, recent orders have largely eliminated spare shop capacity, and delivery times for major manufactured components have risen. These constraints are adding to price increases and are difficult to overcome with imported components because of the lower value of the dollar in recent years.

The increased delivery times can affect utility construction costs through completion delays that increase the cost of financing a project. In general, utilities commit substantial funds during the construction phase of a project that have to be financed either through debt or equity, called “allowance for fund used during construction” (AFUDC). All else held equal, the longer the time from the initiation through completion of a project, the higher is the financing costs of the investment and the ultimate costs passed through to ratepayers.

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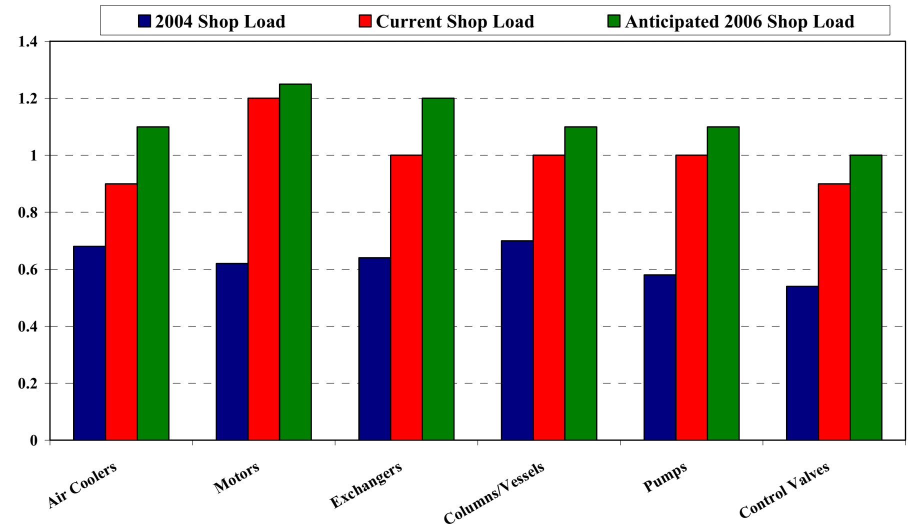
[14] *Id.*, p. 1.

[15] *Workforce Trends in the Electric Utility Industry: A Report to the United States Congress Pursuant to Section 1101 of the Energy Policy Act of 2005*. U.S. Department of Energy, August 2006, p. xi.

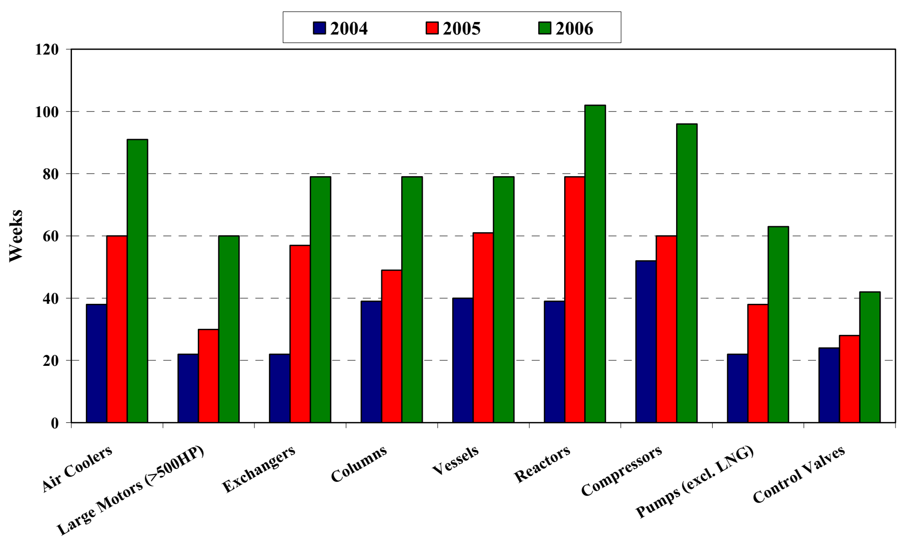
[16] *Id.*, p. 5.

Figure 13
Shop Capacity



Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Figure 14
Delivery Schedules

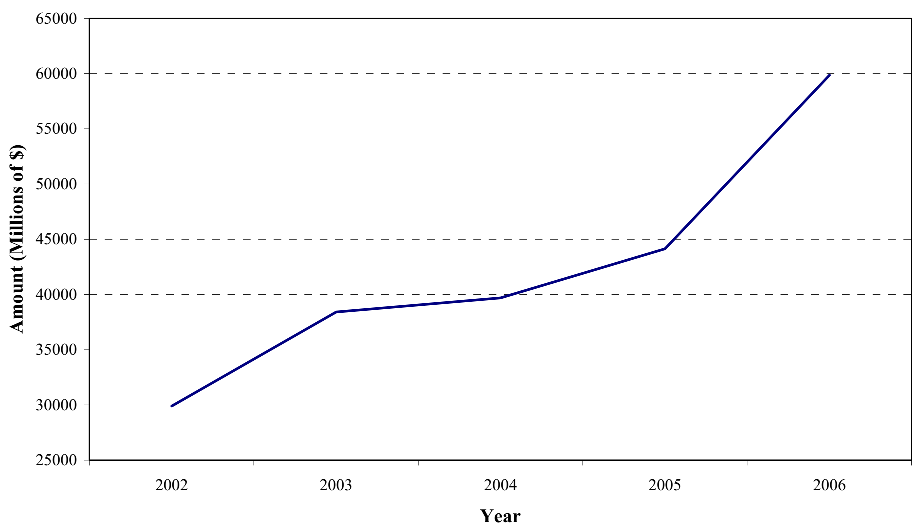


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Engineering, Procurement and Construction (EPC) Market Conditions

Increased worldwide demand for new generating and other electric infrastructure projects, particularly in China, has been cited as a significant reason for the recent escalation in the construction cost of new power plants. This suggests that major Engineering, Procurement and Construction (EPC) firms should have a growing backlog of utility infrastructure projects in the pipeline. While we were unable to obtain specific information from the major EPC firms on their worldwide backlog of electric utility infrastructure projects (*i.e.*, the number of electric utility projects compared with other infrastructure projects such as roads, port facilities and water infrastructure, in their respective pipelines), we examined their financial statements, which specify the financial value associated with their backlog of infrastructure projects. Figure 15 shows the cumulative annual financial value associated with the backlog of infrastructure projects at the following four major EPC firms; Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. Figure 15 shows that the annual backlog of infrastructure projects rose sharply between 2005 and 2006, from \$4.1 billion to \$5.6 billion, an increase of 37 percent. This significant increase in the annual backlog of infrastructure projects at EPC firms is consistent with the data showing an increased worldwide demand for infrastructure projects in general and also utility generation, transmission, and distribution projects.

Figure 15
Annual Backlog at Major EPC Firms



Data are compiled from the Annual Reports of Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. For Bechtel, the data represent new booked work, as backlog is not reported.

The growth in construction project backlogs likely will dampen the competitiveness of EPC bids for future projects, at least until the EPC industry is able to expand capacity to manage and execute greater volumes of projects. This observation does not imply that this market is generally uncompetitive—rather it reflects the limited ability of EPC firms with near-term capacity constraints to service an upswing in new project development associated with a boom period in infrastructure construction cycles. Such constraints, combined with a rapidly filling (or full) queue for project management services, limit incentives to bid aggressively on new projects.

Although difficult to quantify, this lack of spare capacity in the EPC market will undoubtedly have an upward price pressure on new bids for EPC services and contracts. A recent filing by Oklahoma Gas & Electric Company (OG&E) seeking approval of the Red Rock plant (a 950 MW coal unit) provides a demonstration of this effect. In January 2007, OG&E testimony indicated that their February 3, 2006, cost estimate of nearly $1,700/kW had been revised to more than $1,900/kW by September 29, 2006, a 12-percent increase in just nine months. More than half of the increase (6.6 percent) was ascribed to change in market conditions which "reflect higher materials costs (steel and concrete), escalation in major equipment costs, and a significant tightening of the market for EPC contractor services (as there are relatively few qualified firms that serve the power plant development market)."[17] In the detailed cost table, OG&E indicated that the estimate for EPC services had increased by more than 50 percent during the nine month period (from $223/kW to $340/kW).

