BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Proposed Rules	)	
4 CSR 240-3.162 and	)	Case No. EX-2008-0105
4 CSR 240-20.091, Environmental	)	
Cost Recovery Mechanisms.	)	

PREPARED REMARKS OF AMERENUE WITNESS MARK C. BIRK
ECRM RULEMAKING HEARING, JANUARY 17, 2008

I. Introduction

My name is Mark C. Birk, and I am the Vice President of Power Operations for AmerenUE. In that capacity I am responsible for all of AmerenUE's generating plants, other than the Callaway Nuclear Plant.

As explained in the comments previously filed by AmerenUE, we are generally supportive of the proposed rules submitted by the Staff and published by the Commission in this proceeding. The proposed rules reflect the relevant policy decisions made by the Commission in the recent fuel adjustment clause (FAC) rulemaking proceeding, and they generally create a workable environmental cost recovery mechanism (ECRM) which will be critical for electric utilities facing huge, federally mandated environmental costs over the next several years and beyond. The proposed rules also contain numerous consumer protections as required by Senate Bill 179 and as reflected in the FAC rules. We believe this structure fairly balances the need of utilities to promptly recover unavoidable environmental costs, with the protections consumers need to insure that these costs are prudent.

The one aspect of the proposed rules that we disagree with is the requirement that electric utilities must separate all of their existing rate base into "environmental" and "non-environmental" categories, and include any and all changes to existing "environmental" rate base in the ECRM. As explained in detail in our previously filed comments, we believe that this requirement would create an extremely complicated, contentious and unworkable process where parties would be free to debate the "environmental" qualities of every pipe, drain, smokestack, wall, floor, control panel, etc. at every plant. Electric poles and wires as well as transformer cases arguably provide some environmental benefit, and one could expect the opponents of the ECRM to take every opportunity to make such arguments, and mire any Commission proceeding addressing an ECRM for a particular utility in this bog. The bottom line is that the requirement that each piece of rate base must be so classified would effectively make the ECRM unusable, and therefore should be rejected.

The proposed treatment of existing rate base items contained in the prefiled comments of MEDA, and endorsed by AmerenUE, handles capital infrastructure investment under the ECRM in the same way that the Commission determined it should be handled for natural gas and water in the analogous Infrastructure System Replacement Surcharge regulations. This approach is fair to both utilities and consumers, and provides consistency in the treatment of rate base for purposes of a surcharge.

II. Comments of Other Parties

Several other parties, who have consistently opposed rate adjustment mechanisms before the Legislature, in rulemaking proceedings before this Commission, and/or in rate case proceedings, have filed comments that simply rehash arguments that the Commission has previously rejected, or that are designed to prevent utilities from adopting a workable ECRM. My remarks concerning some of these comments are provided below:

Office of the Public Counsel (OPC) Comments:

4 CSR 240-20.091(1)(B) and (4)(C): OPC proposes to change the language of Senate Bill 179 that enables the Commission to adopt an ECRM for an electric utility "to reflect increases and decreases in its prudently incurred costs . . ." to one that reflects "*some or all of*

the net increases or decreases in its prudently incurred costs." If the General Assembly intended to say "some or all" it would have done so in the statute. The criteria the General Assembly established for the costs that could be included in the ECRM are twofold. First, the costs must be prudent. Second, the costs must be incurred in order to comply with an environmental law, regulation or rule. The Commission should not add a third criterion; that is, establish an arbitrary limit on inclusion of increases or decreases in costs that meet the criteria provided by the General Assembly. In fact, counsel advises that adoption of OPC's proposal in this regard may be unlawful.

4 CSR 240-20.091(2)(A) and 4 CSR 240-3.162(2)(E), (4)(C): OPC advocates further amendments to the language contained in the statute by adding the words "necessary and" and "but no greater than a fair return on equity" and other similar language in these sections of the proposed rule. The statutory language does not impose a cap (or floor) on what a utility may actually earn in the up to four years between rate cases that could occur given the rate case requirements in the statute. The General Assembly quite explicitly determined that the Commission needed to find only that a proposed ECRM is "reasonably designed" to provide the utility a sufficient opportunity to earn a fair return on equity, but did not require the Commission to find that an ECRM is absolutely necessary to create that opportunity. Nor did the General Assembly give utilities assurance that an ECRM will guarantee that the utility will earn a fair return. The point is that the Commission needs to find that upon establishment, it is reasonable to expect that with the ECRM in place the utility will have a sufficient opportunity to earn a fair return on equity (ROE), with the recognition that the actual ROE may be above or below that amount. Consistent with other changes OPC proposes, OPC proposes a ceiling on earnings that is not in the statute, but proposes no floor. Neither a floor nor a ceiling is appropriate given the language of the statute.

4 CSR 240-20.091(2)(C): OPC attempts to create yet another non-statutory standard by injecting an examination of "volatility" of costs into the question of whether to approve an ECRM. I believe the context surrounding the adoption of Senate Bill 179 makes clear that the ECRM provisions of the statute were made available as a tool for the Commission's use to address the prospect of huge expenditures to control pollution facing the utility industry. Coupled with the focus on ensuring that the utility has a sufficient opportunity to earn a fair return on equity, it seems clear that the General Assembly was not concerned with whether the cost profile resembled a zig-zagging line, but rather, was concerned with allowing timely cost recovery of these enormous mandated environmental costs. Installation of a $500 million scrubber every couple of years may not be "volatile" in the sense intended by OPC, but it will certainly inject volatility into utility earnings based on an item mandated by law and beyond the utility's control.

4 CSR 240-20.091(2)(F): OPC's next proposed change attempts to limit environmental costs that may be included in the ECRM to "known and measurable" costs. This is an unnecessary addition, since all environmental costs must already be incurred to be included. The addition of this language is at best redundant, and at worst confuses the standard for including environmental costs under the rules.

4 CSR 240-20.091(3)(B): Changing the word "may" to "shall" is another attempt to change the statute itself, which reads the Commission "may take into account any change in business risk …." Again, counsel advises that the Commission cannot simply amend the General Assembly's statute, which is a point that seems obvious.

4 CSR 240-20.091(4)(C)4: This change is OPC's first attempt to inject an "earnings test" into the ECRM rules. It is my understanding that the Commission already found, in the rulemaking for the FAC, that the statute does not contemplate an earnings test, as evidenced by

the following statement in the Commission's Order of Rulemaking for Chapter 20 of the FAC rules: "The Commission finds that an earnings threshold for eligibility to use a RAM is contrary to the intent of the legislature, as articulated in SB 179. Therefore, no such eligibility criteria will be included in the rule." Moreover, the Commission already found that the appropriate mechanism, if others believe that a utility is over-earning, is to use the complaint mechanisms which were included in the FAC rule, and which also appear in this proposed rule at 4 CSR 240-20.091(12). An earnings test would turn every adjustment of the ECRM into a full-blown rate case, and contravene the intent of the Legislature in enacting Senate Bill 179. The Commission properly rejected the idea of an earnings test in developing FAC rules, and it should also reject that concept here.

4 CSR 240-20.091(4)(C)5- 8: These changes all amount to a direct attack on the cap on *annual* increases that are allowed under an ECRM, and an effort to defer cost recovery far beyond the period contemplated by Senate Bill 179. The statutory language could hardly be clearer:

> Any rate adjustment made under such rate schedules shall not exceed an annual amount equal to two and one-half percent . . . * * * Any costs not recovered as a result of the annual two and one-half percent limitation on rate adjustments may be deferred, at a carrying cost each month equal to the utilities net of tax cost of capital, for recovery in a subsequent year or in the corporation's next general rate case or complaint proceeding.

An ECRM only has a "life" of up to four years. Every four years, the earlier ECRM ends, and if an ECRM is to exist, a new ECRM must be approved. OPC's suggestion would apparently allow huge deferrals, with interest, to build up not just in the year following the year in which the *annual* cap may have operated, but years and years into the future, and indeed, beyond the "life" of the ECRM under which the deferral was created. The presence of a two and one-half percent cap in the ECRM provisions (without a cap in the fuel adjustment clause provisions of the statute) reflects that the General Assembly understood that these ECRM investments could be huge, and that some annual cap might be needed. But the General Assembly balanced that need with the recognition that the deferrals would bear interest and needed to be recovered no later than the next rate case, which would end, at most, four years after the ECRM was established.

