BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Power & Light Company d.b.a. Alliant Energy for Authority to Construct a New Coal-Fired Electric Generating Unit Known as the Nelson Dewey Generating Station in Cassville, Grant County, Wisconsin	)))))))	**DOCKET NO. 6680-CE-170**

SURREBUTTAL TESTIMONY OF DAVID A. SCHLISSEL ON BEHALF OF THE WISCONSIN CITIZENS UTILITY BOARD AND CLEAN WISCONSIN

SEPTEMBER 15, 2008

PUBLIC VERSION

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

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

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

A. I am testifying on behalf of the Wisconsin Citizens Utility Board and Clean Wisconsin.

Q. Have you previously filed testimony in this proceeding?

A. Yes. I filed Direct Testimony in this proceeding on August 11, 2008.

Q. What is the purpose of this Surrebuttal Testimony?

A. In this Surrebuttal Testimony, I will be responding to a number of statements and claims made by WPL's Rebuttal Witnesses.

1. WPL's Carbon Reduction Plan Is Misleading

Q. WPL witness Bauer testifies that, contrary to your Direct Testimony, the Company's Carbon Reduction Plan is not misleading because "the carbon reduction plan reduces WPL's CO2 emissions overall compared to the scenario of adding generation to meet future needs without the carbon reduction plan."[1] Do you agree?

A. No. The Company's claim that the Carbon Reduction Plan reduces CO_2 emissions overall compared to the scenario of adding generation to meet future needs without the carbon reduction plan is entirely untrue. First, as I discussed at length in my Direct Testimony, the Company's annual CO_2 emissions would [redacted] under the Carbon Reduction Plan beginning in 2014, not [redacted].[2] Second, WPL compared its Carbon reduction plan to a "No Additions" scenario in which no new generation was [redacted]

[1] Rebuttal Testimony of Randy Bauer, at page 31, lines 8-14.
[2] Direct Testimony of David A. Schlissel, at page 17, lines 1-12.

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[redacted]. So there was no comparison whatsoever between the CO_2 emissions under the Carbon Reduction Plan with a scenario of adding generation to meet future needs with the Carbon Reduction Plan.[3]

Even WPL witness Guelker appears to disagree with Mr. Bauer's most recent description of the "No Additions" alternative against which the Carbon Reduction Plan was measured when he stated in his Rebuttal Testimony "By constructing NED 3 and implementing the WPL carbon reduction plan, WPL's CO_2 emissions are reduced compared to the alternative of relying on purchased power and existing resources to meet its future increasing energy needs."[4]

Q. Mr. Bauer has testified that he does not agree with your conclusion that the "No Additions" plan, with which WPL compared its Carbon Reduction Plan, was "unrealistic."[5] Is this consistent with Mr. Bauer's prior sworn testimony during his deposition in this proceeding?

A. No. As I noted in my Direct Testimony, Mr. Bauer agreed that the "No Additions" plan was:

[redacted]

[3] Id, at page 17, line 13, to page 23, line 2.
[4] Rebuttal Testimony of Eric J. Guelker, at page 13, lines 12-18.
[5] Rebuttal Testimony of Randy Bauer, at page 34, lines 20-21.
[6] Direct Testimony of David A. Schlissel, at page 18, lines 9-15.

Q. Mr. Bauer has presented a new plan in his Rebuttal Testimony in which the EGEAS model was allowed to maintain the reserve margin by making one year peak power purchases.[7] Is this a realistic way for a utility to prudently plan and operate its system?

A. No. I don't believe that it is reasonable to expect a utility to buy one year peak power purchases to meet reserve requirements for 30 or more years into the future instead of adding new generating facilities or undertaking new energy efficiency programs. This new plan may be more realistic than the previous "No Additions" plan because at least in the new plan reserve margins are not allowed to [redacted]. However, it does not reasonably reflect how a utility system would be planned and operated over a long period of time. Most significantly, the new "No Additions" plan does not represent a realistic "scenario of adding generation to meet future needs" as claimed by Mr. Bauer.

Q. Does the Company's proposed Carbon Reduction Plan actually reduce CO_2 emissions as compared to the new "No Additions" plan?

A. [redacted]. WPL's annual CO_2 emissions from the Company's EGEAS runs for its Carbon Reduction Plan and its new "No Additions" plan are presented in Table S1 below.

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7 Rebuttal Testimony of Randy Bauer, at page 35, lines 1-5.

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	Carbon Reduction Plan	New "No Additions Plan	Difference
	(Tons of CO_2e)	(Tons of CO_2e)	(Tons of CO_2e)
2013	[redacted]	13,268,436	[redacted]
2014	[redacted]	13,559,937	[redacted]
2015	[redacted]	13,741,027	[redacted]
2016	[redacted]	13,918,497	[redacted]
2017	[redacted]	14,289,424	[redacted]
2018	[redacted]	14,480,946	[redacted]
2019	[redacted]	14,655,693	[redacted]
2020	[redacted]	14,942,894	[redacted]
2021	[redacted]	15,186,492	[redacted]
2022	[redacted]	15,344,986	[redacted]
2023	[redacted]	15,791,942	[redacted]
2024	[redacted]	15,972,287	[redacted]
2025	[redacted]	16,236,858	[redacted]
2026	[redacted]	16,659,070	[redacted]
2027	[redacted]	16,952,072	[redacted]
2028	[redacted]	17,155,264	[redacted]
2029	[redacted]	17,582,612	[redacted]
2030	[redacted]	17,925,464	[redacted]
2031	[redacted]	18,251,260	[redacted]
2032	[redacted]	18,728,030	[redacted]
2033	[redacted]	19,014,482	[redacted]
2034	[redacted]	20,466,516	[redacted]
2035	[redacted]	20,891,332	[redacted]
Total	[redacted]	375,015,521	[redacted]

This Table shows the following:

[redacted]

[redacted]

Thus, whether one measures reductions in absolute terms or in comparison to WPL's unrealistic "No Additions" theory, WPL's Carbon Reduction Plan does [redacted], contrary to what Mr. Bauer has testified.

Q. Are the annual CO_2 emissions for the Carbon Reduction Plan that are calculated under Mr. Bauer's tabular approach realistic?

A. No. The EGEAS model examines the CO_2 emissions that would be achieved in the context of system dispatch and, therefore, are more reasonable. Indeed, Mr. Bauer testifies that WPL conducted its EGEAS modeling to "insure that under a "real life" resource plan that the results in an EGEAS model were consistent with the tabular approach."[8] As I have shown above, the results of Mr. Bauer's tabular approach are not consistent with the results of the more "real life" EGEAS modeling and, instead, dramatically overstate the levels of CO_2 emissions reductions that would be achieved under the proposed Carbon Reduction Plan.

8 Id. at page 35, lines 12-14.

2. Construction of NED 3 Would Conflict with Evolving State, Regional and Federal Climate Change Policies

Q. Do you have any comment on the claim by WPL witness Guelker that building NED 3 would not conflict with evolving state, regional and federal climate change policies?[9]

A. Yes. Mr. Guelker's claim is demonstrably wrong. As I have shown in my Direct Testimony, WPL's own EGEAS modeling shows that with NED 3 its annual CO_2 emissions would [redacted] each year between 2013 and 2035.[10] This would directly conflict with the evolving state, regional and federal policies that will mandate reductions in CO_2 emissions over time.

Q. Is Mr. Guelker's claim that carbon emissions from NED 3 will not dictate whether the state meets the goal of reducing emissions 22 percent from 2005 levels by 2022 also wrong for the same reason?

A. Yes. Adding NED 3 will increase WPL and the state's CO_2 emissions by 2.9 million tons each year, based on WPL's own numbers. The Company attempts to portray its proposed Carbon Reduction Plan as offsetting these increased emissions. Even if the Carbon Reduction Plan offsets were real, which I don't believe is the case, this would mean that the additional wind resources, energy efficiency and plant retirement that are included in the Carbon Reduction Plan would not be available to reduce WPL's CO_2 emissions below current levels.

It is inconceivable that state, regional and federal climate change policies ultimately will do anything but call for reductions in CO_2 emissions from current levels. If WPL uses renewable energy, efficiency and unit retirements to merely offset the increased CO_2 emissions from NED 3, it will fail to have these same options to actually reduce emissions under future CO_2 reduction goals. You can't count the benefits of the same energy efficiency measures and wind resources and

9 Rebuttal Testimony of Eric J. Guelker, at page 13, line 19, to page 14, line 22.
10 Direct Testimony of David A. Schlissel, at page 17, lines 1-12, at page 23, line 3, to page 36, line 10.

the retirement of Edgewater 3 twice: either you can claim that they will offset the increased emissions from NED 3 or they can be used to reduce CO_2 emissions from current levels. But they can't do both.

Q. Does WPL witness Guelker acknowledge this in his Rebuttal Testimony?

A. Yes. Mr. Guelker has testified that:

> The WPL carbon reduction plan is designed to offset the greenhouse gas emissions associated with NED 3. WPL did not design it to meet the reduction goals recommended by the [Governor's] Task Force. Nor did WPL design it to reduce future greenhouse gas emissions to levels below its current greenhouse gas emissions levels.[11]

Q. Do you have any comment on the claim by WPL witness Zuhlke that "The solution to address GHG cannot be decided in a single docket such as this. It must be addressed on a regional and a national scale, not on a utility-by-utility basis?"[12]

A. Yes. I certainly agree that regional and federal action will be needed to address the threat of climate change. However, I disagree with Mr. Zuhlke in that I believe that significant actions by the state of Wisconsin and by this Commission also will be essential. Local and individual actions also will be needed.

More particularly, the Commission has to decide CPCN applications on a case-by-case basis and shouldn't ignore the climate change impacts when deciding these types of applications. The success or failure in avoiding the most dire consequences of global warming will depend on the cumulative impact of numerous decisions, on personal, corporate, local, state, regional and federal levels. Each is important and cannot be disregarded simply because it, alone, cannot solve the entire problem. Each decision either exacerbates the problem or takes us closer to the solution.

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11 Rebuttal Testimony of Eric J. Guelker, at page 13, lines 12-18.
12 Rebuttal Testimony of Kim K. Zuhlke, at page 8, line 13, to page 9, line 7.

Mr. Zuhlke's testimony is a transparent attempt by WPL to ask the Commission to ignore the fact that it is seeking to build a new coal-fired power plant that will emit approximately 2.9 million tons of CO_2 each year for the next 40-60 years.

3. WPL's New EGEAS Modeling Shows that Conversion of the Neenah Facility to Combined Cycle Technology Would Be Significantly Less Expensive than Building NED 3

Q. Have you had a full opportunity to review the EGEAS modeling analyses presented by WPL witness Bauer in his September 8, 2008 Rebuttal Testimony?

A. No. We have only had a very short time in which to review the inputs to and the outputs from the new EGEAS runs discussed by Mr. Bauer in his Rebuttal Testimony.

Q. Have you nevertheless been able to identify any serious flaws in WPL's new EGEAS runs?

A. Yes. We have identified a number of flaws which bias the results of the analyses in favor of NED 3. These flaws include:

- Except for a single run, all of the Company's new EGEAS runs used an 18 percent reserve margin requirement.
- All of the Company's new EGEAS runs assumed extremely high construction costs for combined cycle and combustion turbine alternatives.
- The Company's new EGEAS runs assumed that CO_2 costs only would begin in 2015 and, thereby, provided NED 3 and other fossil alternatives two years of free CO_2 emissions.
- With no supporting analyses, WPL assumed that the $20/ton CO_2 prices assumed by the PSCW Staff in its EGEAS modeling would increase natural gas prices by 10 percent.

Q. Even with all of the biases towards NED 3, do WPL's new EGEAS runs nevertheless show that converting the Neenah facility to combined cycle technology would be a lower cost option than building NED 3?

A. Yes. As Mr. Bauer's testimony and exhibits show, even with each of the flaws identified above, which tend to bias the analysis towards building NED 3, NED 3 is still not the least cost option. The comparison between WPL's new EGEAS runs SK26_R15 (which includes the Neenah conversion to a CC) and SK26_R17 (which includes NED 3) shows an $817 million NPV benefit to converting Neenah over building NED 3.[13] Both of these EGEAS runs include the same CO_2 prices used by the PSCW Staff in its recent EGEAS modeling of the NED 3 project.

Q. But doesn't Mr. Bauer also testify that this $817 million NPV difference suggests that if there is a significant increase in the price of natural gas over the forecasted values, Staff's recommended plan of converting Neenah to combined cycle may at best be cost neutral to customers of WPL when considering all of the other benefits that WPL claims NED 3 will bring to the State of Wisconsin?[14]

A. Yes. Mr. Bauer does make this claim but he provides no evidence to support it. Indeed, the only EGEAS runs that Mr. Bauer presents to evaluate how much the price of natural gas would have to increase for Neenah "to be in a break even mode with NED 3" do not consider any CO_2 costs at all. In fact, he does not present any evidence as to the magnitude of the natural gas price increases that would be required for NED 3 to be even a "break even" option when CO_2 costs are considered.

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[13] Rebuttal Testimony of Randy Bauer, at page 17, lines 1-11, and Exhibit___(RDB-2), Schedule E, page 1 of 2.

[14] Id, at page 17, lines 8-11.