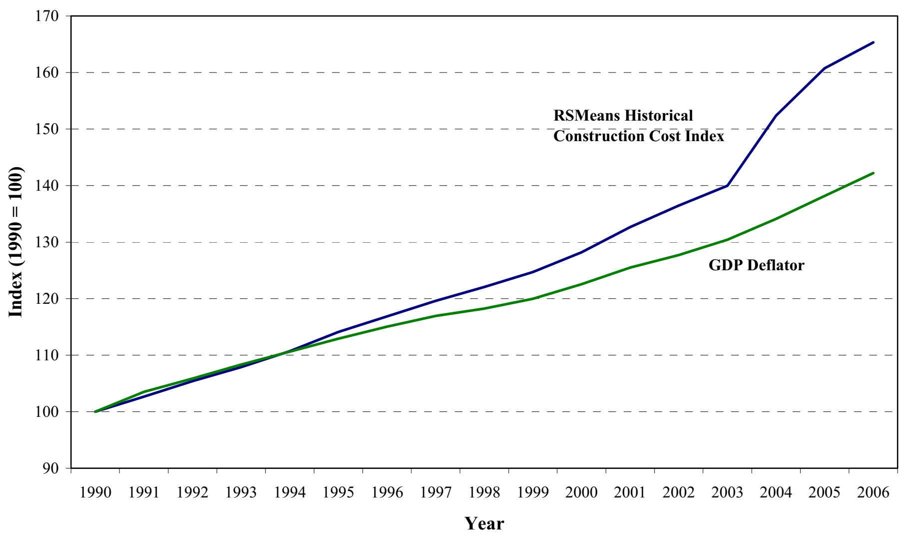
Summary Construction Cost Indices

Several sources publish summary construction cost indices that reflect composite costs for various construction projects. Although changes in these indices depend on the actual cost weights assumed *e.g.*, labor, materials, manufactured components, they provide useful summary measures for large infrastructure project construction costs.

The RSMeans Construction Cost Index provides a general construction cost index, which reflects primarily building construction (as opposed to utility projects). This index also reflects many of the same cost drivers as large utility construction projects such as steel, cement and labor. Figure 16 shows the changes in the RSMeans Construction Cost index since 1990 relative to the general inflation rate. While the index rose slightly higher than the GDP deflator beginning in the mid 1990s, it shows a pronounced increase between 2003 and 2006 when it rose by 18 percent compared to the 9 percent increase in general inflation.

[17] Testimony of Jesse B. Langston before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200700012, January 17, 2007, page 27 and Exhibit JBL-9.

Figure 16
RSMeans Historical Construction Cost Index



Source: RSMeans, Heavy Construction Cost Data, 20th Annual Edition, 2006.

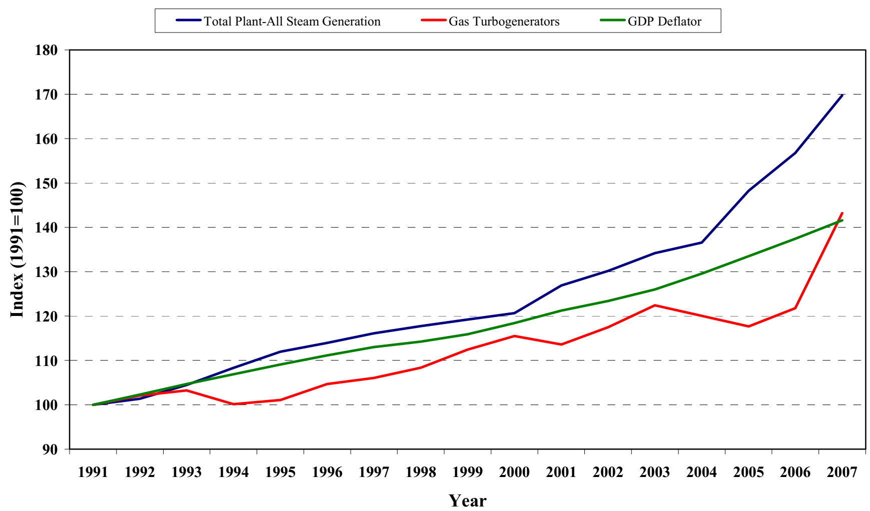
The Handy-Whitman Index© publishes detailed indices of utility construction costs for six regions, broken down by detailed component costs in many cases. Figures 17 through 19 show the evolution of several of the broad aggregate indices since 1991 compared with the general inflation index (GDP deflator).[18] The index numbers displayed on the graphs are for January 1 of each year displayed.

Figure 17 displays two indices for generation costs: a weighted average of coal steam plant construction costs (boilers, generators, piping, etc.) and a stand-alone cost index for gas combustion turbines.

As seen on Figure 17, steam generation construction costs tracked the general inflation rate fairly well through the 1990s, began to rise modestly in 2001, and increased significantly since 2004. Between January 1, 2004, and January 1, 2007, the cost of constructing steam generating units increased by 25 percent—more than triple the rate of inflation over the same time period. The cost of gas turbogenerators (combustion turbines), on the other hand, actually fell between 2003 and 2005. However, during 2006, the cost of a new combustion turbine increased by nearly 18 percent—roughly 10 times the rate of general inflation.

[18] Used with permission. See Handy-Whitman© Bulletin, No. 165 for detailed data breakouts and regional values for six regions: Pacific, Plateau, South Central, North Central, South Atlantic and North Atlantic. The Figures shown reflect simple averages of the six regions.

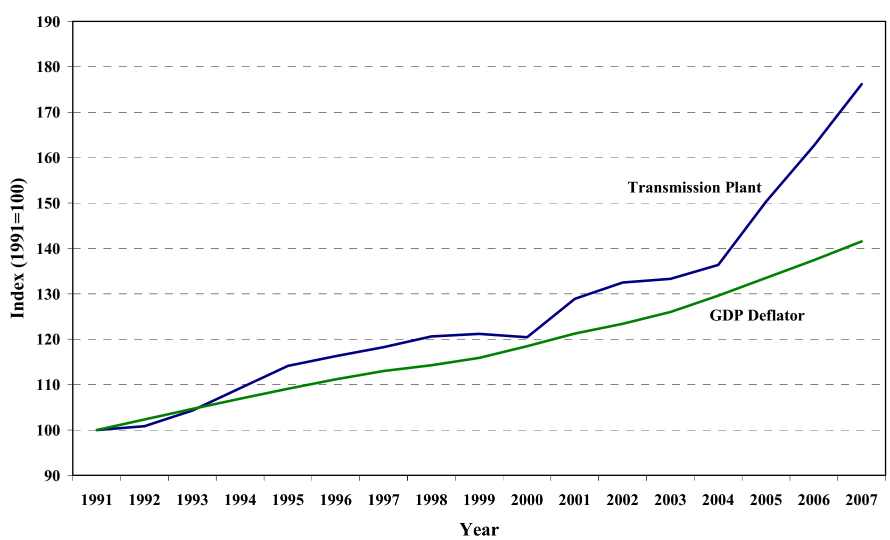
Figure 17
National Average Generation Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indices for the specified components.

Figure 18 displays the increased cost of transmission investment, which reflects such items as towers, poles, station equipment, conductors and conduit. The cost of transmission plant investments rose at about the rate of inflation between 1991 and 2000, increased in 2001, and then showed an especially sharp increase between 2004 and 2007, rising almost 30 percent or nearly four times the annual inflation rate over that period.

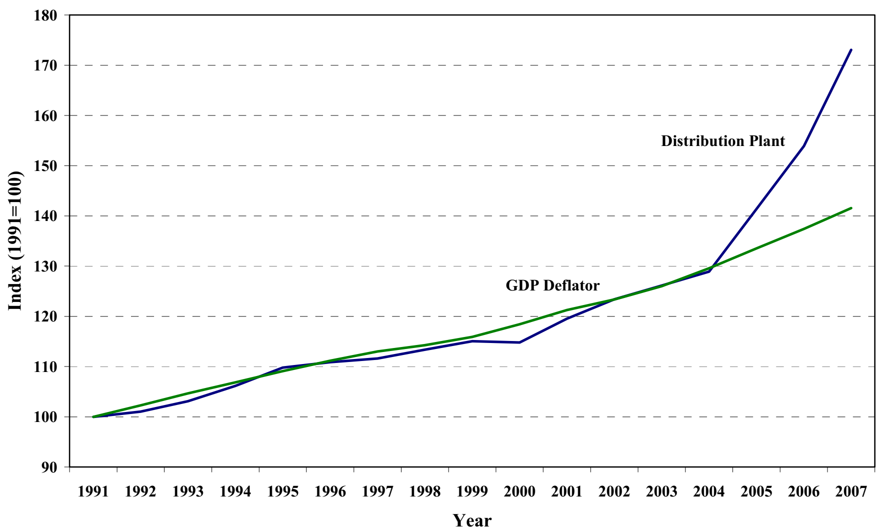
Figure 18
National Average Transmission Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional transmission cost indices.