It is also my understanding that if proposals such as that advocated by OPC were adopted, the support to credit quality provided by the ECRM will be significantly eroded if not eliminated because credit rating agencies will view the cash flows the ECRM was supposed to timely provide as too small or too speculative to support credit quality. This, in turn, may raise borrowing costs at the very time when the utility's borrowing needs are greatest. This, ultimately, creates more ratepayer expense in the form of higher borrowing costs.

<u>4 CSR 240-20.091(11):</u> With this addition, the OPC proposes to permit parties to propose incentive mechanisms or performance-based programs as part of an ECRM. The same provision appears in Chapter 20 of the FAC rules, but as Staff points out in its Comments filed in this rulemaking, it is not authorized for an ECRM due to the clear difference between the statutory language in subsection 1 of Section 386.266 (dealing with FACs) and the statutory language in subsection 2 (dealing with ECRMs). Subsection 1 gives the Commission authority to "include . . . incentives to improve the efficiency and cost-effectiveness of its fuel and purchased power procurement activities." Subsection 2 contains no such authority. Consequently, subsection (11) of the proposed rule is not authorized by statute and cannot be included in the ECRM rules.

<u>4 CSR 240-3.162(2)(P) & (Q) and (3)(P):</u> With this change, OPC proposes to require five years of extensive historic "rate case" type data and forecasts of such data four years into the future. Participants in the roughly 15 roundtables which led to the initial proposal of FAC rules also proposed similar provisions for inclusion in the FAC rules, which were rejected. 4 CSR

240-3.162(2)(O) requires electric utilities seeking an ECRM to authorize the Staff to release five years of surveillance reports to all parties to the case. This was deemed adequate by the Commission for the FAC regulations and it is adequate for these regulations as well. Staff, which historically performs the most regular and complete audit of rate adjustment filings, did not agree to include these provisions and the Commission did not include them in the FAC rules. As a consequence, they should not be included in these ECRM rules.

AARP Comments:

AARP echoes OPC's advocacy of an "earnings test" and of provisions in the rules that would create huge deferrals that are inconsistent with the statute. Insofar as I have already addressed both issues earlier, I won't repeat them here.

AARP does advance some additional arguments regarding the earnings test issue. First, AARP argues that the proposed rules "place no check" on the possibility that a utility would overearn. As I previously noted, the Commission has already rejected this argument, and found that the existing protections against overearning do not require the adoption of an earnings test for each and every filing. The statute was specifically designed to limit the operation of the ECRM to a period of just four years. If an earnings test were intended, a rate case on the front end and on the back end would simply not have been required. In addition, if an overearnings complaint is filed, the rules require that a procedural schedule must be set within 60 days (4 CSR 240-20.091(12)), a framework that hardly can be described as placing no check on the earnings of utilities.

AARP also proposes an additional change to limit the "environmental costs" that could be recovered under the ECRM to only costs incurred because of a law or regulation that takes effect *after* the ECRM is established in the rate case. If AARP's proposal were adopted, none of the enormous costs utilities will soon incur under the Clean Air Act Amendments of 2005, including the resulting Clean Air Mercury Rule and Clean Air Interstate Rule, could be recovered under the ECRM. No costs incurred after the rate case is over, but before the next rate case to occur 37 months later, could be recovered if those costs arose under the Clean Air Act of 1970, the Clean Air Act Amendments of 1990, or under the host of environmental laws and regulations adopted over the past four decades. In my opinion, to believe that the General Assembly enacted this mechanism, with an every-four-year rate case requirement, and with an annual cap on rate increases, but intended for the Commission to ignore these significant costs is ludicrous.

AARP's arguments also fail to withstand scrutiny. AARP argues that "surely, the intent of the law was not to permit recovery for costs that could have been taken into account during the rate case." Exactly how AARP believes that a future environmental cost could be "taken into account during the rate case" when rates in Missouri are set based upon an historic test year is unknown.

If the Commission adopts AARP's proposal, it might as well adopt no ECRM rules at all. This is because the ECRM will be useless to utilities. Credit quality will not be supported, and borrowing costs will very likely simply increase dramatically given the huge borrowing needs utilities will face to make mandated environmental investments in the coming years. Moreover, the ECRM will provide no incentive to more timely make these investments, an initiative I believe the General Assembly and this Commission would support.

Noranda:

Noranda has resurrected a proposal it made in the FAC rulemaking that was flatly rejected. Noranda suggests that the proposed rule (4 CSR 240-20.092(2)(D)) allows the Commission to not only decide that some portion of environmental costs should be recovered in base rates, with the rest to be recovered in the ECRM, but that the Commission can just arbitrarily deny recovery of a part of the costs entirely.

In rejecting this reading of the statutory language relied upon by Noranda, the Commission stated that it "must disagree with this comment in that it would not allow for the setting of just and reasonable rates that allow the utility a reasonable return." (Order of Rulemaking for the FAC Rules, p. 4).

MIEC:

MIEC's central comment also consists of its advocacy, as it did in the FAC rulemaking proceedings, for an earnings test. I (and the Commission) have already addressed why an earnings test is inappropriate.

I would note that MIEC misstates some important facts, however. MIEC argues that there is a "high likelihood" that utilities will overearn. Every electric utility in this state has obtained a Commission-approved rate increase in the very recent past. Relentlessly increasing fuel and material costs, as well as the huge environmental expenditures which would be the subject of this rule, are well-documented. (*See* the attached article from the September/October edition of *Electric Perspectives—An Upward Climb* by Marc Chupka and Gregory Basheda.) In this environment, the idea that it would be "highly likely" that a utility will overearn is simply untrue. This renders MIEC's reference to rate decreases, the last of which occurred nearly six years ago, irrelevant.

III. <u>A Workable Alternative to Include Changes to Existing Environmental Rate Base</u>

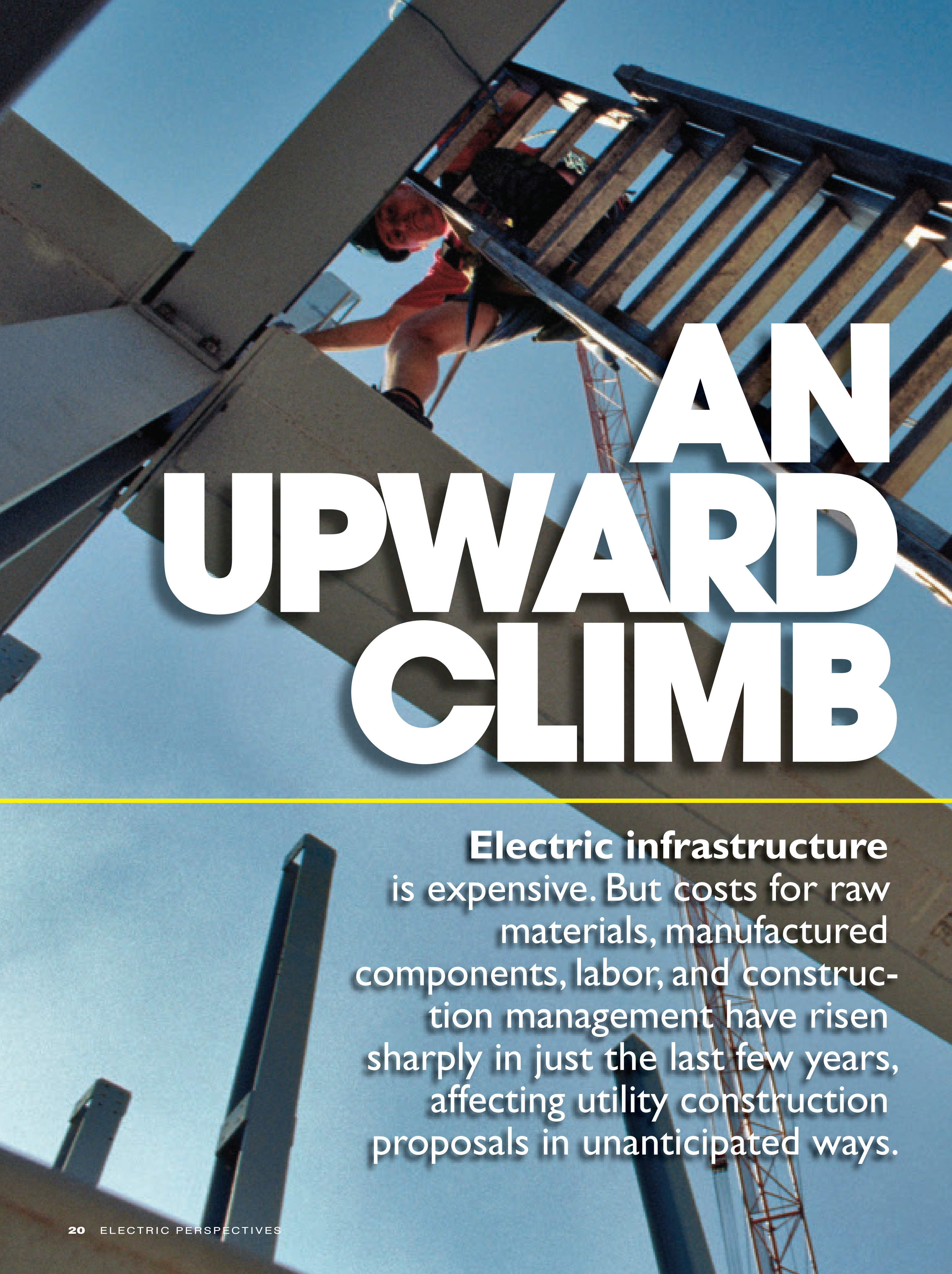
As previously discussed, AmerenUE does not believe that it is appropriate for changes in existing "environmental" rate base to be included in the ECRM. In AmerenUE's view, changes in existing environmental rate base should be addressed in a general rate proceeding, similar to changes in existing rate base that would qualify for ISRS treatment. However, if the