Q. But doesn't WPL witness Zuhlke also testify that WPL's claimed approximate $50 million annual benefit to the State of Wisconsin from burning RRFs at NED 3 would entirely offset the NPV cost benefit that WPL's new EGEAS runs show for the conversion of Neenah to a combined cycle unit?

A. Yes. Mr. Zuhlke does make that claim in his Rebuttal Testimony.[15] However this testimony is critically flawed for several reasons. First, and most importantly, the two EGEAS runs from which Mr. Zuhlke derived the $237.7 million NPV benefit to converting Neenah as opposed to building NED 3 completely ignored CO_2 costs. As noted above, when a reasonable level of CO_2 costs are considered, converting Neenah to a combined cycle facility would be $817 million NPV less expensive than building NED 3. Even if the claimed economic benefits from burning RRFs are included, conversion of Neenah to a combined cycle unit would still be approximately $570 million NPV less expensive than building NED 3 even if the claimed economic benefits from burning RRFs are included when CO_2 costs are considered.

Thus, while WPL witness Bauer has criticized the Staff EGEAS modeling of the proposed Neenah conversion because it did not consider the costs of potential CO_2 regulations,[16] Mr. Zuhlke does precisely that in his Rebuttal Testimony when trying to minimize the significantly higher cost of NED 3.

Second, the two EGEAS runs from which Mr. Zuhlke derived the $237.7 million NPV cost difference both assumed an 18 percent reserve margin requirement, not the 14.5 percent reserve margin that would be required beginning in the summer of 2009, as recently ordered by the Commission.[17]

Third, Mr. Zuhlke completely ignores any economic benefits that would be derived from the conversion of the Neenah facility and the plant's operation as a

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15 Rebuttal Testimony of Kim Zuhlke, at page. 5, lines 17-22.
16 Rebuttal Testimony of Randy Bauer, at page 13, lines 5-12.

combined cycle unit. Additionally, Mr. Zuhlke does not consider any of the negative impacts of the higher rate increases that would be required to pay for the more expensive NED 3. He **only** considers the claimed economic benefits of NED 3.

Q. WPL witness Bauer similarly testifies that when biomass economic benefits are netted against the EGEAS cost comparison of building NED 3 or converting Neenah to combined cycle, NED 3 is effectively equal cost to the Neenah conversion.[18] Is this correct?

A. No. Again, as I have just explained, Mr. Bauer's comparison appears to be based on two EGEAS runs that (1) do not include any CO_2 costs and (2) that have 18 percent reserve margin requirements, contrary to the Commission's recent order. WPL's own EGEAS runs show that when CO_2 costs are considered, conversion of Neenah is by far the lower cost option, even if the claimed biomass economic benefits are included.

4. Combined Cycle Construction Costs

Q. PSCW Staff witness Detmer has testified that in its EGEAS modeling for the Final EIS Staff used an estimated construction cost for a new combined cycle ("CC") plant of $973/kW.[19] In your experience is this a reasonable estimate for the cost of building a new CC plant to use in resource planning analyses?

A. Yes. An estimated construction cost of $973/kW for a new combined cycle unit is reasonable.

For example, an article in the October 2007 issue of *Power Engineering* noted that combined cycle plants could be built for around $750 to $850/kW. Even if an additional 20% is added for owners' costs, these figures suggest an estimated cost within the same range as the figure used by Mr. Detmer.

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17 Docket No. 05-EI-141, PSCW Open Meeting discussion held September 4, 2008.
18 Rebuttal Testimony of Randy Bauer, at page 31, line 15, to page 32, line 5.
19 Rebuttal Testimony of Kenneth J. Detmer, at page 2, lines 11-14.

Xcel Energy used $806/kW for the capital cost of new CC capacity and $560/kW for the cost of new CT capacity in the modeling for its 2007 Colorado Resource Plan.[20] At the same time, a report for the Maryland Public Service Commission in November 2007 recommended using capital costs of $670/kW for CT capacity and $950/kW for CC capacity.[21]

Q. Has Synapse used higher estimated costs for new combined cycle capacity in any of its recent modeling analyses than the PSCW Staff used in its EGEAS modeling?

A. Yes. In modeling we performed in late 2007 for the proposed Big Stone II coal-fired power plant we used estimated costs of $1195/kW for a new combined cycle plant and $870/kW for a new combustion turbine. We used these figures in order to be extremely conservative and to be consistent with the modeling assumptions used by several of the five Big Stone II joint owners.

Q. Is it your conclusion, therefore, that the estimated CC and CT construction costs used by Mr. Detmer in the Final EIS EGEAS modeling were too low?

A. No. As I have shown above, the estimated CC and CT construction costs used by Mr. Detmer certainly were in a zone of reasonableness. In particular, the estimated cost of building a new combined cycle facility used by the PSCW Staff was much more reasonable that the $1684/kW estimated cost used by WPL in the new EGEAS runs presented in Mr. Bauer's Rebuttal Testimony.

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20 Xcel Energy *2007 Colorado Resource Plan*, Volume 2 Technical Appendix, at page 2-262.

21 *Analysis of Options for Maryland's Energy Future*, prepared for the Maryland Public Service Commission by Kaye Scholer LLP, Levitan & Associates, Inc., and SEMCAS Consulting Associates, November 30, 2007, at page 82.

5. The Likelihood of Further NED 3 Construction Cost Increases

Q. Do you have any comment on the claim by WPL witnesses Dusett and Mandarino that it is not reasonable to expect significant further increases in the estimated cost of NED 3?

A. Yes. It is imprudent to assume that there will not be any further significant increases in the cost of building NED 3 given recent industry experience, the current power plant construction environment and the recent experience of NED 3 itself.

Q. What is the recent experience concerning the costs of building coal-fired power plants?

A. As I discussed in detail in my August 11, 2008 Direct Testimony, many power plants construction projects have experienced significant cost increases in the past few years.[22] Even power plants that are already under construction or are in the process of negotiating major equipment contracts have experienced substantial increases in cost during the past year.[23] NED 3 cannot be expected to avoid similar increases just because the contract with URS-WD has a target price.

Q. What is the current environment for power plant construction projects?

A. As I discussed in my August 11, 2008 Direct Testimony, the cost increases now being experienced by power plant construction projects are the result of a worldwide competition for power plant design and construction resources, commodities and equipment.

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22 Direct Testimony of David A. Schlissel, at 45 to 57 and 87 to 90.
23 Id, at page 53, line 24, to page 54, line 18.

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

A. Yes. The worldwide competition for power plant resources is generally recognized as the driving force for skyrocketing construction costs. For example, a June 2007 report by Standard & Poor's, *Increasing Construction Costs Could Hamper U.S. Utilities' Plan to Build New Power Generation*, found that:

> As a result of declining reserve margins in some U.S. regions … brought about by a sustained growth of the economy, the domestic power industry is in the midst of an expansion. Standing in the way are capital costs of new generation that have risen substantially over the past three years. Cost pressures have been caused by demands of global infrastructure expansion. In the domestic power industry, cost pressures have arisen from higher demand for pollution control equipment, expansion of the transmission grid, and new generation. While the industry has experienced buildout cycles in the past, what makes the current environment different is the supply-side resource challenges faced by the construction industry. A confluence of resource limitations have contributed, which Standard & Poors' Rating Services broadly classifies under the following categories
>
> - Global demand for commodities
> - Material and equipment supply
> - Relative inexperience of new labor force, and
> - Contractor availability
>
> The power industry has seen capital costs for new generation climb by more than 50% in the past three years, with more than 70% of this increase resulting from engineering, procurement and construction (EPC) costs. Continuing demand, both domestic and

> international, for EPC services will likely keep costs at elevated levels.[24]

Standard & Poor's warned, therefore, that "it is possible that with declining reserve margins, utilities could end up building generation at a time when labor and materials shortages cause capital costs to rise, well north of $2,500 per kW for supercritical coal plants and approaching $1,000 per kW for combined-cycle gas turbines (CCGT)."[25]

Standard & Poor's also concluded that "as capital costs rise, energy efficiency and demand side management already important from a climate change perspective, become even more crucial as any reduction in demand will mean lower requirements for new capacity."[26]

Price increases have become so dramatic that the president of the Siemens Power Generation Group told the New York Times in mid-2007 that "There's real sticker shock out there."[27] Similarly, in its 2007 Application to the Ohio Power Siting Board, American Municipal Power-Ohio noted that the price increases currently being experienced in the expected construction costs of coal based electric generation were "staggering."[28]

Finally, a September 2007 report on *Rising Utility Construction Costs* prepared by the Brattle Group for the EDISON Foundation of the Edison Electric Institute similarly concluded that:

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

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[24] *Increasing Construction Costs Could Hamper U.S. Utilities' Plans to Build New Power Generation*, Standard & Poor's Rating Services, June 12, 2007, at page 1. A copy of this report is included as Exhibit___(DAS-S1).
[25] Id.
[26] Id.
[27] "Costs Surge for Building Power Plants," *New York Times*, July 10, 2007.
[28] AMP-Ohio's May 2007 Application to the Ohio Power Siting Board, Section OAC 4906-13-05, at page 4.

> 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.[29]

The report further found that:

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

- Increased labor costs are a smaller contributor to increased utility construction costs, although that contribution may rise in the future as large construction projects across the country raise the demand for specialized and skilled labor over current or 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, it is reasonable to assume that bids will become less cost-competitive as new construction projects are added to the queue.

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

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

[29] *Rising Utility Construction Costs: Sources and Impacts*, prepared by The Brattle Group for the EDISON Foundation, September 2007, at page 31. A copy of this report is included as Exhibit___(DAS-S2).

> may be imperiled by the high cost environment. These rising construction costs have also motivated utilities and regulators to more actively pursue energy efficiency and demand response initiatives to reduce the future rate impacts on consumers.[30]

Q. Is it reasonable to expect that the worldwide competition for power plant design and construction resources will continue to lead to further construction cost increases in future years?

A. Yes. I have seen no evidence that these long term factors will abate at any point in the foreseeable future. For example, an October 2007 report by the consulting engineering firm of Burns and Roe for the City of Cleveland Division of Cleveland Public Power noted that it is difficult to predict the escalation of future power plant costs and expressed concern that "India is on the threshold of beginning a rapid expansion in the upcoming years that will place additional pressure on the availability of raw materials, shop fabrication space and available work force for engineering, site management staff and field labor and supervision."[31]

Similarly, Cambridge Energy Research Associates, ("CERA") the firm where WPL witness Yeasting is employed, tracks power plant construction cost increases through its Power Capital Costs Index ("PCCI"). CERA's most recent press release on the PCCI, issued on May 27, 2008, noted that:

> "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 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."

30 Id, at pages 1-3.
31 *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 10-9.

> "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.[32]

Q. But isn't it reasonable to expect, as WPL witness Hookham has testified, that "immediately after CPCN award, WPL will be in a position to negotiate a number of fixed price contracts?"[33]

A. Mr. Hookham may be correct that after awarding of a CPCN, WPL might be in a position to negotiate fixed price contracts for some pieces of the project equipment, but it would not be able to fix the cost for the entire project. In fact, Mr. Hookham does not claim that WPL will be able to fix the cost of the entire project. The key questions, which neither Mr. Hookham nor Messrs. Dusett and Mandarino answer, are how many fixed price contracts will WPL be able to negotiate (Mr. Hookham just says "a number") and what portions of the total project costs can reasonably be expected to be covered by such fixed price contracts. My understanding from other project reviews is that it is not reasonable to expect in the current construction environment that major project costs, such as for labor and commodities, could be covered by fixed price contracts. Thus, even after awarding of a CPCN, there would continue to be significant project cost uncertainty. Indeed, Mr. Hookham testifies in his Rebuttal Testimony that recent negotiations with a steam turbine generator vendor have resulted in "**reasonably** fixed costs" for this equipment not for "fixed costs."[34] (emphasis added) This suggests that, even under this contract that WPL uses as an example of fixed costs, a portion of the costs would be subject to future escalation.

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32 Available at http://energy.ihs.com/NEWS/Press-Releases/2008/IHS-CERA-Power-Capital-Costs-Index.html.

33 Rebuttal Testimony of Charles J. Hookham, at page 4, lines 7-9.

34 Id, at page 4, lines 1-2.

Q. Does the recent history of NED 3 itself suggest that further cost increases should not be anticipated?

A. No. After announcing a 38 percent increase in the project's estimated cost in the spring, a short three months later, WPL witnesses Hookham, Dusett and Mandarino announce a further cost increase in their Rebuttal Testimony. Moreover, WPL has not presented any testimony that it has signed any significant contracts for the NED 3 project other than the EPC agreement with URS-WD. With so much uncertainty, and the history of other projects as a warning, it would be imprudent to expect that there will not be further cost increases at any time over the next five to six years, a period which would include the time for licensing and construction of NED 3.

Q. Is there any evidence in the Company's rebuttal testimony that leads you to believe that it is reasonable to expect that there will not be further significant increases in the cost of building NED 3?

A. No.

Q. WPL witnesses Dusett and Mandarino have disagreed with your observation that there are factors that could lead to a construction schedule for NED 3 of longer than 50 months.[35] Do you have any comment on their testimony on this point?