Figure 19 shows distribution plant costs, which include poles, conductors, conduit, transformers and meters. Overall distribution plant costs tracked the general inflation rate very closely between 1991 and 2003. However, it then increased 34 percent between January 2004 and January 2007, a rate that exceeded four times the rate of general inflation.

Figure 19
National Average Distribution Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional distribution cost indices.

Comparison with Energy Information Administration Power Plant Cost Estimates

Every year, EIA prepares a long-term forecast of energy prices, production, and consumption (for electricity and the other major energy sectors), which is documented in the *Annual Energy Outlook* (AEO). A companion publication, *Assumptions to the Annual Energy Outlook*, itemizes the assumptions (*e.g.*, fuel prices, economic growth, environmental regulation) underlying EIA's annual long-term forecast. Included in the latter document are estimates of the "overnight" capital cost of new generating units *(i.e.,* the capital cost exclusive of financing costs). These cost estimates influence the type of new generating capacity projected to be built during the 25-year time horizon modeled in the AEO.

The EIA capital cost assumptions are generic estimates that do not take into account the site-specific characteristics that can affect construction costs significantly.[19] While EIA's estimates do not necessarily provide an accurate estimate of the cost of building a power plant at a specific location, they should, in theory, provide a good "ballpark" estimate of the relative construction cost of different generation

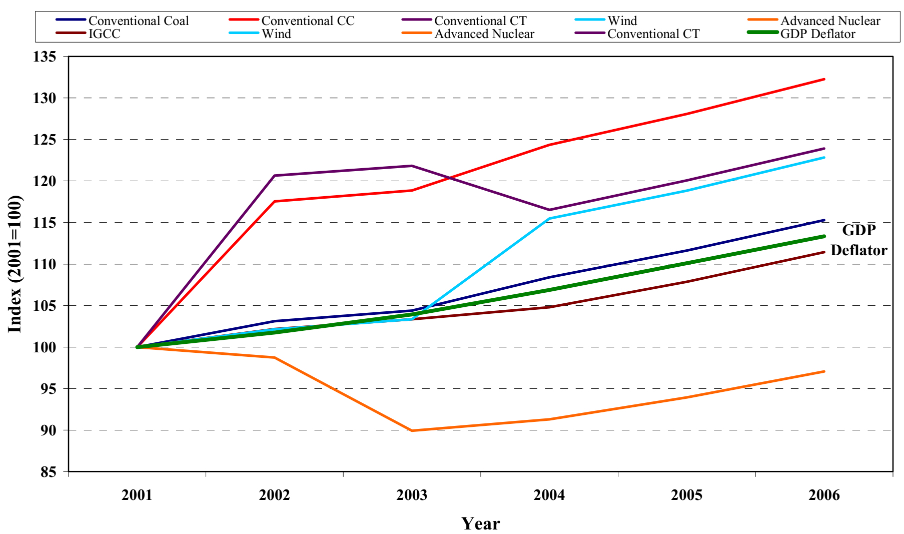
[19] EIA does incorporate regional multipliers to reflect minor variations in construction costs based on labor conditions.

technologies at any given time. In addition, since they are prepared annually, these estimates also should provide insight into construction cost trends over time.

The EIA plant cost estimates are widely used by industry analysts, consultants, academics, and policymakers. These numbers frequently are cited in regulatory proceedings, sometimes as a yardstick by which to measure a utility's projected or incurred capital costs for a generating plant. Given this, it is important that EIA's numbers provide a reasonable estimate of plant costs and incorporate both technological and other market trends that significantly affect these costs.

We reviewed EIA's estimate of overnight plant costs for the six-year period 2001 to 2006. Figure 20 shows EIA's estimates of the construction cost of six generation technologies—combined-cycle gas-fired plants, combustion turbines (CTs), pulverized coal, nuclear, IGCC, and wind—over the period 2001 to 2006 and compares these projections to the general inflation rate (GDP deflator). These six technologies, generally speaking, have been the ones most commonly built or given serious consideration in utility resource plans over the last few years. Thus, we can compare the data and case studies discussed above to EIA's cost estimates.

Figure 20
EIA Generation Construction Cost Estimates



Sources: Data collected from the Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

The general pattern in Figure 20 shows a dramatic change in several technology costs between 2001 and 2004 followed by a stable period of growth until 2006. The two exceptions to this are conventional coal and IGCC, which increase by a near constant rate each year close to the rate of inflation throughout the period. The data show conventional CC and conventional CT experiencing a sharp increase between 2001 and 2002. After this increase, conventional CC levels off and proceeds to increase at a pace near inflation, while conventional CT actually drops significantly before 2004 when it too levels near the rate of inflation. The pattern seen with nuclear technology is near to the opposite. It falls dramatically until about 2003 and then increases at the same rate as the GDP deflator. Lastly, wind moves close to inflation until 2004 when it experiences a one-time jump and then flattens off through 2006.

These patterns of cost estimates over time contradict the data and findings of this report. Almost every other generation construction cost element has shown price changes at or near the rate of inflation throughout the early part of this decade with a dramatic change in only the last few years. EIA appears to have reconsidered several technology cost estimates (or revised the benchmark technology type) in isolation between 2001 and 2004, without a systematic update of others. Meanwhile, during the period that overall construction costs were rising well above the general inflation rate, EIA has not revised its estimated capital cost figures to reflect this trend.

EIA's estimates of plant costs do not adequately reflect the recent increase in plant construction costs that has occurred in the last few years. Indeed, EIA itself acknowledges that its estimated construction costs do not reflect short-term changes in the price of commodities such as steel, cement and concrete.[20] While one would expect some lag in the EIA data, it is troubling that its most recent estimates continue to show the construction cost of conventional power plants increasing only at the general rate of inflation. Empirical evidence shows that the construction cost of generating plants—both fossil-fired and renewable—is escalating at a rate well above the GDP deflator. Even the most recent EIA data fail to reflect important market impacts that are driving plant construction costs, and thus do not provide a reliable measure of current or expected construction costs.

[20] *Annual Energy Outlook 2007*, U.S. Energy Information Administration, p. 36.

Conclusion

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 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.

Despite these higher costs, utilities will continue to invest in baseload generation, environmental controls, transmission projects and distribution system expansion. However, rising construction costs will put additional upward pressure on retail rates over time, and may alter the pace and composition of investments going forward. The overall impact on the industry and on customers, however, will be borne out in various ways, depending on how utilities, markets and regulators respond to these cost increases. In the long run, customers ultimately will pay for higher construction costs—either directly in rates for completed assets of regulated companies, less directly in the form of higher energy prices needed to attract new generating capacity in organized markets and in higher transmission tariffs, or indirectly when rising construction costs defer investments and delay expected benefits such as enhanced reliability and lower, more stable long-term electricity prices.

Final Report

ANALYSIS OF MOG AND LADCO'S FGD AND SCR CAPACITY AND COST ASSUMPTIONS IN THE EVALUATION OF PROPOSED EGU 1 AND EGU 2 EMISSION CONTROLS

Prepared for

Midwest Ozone Group

Prepared by

James Marchetti
J. Edward Cichanowicz

January 19, 2007

Executive Summary

The focus of this analysis is two-fold: (i) to evaluate differences in the levels of FGD and SCR capacity estimated by the Midwest Ozone Group (MOG) and the Lake Michigan Air Directors Consortium (LADCO) in their evaluations of proposed "CAIR-Plus" control measures for electric generation units in the Midwest (EGU1 and EGU2); and, (ii) to assess the difference in control cost assumptions used in both analyses.