Commission determines that such changes must be included in the ECRM, the changes should be limited to major components of rate base that clearly serve an environmental purpose. Parties should not be free to squabble over every pipe, drain, control panel, etc. AmerenUE believes that the rules would reflect this approach if the definition of "environmental revenue requirement" contained in the rules is modified as follows:

> The environmental revenue requirement shall be comprised of the following: (i) all environmental costs that are expensed, rather than capitalized, included in the electric utility's revenue requirement in the general rate proceeding in which the ECRM is established, plus (ii) the costs of any major capital items whose primary purpose is to permit the electric utility to comply with any federal, state or local environmental law, regulation or rule. Representative examples of such capital items to be included (as of January, 2008) are electrostatic precipitators, NOx emissions control equipment and flue gas desulfurization equipment. The costs of such capital items shall be those reflected on the electric utility's books and records as of the last day of the test year, as updated, utilized in the general rate proceeding in which the ECRM is established.

If this approach is adopted, there may have to be some additional conforming changes to the proposed rules. In addition, if this change is adopted, AmerenUE recommends that electric utilities be permitted up to three (3) ECRM adjustments each year. This would make sense since the change would be a departure from the ISRS approach to addressing rate base, and it would be consistent with the FAC rules, which permit up to three adjustments per year.

If there must be a departure from the ISRS method, this definition of "environmental revenue requirement" will prevent the rule from being completely unworkable.



AN UPWARD CLIMB

Electric infrastructure is expensive. But costs for raw materials, manufactured components, labor, and construction management have risen sharply in just the last few years, affecting utility construction proposals in unanticipated ways.

BY MARC CHUPKA
AND
GREGORY BASHEDA

Right now, increases in fuel and purchased power costs put most of the pressure on current electricity rates. Rising pressure also comes from the fact that utilities have entered an infrastructure expansion phase, with significant investment in new baseload generating capacity, expansion of the bulk transmission system, distribution system enhancements, and mandated environmental controls—all to meet reliability and economic growth demands for the next 25 years. In a generally supportive rate environment that recognizes the reality of rising

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Recent rise. Steel prices have increased about 60 percent since 2003. Prices for gas turbines shot up 17 percent in 2006 alone. Generation projects already in the works—mostly combined-cycle gas and wind power—feel the pinch, but the real squeeze is on proposed projects.

prices, the industry could probably make the infrastructure investments cost-effectively.

That's essentially what we concluded in a June 2006 Edison Foundation report, "Why Are Electricity Prices Rising?" [See also "Behind the Rise in Prices" in the July/August 2006 *Electric Perspectives*.]

The cost pressures from elevated fuel and purchased power prices will continue, and the infrastructure needs remain. But pressures on the long-run price of electric power have another dimension: Namely, substantial increases in the construction costs for utility infrastructure projects. Some of the factors underlying these cost trends are straightforward. Dramatic spikes in the prices for raw materials—such as steel and cement—have increased construction costs directly, for example. Some factors are less transparent, like the effect those commodity prices have on the cost of manufactured components. In most cases, the driving forces behind such cost increases have been high global demand for commodities and manufactured goods, higher production and transportation costs (in part owing to elevated fuel prices), and a weakening U.S. dollar.

This article is based on "Rising Utility Construction Costs: Sources and Impacts," a white paper published under the auspices of the Edison Foundation in Washington, DC. The Foundation is a nonprofit organization founded to provide knowledge, insight, and leadership to the goal of bringing the benefits of electricity to families, businesses, and industries worldwide. To view an electronic copy of the full paper, visit www.eei.org.

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Labor costs are a smaller contributor to the general rise, but that contribution may grow as new, large construction projects boost the demand for increasingly scarce specialized and skilled workers. There also is a growing backlog of project contracts at large engineering, procurement, and construction (EPC) firms—the utility industry's construction contractors—and bids for construction management have begun to rise as a result. Although it is not possible to quantify the impact on future proposals by EPC firms, it is reasonable to assume that bids will become less cost-competitive as new projects go into the queue. (And investments by power companies around the world will total about $11 trillion dollars by 2030, according to "World Energy Investment Outlook 2006.")

The jumps in material, equipment, labor, and management costs for utility construction have affected all electric-sector investment. In the generation area, all technologies have seen cost increases in the past three years, from coal plants to wind projects. Large proposed transmission projects have undergone cost revisions. Distribution system equipment costs have risen rapidly. Indeed, between January 2004 and January 2007, the costs of steam-generation plants, transmission projects, and distribution equipment rose by 25-35 percent. The cost of gas turbines, fairly steady in the early part of the decade, increased by 17 percent during 2006 alone. Compare this to the 8-percent general price increase during the three-year period.

The rapid increases in utility construction costs have raised the price of recently completed projects (mostly gas-fired and wind-powered projects), though in many of those cases the

builders acquired materials and components before the sharp upturns. The impact is much more dramatic on the estimated cost of proposed projects, which fully incorporate recent price trends. (See the sidebars, “What Are We Building?”)

Moreover, these recent increases follow roughly a decade of relatively stable (or even declining) real construction costs, which adds to “sticker shock” both for utilities obtaining cost estimates or bids and for public utility commissions reviewing construction applications. Customers will not feel the full impact of construction cost increases until the utility completes a project, but the issue currently affects the industry’s investment plans.

Despite their best estimates just a few years ago, utilities and regulators find themselves face-to-face with these unanticipated increases. How we un-

Generation: What Are We Building?

The need for new generating capacity correlates with load growth and projected growth in peak demand. According to the most recent EIA projections, U.S. electricity sales will grow at an annual rate of about 1.4 percent through 2030. The North American Electric Reliability Council (NERC) expects peak demand to grow by 19 percent (141 GW) in the United States from 2006 to 2015. EIA concludes that utilities will need to build 258 GW of new generating capacity by 2030 to meet the growth in electricity demand and to replace old, inefficient plants that will be retired. EIA further projects that coal-fired capacity, which is more capital-intensive than natural gas-fired capacity (the dominant additions to new capacity over the last 15 years), will account for about 54 percent of total additions from 2006 to 2030. Gas-fired plants comprise 36 percent of the total; renewable generators and nuclear power plants will provide the remaining additions (6 percent and 4 percent, respectively). Like coal, renewable and nuclear technologies are capital-intensive with relatively high construction but low operating costs.

Courtesy: Sierra Pacific Power

Corbis

Lines and labor. A few facts for builders of the 13,000 miles of new transmission needed by 2015: Aluminum prices tripled between 2003 and 2006; copper prices nearly quadrupled; skilled labor costs rose 26 percent between 2001 and 2007.

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derstand these construction pressures will be crucial in how we address the next generation of utility investments.