A. Yes. Messrs. Dusett and Mandarino also testify that the project now has a 55-56 month construction schedule which is 5-6 months longer than the 50 month schedule WPL claimed for the project at the time I filed my August 11, 2008 Direct Testimony. This new and longer construction schedule proves that the observation in my Direct Testimony, with which Messrs. Dusett and Mandarino have taken issue, was correct.

35 Rebuttal Testimony of Charles E. Dusett, Jr., and Mario L. Mandarino, at page 10, lines 10-14.

Q. Is it reasonable to expect that the construction of NED 3 might take longer than this new 55-56 month schedule?

A. Yes. As I noted in my Direct Testimony the same worldwide competition for power plant design and construction resources, commodities and equipment that have led to the soaring coal plant construction costs also could extend the NED 3 construction schedule.

Q. WPL witnesses Dusett and Mandarino have discussed the target price set in the contract between WPL and URS-WD.[36] Is the target price fixed or can it be increased during the construction of NED 3?

[redacted]

6. The Commercial Availability of Carbon Capture and Sequestration Technology for Coal Plants Like NED 3

Q. Do you have any comment on the testimony by WPL witness Hookham that he does not entirely agree with your conclusion that there is not a commercially viable technology for carbon capture and sequestration from coal plants like the proposed NED 3?[39]

A. Mr. Hookham's testimony is in direct conflict with WPL's stated position that "CO_2 emissions control technologies are not currently commercially available at

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36 Id, at page 6, line 17, to page 7, line 12.

37 Target Cost Engineering, Procurement and Construction Agreement, provided in response to 4-CUB/RFP-9, at Bates Page Number WPL 076401.

38 Id, at Bates Page Numbers WPL 076341-342.

39 Rebuttal Testimony of Charles J. Hookham, at page 4, lines 10-13.

the scale needed for utility type applications."[40] Additionally, Mr. Hookham's testimony does not identify any CCS technologies that are commercially available and applicable to NED 3.

7. National Gas Price Volatility

Q. A number of WPL's rebuttal witnesses discuss natural gas price volatility.[41] Do you agree that the Commission should be concerned about the volatility of natural gas prices?

A. Yes. All fuel prices will exhibit some degree of price volatility – that is daily, weekly or monthly variations based on fluctuations in the relationships between supplies and demand, and weather. Of course, Commissions should be concerned about such volatility and should require utilities to take reasonable actions to hedge natural gas supplies in order to minimize volatility.

It is obvious that WPL's focus on only natural gas price volatility is intended to taint the lower cost option of converting the Neenah unit to combined cycle technology or building a greenfield CC unit. However, there are a number of other key variables, in addition to future natural gas prices, which also are highly uncertain. These include the ultimate cost of NED 3, future coal prices, prices for the biomass that could be co-fired at NED 3, and, especially, future CO_2 prices. A utility such as WPL should consider all of these uncertainties in its resource planning and the Commission also should consider them in its deliberations. A narrow focus on only one uncertain variable is not helpful or prudent.

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40 See the Direct Testimony of David A. Schlissel, at page 79, lines 7-14, citing WPL Response to Interrogatory 4-CUB-29.

41 For example, see the Rebuttal Testimony of Kim K. Zuhlke, at page 4, lines 20-21, and the Rebuttal Testimony of Randy Bauer, at page 21, line 16, to page 22, line 4.

Q. WPL witness Bauer disputes your observation that neither WPL nor the region is highly dependent on natural gas as part of their generation mix.[42] Does the information he cites support his claim that the Company and region are "highly dependent" on natural gas?

A. No. The data in Mr. Bauer's Exhibit___(RDB-2), Schedule L shows that as late as 2012, the state of Wisconsin would be dependent on natural gas-fired generation for only 11 percent of its total energy and that the Company would depend on natural gas generation for only 17 percent of its generation. At the same time, the former Mid-American Interconnected Network area would be dependent on gas for only 8 percent of its generation and the Mid-Continent Area Power Pool area would be dependent on natural gas for just 2 percent of its generation. None of these areas would be anywhere near "highly" dependent on natural gas.

Q. How does Wisconsin's dependence on natural gas as a fuel for electric generation compare with other states?

A. Data published by the U.S. Department of Energy shows that a number of other states are far more heavily dependent on natural gas as a fuel for electric generation that Wisconsin. For example, data for 2006, the most recent year available, shows that:[43]

- Arizona was dependent on natural gas as a fuel for 49 percent of its electric generation
- California was dependent on natural gas for 49 percent of its electric generation
- Connecticut was dependent on natural gas for 30 percent of its electric generation
- Florida was dependent on natural gas for 43 percent of its electric generation
- Louisiana was dependent on natural gas for 45 percent of its electric generation

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42 Rebuttal Testimony of Randy Bauer, at page 37, line 16, to page 38, line 5.
43 Data available at http://www.eia.doe.gov/cneaf/electricity/epa/generation_state.xls

- Massachusetts was dependent on natural gas for 51 percent of its electric generation
- Mississippi was dependent on natural gas for 34 percent of its electric generation
- Oklahoma was dependent on natural gas for 47 percent of its electric generation
- Texas was dependent on natural gas for 49 percent of its electric generation

Q. Have any of these states recently rejected proposed coal plants despite their relatively heavy dependence on natural gas as a fuel for electric generation?

A. Yes. As I discussed in my Direct Testimony, The Florida Public Service Commission's decided in mid-2007 to deny approval for the 1,960 MW Glades Power Project. This decision was based on concern over the uncertainties over plant costs, coal and natural gas prices, and future environmental costs, including carbon allowance costs.[44] The Oklahoma Corporation Commission similarly voted in September 2007 to reject Public Service of Oklahoma's application to build a new coal-fired power plant.[45]

New coal-fired power plants have been approved by the regulatory Commissions in Louisiana and Texas. However, the Texas PUC recently placed a cap on the cost of SWEPCO's proposed Turk coal plant at the unit's currently estimated construction cost.[46] The Commission said that such a cap "limits the financial risk to Texas retail ratepayers arising out of uncertainties identified in the testimony including, but not limited to, the following: increased material and labor costs because of delays…."

The Commission also placed a limit on the extent to which carbon mitigation costs will be passed on to Texas retail ratepayers. The Commission explained "It is unreasonable to expect the retail ratepayers to be responsible for these costs that

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44 Order No. PSC-07-0557-FOF-EI, Docket No. 070098-EI, July 2, 2007.
45 Cause No. PUD 200700012 signed Order No. 545240, October 2007.
46 Texas PUC Order in Docket No. 33891, dated August 12, 2008.

exceed $28 per ton of CO2 emissions through the year 2030. To the extent that carbon legislation or implementation of mitigation technology results in costs that exceed that amount per ton, these costs shall not be borne by Texas ratepayers."

Q. Are there other alternatives for limiting the dependence of WPL, the State of Wisconsin, and the northern Midwest region on natural gas besides building NED 3?

A. Yes. Energy efficiency (both for electricity and for natural gas) and renewable technologies are reasonable alternatives for limiting dependence on natural gas. Repowering older natural gas-fired units with newer, more efficient combined cycle technology is another option.

Q. Does the data in Mr. Bauer's Exhibit___(RDB-2), Schedule L offer any insights into the region's dependence on coal?

A. Yes. WPL, the State of Wisconsin and the upper Midwest region are all very heavily dependent on coal-fired generation, even without construction of NED 3. For example, the information in Mr. Bauer's Schedule L projects that the State of Wisconsin will be dependent on coal for 68 percent of its energy in 2012. WPL would be dependent on coal-fired generation for 64 percent of its generation in that year. The Mid-America Interconnected Network and Mid-Continent Area Power Pool regions would be dependent on coal for 55 percent and 71 percent of their energy generation, respectively. These figures show an extremely heavy dependence on a single fuel - coal, not gas. And they do not even reflect the additional coal-fired generation that would be provided by NED 3.

Q. Is it prudent for WPL and the State of Wisconsin to be so heavily dependent on coal-fired generation in light of evolving state, regional and federal climate change policies?

A. No. Almost everyone, including WPL, agrees that some regulation of CO_2 emissions is imminent and that that regulation will involve some form of allowance prices or carbon tax. Ratepayers in the State of Wisconsin are already heavily exposed to the costs of such CO_2 regulation due to the State's already heavy dependence on coal-fired generation. It would not be prudent to increase that exposure by adding NED 3 and the additional 2.9 million tons or so of CO_2 it will emit every year for the next 40 to 60 years.

8. WPL's Failure to Include CO_2 Costs in its Base Case Analyses

Q. WPL witness Bauer defends the Company's failure to include any CO_2 costs in its base case analyses by claiming there is too much uncertainty about what carbon regulation will look like.[47] Is uncertainty a valid reason for not including CO_2 costs in base case analyses?

A. No. Future fuel prices, especially 10 to 20 years in the future, are uncertain. Yet no one would suggest preparing any resource planning analyses without any estimates of future natural gas or coal prices. By ignoring CO_2 costs in its base case analyses, WPL is implicitly assuming a price of $0 per ton for CO_2 emissions. Therefore, the question is not whether WPL is reasonable in not considering CO_2 emissions in its base case analyses, but whether the Company is reasonable in assuming a $0/ton price for those emissions. There can be reasonable debate on the *exact* future cost of CO_2 emissions, but it is not prudent to assume it will be $0/ton.

Q. Mr. Bauer has cited a recent decision by the Iowa Utility Board in support of WPL's failure to include any CO_2 costs in its base case analyses.[48] Do other regulatory commissions require utilities to include CO_2 costs in their resource planning?

A. Yes. An increasing number of state regulatory commissions are requiring utilities to include CO_2 costs in their resource planning. For example, in June 2007, the New Mexico Public Regulation Commission required utilities to use CO_2 prices

[47] Rebuttal Testimony of Randy Bauer, at page 36, line 21, to page 37, line 10.
[48] Rebuttal Testimony of Randy Bauer, at page 37, lines 9-15.

of $8/metric ton, $20/metric ton and $40/metric ton in their resource plans. These prices are assumed to start in 2010 and escalate at 2.5 percent per year.[49]

9. The Significance of the Carbon Principles Issued by Citigroup and Other Financial Institutions

Q. WPL witness Bacalao's Rebuttal Testimony says that "Without saying so, Mr. Schlissel seems to imply that WPL will have difficulty financing the proposed electric generating facility."[50] In fact, did you state or imply that WPL would have difficulty financing NED 3?

A. The use of the phrase "Without saying so, Mr. Schlissel seems to imply" shows clearly that Mr. Bacalao and WPL are seeking to put words in my mouth that I never included or even implied in my Direct Testimony. Although I have spoken to investors and securities analysts on numerous occasions about the risks of investing in coal-fired power plant construction projects, I have never asked anyone whether WPL would have difficulty financing NED 3. As can be seen from my Direct Testimony, I included the discussion of the Carbon Principles to show that the financial community is taking actions to ensure that utilities are properly accounting for CO_2 prices in their resource planning.[51] Mr. Bacalao does not dispute this fact.

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49 New Mexico Public Regulation Commission, *Order Approving Recommended Decision and Adopting Standardized Carbon Emissions Costs for Integrated Resource Plans*, Case No. 06-00448-UT, June 19, 2007.

50 Rebuttal Testimony of Enrique Bacalao, at page 16, line 1, to page 17, line 2.

51 Direct Testimony of David A. Schlissel, at page 62, line 32, to page 63, line 14.

10. The Evidence to Support the Assumptions that CUB and Clean Wisconsin Asked the PSCW Staff to Include in its New EGEAS Runs

Q. WPL Bauer has testified that you provided "scant" evidence that supports the assumptions in the new EGEAS runs that CUB and Clean Wisconsin asked the PSCW Staff to run for the FEIS.[52] Is Mr. Bauer correct?

A. No. I believe we provided sufficient information to justify the revised assumptions we requested the PSCW Staff to include in the three new EGEAS runs we requested.

For example, I discussed the basis for the \$20/ton and \$30/ton CO_2 prices that we asked the PSCW Staff to include in the new runs at page 38, line 17, to page 42, line 9 and at page 60, line 5, to page 65, line 23, of my Direct Testimony.

I similarly discussed the basis for the 14 percent and 15 percent reserve margins that we asked the PSCW Staff to assume in the new runs at page 37, line 23, to page 38, line 10, of my Direct Testimony.

I discussed the appropriateness of using the Company's then-current construction cost estimate for NED 3 and for assuming even further cost escalation at page 45, line 24, to page 57, line 24, of my Direct Testimony.

I provided an explanation of why we were asking the PSCW Staff to use higher fossil fuel prices at page 38, lines 14-14, and at page 74, line 14, to page 78, line 25, of my Direct Testimony.

Finally, in request CUB/CW-2 we only asked the PSCW Staff to assume the same additional DSM and 30 percent renewables by 2030 as it had included for the Draft EIS. We did not make the same request for runs CUB/CW-1 or CUB/CW-3.

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52 Rebuttal Testimony of Randy Bauer, at page 36, lines 13-20.

Q. Is there any other information you want to present to justify that the assumptions that you requested the PSCW Staff to include in their new EGEAS runs are appropriate?