LADCO Database Accuracy

The LADCO database does not contain emission controls on several units known to be installed and operating. These include, among others, SCR installations at Merom Units 1 and 2, and Petersburg Units 2 and 3. Omission of these and other control technology installations likely causes LADCO's estimates of SO2 and NOx emissions to exceed expected levels, and thus to impose a higher percent reduction than is actually needed.

Similarity of LADCO and MOG Technology Estimates When SO2 Allowances Are Not Banked

The use of allowance banking in the LADCO study – and how allowances are used – is a primary factor responsible for differences in estimates of technology deployment between LADCO and MOG. LADCO's analyses assume that banked allowances would be used to defer the installation of emission controls, thus deferring the eventual costs of control with EGU1 and EGU2. However, if SO2 and NOx allowance banking is not considered, then estimates of technology deployment between the two studies would be similar.

Significantly Higher Capital Costs

LADCO's capital cost estimates for EGU1 and EGU2 compliance are based on cost assumptions for FGD and SCR that do not reflect actual costs incurred by industry. Specifically, LADCO's FGD capital costs are approximately $200/kW below industry estimates, while SCR equipment costs range from $25 to $45/kW below industry experience. The IPM model's significant understatement of equipment capital costs explains much of the difference between MOG and LADCO's estimates of the costs of implementing EGU1 and EGU2.

Finally, as discussed below, a number of assumptions were made in our assessment of LADCO's control proposals, based on limited information contained in the initial LADCO EGU White Paper. LADCO's subsequent IPM modeling reveals several critical additional dimensions to the EGU proposals, including the use of multiple phases and a "floating" emission rate-based cap. Our estimates of EGU control costs assumed a more traditional tonnage-based cap similar to that used in the acid rain program and the EPA NOx SIP Call.

INTRODUCTION

In January 2005, the Midwest Regional Planning Organization (MRPO) issued a White Paper outlining a possible set of control measures that electric generating units within the states of Illinois, Indiana, Michigan, Ohio and Wisconsin would have to meet beginning in 2008 and with final implementation in 2013. These control measures would establish regional emission caps based upon specified emission rates for both NOx and SO2. Two sets of emission rates are described in the White Paper: referred to as Electric Generating Unit (EGU) 1 and 2. Since the release of this initial White Paper, two economic studies have been conducted to evaluate the compliance implications to electric generators in meeting EGU1 and EGU2. The first study was conducted by the Midwest Ozone Group (MOG) in the spring of 2005.[1] The second study was conducted by the Lake Michigan Air Directors Consortium (LADCO) in the fall of 2006.[2]

This analysis evaluates differences in the levels of FGD and SCR capacity estimated by MOG and LADCO needed to comply with EGU1 and EGU2, and discusses differences in the control cost assumptions used in both analyses. The discussion of cost assumptions is an update of a previous analysis for MOG.[3]

EMISSIONS, CAPS AND CONTROL TECHNOLOGIES – HAS THE IPM ANALYSIS MODELED ENOUGH SO2 AND NOx CONTROL TECHNOLOGY TO ACHIEVE EGU2?

This section evaluates the level of SO2 and NOx control technology that has been modeled by LADCO to achieve the reduction targets outlined by EGU2, and whether the level of capacity approaches the level of capacity modeled by MOG in order to achieve EGU2 emission caps.

It should be noted that LADCO's (IPM) modeled control capacity seems to represent "summer net" capacity, while MOG's estimated control capacity is the "nameplate" capacity of the affected generating units Therefore, to enable a better comparison between MOG and LADCO's modeled control capacities, we converted MOG's "nameplate" to "summer net" capacity.

SO2 and NOx Control Capacity in 2012

Before evaluating the LADCO modeled control capacities for EGU2, we compared the level of existing, planned and modeled FGD and SCR expected to be on-line beginning in 2012 under CAIR. It should be noted that 2012 is also the first year of

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[1] Marchetti, Cichanowicz and Hein, (MCH), *Evaluation of the Midwest RPO Interim Measures and EGU1 and EGU2*, August 1, 2005.
[2] ICF Resources, *Implementation of EGU1 and EGU2 Policies Using the Integrated Planning Model in the Midwest RPO Region*, September, 2006.
[3] Marchetti, Cichanowicz and Hein, *Comparison of FGD and SCR Capital Cost Assumptions Used by MCH and EPA*, September 29, 2005.

implementation of EGU1 and EGU2 in the 5-State MRPO. The MOG capacity levels are drawn from its 2005 study and updated information from the *Emission-Economic Modeling System's* Data Base, while the LADCO capacity levels were obtained from its *VISTASII_PC_1f* run, which includes the 5-State MRPO Region.

Table 1 compares the level of existing and planned capacity in both studies, revealing significant differences between the two sources. Specifically, MOG has identified almost 37.9 GW of FGD capacity that is or will be installed (existing and planned) by electric generators in the 5-State Region by 2012, while IPM only shows 14.7 GW. This same type of differential can also be seen with regard to SCR capacity in the 5-State Region. Specifically, MOG estimates 36.8 GW of SCR capacity (existing and planned) will be in operation by 2012, while IPM only has 26.4 GW operating in 2012.

Table 1: Comparison of 2012 Controlled Capacity in the 5-State MRPO (GW)

FGD Capacity	Existing (2005)	Planned	Modeled	Total
MOG	12.0	25.9	2.2	40.1
LADCO	11.9	2.8	18.4	33.1
SCR Capacity				
MOG	27.5	9.3	9.1	45.9
LADCO	23.0	3.4	10.3	36.7

Note: 1. Existing is installed capacity for year end 2005.
2. Planned capacity is based upon announced FGD and SCR systems by electric generators in the 5-State MRPO.

Even taking into account the modeled capacity (additional technology required beyond already known deployments) to meet CAIR for both SO2 and NOx, the IPM results fall significantly below the MOG results. Consequently, there is a concern that base data used in the IPM analysis is not reflective of industry experience/compliance, specifically with regard to what is installed and planned to be installed. For example, MOG indicates there are 27.5 GW of existing SCR capacity, while LADCO (IPM) shows only 23.0 GW, a 4.5 GW difference. In reviewing the IPM file (*VISTASII_PC_1f*), we noticed several operating SCRs missing, including E.W. Stout 7 (422 MW), Merom 1 & 2 (1,020 MW), Warrrick 4 (270 MW) and Petersburg 2 & 3 (917 MW). Therefore, if the base data is not correct, the question then arises whether the modeled data is a realistic representation of industry compliance and thereby may have *over-estimated* pre-EGU 1 and 2 SO2 and NOx emission levels.

SO2 and NOx Control Capacity to Meet EGU2

The LADCO report contains several new elements related to EGU compliance with EGU1 and EGU2, which were not made known to us when our original work was undertaken in the spring of 2005. These new elements are as follows:

- EGU1 and EGU2 compliance date is 2012, whereas, the MOG analysis assumed 2013;
- The EGU SO2 and NOx emission caps are moving or floating caps, which change from year-to-year based upon changes in annual heat input, unlike the MOG caps which are fixed and based upon a historical baseline;
- Compliance with EGU1 and EGU2 utilizes two phases: (i) Phase I is from 2009 to 2011, which has caps based upon the Interim Measures in the White Paper; and, (ii) Phase II is 2012 and beyond and has caps based upon EGU emission rates from the White Paper;
- MRPO electric generators that over-control in Phase I are able to carry-forward their excess/banked allowances for compliance in Phase II. This feature was not included in the MOG analysis because phases were not assumed or modeled and the White Paper *did not* mention that generators would be allowed to carry-forward allowances from a earlier phase; and,
- MRPO electric generators are allowed to sell excess/banked allowances from EGU1 and EGU2 compliance to electric generators outside the 5-State MRPO Region.

Our review compares incremental control capacity, as modeled by MOG and LADCO, which generators in the 5-State MRPO Region would install under EGU2. The LADCO EGU2 policy run is identified as *LADCO_PC_1d*. However, both analyses were modeled under different regulatory regimes; therefore, our approach compares outcomes under a similar regulatory regimes and data. As mentioned above, the MOG analysis assumed a 2013 compliance date, with no carry over of allowances from any earlier phases. Under this type of regulatory regime, electric generators within the 5-State MRPO Region would be required to meet EGU2 SO2 and NOx emission caps by that date. The LADCO analysis indicates EGU2 would be implemented in 2012; however, between 2012 and 2020, generators are allowed to carry-forward both SO2 and NOx allowances for compliance, as illustrated in Table 6 of the LADCO report.