Higher, Now Sharply Higher

Since the 1990s, most of the new generating capacity built in the United States has been either gas-fired—combined-cycle units or combustion turbines—or wind-powered. Both have displayed much higher real costs in recent years.

Prices for gas-fired combustion turbines rose very recently, after years of real price decreases. For installed combined-cycle combustion capacity, however, the increases have been over the past several years. According to a review of commercially available databases and other sources, the average real construction cost of combined-cycle units built in the United States during the last major construction cycle—that is, plants brought into service between 2000 and 2006—was approximately $550 per kilowatt (in 2006 dollars), with a range of costs between $400/KW to approximately $1,000/KW.

Four factors influenced the real installation cost of combined cycle facilities: plant size, turbine technology, the region in which the plant was located, and the commercial online date. Most notable, however, is the significant relationship between a plant's construction cost and its online date: Everything else equal, the later a plant came online, the higher its real cost. The average cost increased gradually between 2000 and 2003, rose fairly significantly in 2004, and then escalated a great deal—more than $300/KW—in 2006. This sharp rise outpaces inflation: Over the same period, 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.

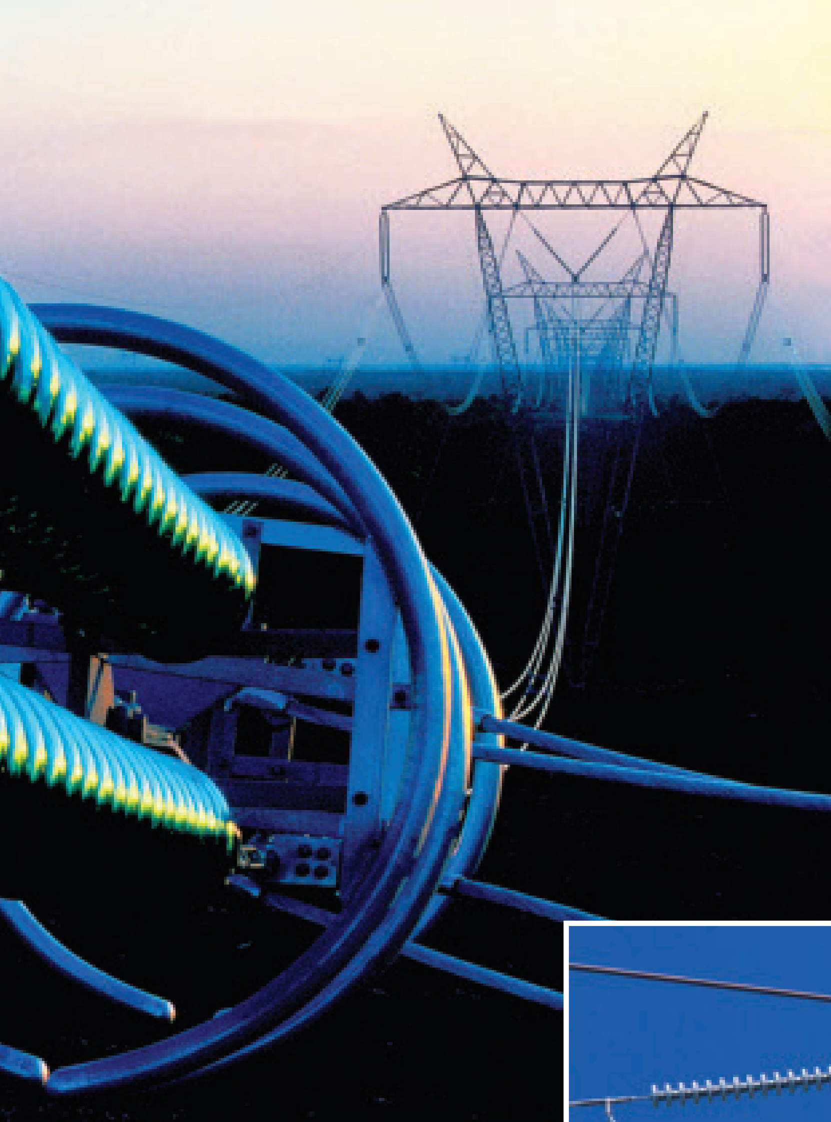
The costs for wind generation have risen recently as well. In a July 2006 report, for example, the Northwest Power and Conservation Council (NPCC), which prepares long-term electric resource plans for the Pacific Northwest, found that the cost of new wind projects rose substantially in real terms in the two previous years and was much higher than NPCC assumed in its most recent resource plan. The lifecycle cost of power from new wind projects rose by 50-70 percent, which NPCC attributed to higher construction costs. According to the council, the construction cost, in real dollars, has increased from about $1,150/KW to $1,300-$1,700/KW in the past few years, with an average capital cost of wind projects in 2006 at $1,485/KW. Some factors contributing to this rise include a weakening dollar, escalation of commodity and energy costs, and increased demand for wind power under renewable portfolio standards in many states. NPCC 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.

In a May 2007 report, the Department of Energy (DOE) found that prices for wind turbines (the primary cost component of installed wind capacity) rose by more than $400/KW between 2002 and 2006, nearly a 60-percent increase.

Upward Trajectories

But the most dramatic cost escalations are found in proposed utility investments, because they fully reflect the recent, sharply rising prices of construction and installation costs.

The effects on generation proposals are the most visible. Consider the significant construction cost increases in recent utility applications for regulatory approval to build coal-fired plants. Otter Tail Power, for example, leads a consortium of seven Midwestern utili-



ties that wants to build a 630-MW coal-fired unit on the site of the existing Big Stone Plant in South Dakota, along with a new high-voltage transmission line to deliver power from both the new plant and other sources, including possibly wind and other renewable forms of energy. In June 2005, the initial estimate for the power plant was about $1 billion, with an additional $200 million for the transmission line. However, those estimates increased dramatically after design changes required a second proposal. While other factors were involved (making changes to boost the unit's output and efficiency and raising the voltage of the proposed transmission line), the cost increase was largely due to higher costs for construction materials and labor. The consortium now expects the entire project to cost $1.6 billion.

In June 2006, Duke filed for a certificate of public convenience and necessity for the construction of two 800-MW coal-fired units at the utility's Cliffside

Transmission: What Are We Building?

Transmission investment began a significant upward trend in 2000. Between 2000 and 2006, shareholder-owned electric utilities and stand-alone transmission companies have invested more than $32 billion in the transmission system. In 2006 alone, the industry invested $6.9 billion, with $8.0 billion estimated during 2007. A recent Edison Electric Institute survey shows that its members plan $31.5 billion in transmission investment from 2006 to 2009, a nearly 60-percent increase over the 2002-2005 period. One reason for this surge is the large amount of new baseload generation built farther from load centers, creating a need for larger and more costly transmission projects compared to those of the past 20 years. In addition, new government policies and industry structures are enhancing the ability to invest in transmission.

NERC projects that utilities will add 12,873 miles of new transmission by 2015, an increase of 6.1 percent in the total miles of installed extra-high voltage lines in North America. (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 Pennsylvania-New Jersey-Maryland (PJM) Interconnection.)

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No insulation. Between 2004 and 2007, distribution infrastructure costs rose at a faster pace than generation and transmission. Prices of line and pad transformers, for example, went up 68 percent and 79 percent, respectively. And overhead conductors went up by 34 percent.

Steam Station in North Carolina. In its initial application, Duke estimated a construction cost of $2 billion, based on a May 2005 projection. Five months later, the company submitted a second filing with a revised estimate of $3 billion. The North Carolina Commission approved the construction of one unit at Cliffside but disapproved the other, primarily on the basis that Duke had not shown that it needed the capacity to serve projected growth in native load. The utility's estimate for building one unit at Cliffside is $1.8 billion—about $2,250/KW. With the financing charges and allowance for funds used during construction, the estimated capital cost is $2.4 billion (or about $3,000/KW).

Rising construction costs have led utilities to reconsider expansion plans even before the commission gets involved. In December 2006, Westar announced that it was deferring consideration of a 600-MW coal-fired facility due to significant increases in construction estimates—from $1.0 billion in May 2005 to about $1.4 billion a year and a half later.