A. Yes. I would just note the following:

1. The Commission's decision in early September to eliminate the 18 percent reserve requirement and, instead, to require a 14.5 percent reserve margin requirement beginning in the summer of 2009 supports our request that the PSCW Staff use 14 percent and 15 percent reserve margin requirements in the three EGEAS runs requested by CUB and Clean Wisconsin.

2. Elsewhere in this Surrebuttal Testimony I have provided additional information on why I believe it is reasonable to consider in resource planning analyses the potential for further increases in the cost of building NED 3.

3. Given WPL's Rebuttal Testimony, I cannot see how the Company can object to our request that the PSCW Staff consider higher natural gas prices in the EGEAS modeling it undertook for CUB and Clean Wisconsin.

Finally, as shown in Figure 6 on page 41 of my Direct Testimony, the \$20/ton and \$30/ton CO_2 prices that CUB and Clean Wisconsin asked the PSCW Staff to use are very conservative (i.e., low) compared to the results of numerous modeling analyses of the major climate change legislation in the current U.S. Congress.

11. The Relationship Between the Enactment of CO_2 Regulatory Legislation and Natural Gas Prices

Q. WPL witness Bauer presents two documents that he cites as supporting the position that if planned coal plant capacity is cancelled in favor of natural gas, natural gas prices could double and that this would not be in the best interests of the customers of WPL.[53] Did Mr. Bauer present sufficient evidence to support his claim?

A. No. Both of the documents presented by Mr. Bauer make far reaching statements but contain only a very limited amount of supporting information, and barely any calculations, to show how they reached their often extreme conclusions.

For example, the NETL White Paper, included as Exhibit____(RDB-2), Schedule D, concludes that natural gas prices could increase dramatically due to opposition to coal plants and the prospect of climate change legislation, and that this could "lead to the collapse of U.S. industrial competitiveness." However, these conclusions appear to be based on the assumption that all of the new coal capacity now under construction or being proposed would be cancelled and would be replaced by natural gas, as would roughly 20-35 percent of existing coal capacity. The White Paper does not allow for any new energy efficiency (either for electricity or natural gas) or for any renewable resources in place of coal facilities. Thus, it overstates the impact that the adoption of regulations limiting CO_2 emissions would have on natural gas demand and, consequently, on prices.

The confidential EPRI presentation presented as Mr. Bauer's Exhibit___(RDB-2), Schedule C, also contains lots of conclusory statements with little supporting information and few, if any, calculations. For example, one slide says that [redacted]

[redacted]

Q. WPL rebuttal witness Yeasting presents an additional study to respond to Staff witness Koepke's conclusion that natural gas prices are not likely to increase faster than coal if a program to control CO_2 emissions is enacted.[54] Have you had a full opportunity to review Mr. Yeasting's analysis?

A. No. We only received this study on Monday, September 8, 2008.

Q. Do you nevertheless have any observations about Mr. Yeasting's study?

A. Yes. I have the following observations which suggest that Mr. Yeasting's study overstates the impact of the enactment of CO_2 regulations on natural gas prices.

First, Mr. Yeasting assumes CO_2 prices of $40/metric tonne and $80/metric tonne. These prices, while reasonable, are substantially higher than the CO_2 costs used by the PSCW Staff in their EGEAS modeling of the NED 3 project.

Second, Mr. Yeasting assumes that coal would be displaced only by natural gas. He allows for no displacement of coal by DSM or renewable resources. Therefore, his study overstates the amount of additional natural gas that would be required and the impact on natural gas prices. Mr. Yeasting's study

[53] Rebuttal Testimony of Randy Bauer, at page 10, lines 3-10.
[54] Rebuttal Testimony of Kenneth L. Yeasting, at page 3, lines 17-20, and Exhibit___(KLY-1).

acknowledges that the impact of non-CO_2 emitting sources of generation would reduce the impact of CO_2 regulations on gas prices.[55]

Third, Mr. Yeasting assumes that the $40/metric tonne or $80/metric tonne prices would be implemented in a single step almost overnight. Instead, all of the proposals in Congress would phase in required CO_2 reductions over decades in a series of declining emissions caps. This means that CO_2 allowance prices can be expected to increase over time. Thus, even if the higher natural gas prices that Mr. Yeasting forecasts actually occurred, they might not be experienced for years, if not decades. Shorter term natural gas price impacts from the enactment of CO_2 regulations would be smaller.

Finally, Mr. Yeasting's study acknowledges that the impact of CO_2 regulations on natural gas prices could be expected to decline over time: "Of course, higher gas prices would drive more drilling and increase future gas production, allowing gas prices to decline, but not fully."[56]

Q. Do the results of Mr. Yeasting's study support the additional 10 percent by which WPL raised natural gas prices in its new EGEAS runs comparing the building of NED 3 to the conversion of Neenah to a combined cycle unit?

A. No.

Q. What impact does Synapse believe the enactment of CO_2 emissions regulations could have on natural gas prices?

A. It is possible that natural gas demand could be higher due to CO_2 emission regulations and, as a result, natural gas prices could be expected to be somewhat higher than otherwise would be the case. However, the effect is very complicated and will depend on a number of factors such as how much new natural gas capacity is built as a result of the higher coal-plant operating costs due to the CO_2 emission allowance prices, how much additional DSM and renewable alternatives

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[55] Exhibit___(KLY-1), at page 18.

are added to the U.S. system, the levels and prices of any incremental natural gas imports or resources developed in the U.S., and changes in the dispatching of the electric system. Indeed, depending on future circumstances there may be some periods in which the prices of natural gas may be lower as a result of CO_2 regulations. Thus it is very difficult to determine, at this time, the amount by which natural gas prices might be raised due to CO_2 emission regulations.

Q. Has Synapse attempted to study the impact that the enactment of CO_2 emissions regulations might have on natural gas prices?

A. Yes. As I discussed in my Direct Testimony, we have reviewed the results of the modeling analyses that have been undertaken to evaluate the CO_2 emissions allowance prices that likely would result from the enactment of the major greenhouse gas regulatory legislation that has been introduced in the current U.S. Congress.[57] As part of this work, we have looked at the available data on the impact that enactment of CO_2 regulatory legislation would have on natural gas prices.

Q. What were the results of this review?

A. Figure DAS-S1 below shows the levelized percentage changes in natural gas prices from the base case forecasts with no CO_2 prices versus the levelized CO_2 prices for various scenarios modeled by the Joint Program at the Massachusetts Institute of Technology ("MIT") on the Science and Policy of Global Change, the U.S. EPA, and the Energy Information Administration ("EIA") of the Department of Energy of climate change proposals in the current U.S. Congress: Senate Bill S.280 (the McCain-Lieberman bill), Senate Bill S.1766 (the Bingaman-Specter bill) and Senate Bill S.2191 (the Lieberman-Warner bill).

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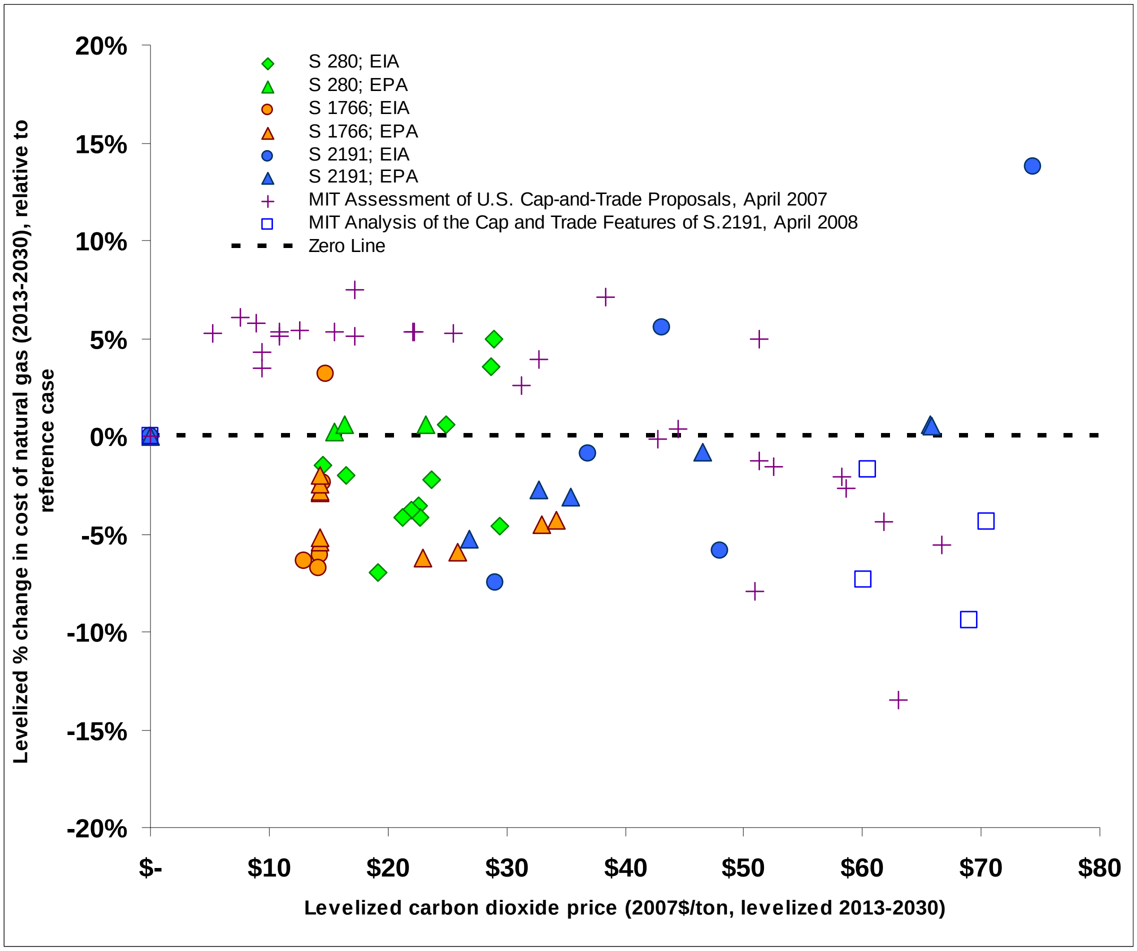
56 Id.
57 See the Direct Testimony of David A. Schlissel, at page 39, line 1, to page 42, line 9.

Figure S1: The Relationship Between CO_2 Emissions Allowance Prices and Natural Gas Prices



This analysis shows that for the relatively modest levels of CO_2 prices assumed by the PSCW Staff in its EGEAS modeling, (that is between $15/ton and $25/ton on a levelized basis) the evidence concerning the impact of the enactment of CO_2 regulatory legislation on natural gas prices is inconclusive: that is, there is no clear evidence that CO_2 prices in this range will have a positive impact on natural gas prices. The data certainly does not support the assumption made by WPL that $20/ton CO_2 emissions allowance prices would cause natural gas prices to rise by 10 percent in each year of the analysis.

12. The Potential to Co-Fire Up to 20 Percent Biomass at NED 3

Q. Are you opposed to utilities using biomass to fire or co-fire electric generating facilities?

A. Not at all.

Q. Why then have you presented testimony that disputes WPL's claim that it will co-fire biomass at NED 3?

A. While there are good biomass proposals, in this case, WPL is seeking to justify the construction of a mostly (i.e., 80 percent to 90 percent) non-renewable fossil-fired generating facility that will emit at least 2.9 million tons of CO_2 each year for 40 to 60 years on the basis that it might co-fire up to 20 percent biomass, if and when a market develops to supply that biomass at an unknown price. As I noted in my Direct Testimony, key uncertainties remain unresolved. Moreover, WPL has failed to show that building NED 3, with or without the capability to co-fire biomass, is part of a least cost, low risk resource plan.

Q. Has WPL presented a plan in its rebuttal testimony for acquiring, transporting and storing the RRFs necessary to co-fire 20 percent biomass at NED 3?

A. No.

Q. Has WPL presented in its rebuttal testimony any information on the potential environmental impacts associated with growing and aggregating the biomass fuel stocks necessary, processing them and transporting them to the NED 3 site?

A. No.

Q. Has WPL presented in its rebuttal testimony any information on the cost of acquiring, transporting and processing biomass fuel stocks for co-firing at NED 3?

A. No.

Q. Has WPL presented in its rebuttal testimony any evidence showing that it has resolved the precise specifications for the fuel that can be burned in the boiler planned for NED 3?

A. No.

Q. WPL's rebuttal witnesses Fiene and Maki criticize what they say is your testimony that there presently is no infrastructure in place to provide RRFs to NED 3.[58] Do these witnesses accurately represent your Direct Testimony?

A. No. What I said in my Direct Testimony was that "The Company has acknowledged that there really is no infrastructure or supply chain organization in the areas near the proposed NED 3 site to provide the required supply of biomass for NED 3."[59] I then cited statements from the Company's documents and testimony that formed the basis for this statement.[60]

Q. Several WPL rebuttal witnesses discuss the Company's commitment to burn 10 percent RRFs in NED 3 by heat input one year after NED 3 reaches COD and 20 percent by heat input by five years after COD.[61] Have any of these witnesses indicated what the Company will do if it is unable, for any reasons, to achieve these goals?

A. No. It is unclear what WPL will seek to do if it is unable to follow through on its "commitment."

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58 Rebuttal Testimony of Andrew J. Fiene, at page 7, lines 14-15 and Rebuttal Testimony of A. Eric Maki, at page 6, lines 11-13.