There is a particular concern with regard to modeling in 2012. The LADCO report illustrates in 2012 affected units within the 5-State MRPO Region would have SO2 emissions of 432,000 tons under EGU2. Also shown in Table 6, the 2012 EGU2 SO2 emission budget computed by IPM is 473,000 tons, which seems to allow the banking of excess allowances. However, there may be an issue concerning the precision of the IPM model related to emissions and banking, which ultimately would affect the deployment of technology. Since the model *does not* evaluate compliance on an annual basis, the LADCO report indicates the 2012 cap is an average of 2010 – 2013 year caps, which encompasses the two phases of EGU2. Also, the related LADCO Stratus report seems to imply on pages ES-2 and ES- 4 that the SO2 emissions may be an average of the same years.[4] As mentioned earlier, Phase II of EGU2 compliance begins in 2012, when affected EGUs would have to meet SO2 emission caps based upon an SO2 emission rate

[4] Stratus Consulting Inc., *Benefit Study of MRPO Candidate Control Options for Electricity Generation*, August 25, 2006.

of 0.10 lbs/mmbtu, and not an average or hybrid cap. Consequently, the lack of precision in the LADCO IPM report could erroneously project a 2012 EGU2 SO2 cap and emissions that are too high. *This error creates unrealistic SO2 reduction targets and allowance banks from 2010 to 2013, which results in the deferral of technology deployment beyond 2012.*

Differences in Heat Input Assumptions

Regardless of these concerns about banked allowances, our review of the LADCO report suggests that by 2020 electric generators would achieve the 2020 SO2 EGU2 cap *without* the use of banked allowances. Further, their NOx emissions would be slightly above the EGU2 cap, requiring the withdrawal of a small amount of banked NOx allowances. In addition, as best as we can determine, LADCO's 2020 regional heat input of 6,011 TBtu is comparable to MOG's 2013 regional heat input of 6,088 TBtu.[5] A discrepancy does arise when performing the same calculation using the 2020 NOx EGU2 cap (from Table 6) and the EGU2 NOx emission rate. This method provides an estimate of 2020 regional heat input of 6,482 TBtu, representing a significant difference. Therefore, two questions arise: (i) is there a computational error in computing the regional heat input; or, (ii) has the LADCO report included more capacity in computing the EGU2 NOx budget than they used in computing the EGU2 SO2 budget. Since this question cannot be answered based upon the available information in the LADCO report, we used the regional heat input derived from the SO2 budget of 6,011 TBtu. This value is very close to MOG's 2013 regional heat input (for units >25 MW) of 6,088 TBtu, and allows a better comparison of technology deployment.

Therefore, comparing MOG's 2013 technology deployment with LADCO's 2020 technology deployment is appropriate, because LADCO's compliance requires either very little or no use of allowances, and the regional heat input is comparable to both studies. However, we were unable to obtain and review the IPM parsed files for 2018 and 2020 for the EGU2 policy run (*LADCO_PC_1d*); consequently, we had to make some inferences on the level of FGD and SCR capacity that would have to be installed within the LADCO region to meet EGU2 in 2020. To do this, we evaluated two distinct data sets, based upon available data.

Because only aggregated information is available from the LADCO report, we can make only initial comparisons between MOG's 2013 compliance and LADCO's 2018 compliance estimates. As shown in Table 2, MOG's FGD capacity in 2013 is about 9.3 GW greater than LADCO, while MOG's SCR capacity is 13.1 GW greater than LADCO.

[5] The 2020 LADCO regional heat input is determined by dividing the 2020 SO2 EGU cap of 301,000 tons (from Table 6) by the EGU SO2 emission rate (0.10 lbs/mmbtu) yields a regional heat input of 6,011 TBtu.

Table 2: Estimated Incremental FGD & SCR Capacity under EGU2 (GW)

Study	FGD	SCR
MOG (2013)	60.7	41.0
LADCO (2018)	51.4	27.9

As mentioned earlier, the LADCO analysis allows for the banking and carrying forward of allowances, which allows for the *deferral* of both FGD and SCR deployment, while the MOG analysis did not allow for this type of banking. Even with the use of banked SO2 allowances for compliance and a less stringent emission cap in the LADCO analysis, the levels of FGD capacity in the two studies are very close. So the question arises, when the banks are drawn down to zero, would the LADCO FGD and SCR capacity mirror the MOG capacity?

Comparison of Emissions and Caps

Evaluating regional heat input and emissions in 2020 may provide additional insight. Using the regional heat inputs described earlier and computed emission rates from Table 6 of the LADCO report yields the following emission/cap comparisons for both studies:

Table 3: 5-State SO2 & NOx Emissions and Caps under EGU2 (tons)

	MOG (2013)			**LADCO (2020)**		
	Emissions	**Cap**	**Over/Under**	**Emissions**	**Cap**	**Over/Under**
SO2	**371,536**	**304,403**	**67,133**	**300,530**	**300,530**	**0**
NOx	**249,203**	**213,082**	**36,121**	**213,391**	**210,385**	**3,006**
Regional Heat Input	**6,088 TBtu**			**6,011 Tbtu**		

Note: 1. The 2020 LADCO NOx emissions are based upon multiplying a computed NOx emission rate (from Table 6) of 0.071 and multiplying it by the LADCO regional heat input.
2. The SO2 and NOx caps for both MOG and LADCO were computed by multiplying the EGU2 SO2 and NOx emission rate by the regional heat input.

As shown in the above table, both the SO2 and NOx emission caps for both MOG and LADCO are very close; however MOG's emissions are higher. The primary factor affecting the emissions disparity between MOG and LADCO are assumptions defining the capabilities of control technologies. LADCO assumes more aggressive control levels can be achieved by FGD and SCR technology. Specifically, LADCO estimates that electric generators would achieve a NOx emission rate of 0.071 lbs/mmbtu and a SO2 emission rate of 0.10 lbs/mmbtu by 2020. In comparison, MOG estimated control levels of 0.082 lbs/mmbtu for NOx and 0.122 lbs/mmbtu for SO2.

It should be noted that MOG modeling to achieve these NOx and SO2 emission rates showed 18.6 GW of existing coal-fired capacity would switch to PRB coal with FGD systems. The LADCO study still models a NOx bank; however to achieve a region-wide SO2 emission rate of 0.10 lbs/mmbtu it would seem the LADCO modeling would require either: (i) a larger shift to PRB coal with scrubbing within the 5-State Region than projected by MOG; or, (ii) the retirement of a significant amount of existing coal capacity. *Therefore, it seems the use of banked allowances has allowed LADCO to defer the level FGD and SCR capacity to 2020 or beyond what MOG projected in 2013 under a no allowance carry-over regime. This suggests that the compliance implications discussed by MOG eventually would occur in the LADCO modeling if it were extended further in time.*

IPM COSTS AND INDUSTRY EXPERIENCE

This second section of the analysis provides an update of control technology capital costs for flue gas desulfurization (FGD) and NOx control, focusing on wet FGD for the former and selective catalytic reduction (SCR) NOx control for the latter. The wet FGD process cited in this documents refers to a wet limestone-based process, producing gypsum as a byproduct, and capable of 95-97% SO2 removal, depending on coal composition and averaging time.

Background

There is considerable information both in the public domain and reported anonymously describing the capital and operating cost of process equipment to control SO2 and NOx. Significant discrepancies exist among these various data sources provided by equipment suppliers, EPA, and industry.

Recent capital cost estimates for conventional wet FGD and SCR reported by owners significantly exceed those estimated using information published by the supplier community or the EPA. Several factors are likely responsible for this discrepancy; one significant factor is the strong demand for environmental control equipment, coinciding with strong demand for general chemical process facilities. The confluence of these demands escalates the cost of labor and materials essential for this category of equipment. Compounding these differences in capital cost estimates is that some source data from EPA may not represent current market conditions, due to both the methodology and timing of the estimate.