Increased construction costs are also affecting proposed demonstration projects. For example, the DOE announced earlier this year that the projected cost for FutureGen, its most prominent clean-coal demonstration project, had nearly doubled. (FutureGen is a public-private partnership involving DOE, industrial coal producers, and electric utilities to build an advanced integrated coal gasification combined cycle plant aiming for near zero emissions of sulfur dioxide, nitrogen oxides, carbon dioxide, and particulates.) The initial estimate was $950 million. After re-evaluating the cost of construction materials, labor, and inflation, DOE put the price at $1.7 billion.

Higher Wires

To enhance reliability and improve import capability into Boston, a heavily transmission-constrained "load pocket," NSTAR Electric is building two 345-kilovolt lines from Stoughton, MA, to substations in Boston's Hyde Park section and South Boston, respectively. In an August 2004 filing before ISO-New England (the grid's independent system operator), NSTAR indicated that the project would cost $234.2 million. In March 2007, NSTAR informed ISO-NE that estimated costs had increased by almost 25 percent to $292.0 million. NSTAR attributed the rise to jumps in both construction and material costs. Construction bids came in at 24 percent higher than initially estimated: Copper had increased by 160 percent, core steel by 70 percent, flow-fill concrete by 45 percent, and dielectric fluid (used for cable cooling) by 66 percent.

Transmission projects require land, and in many areas of the country land prices have increased substantially over the last few years. In March 2007, the California Public Utility Commission approved construction of a 25.6-mile, 500-KV line between Southern California Edison's (SCE's) Antelope and Pardee substations. SCE initially estimated $80.3 million for the line. As California real estate prices rose, so did the cost of right-of-way: The company subsequently revised its estimate to $92.5 million, an increase of more than $3.5 million per mile.

Distribution Equipment Costs Rise

Most distribution projects are small relative to those for generation and transmission (which are more visible and public) and therefore receive less scrutiny on a project-by-project basis. But costs have been rising in this sec-

Distribution: What Are We Building?

Utilities require continual investment in distribution facilities—from poles and transformers to metering, billing, and other related infrastructure and software—to keep pace with growth in customer demand. In real terms, investment began to increase in the mid-1990s, and the steady climb in investment shows no sign of diminishing. The needs to replace aging infrastructure, address increased population growth, and meet demand for power quality and customer service continue to motivate utilities. In 2006, utilities invested about $17.3 billion in upgrading and expanding distribution systems, a 32-percent increase over 2004 investment levels. Edison Electric Institute projects that distribution investment during 2007 will total about $21.8 billion, nearly a 50-percent increase over the previous year. While much of the recent increase in distribution investment reflects expanding physical infrastructure, a substantial portion is due to the increased input costs of materials and labor.

tor, as well. According to the Handy-Whitman Index (which tracks costs in all areas of construction), several important categories of distribution equipment and components have seen large price increases over the past three years. For example, the prices of line transformers and pad transformers went up by 68 percent and 79 percent, respectively, between January 2004 and January 2007, with increases during 2006 alone of 28 percent and 23 percent. The cost of overhead conductors and similar devices went up by 34 percent; the cost of station equipment, 38 percent. These are in contrast to the overall price increases of roughly 8 percent over the past three years.

The Sum of the Parts

Utility construction projects involve large quantities of aluminum, copper, and steel (and components manufac-

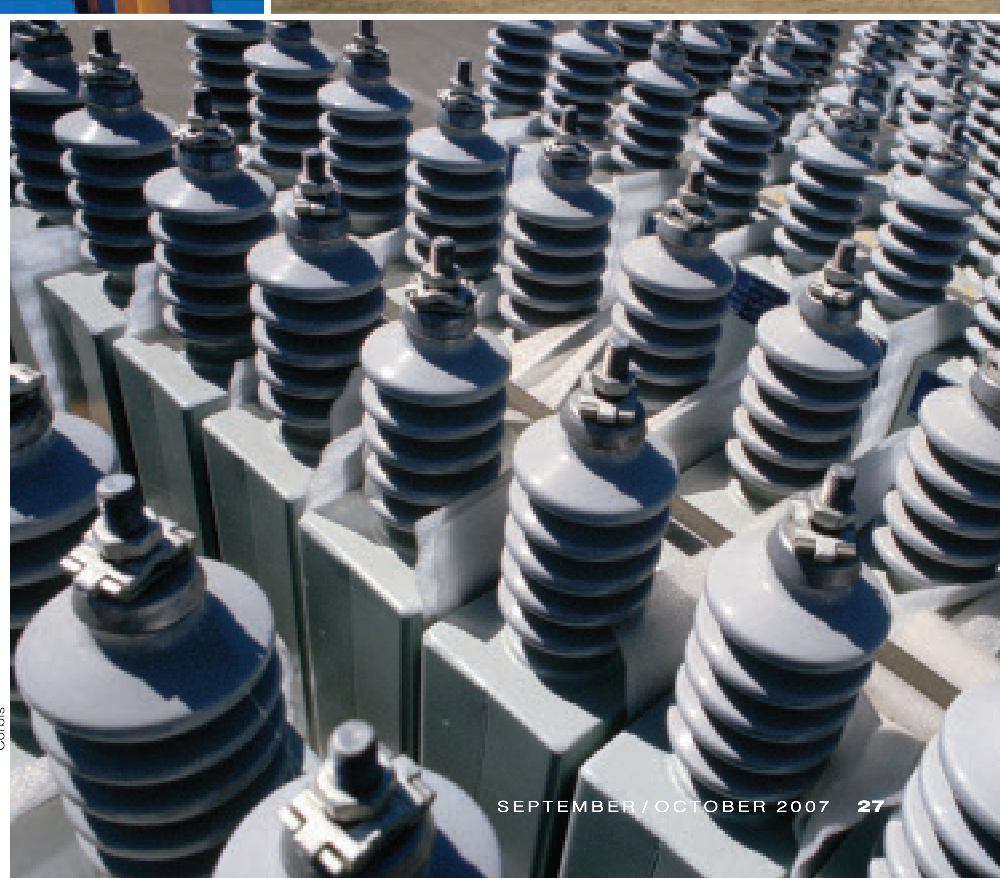

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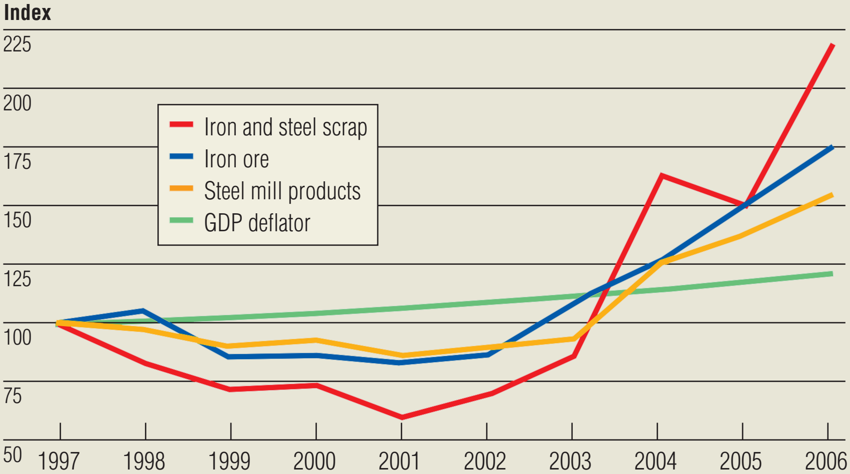
FIGURE 1

IRON AND STEEL PRODUCTION INPUTS AND STEEL MILL PRODUCTS PRICES

(Index: 1997=100)



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

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UNDERSTANDING THE GDP DEFLATOR

The gross domestic product deflator in many of the accompanying figures measures the changes in the overall cost of goods and services purchased by households, industry, and government and serves as a measure of inflation. It is a broader price index than the consumer price and producer price indices, which track the costs of goods and services purchased only by households and by industry, respectively.

tured from these metals), as well as cement for foundations, footings, and structures. Prices for those commodities had been relatively stable for many years, even declining in real terms. But high domestic and global demand and increased production costs (in mining, transportation, and energy) have pushed up prices dramatically. A weakening U.S. dollar has also contributed to high domestic prices for imported materials and major component products: Although the dollar appreciated against other major trading partner currencies between 1997 and 2001, it has lost 20 percent of its value since 2002.