59 Direct Testimony of David A. Schlissel, at page 13, lines 5-7.

60 Id, at page 13, lines 8-20.

61 For Example, see the Rebuttal Testimony of Kim K. Zuhlke, at page 2, lines 20-21.

Q. Has WPL presented any modeling analyses that show the relative economics of co-firing biomass at NED 3 versus building a stand-alone biomass facility as part of a portfolio of alternatives that also would include converting the Neenah facility to combined cycle technology and adding more wind and energy efficiency?

A. I have not seen any such modeling analyses.

Q. Does this complete your Surrebuttal Testimony?

A. Yes.

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RESEARCH

Increasing Construction Costs Could Hamper U.S. Utilities' Plans To Build New Power Generation

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

While the industry has experienced buildout cycles in the past, what makes the current environment different is the supply-side resource challenges faced by the construction industry. A confluence of resource limitations have contributed, which Standard & Poor's Ratings Services broadly classifies under the following categories:

- Global demand for commodities,
- Material and equipment supply,
- Relative inexperience of new labor force, and
- Contractor availability.

The power industry has seen capital costs for new generation climb by more than 50% in the past three years, with more than 70% of this increase resulting from engineering, procurement, and construction (EPC) costs. Continuing demand, both domestic and international, for EPC services will likely keep costs at elevated levels. As a result, it is possible that with declining reserve margins, utilities could end up building generation at a time when labor and materials shortages cause capital costs to rise, well north of $2,500 per kW for supercritical coal plants and approaching $1,000 per kW for combined-cycle gas turbines (CCGT) (1). In a separate yet key point, as capital costs rise, energy efficiency and demand side management, already important from a climate change perspective, become even more crucial as any reduction in demand will mean lower requirement for new capacity.

Increasing capital costs will affect market participants to varying degrees. For regulated utilities, regulation remains the dominant credit driver. The key credit consideration for utilities with plants under development will be the preapproval of costs in rate base and timeliness of allowed returns as construction progresses. For utilities that choose to accept additional risks posed by nontraditional EPC contracts, agreements for recovery of potential cost increases or self-insurance against contingencies through reserve funds will also be important.

Construction risks of large projects undertaken by unregulated generation affiliates of diversified energy companies may affect the consolidated business risk profile, especially if costs aren't locked in and overages must be recovered from competitive market revenues. Project-financed, single-asset constructions that rely on nonstandard EPC contracts could be challenged to reach investment-grade ratings even if they are fully contracted post-construction.

The Resource Challenge

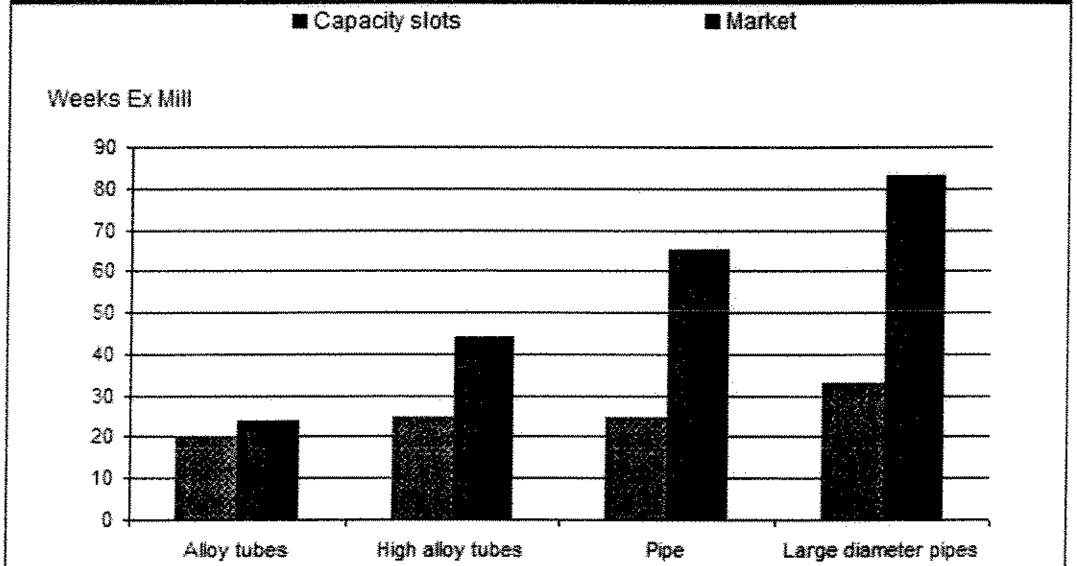
Global demand for commodities

A rapid increase in global demand, predominantly from Asia, has resulted in a sharp increase in prices for commodities important in the power sector. Some industry sources estimate that China's consumption accounted for about 40% of world cement supply and 25% of world steel supply in 2005 (2). A number of construction materials have seen a dramatic price increase in each of the years since the first quarter of 2004, and still remain at elevated levels. Prices of steel--up 50% in first half of 2004 alone--leveled off in 2005 but were on the rise again in 2007, up 20% over December 2005 (3). Copper products (up 60% since December 2005) and cement (up 15% since 2005) are the current drivers for continuing upward price pressures.

Material and equipment supply

In recent years, price competitiveness has encouraged (read: forced) original equipment manufacturers to employ global sourcing for raw material and fabrication needs. But here too the rapid growth in Asia, which is drawing on global supply for raw materials, is resulting in longer lead times and price increases. An example of this rapid growth is China: It went from an exporter of iron ore to being the world's largest importer by 2004 (4). Lead times for materials have increased (see chart) as raw material suppliers and fabrication facilities are taking reservation fees in order to secure availability of material and fabrication slots.

Tube And Pipe Leadtimes*



*As of March 2007. Source: Burns & Roe. Market implies no reservation.
© Standard & Poor's 2007.

Relative inexperience of new labor

While an extreme materials price escalation may have run its course, labor costs are becoming the new driver for industry inflation. The Construction Cost Index (CCI) (4) and the Building Cost Index (BCI) have increased at a compound annual growth rate of 5% and 5.5%, respectively, over the past three years. We learned in discussions with EPC contractors that the cost of labor has nearly doubled since the last round of construction in 2001. This labor cost and supply situation is due to a significant amount of construction experience that has retired and replaced by a new, less experienced work force resulting in reductions in labor productivity. And it could get worse: In the engineering sector, over 45% of labor will be eligible for retirement over the next five years. At the same time, strong global labor construction demand is leading to shortages of skilled labor, especially in the energy sector, which threatens the schedule and in-service dates of projects.

Contractor availability

Only a few contractors can absorb the risk of major construction projects. Sponsors are seeing more single bidder projects and an overall reduction in the number of bidders for projects.

Contract provisions are changing

The supply-side issues are causing a change in contract provisions offered by the construction industry. EPC contracts with guaranteed prices that shield utilities from cost overruns are now either very expensive, contain clauses that one can drive a truck through, or simply aren't offered. Simultaneously, we have seen the advent of risk-sharing mechanisms such as multi-prime contracting (EPCM), which distributes construction risk between contractor and sponsor but lowers installed cost.

To be clear though, the record of construction over the past few years when contractors got hit with performance penalties is another reason that contract provisions have changed. Still, the supply issues have allowed contractors the upper hand. We have increasingly seen the use of adjustment clauses as contractors respond to material price escalations, including:

- Material escalation clauses that track the actual variation of prices from bid amounts,
- The use of indices to adjust prices, commonly CCI (which assigns a higher weighting to labor costs) and also the Materials Cost Index,
- An escalation allowance line item in contracts that serves as a cap for the contractor to recover unanticipated cost increases,
- The use of surcharges typically to limit fuel-only escalations, and
- The re-emergence of cost-based plus contracting.

Extent Of Cost Increase

We assessed the magnitude of cost increases by comparing coal projects under construction during 2003 to 2006. Table 1 lists some coal-fired generation projects currently under development:

Table 1

Coal Plants Under Construction

Power plant	Location	Primary owner	Size (MW)	Type of unit	EPC contract	Year EPC contracted	Broke ground	Expected completion	Project cost ($ per kW)
Council Bluffs Unit 4	Iowa	MidAmerican Energy Co.	790	Super-critical	Fixed	2002	2003	2007	1,816
Elm Road	Wisconsin	Wisconsin Energy Corp.	1,230	Super-critical	Fixed	2002/2003	2004	2009/2010	1,781
Weston 4	Wisconsin	WPS Resources Corp.	500	Super-critical	Multi-prime	2002/2003	2004	2008	1,560
Nebraska City 2	Nebraska	Omaha Public Power District	653	Sub critical	Fixed	2004	2005	2009	1,600
Iatan Unit 2	Missouri	Kansas City Power & Light Co.	850	Super-critical	Multi-prime	December 2005	2006	2010	1,965
Plum Point	Arkansas	Plum Point Energy Associates	663	Sub-critical	Fixed	2005	2006	2010	2,150
LongView	Pennsylvania	LongView Power LLC	695	Super-critical	Multi	2006	2007	2010	2,600

Sub and supercritical technologies result in minor differences to capital cost. Adjustments were made to AFUDC/funded interest to make the comparison relevant. Some projects also have modest other costs such as coal cars or transmission connects. AFUDC--Allowance for funds used during construction. EPC--Engineering, procurement, and construction.

The sample is small but the trend is evident. Broadly, capital costs have risen, from about $1,700 per kW in 2003-2004 to about $2,500 per kW by year-end 2006. The increase was sharp from 2005 to 2006. A key comparison is between Nebraska City #2 (NC#2) and the Plum Point Project as these two allow us to control all other cost variables--they are of similar size and have a fixed priced EPC that is contracted with the same construction consortium (we recognize that the existing site gives NC#2 some advantages). The important distinction is that the construction contracting was a year apart. Capital costs for Plum Point were almost 35% higher. The fixed price EPC component for Plum Point was almost 40% higher, increasing to nearly $1,325 per kW compared with $960 per kW for NC#2. For the Longview project, which completed construction contract negotiations a year after Plum Point, the EPC contract price is a further 30% higher at about $1,700 per kW.

New combined-cycle plants have similar issues

We had informal discussions with some EPC contractors to determine the effect on new combined-cycle plants (see table 2). The theme is similar. Labor costs have nearly doubled since the last construction cycle, from about 25% to nearly 40% of total project cost. Other factors included higher costs of commodities like copper, steel, and cement, somewhat offset by reductions in turbine costs. The range of about $745 to $785 per kW is about 20% to 25% higher than costs in 2002. The high range is about 60% higher than price in 2002.

Table 2

Combined-Cycle Plant Cost Comparison*

($ per kW)	EPC 1	EPC 2 low range	EPC 3	Average	EPC 1 high range	EPC 2 High Range
EPC cost	630	615	650	632	870	760
Soft cost¶	160	125	195	160	220	225
Total	790	740	845	792	1090	985

*Costs estimated by three different EPC contractors. Estimates are identified as EPC 1, EPC 2, and EPC 3. ¶Soft costs include water supply, finance, legal, IDC, and natural gas pipe connects. EPC--Engineering, procurement, and construction.

Still, these units have shorter construction lead times and can be carried on utilities' balance sheets without significant credit impact. Together with potential future costs relating to climate change, we could see the cancellation of some coal-fired construction projects and a shift in favor of natural gas fired units. However, supply, longer-term prices, and volatility of natural gas will remain concerns.

Credit Implications For Industry Participants

Because the electric industry is entering a period of sustained building after a prolonged absence, companies are again highly dependent on regulatory decisions for full recovery of these growing costs. There has also been a shift in this round of heavy construction to predominantly rate-based recovery as regulated utilities undertake many large projects. However, regulators are dealing with cost pressures from a variety of other factors, such as expiring frozen/capped periods, fuel cost recovery, distribution related base rate requests, and extensive spending related to environmental emissions control. After the relatively calm period of transition/rate freeze agreements between 1996 and 2005, the sheer volume of rate cases facing regulators will pose a challenge. Balancing competing priorities of maintaining reliability and avoiding rate shocks will be an unenviable job, and some rate-case orders may result in regulatory deferrals or even pressure the full recoverability of rate-based plants, which could weaken some utilities' credit quality.

Recognizing the need for new power, some states are enacting laws that allow utilities to seek regulatory decisions that effectively preapprove the costs of new generation facilities. Rulemaking clarity is also being provided by specifying the rate-making principles that commissions will apply when that new generation can be placed in the utility's rate base. House Bill 577 in Iowa, Senate Bill 79 in Wisconsin, Senate Bill 1416 in Virginia, and House Bill 1910 in Oklahoma are examples of such efforts. While the laws in Wisconsin, Oklahoma, and Virginia remain untested, MidAmerican Energy Co. used Iowa's HF 577 to seek preapproval of its 60.67% ownership interest in the Council Bluffs facility. Pursuant to rate settlements in Iowa, MidAmerican Energy will be permitted to include in its rate base the Iowa portion of up to $682.5 million in construction costs and earn a 12.29% return on equity once the 790 MW plant is completed. Costs exceeding this cap would be recoverable if determined to have been prudently incurred.