It is instructive to consider the escalation in the cost for chemical process equipment. One popular indicator of such costs is the Chemical Engineering Plant Index, which reflects the escalation in cost for a wide variety of process equipment. Figure 1 depicts the change in the Chemical Engineering Plant Index (Chemical Engineering, 2006) reflecting the construction cost of general plant process equipment, specifically from 1995 through mid-2006.

Figure 1: Chemical Engineering Plant Index (CEPI): 1995 – July 2006)
(Note: 1957-1959 = 100)

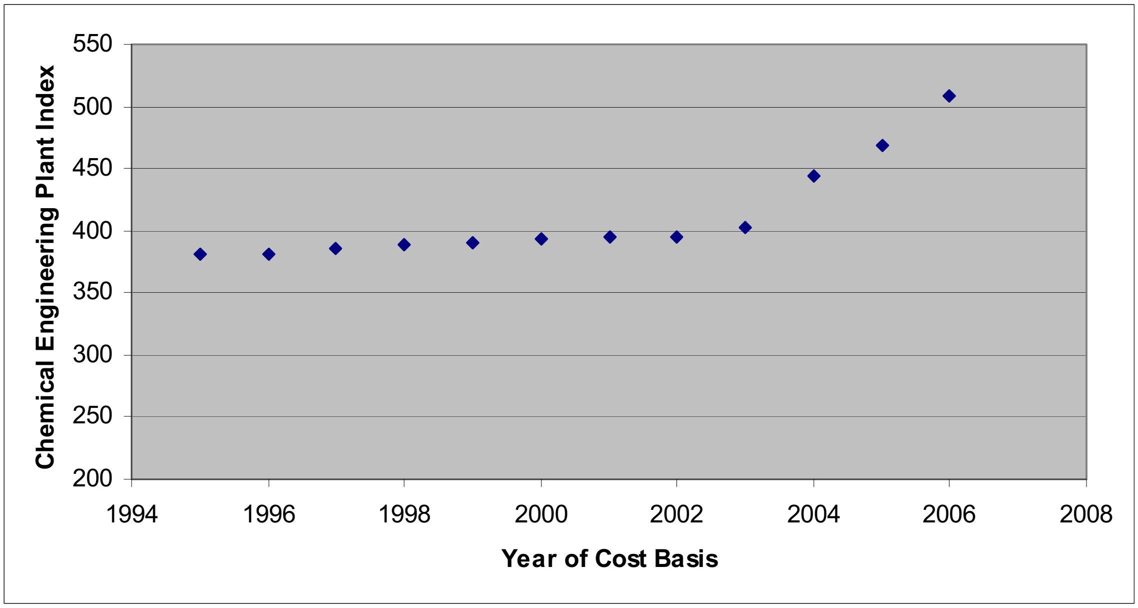


Figure 1 shows little change in the Chemical Engineering Plant Index from 1995 through the end of 2003, but 2004 marked the beginning of significant escalation that continues unabated. This trend reflects several factors important to environmental controls, such as escalation in material cost for upgrading electrical equipment. Due to intensive use of copper and a four-fold increase in copper prices, this index has risen rapidly since 2003. Competition for materials from China, driven by their rapid electrification program, is adding demand-push pressures to U.S. pollution control construction costs. Figure 1 shows that even with all other factors equal, cost escalation due to a robust demand will increase installed cost of process equipment.

Comparison of FGD Estimates: 2000-2006

Estimates of capital and operating cost for both wet and dry FGD equipment have been derived in the last five to seven years from a variety of sources. These include estimates for CAIR compliance, specific costs announced for CAIR retrofits, and projections by EPA and regulatory agencies based upon knowledge of equipment cost and availability. Compounding the complexity of preparing realistic cost estimates is the uncertainty in labor pool availability and cost, and the project scope – what equipment changes are included or excluded in the budget. This section summarizes the cost trends noted prior to the year 2006.

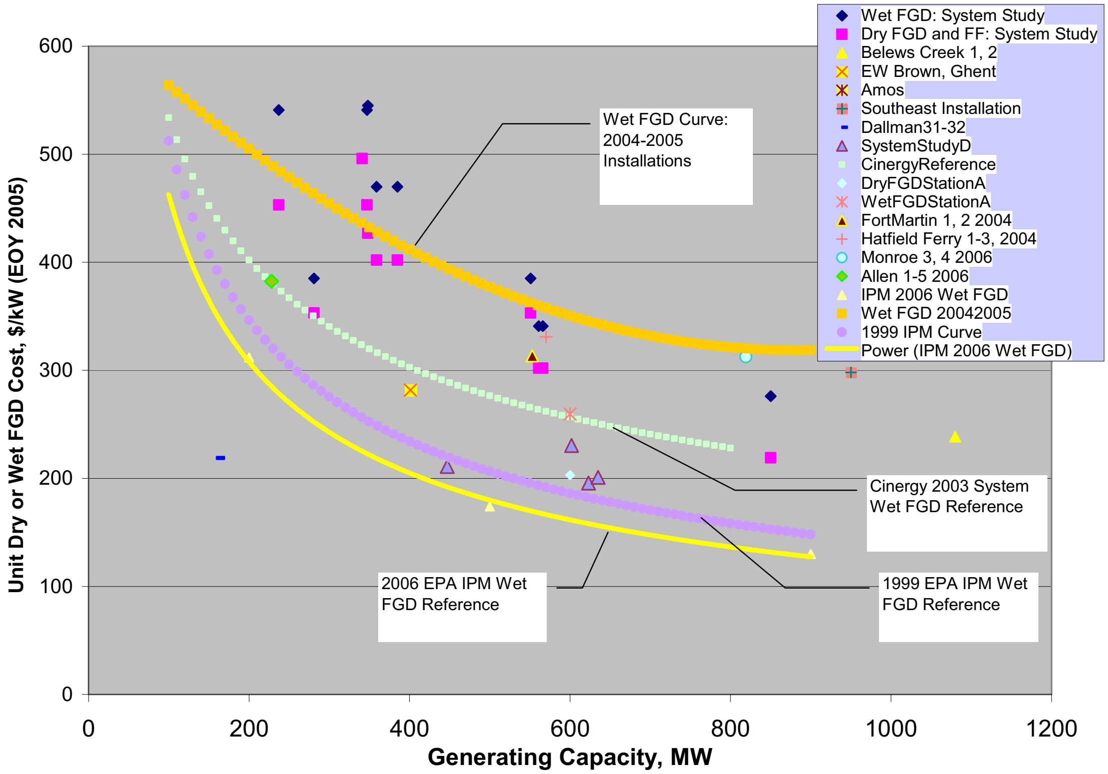
Figure 2 presents a summary of FGD capital cost, shown as a function of unit generating capacity, for both dry and wet FGD, derived from a number of sources. All reported equipment costs have been adjusted to the end-of-year 2005, using the GDP escalating factor. It should be noted that FGD costs for all generating stations are reported per unit of generating capacity, even for system-wide designs for large generating systems. For example, FGD capital for Duke Energy's Allen Units 1-4 is reported for a single Allen unit capacity of 270 MW; however the design is predicated on the generating capacity of the entire station of 1200 MW. Consequently, the available economies of scale – particularly important in reagent receiving and solid byproduct management - serve to reduce the unit cost.

Figure 2 shows a wide disparity in projected costs between several sources and periods of time. These are discussed in the following sections.

2006 EPA IPM Data

The lowest capital cost projections for wet FGD are derived by EPA using their IPM cost correlations, which are applied for EPA modeling of system compliance costs. The IPM supporting documentation (EPA, 2006) and the key source papers (Staudt, 2006, and Khan, 2004) describe the basis of the estimates. The estimating methodology appears to reflect authentic utility cost accounting, and considers both direct and indirect costs. However, it is not clear if these estimates reflect a complete suite of balance-of-plant items, such as upgrade of flue gas fans and electrical distribution components, or reflect the most recent market conditions.

Figure 2: Wet and Dry FGD Capital Cost: Estimates Prior to 2006 (End-of-Year 2005 Dollar Basis)



The EPA IPM capital costs were based on soliciting budget estimates of uninstalled capital equipment costs – and as stated in the reference paper (Staudt, 2006) only one response was received. It is possible that the exploratory and budgetary nature of the estimate as developed by the supplier resulted in an atypically low estimate, which could not be detected by comparison to other sources. In addition, the supplier developed equipment costs for a new "greenfield" application, with the installed retrofit cost provided by a semi-quantitative "retrofit" factor. The retrofit factor selected for this analysis of 1.3 – an appropriate selection by historical standards – may be too small to reflect the complexity of the most recent sites for which FGD is considered. It is widely believed that the first 100,000 MW of FGD capacity retrofit were installed first on those units that provided the lowest removal cost ($ per ton basis), which implies the least capital cost. The units remaining may present more challenging site conditions for retrofits.