The price of iron and steel scrap and iron ore fell in real terms during the late 1990s but rose sharply after 2002. (See Figure 1.) Compared to the 20-percent increase in the general inflation rate between 1997 and 2006, iron ore prices rose 75 percent, and iron and steel scrap prices rose nearly 120 percent. (See the sidebar, "Understanding the GDP Deflator.") The increase over the last few years was especially acute—between 2003 and 2006, prices for iron ore rose 60 percent and iron and scrap steel rose 150 percent.

The increase in input prices shows up in steel mill product prices, which have increased about 60 percent since 2003. The Congressional Research Service (CRS), which issued a report on steel prices and related industry issues in August 2006, points to the rapid growth of steel production and demand in China as the primary causes. China has become the world's largest steel maker and the world's largest steel consumer. In addition, CRS contends that steel companies have achieved much greater pricing power, partly through industry consolidation. The CRS report further notes that, in 2006 more so than in the past, what drove demand for steel were products used in energy and heavy industry, such as plate and structural steels.

From the steel industry's perspective, the rapid increase in prices of steel inputs (and not just scrap and iron ore, but also coking coal and natural gas fuel) justifies the substantial rise in prices for the finished product. Today's steel prices are at historically high levels—and it appears they will remain there at least for the near future.

Other metals display similar price patterns: declining real prices over the first five years or so of the previous ten years, followed by sharp increases in the last few years. Aluminum prices doubled between 2003 and 2006; copper prices nearly quadrupled. (See Figure 2.) Metals that contribute to important steel alloys, such as nickel and tungsten, follow similar patterns.

Large infrastructure projects require huge amounts of cement, as well as basic stone materials. Like the price of metals, the price of cement has also risen substantially in the past few years and for much the same reason: It is an internationally traded, energy-intensive product that faces powerful global demand. (See Figure 3.) Utility builders often combine cement with stone and other aggregates for concrete (often reinforced with steel); there are other construction site uses for sand, gravel, and stone, as well. Increased energy costs in extraction and transportation have put pressure on stone prices, which have increased about 30 percent between 2004 and 2006.

While large utility construction projects use many unassembled or semi-finished metal products (reinforcing bars for concrete, for example, and structural steel), such components as conductors and transformers are manufactured elsewhere and shipped to

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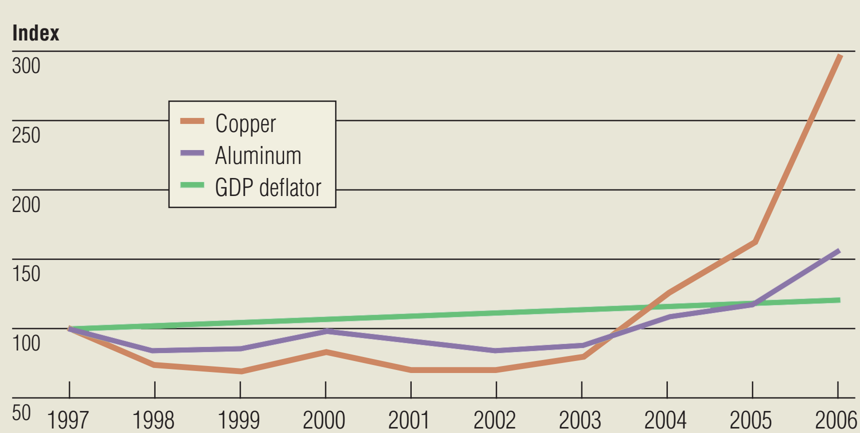
FIGURE 2

ALUMINUM AND COPPER PRICES

(Index: 1997=100)



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

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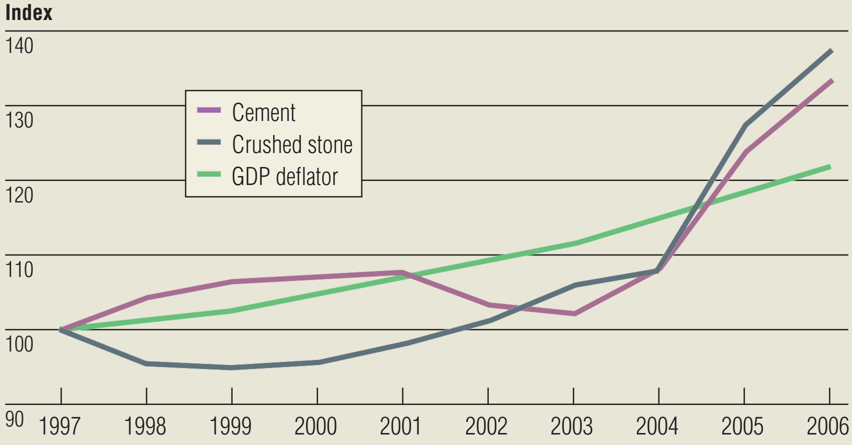
FIGURE 3

CEMENT AND CRUSHED STONE PRICES

(Index: 1997=100)



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

the construction site. Prices for these components display similar patterns of recent sharp price increases, as do manufactured components of generating facilities—large pressure vessels, condensers, pumps, and valves. (See Figure 4.) Prices for wires tend to follow the upward trend of their underlying metals.

People Who Need People

Labor costs for both unskilled (common) labor and craft labor (such as pipefitters and electricians) have also increased at rates higher than the general inflation rate, but more steadily since 1997 and with recent jumps that are less dramatic than for commodities. (See Figure 5.) Between January 2001 and January 2007, while the general inflation rate increased about 15 percent, the cost of craft labor and heavy construction labor increased about 26 percent, while common labor increased 27 percent. Labor takes up a large share of overall utility infrastructure costs, so even a moderate jump has a significant effect.

Moreover, there is deep concern about the growing gap between the supply of and demand for skilled construction labor—especially considering utility plans for infrastructure build-out. In 2002, the Construction Users Roundtable found that recruitment, education, and retention of craft workers continue to be critical issues for the construction industry. The average age of the skilled construction workforce is rising rapidly, and the industry's high attrition rates—not only at the entry level, but also among many workers in the 35- to 40-year-old age group—compound the problem. The latest projections are that the construction industry must recruit 200,000 to 250,000 new craft workers per year to meet future needs. Demographics are working against that effort.

There also could be a growing gap between the supply of and demand for electrical lineworkers—who erect poles and transmission towers, install and repair cables and wires, and generally perform much of the labor for transmission and distribution investments.

According to a DOE report, demand for such workers will outpace supply over the next decade, revealing a shortage of 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 an hour, or $52,300 per year. To attract more lineworkers, those wages will have to rise.

Not in Stock

Many of the components of utility projects—including large equipment like turbines, condensers, and transformers—are manufactured, often as special orders. Underlying material costs affect their prices, obviously. But most of these components are not part of large inventories, so the overall capacity of their manufacturers (relative to near-term demand) can also influence both the item's price and the length of time between order and delivery. Some of the price increases due to manufacturing capacity constraints are not readily overcome in the near term.

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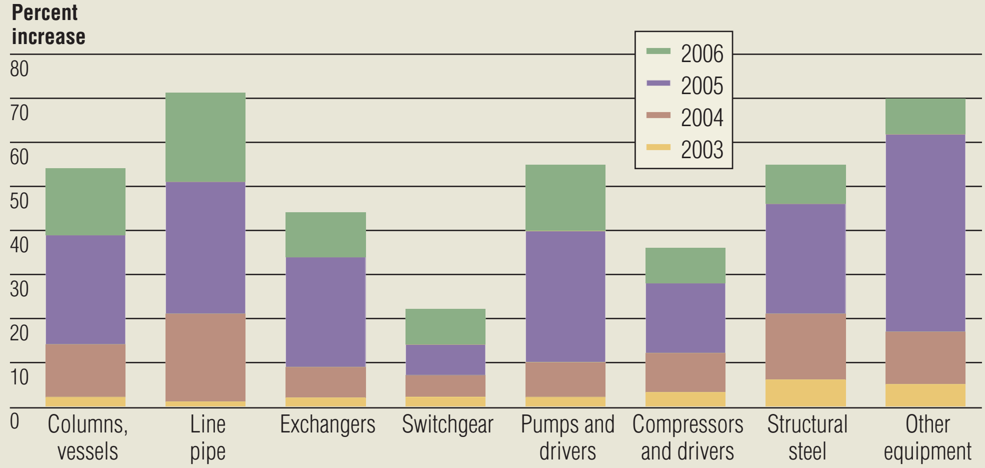
FIGURE 4