Credit implications for regulated utilities should be fairly straight forward. As long as the utility in the process of building a large project has access to protective safeguards like regulatory preapproval for construction, timely recovery on capital work in progress, and other cost-recovery mechanisms, it can meaningfully mitigate the large risks posed by construction projects. Still, these utilities will have to manage overall risks during the construction process to avoid cost overruns. For example, despite their approved fixed-price EPC construction for the Elm Road project, Wisconsin Energy Corp. and Madison Gas & Electric Co. will have to absorb cost escalations from more stringent environmental requirements if overall cost overruns exceed 5% of the approved capital cost.

Regulated utilities that forego the protection of a fixed EPC will increase their exposure to construction risk from material cost increases, scheduling delays, and performance issues. In such cases, we look for regulatory pre-agreements that lessen the risk of disallowance or restricted reserves that mitigate the risk of overruns. Some utilities also address risk by partaking in large projects through joint ownership interest. Utilities have also used a combination of these strategies. The Iaton 2 project is a good example of a EPCM approach that is structured to protect its owners' credit quality. The project has five owners, but two owners, Kansas City Power & Light Co. and Empire District Electric Co., are allowed to accelerate plant-related amortization expense in rate proceedings occurring before the in-service date, and the project has nearly 12.5% of project costs in contingency reserves.

Unregulated generation companies can't recover any of their capital investment through regulated means and must rely on market prices to recover these investments. The current environment of increasing prices has pressured the economics of merchant generation. While capacity markets can provide visibility into market-based revenues in some areas, they have not developed enough to provide the certainty needed to support generation projects with long lead times. However, the capacity clearing price of PJM's first reliability pricing model auction for the eastern Mid-Atlantic Area Council subregion is close to the price that can support new CCGT capital costs. However, it's too early to tell whether this will drive significant unregulated construction activity. We do expect some unregulated generation affiliates of diversified utilities to consider self-build options for CCGTs to lower installed cost. Implications for credit quality will depend on the relative magnitude of construction risk and the presence of mitigating factors like contingency reserves.

Regions with strong demand and depleting reserve margins will see some project finance-based debt issuances. The 695 MW Longview project is a good example of a recently rated merchant project finance transaction. However, in that case, merchant risks dominated the credit--quality considerations. Plum Point is an example of a fully contracted coal-fired plant with a fixed-price EPC currently under construction. The project has investment-grade characteristics supported by 16.5% of the EPC contract price in contingency reserve and contingent equity during construction.

Notes

(1) We exclude nuclear from this discussion as investments in nuclear units may only be in the medium to long term, and potentially at over $4,000 per kW.

(2) John Gallagher and Frank Briggs, Construction Briefings, December 2006, Thomas West.

(3) U.S. Bureau of Labor Statistics.

(4) The Financial Times, Jan. 27, 2004.

(5) Engineering News-Record, a unit of McGraw-Hill Companies. Both the CCI and BCI indexes have labor as the major component at 80% and 64%, respectively.

Other Sources

- "Construction Contract Provisions: Credit Considerations For Utilities That Are Building Owned Generation" published on RatingsDirect on March 30, 2005.
- "Regulatory Support Is Key For U.S. Utilities Building New Coal-Fired Power Plants" published on RatingsDirect on Nov. 3, 2006.

Rising Utility Construction Costs:

Sources and Impacts

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Prepared for:

The EDISON FOUNDATION

SEPTEMBER 2007

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Published by:
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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.

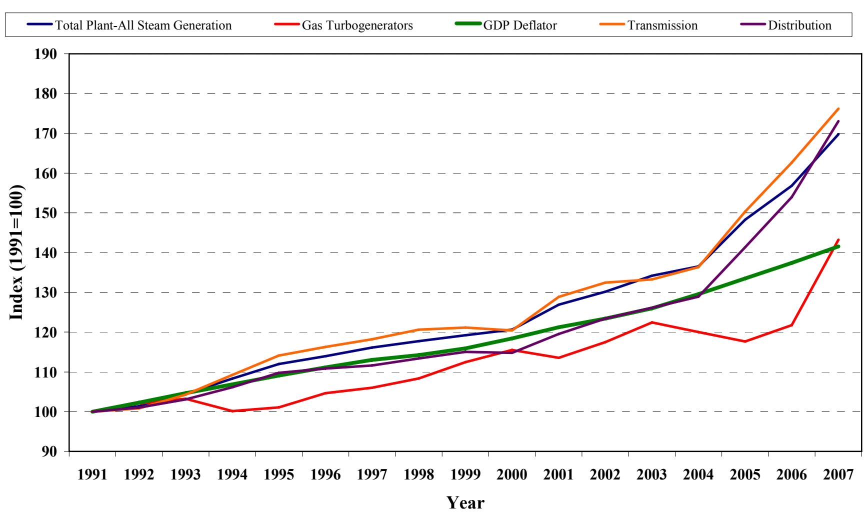
The purpose of this study is to a) document recent increases in the construction cost of utility infrastructure (generation, transmission, and distribution), b) identify the underlying causes of these increases, and c) explain how these increased costs will translate into higher rates that consumers 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

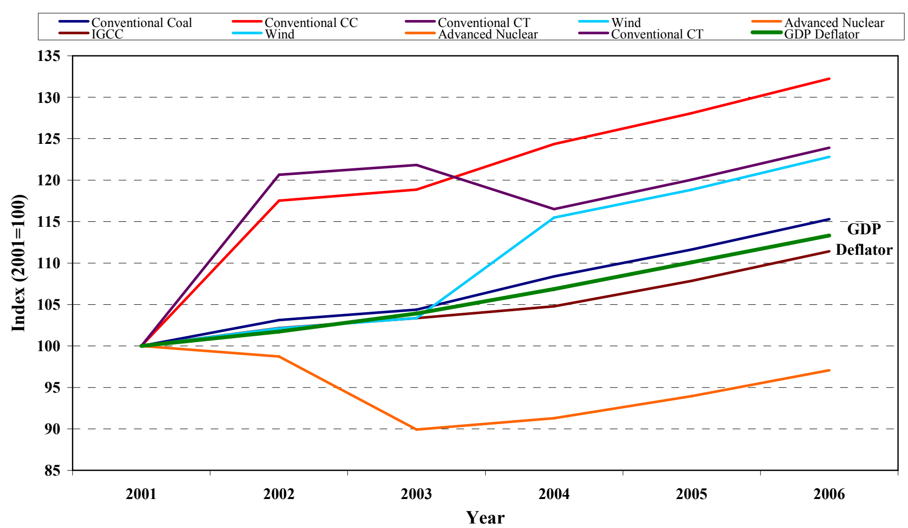


Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indexes for the specified components.

[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

---

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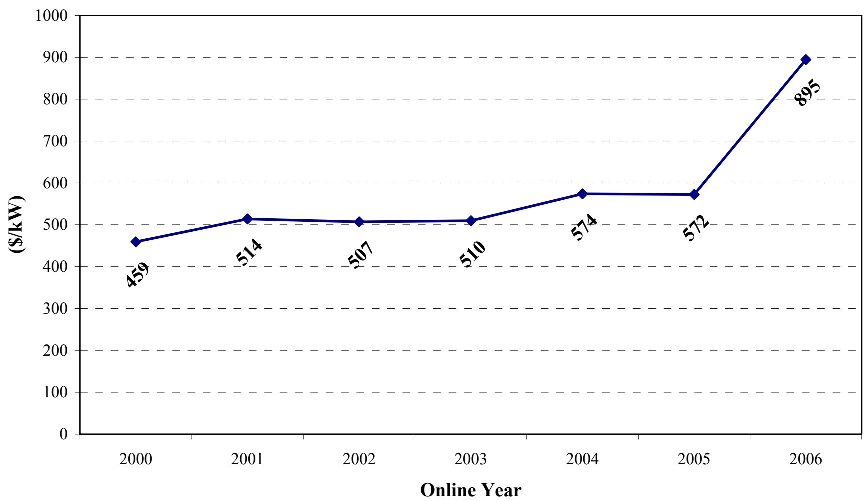
[4] To be precise, we used a "dummy" variable to represent each year in the analysis. The year-specific dummy variables were statistically significant and uniformly positive; *i.e.*, they had an upward impact on installation cost.

[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.

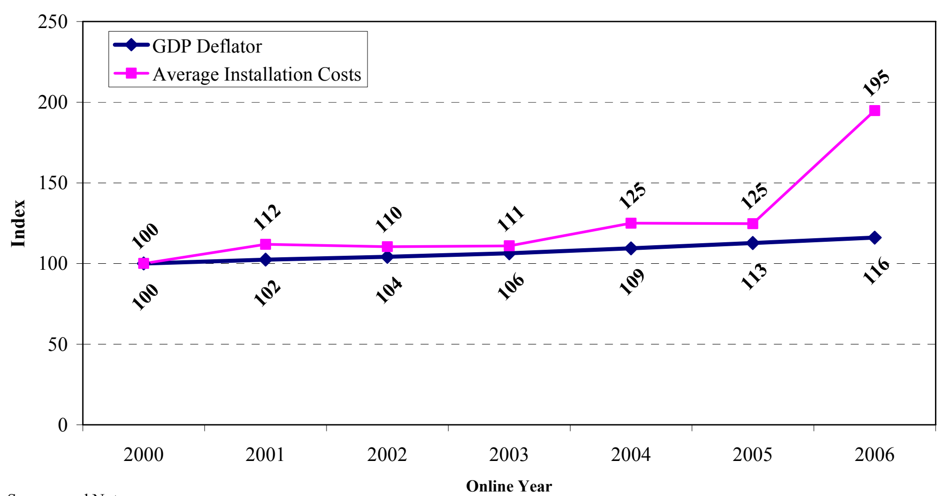
Figure 1
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year ($/kW)



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.

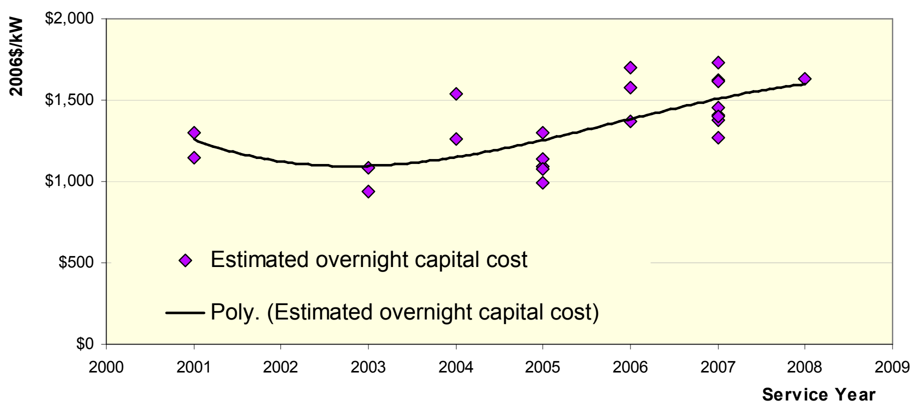
Figure 2
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year (Index Year 2000 = 100)



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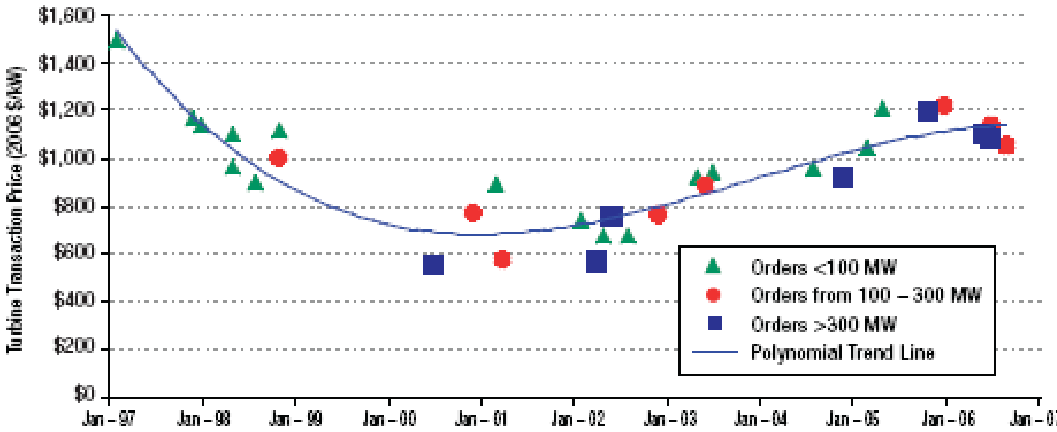
6 The NPCC planning studies and analyses cover the following four states: Washington, Oregon, Idaho, and Montana. See “Biennial Review of the Cost of Windpower” July 13, 2006, at www.bpa.gov/Energy/N/projects/post2006conservation/doc/Windpower_Cost_Review.doc. This study provides many reasons for windpower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



Source: Berkeley Lab database.