Also shown in Figure 2 for comparison is the wet FGD capital cost curve used by EPA in IPM modeling in 1999, which has served as the basis for all but the most recent IPM modeling runs. The projected capital costs (also in end-of-year 2005 dollars) are slightly higher than the updated 2006 cost curve. It is not clear why the 2006-derived costs are lower, given significant increases in demand and material cost as shown by Figure 1.

Cinergy 2003 System Wet FGD Study

A comprehensive evaluation of wet FGD cost for the Cinergy system was conducted in 2003 by Sargent & Lundy Engineers. Individual data points derived in this analysis are not shown but the curve fit for the seven units in the study is reported and corrected to an end-of-year 2005 dollar basis. The shape of the curve is similar to that projected by EPA, but for the same generating capacity, Cinergy projects approximately $75 to $100/kW higher capital cost.

2004-2006 Industry Estimates

Figure 2 reports a locus of points for both wet and dry FGD, derived from numerous cost references in 2004 and 2006, some of which are public. For example, AEP published wet FGD capital cost for Amos, and Allegheny Energy for both Hatfield Ferry Units 1-3 and Fort Martin Units 1 and 2. Detroit Edison released capital cost for Monroe Units 3 and 4. Duke Power released costs for Belews Creek and five units at Allen, the latter each 270 MW but totaling 1200 MW of generating capacity. LG&E energy similarly published results for E.W. Brown and Ghent.

Several anonymous sources contributed cost estimates based on thorough engineering procurement studies: a southeast utility and two system studies for operators in the Midwest.

The locus of data points from these estimates –all derived during the 2004-2006 timeframe – is shown. Also shown is a curve reflecting the general relationship between these data points. Significantly*, these costs exceed those projected by EPA for IPM by over $200/kW – more than double the projected level*.

Sources for Cost FGD Differences

There are several reasons why EPA and industry-generated wet FGD capital costs differ to the extent reported in Figure 2. Each of these is addressed in the following sections. The individual data points on Figure 2 may not all be directly comparable. Except for adjusting all cost estimates to an end-of-year 2005 dollar basis, no effort has been made to assure a uniform basis. The following factors, also included in the EPA methodology (Staudt, 2006), are all usually derived as a fraction of the total process capital, which describes the total cost for process equipment prior to installation. The cost factors are described as follows:

<u>Engineering and Construction Management Charges</u>. The cost for engineering services to define the design of process equipment, and management of these services, is generally 10%, similar to that assumed by Staudt (2006). It is possible that challenging retrofit requires greater engineering expenditure.

<u>Process & Project Contingency</u>. The usual assumptions for these standard contingency values for the relatively mature wet and/or dry FGD is 10% and 5%, respectively. For

reported costs that reflect firm prices from suppliers, it is unlikely any such charges are included as line-item cost elements. For these fixed price bids, each equipment and process supplier will utilize an internal proprietary margin to account for uncertainties. Projects that are conducted on an "open book" basis with a strategic partner will not include such cost elements, but allow cost recovery if actual incurred costs exceed those predicted.

General Facilities. This cost element covers roads, providing for special access, and buildings; any differences are expected to be small.

Contractor Profit/Fees. These charges can be 5-10% of the total

Project Scope. The specific equipment included in the FGD budget can vary. For example, Staudt (2006) discusses the possibility of fan modifications and ductwork changes in an FGD retrofit, but these items are not addressed in the cost estimate. The additional resistance to flue gas flow for a conventional wet and dry FGD system – from 4 to 8 in w.g. – will in most cases require some type of fan upgrade. Further, depending on how the flue gas handling system was originally designed, a significant run of ductwork may have to be strengthened, to avoid damage from significant negative pressure. Again, there is no indication these or the costs – albeit very site specific – are included in the EPA-derived estimates.

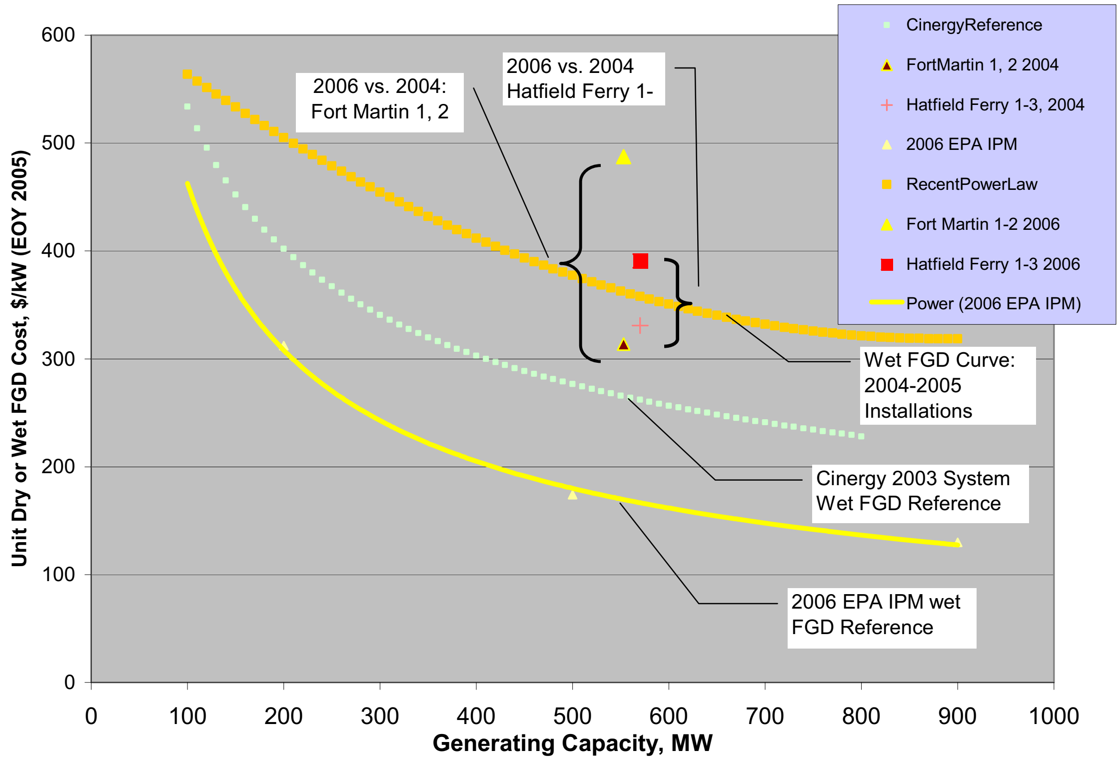
Timing of Costs. The significant demand in flue gas processing equipment – for both FGD and SCR – has evolved into a premium for equipment and services since 2000, and especially so in the last year.

The role of the project schedule and the subsequent timing of the cost estimate are shown by Figure 3. This figure repeats the curve-fit description of capital cost presented in Figure 2, along with 2006 revised costs as reported for two Allegheny Power stations – Fort Martin and Hatfield Ferry. Fort Martin's capital costs escalated significantly from estimates prepared in 2004.

Discussions with representatives of architectural engineering companies involved in wet FGD procurement indicate that a strong demand for essential equipment and services is responsible for the cost escalation. Specific examples are:

Limited access to flue gas fans and slurry pumps. A limited number of equipment suppliers are qualified to provide the large, high reliability fans for flue gas and pumps for process slurry that are critical to reliable performance. At present, the manufacturing capabilities of key suppliers are booked – and establish the limiting step in FGD installation of 30-36 months. Both the shortage of equipment and willingness of purchasers to pay to expedite procurement contribute to these higher costs.

Figure 3: FGD Capital Cost: 2004 vs. 2006 Estimates (End-of-Year 2005 Dollar Basis)



Some observers have noted that the U.S. utility industry qualifies a limited number of suppliers of this equipment, and that relaxing qualification requirements is one way to increase the number of suppliers (Hartenstein, 2006). Given the large and complex nature of recent system FGD installations, it is not known if this action would introduce the use of equipment with less proven reliability.