POWER PLANT EQUIPMENT PRICES, 2003-2006



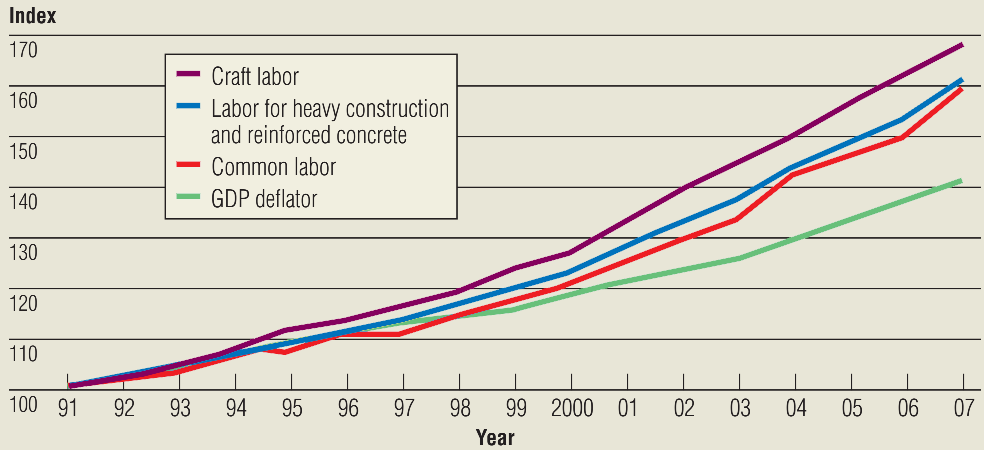
Source: Bechtel

FIGURE 5

NATIONAL AVERAGE LABOR COSTS, 1997-2007

(Index: 100=1997)

Simple average of all regional labor cost indices.



Sources: Handy Whitman Index and U.S. Bureau of Labor Statistics

Indeed, recent orders have largely eliminated spare shop capacity, and delivery times for major manufactured components have lengthened. (See Figures 6 and 7.) In addition, these problems are difficult to solve with imported components due to the dollar's lower value in recent years.

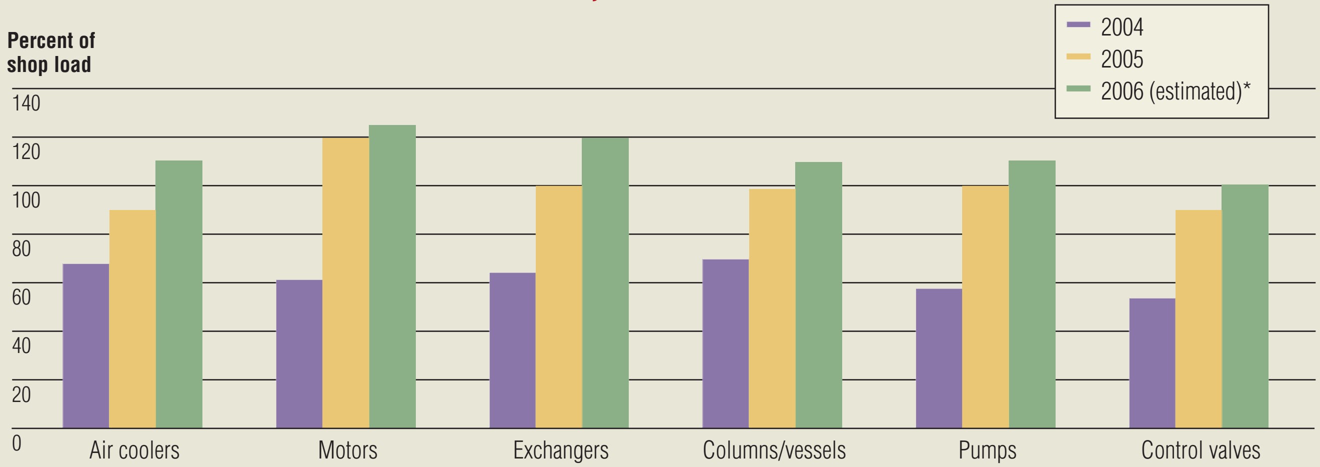
Lengthened delivery times can create completion delays that increase the project's financing costs. In general, during a project's construction phase, utilities commit substantial funds that must be financed through either debt or equity. Everything equal, the longer the time from the initiation through completion of a project, the higher the financing costs of the investment and the ultimate cost passed through to ratepayers.

Finding a Contractor

If it is true that worldwide demand for new generating and other electric infrastructure projects, particularly in China, is a significant reason for the recent escalation in utility construction costs, then engineering, procurement, and construction (EPC) firms would probably have a growing project backlog. We could not get specific information from the major EPC firms on what they have in the queue (that is, the number of electric utility projects compared with other infrastructure projects, such as roads, port facilities, and water infrastructure), so we examined their financial statements, which specify the backlog's financial value.

FIGURE 6

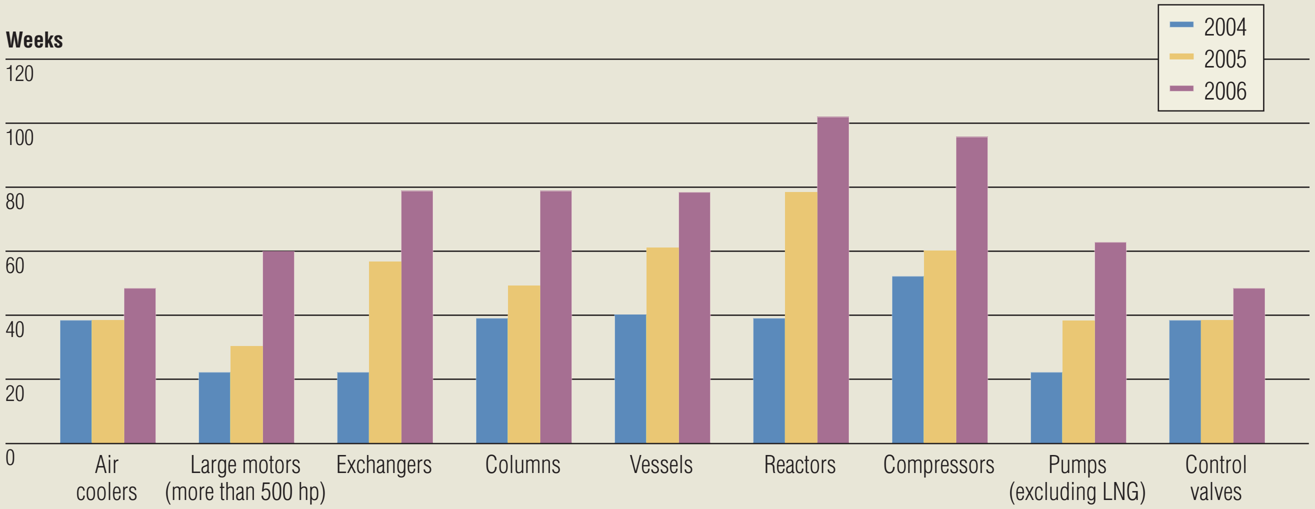
SHOP CAPACITY FOR CERTAIN EQUIPMENT, 2004–2006



*Most current reported data. Source: Bechtel

FIGURE 7

EQUIPMENT DELIVERY SCHEDULES, 2004-2006



Source: Bechtel

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Big boom. China is the biggest producer and consumer of steel and, with the rest of the world, competes for raw materials.

We found that the value rose sharply between 2005 and 2006, from $4.1 billion to $5.6 billion, an increase of 37 percent. This is consistent with the data showing increased worldwide demand for infrastructure projects in general, including utility generation, transmission, and distribution projects.

That backlog will dampen the competitiveness of EPC bids for future projects, at least until the EPC industry can expand capacity to manage greater volumes of projects. This is not to suggest that this market is uncompetitive. Rather, it reflects the limited ability of EPC firms with constrained near-term capacity to service an upswing in new project development during a boom period in infrastructure construction cycles. There is little incentive to bid aggressively on new projects when the queue is already filled.