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

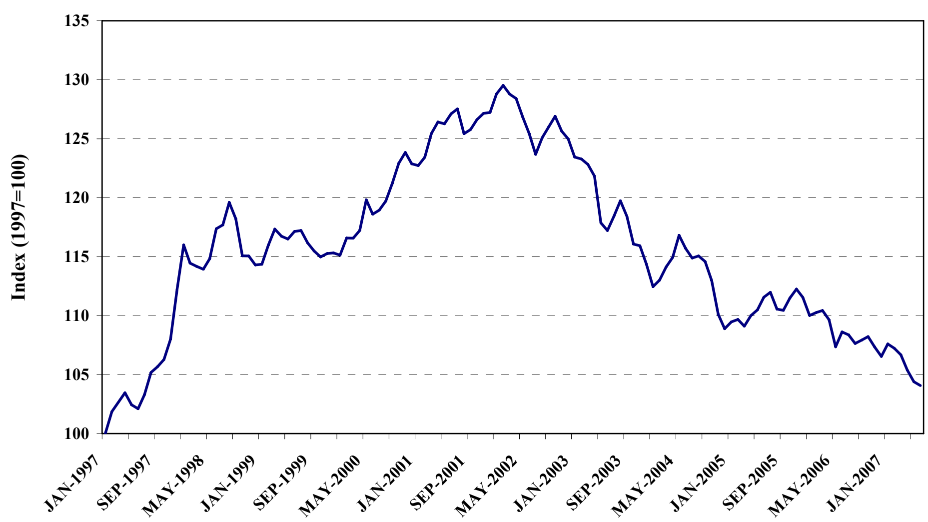
After being relatively stable for many years (and even declining in real terms), the price of various metals, including steel, copper and aluminum, has increased significantly in the last few years. These increases are primarily the result of high global demand and increased production costs (including 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

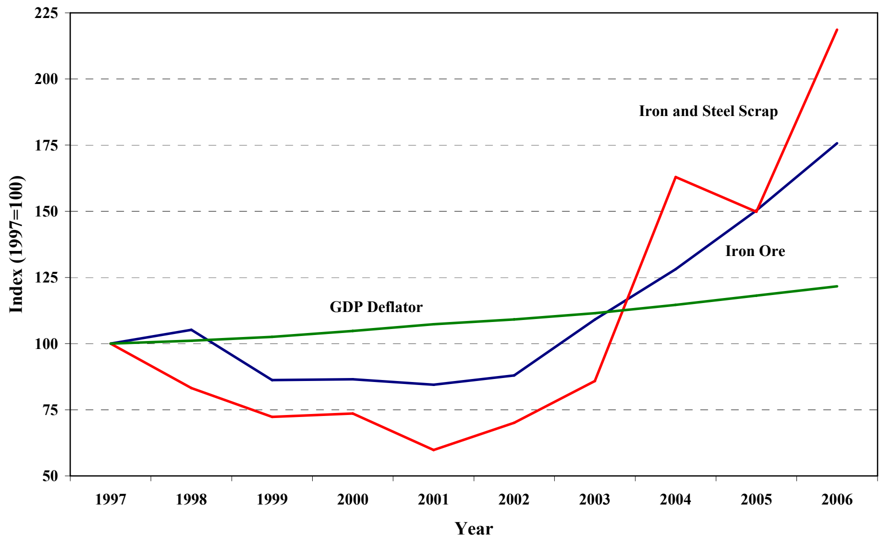
Many of the raw materials involved in utility construction projects (e.g., steel, copper, cement), as well as many major manufactured components of utility infrastructure investments, are globally traded. This means that prices in the U.S. are also affected by exchange rate fluctuations, which have been 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.

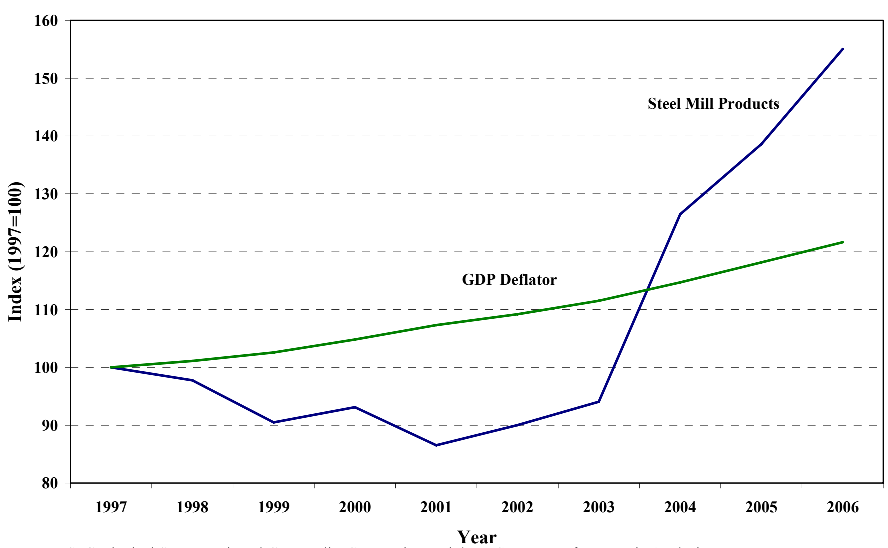
Figure 5
Inputs to Iron and Steel Production Cost Indices



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



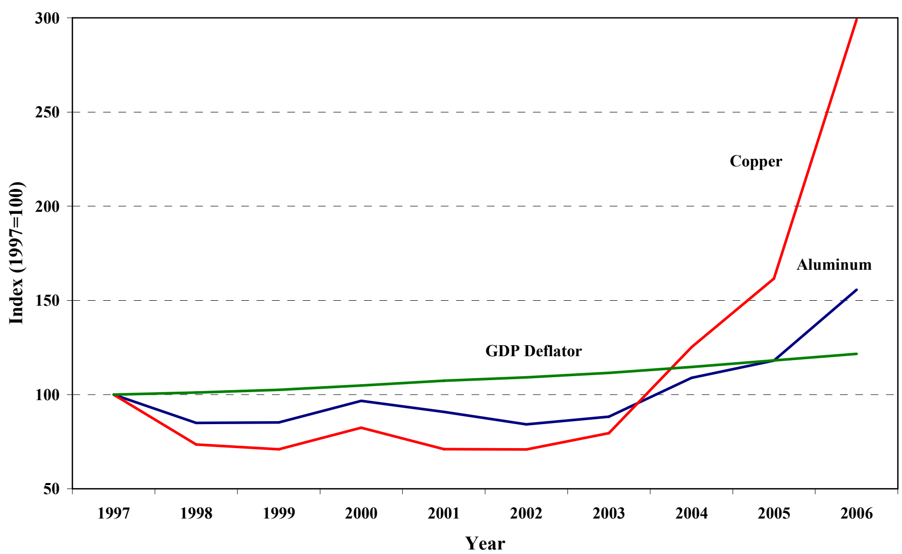
Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

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.

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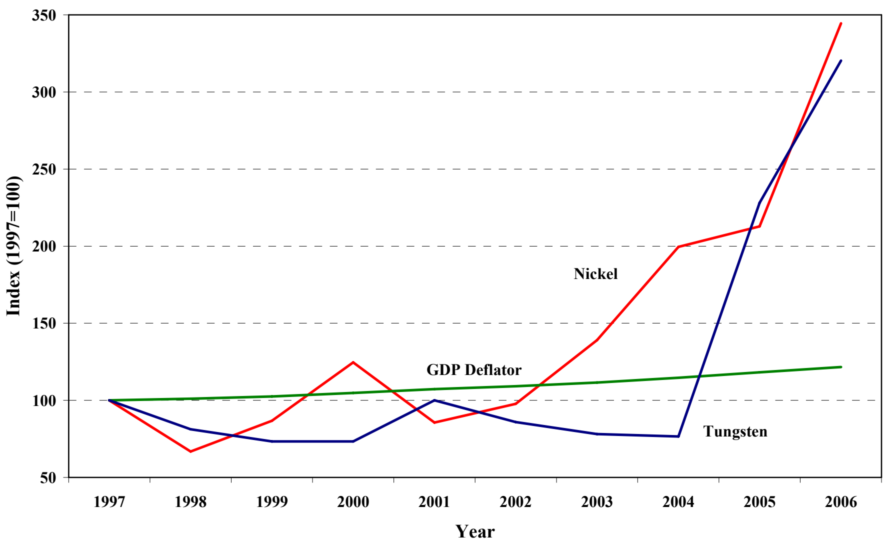
[11] See, for example, *Steel: Price and Policy Issues*, CRS Report to Congress, Congressional Research Service, August 31, 2006.

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

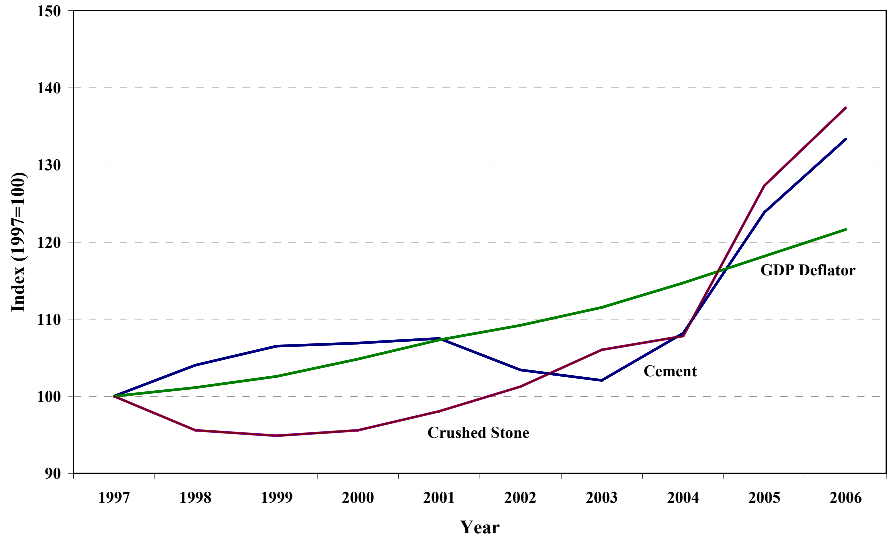


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

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.

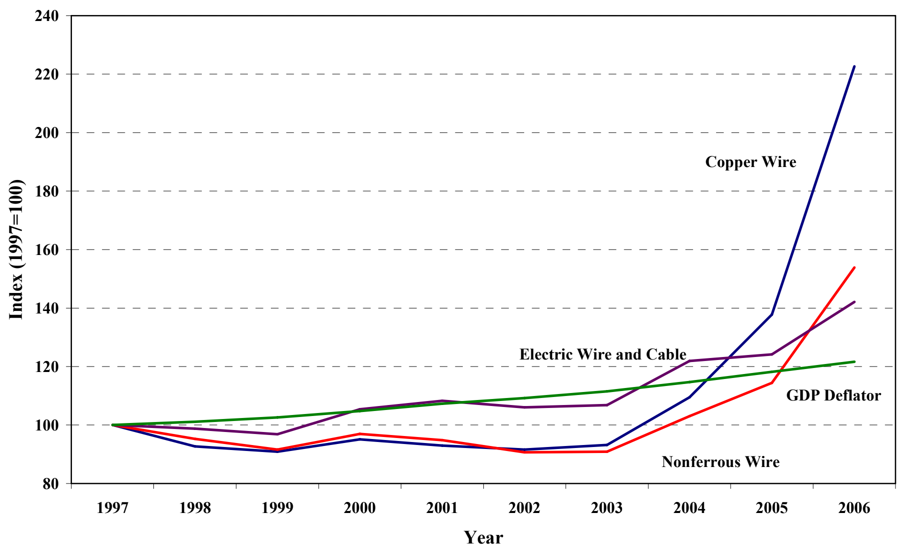
Manufactured Products for Utility Infrastructure

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.

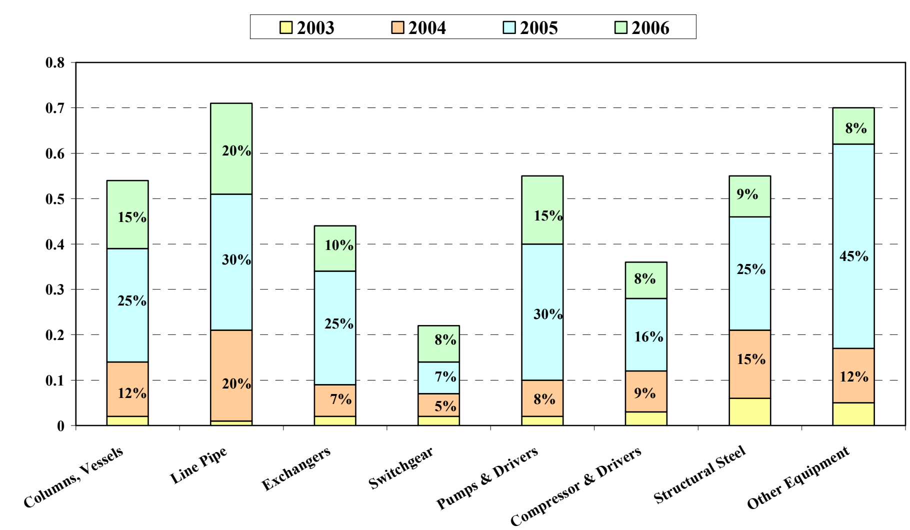
Manufactured components of generating facilities—large pressure vessels, condensers, pumps, valves—have also increased sharply since 2004. Figure 11 shows the yearly increases experienced in key component prices since 2003.