Limited Stack Erectors. Similarly, there are reportedly a limited number of suppliers world-wide that can fabricate the wet stack designs required to withstand the wet flue gas from FGD. Similar to the case for flue gas and slurry equipment, this can be a limiting step in FGD process installation. At present, it is reported that the four major stack erectors are booked through 2010; any new installation reportedly will not be able to install new wet stacks before the beginning of 2011.

Electrical Equipment. The requirement for additional power for pumps, fans, and associated equipment can significantly increase the on-site demand for power, and distribution such as motor control centers for power management and distribution. The cost of these upgrades – dependent on copper-containing products – has increased reflecting the four-fold increase in copper prices in recent years. Upgrade of electrical subsystems – historically 6-8% of an FGD project - can now exceed 15%.

Installation Difficulty. The units reflected in Figure 2 and 3 represent approximately the second 100 GW of wet FGD installed. As discussed previously, the first 100 GW were initially selected for a large number of reasons – of which ease of retrofit and low capital cost was likely the most significant factor. It is these early applications that provided the bases for the historical retrofit factor of 1.3. It is likely that units within the second 100 GW of retrofit candidates represent more difficult retrofit applications, which the historical 1.3 retrofit factor does not capture. Compounding the retrofit difficulty is the higher cost of labor, due to shortages reported by many operators of FGD process equipment.

In summary, the capital cost for wet FGD process equipment between estimates derived for use in IPM modeling and industry-reported costs differ significantly, by approximately a factor of two. The key reasons for this difference are likely the timing of the estimates (e.g. reflecting 2005 and 2006 market conditions), the complexity of the retrofit sites, and the scope of equipment included.

The consequence of the difference in capital cost, combined with differences in operating cost assumptions (the latter not addressed in this document) is a similarly wide difference in calculated cost per ton ($/ton) of SO2 removal. Specifically, the reported marginal cost values in Table 3 of the ICF report for the EGU2 category notes a range from $1,847 to $2,951/ton for SO2. In contrast, the recent analysis of the authors evaluating the IL Mercury Rule reports dry FGD removal costs between $2,600 and $4,200/ton.[6] These costs are based upon inputs from system generators in Illinois and reflect industry FGD capital costs discussed in this section.

SCR NOx Control

Similar to the case of wet FGD, capital cost estimates derived for SCR NOx control from industry-reported sources and EPA differ significantly. Several reports of SCR capital cost have been published in recent years (Hoskins, 2003; Cichanowicz, 2004; Marano, 2006). The most detailed and comprehensive analysis is provided by Marano, reporting global trends based on approximately 70 SCR installations erected between 1999 through 2005. As shown in Table 4, Marano reports most SCR costs range from $100 to $200/kW. There is a noted increase in capital cost for units installed after 2003.

It is instructive to compare the trend in reported and estimated SCR capital between industry sources and projections by EPA. Figure 4 depicts this trend, utilizing the individual data points reported by Cichanowicz. (Marano did not report individual data so developing such a trend is not possible). Figure 4 shows the wide disparity in capital cost for industry-reported units, which vary by a factor of two or more. The industry-reported data show that increasing generating capacity does not always lower unit (e.g. per $/kW) process cost, as the complexities imposed by the larger generating sites can complicate installation and elevate cost. Also shown on Figure 4 is the trend in projected SCR capital using the relationship employed in EPA IPM modeling (Khan, 2004). This trend is well below that reported by industry.

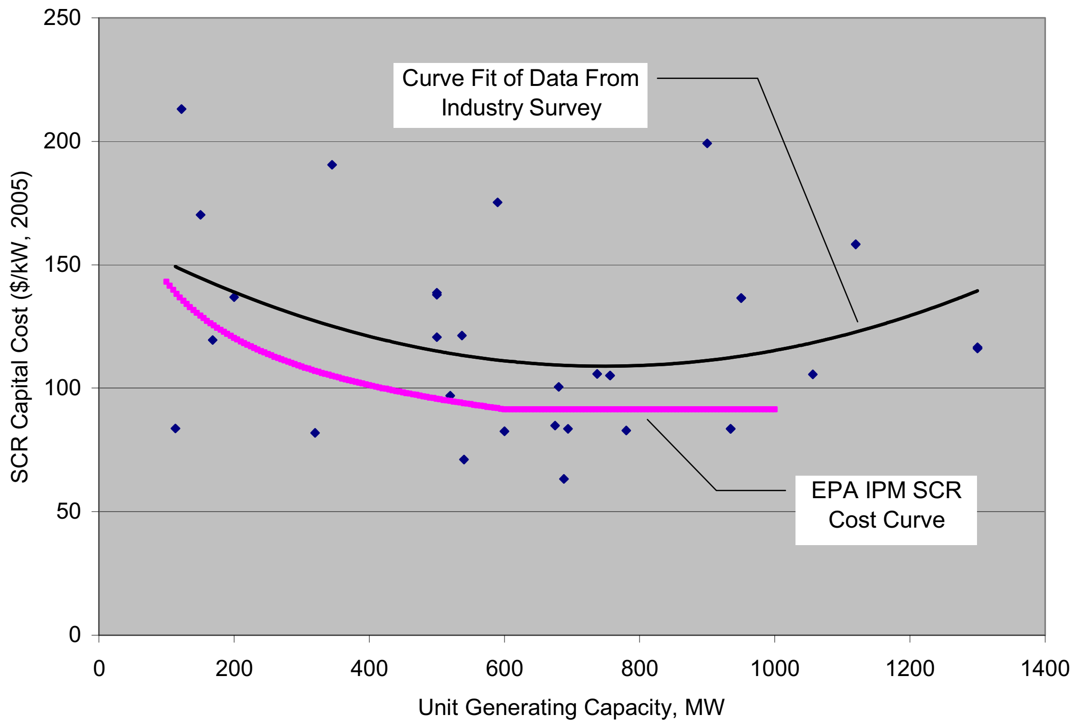
[6] Testimony of James Marchetti before the Illinois Pollution Control Board in rulemaking R06-25 dated July 28, 2006.

Table 4: SCR Capital Cost Survey Results

Reference	Average Capital, MW ($/kW)	Low-High Cost Observed ($/kW)	Observation
Hoskins, 2003	120 (400 MW)	80-160	Cost Basis: 2002. 15 of 20 reported unit costs exceeded $100/kW. Weak relationship of unit cost and scale.
Cichanowicz, 2004	81 (600-899 MW) to 123 (100-399 MW)	56-185	Cost Basis: 2003. For four categories of generating capacity, the least cost units were among the first installed.
Marano, 2006	118 (>900) to 167 (<300 MW)	Most costs reported to be within 100-200	Cost Basis: 2005. "Units with a capacity of 600 to 900 MW appear to be more difficult to retrofit than those in other size ranges."

As explained by Khan (2004), the EPA IPM methodology uses reports of industry SCR costs but adopts these into a fixed scaling relationship. In contrast, we relied on the trend curve depicted in Figure 4 to estimate SCR capital costs.

Figure 4. SCR Capital Cost: Industry Reports versus EPA IPM Modeling (2005 End-of-Year Dollar Basis)



The reason for the disparity in SCR capital costs is likely the same as cited for wet FGD: the recent escalation in material prices has elevated the cost of materials and labor, and the plant sites for industry-reported costs may be more complex than earlier estimates. Consequently, *the difference between EPA and estimates derived from industry experience for SCR equipment can range from $25 to $45/kW.*

Similar to the case for wet FGD, the EPA IPM cost assumptions for SCR are significantly below those reported by industry. The consequence of the difference in capital cost, combined with differences in operating cost assumptions (the latter not addressed in this document) is a similarly wide variance in calculated cost per ton ($/ton) for SCR NOx removal. Specifically, the reported marginal cost values in Table 3 of the ICF report cites for the EGU2 category a range from $$639 to $1,020/ton for NOx. In contrast, the MCH recent analysis evaluating the IL Mercury Rule reports SCR NOx removal costs between $1,500 to $9,800/ton.[7] These costs are based upon inputs from system generators in Illinois and reflect industry SCR capital costs discussed in this section.

[7] Ibid.

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