Although difficult to quantify, the EPC market's lack of spare capacity will undoubtedly put upward price pressure on new bids for EPC services. We can see this in a January 2007 filing by Oklahoma Gas & Electric (OG&E), which sought approval of the Red Rock plant, a 950-MW coal unit. OG&E noted that it had revised a February 2006 cost estimate of nearly $1,700/KW to more than $1,900/KW by the end of September 2006—a 12-percent increase in just nine months. The utility ascribed more than half of the increase (6.6 percent) to changes in market conditions regarding not only materials and equipment costs, but also "a significant tightening of the market for EPC contractor services (as there are relatively few qualified firms that serve the power plant development market)." OG&E's estimate for EPC services had increased by more than half in nine months—from $223/KW to $340/KW.

Construction Indices: A Pattern of Recent Jumps

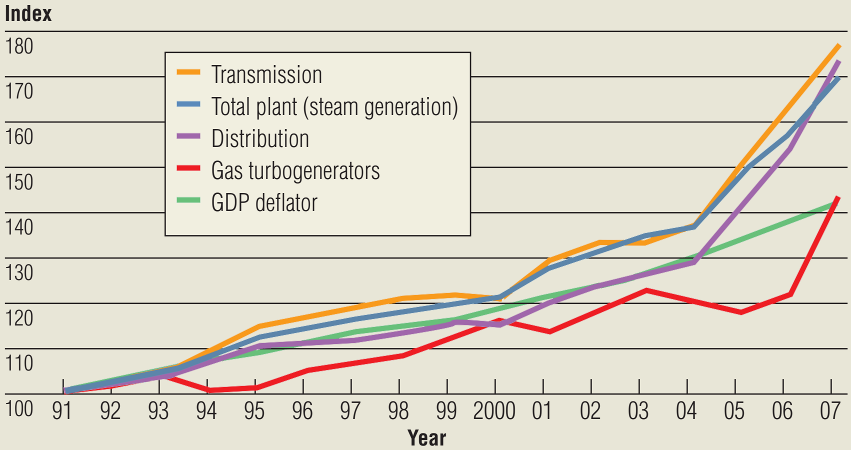
Several sources publish indices that reflect composite costs for various construction projects. Although differences in these indices depend on assumptions about weighted costs (for labor, materials, and manufactured components, for example), they provide useful summary measures for large infrastructure projects.

RS Means, for example, provides a construction cost index that primarily addresses building construction (as opposed to utility projects) but reflects many of the shared cost drivers, such as steel, cement, and labor. While the index rose slightly higher than the GDP deflator beginning in the mid-1990s,

FIGURE 8

NATIONAL AVERAGE UTILITY INFRASTRUCTURE COSTS, 1991-2007

(Index: 1991=100)



Sources: Handy Whitman Index and U.S. Bureau of Labor

it shows a pronounced increase between 2003 and 2006, when it rose by 18 percent (compared to the 9-percent increase in the general price level).

The Handy-Whitman Index publishes indices of utility construction costs—often broken down by detailed component costs—for six regions. (See Figure 8.) Steam generation construction costs (for boilers, generators, piping, etc.) tracked the general inflation rate fairly well through the 1990s, began to rise modestly in 2001, and have increased significantly since 2004. Between January 1, 2004, and January 1, 2007, the cost of building steam generation increased by 25 percent—more than triple the inflation rate. Costs for gas-fired combustion turbines actually fell between 2003 and 2005, but during 2006 the cost of new turbines increased

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by nearly 18 percent—roughly 10 times the inflation rate.

The cost of transmission plant investments (for towers, poles, station equipment, conductors, and conduit) more or less tracked inflation between 1991 and 2000, increased significantly in 2001, and then showed an especially sharp increase between 2004 and 2007, rising almost 30 percent and nearly four times the inflation rate. Overall distribution plant costs (for poles, conductors, conduit, transformers, meters, and so on) stayed close to the inflation rate until 2004, then increased by 34 percent between January 2004 and January 2007, a rate that exceeded four times that of inflation.

By Any Other Measure

EIA's 2007 "Annual Energy Outlook" indicates that construction costs since 2004 have generally tracked inflation and will in future, but recent experi-

What EIA Says

Along with its "Annual Energy Outlook," the Energy Information Administration (EIA) prepares a report on the assumptions (about fuel prices, economic growth, environmental regulation, and so forth) that underlie the 25-year forecast. Aside from reflecting regional labor conditions, the assumptions are generic and do not take into account a project's site-specific characteristics. But in theory EIA's assumptions support a ballpark estimate of the relative construction cost of different generation technologies at any given time. Industry analysts, consultants, academics, and policymakers use the estimates extensively, and they frequently are cited in regulatory proceedings, sometimes as a yardstick by which to compare a utility's projected or incurred capital costs for a generating plant.

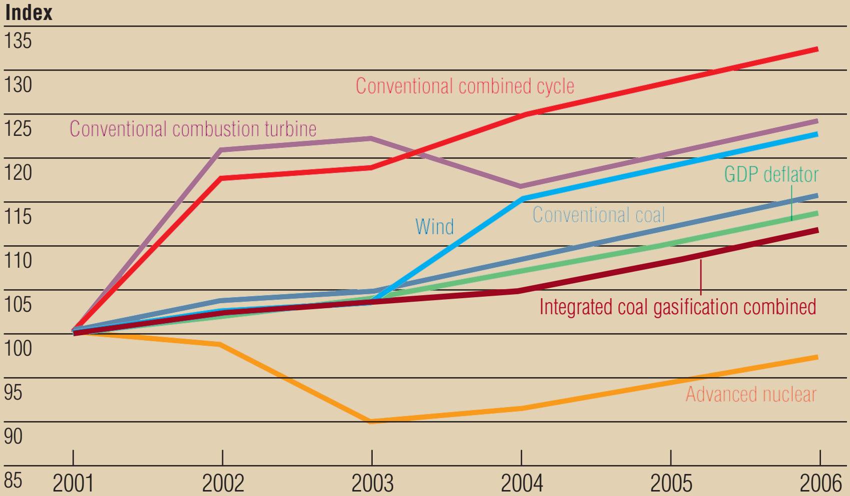
But are the data adequately taking into account current or expected construction costs?

We reviewed EIA's estimate of overnight plant costs (that is, the capital cost exclusive of financing costs) for 2001-06. We focused on the six technologies that have been most commonly built or given serious consideration in utility resource plans in the last few years—combined-cycle gas-fired plants, combustion turbines (CTs), pulverized coal, nuclear, integrated coal gasification combined cycle (IGCC), and wind.

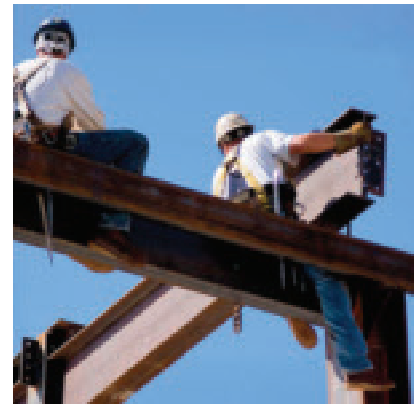
The general pattern in EIA's assumptions shows a dramatic change in several technology costs between 2001 and 2004, followed by a stable period of growth until 2006. (See the figure.) The two exceptions to this are conventional coal and IGCC, which increase throughout the period by a near-constant rate, close to the rate of inflation. The data show conventional coal and conventional CT experiencing a sharp increase between 2001 and 2002. After this increase, conventional coal cools off and increases at a pace near inflation; conventional CT actually drops significantly before 2004 and also levels off near the rate of inflation. In comparison, nuclear technology falls dramatically until about 2003 and then continues increasing with inflation. Wind moves close to inflation until 2004 when it experiences a one-time jump and then flattens off through 2006.

The pattern (described in this article) for almost all other generation construction cost elements is quite different, however: They show price changes at or near the inflation rate through the early part of this decade, with a dramatic change in only the last few years. 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). But for 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 the trend.

EIA CONSTRUCTION COST ESTIMATES
(Index: 2001=100)



Sources: Energy Information Administration, Bureau of Economic Analysis



ence shows otherwise. (See the sidebar, "What EIA Says.") This is a critical discrepancy, in that utilities and commissions have often relied on EIA projections as cost benchmarks for recent construction proposals, but have found that actual costs have jumped significantly, rapidly, and in a fashion unanticipated just a few years ago. EIA acknowledges that its estimates do not reflect short-term changes in the price of commodities. But increased prices for components, rising wages, and a tighter market for construction management services have also increased the costs of investing in utility infrastructure. These elevated numbers show no immediate signs of abating.

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