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

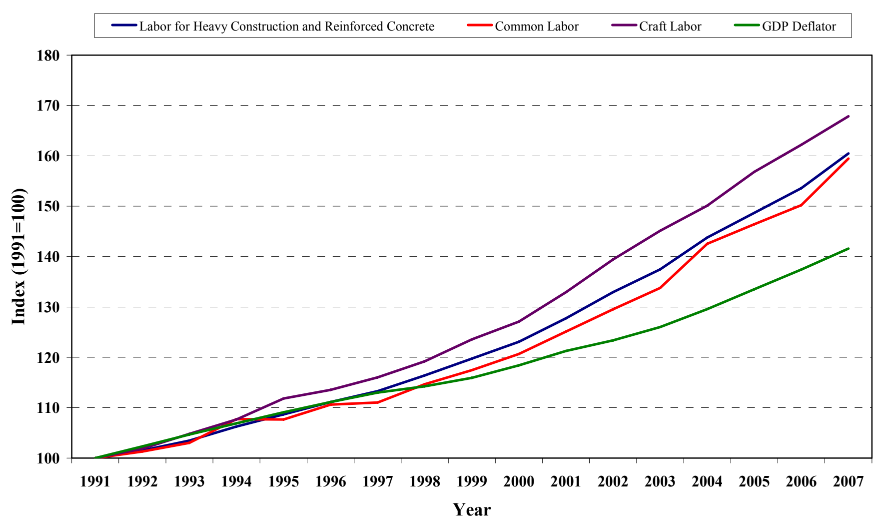


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

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.

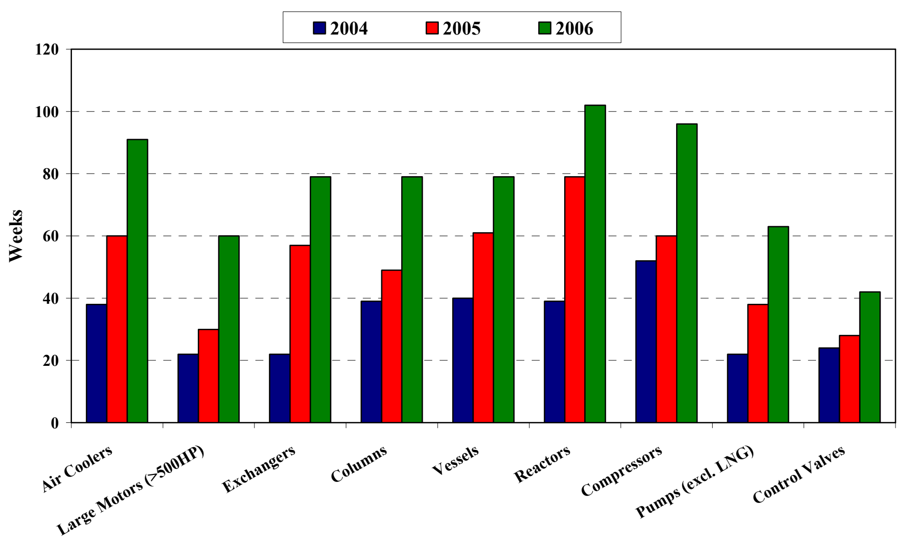
[15] *Workforce Trends in the Electric Utility Industry: A Report to the United States Congress Pursuant to Section 1101 of the Energy Policy Act of 2005*. U.S. Department of Energy, August 2006, p. xi.

[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

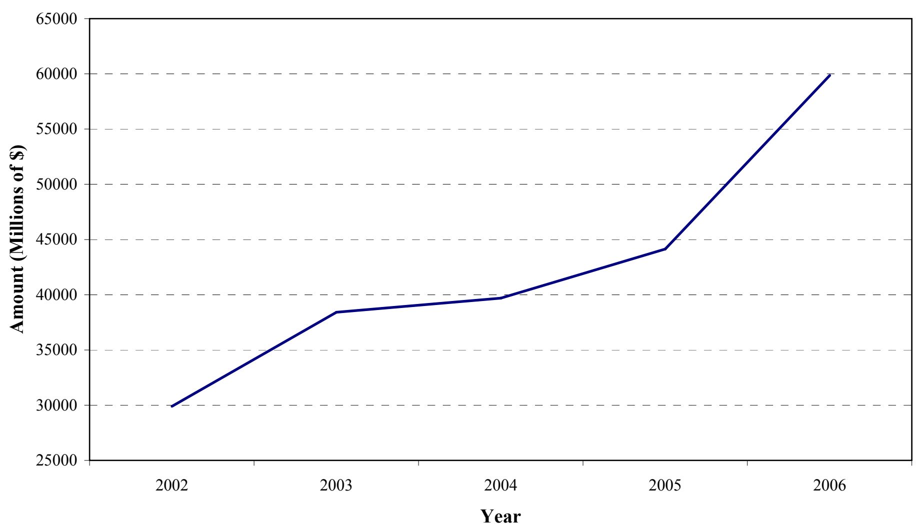


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

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).

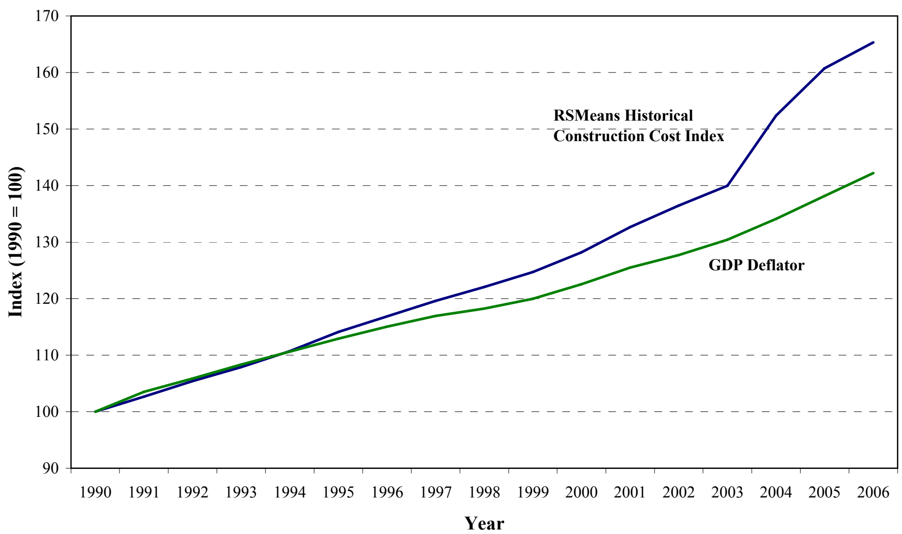
Summary Construction Cost Indices

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.

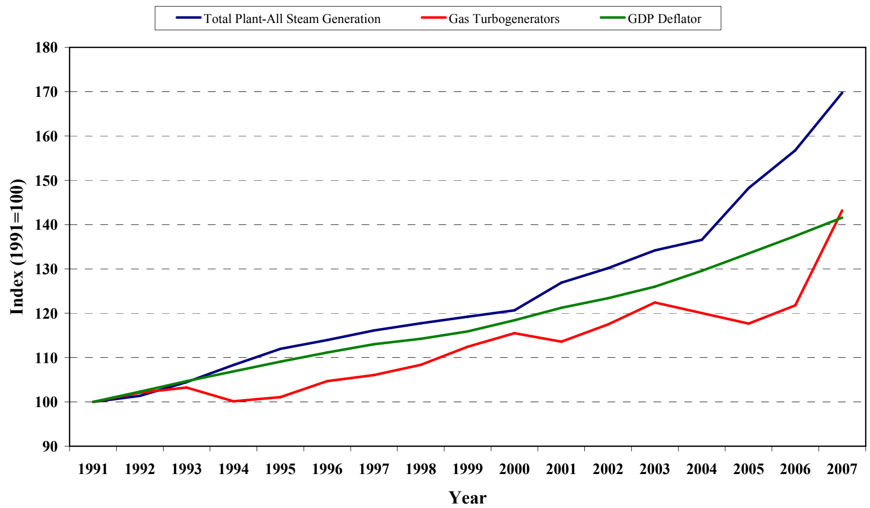
The Handy-Whitman Index© publishes detailed indices of utility construction costs for six regions, broken down by detailed component costs in many cases. Figures 17 through 19 show the evolution of several of the broad aggregate indices since 1991 compared with the general inflation index (GDP deflator).[18]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

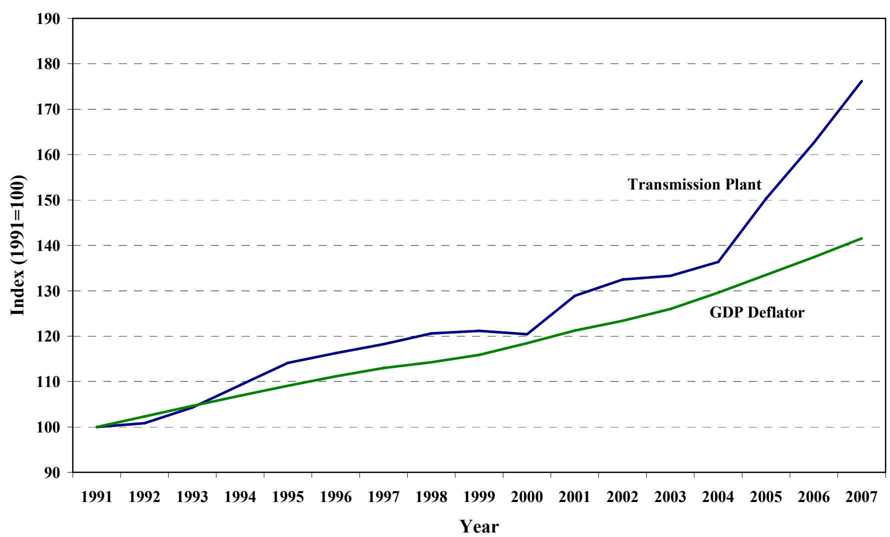
Figure 17
National Average Generation Cost Index



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.

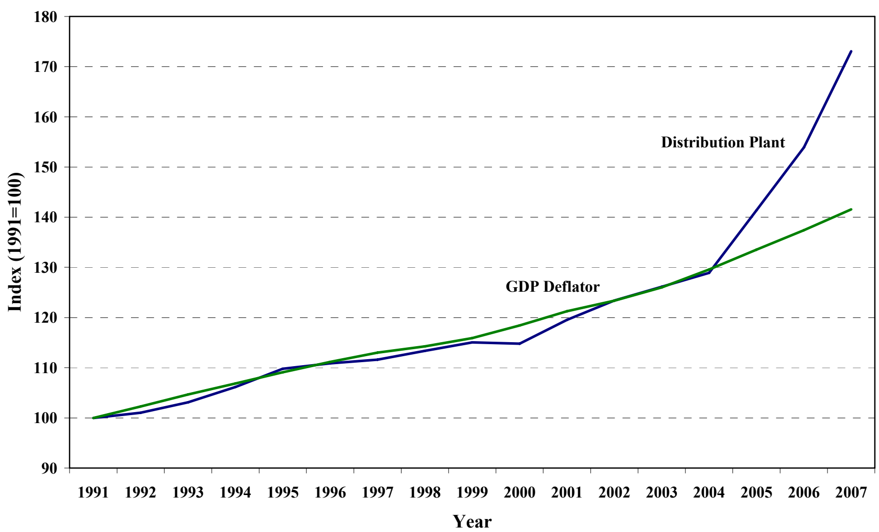
Figure 18
National Average Transmission Cost Index



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

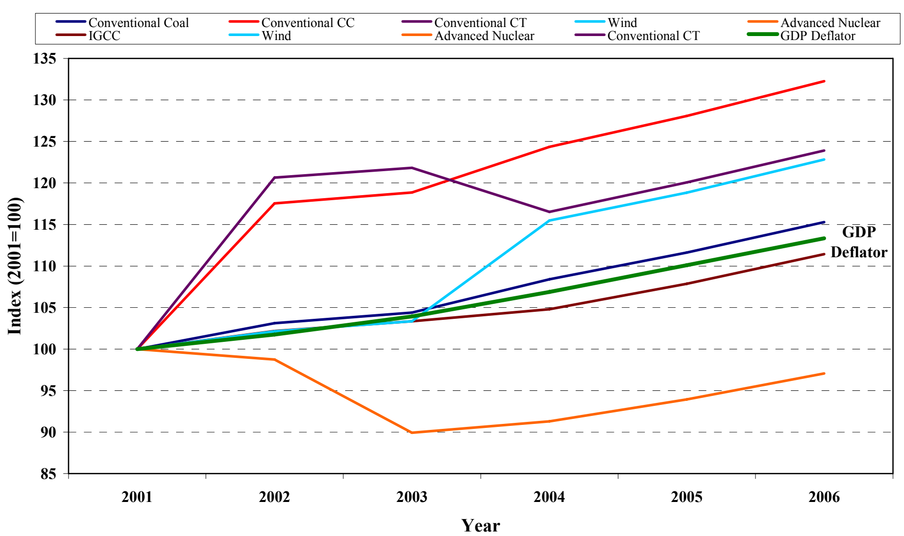
[19] EIA does incorporate regional multipliers to reflect minor variations in construction costs based on labor conditions.

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.