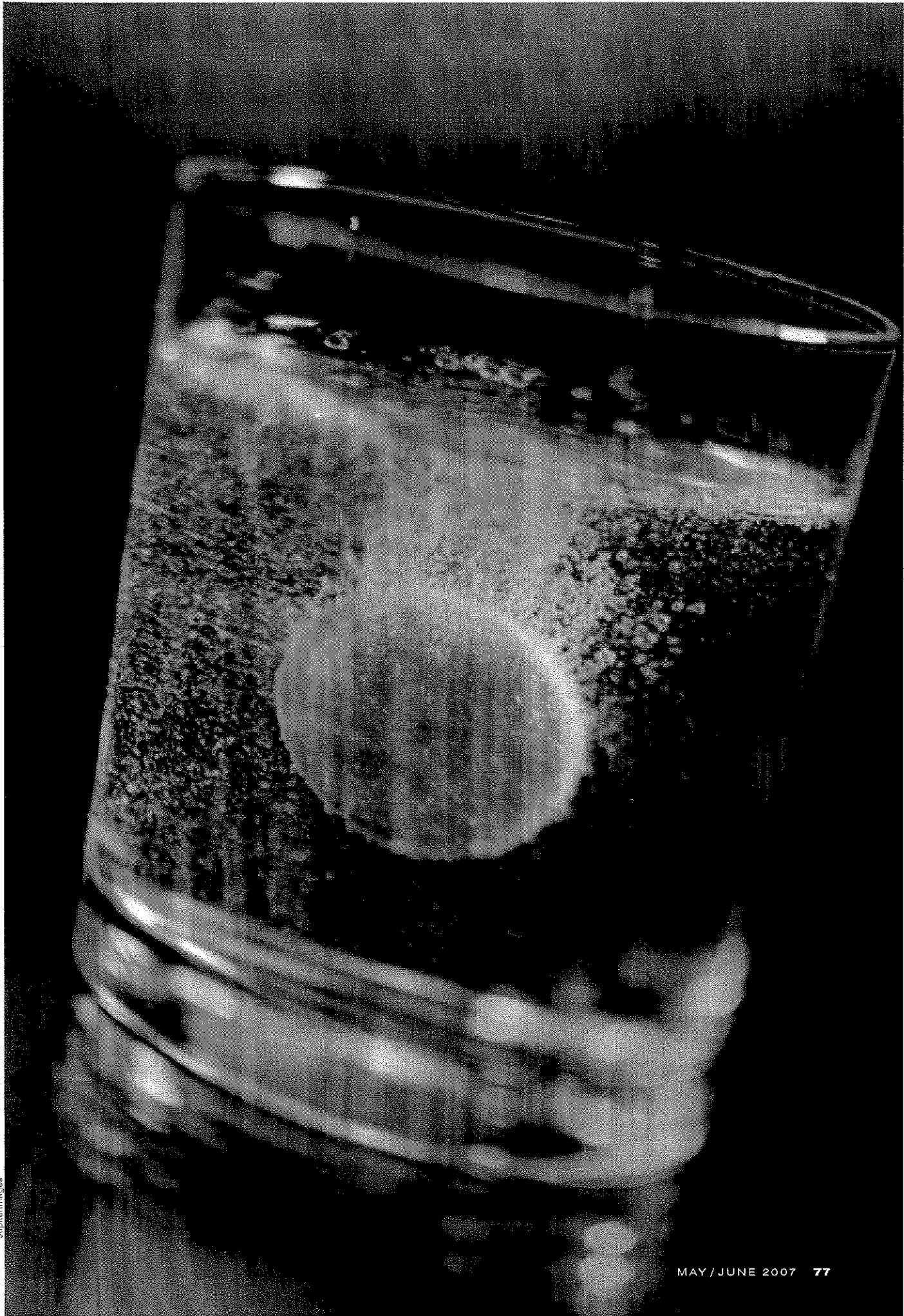
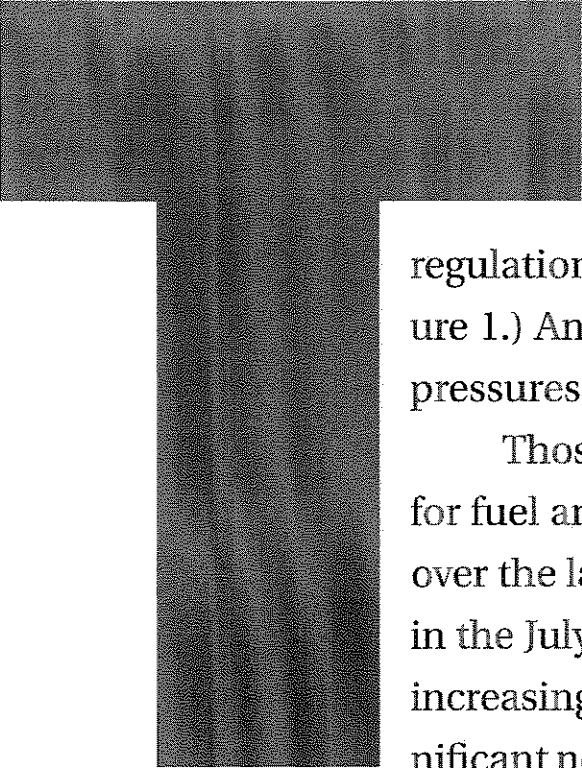


RATE SHOCK RELIEF

It may not be possible to avoid rate shock altogether, but regulators and utilities have several ways to mitigate it.

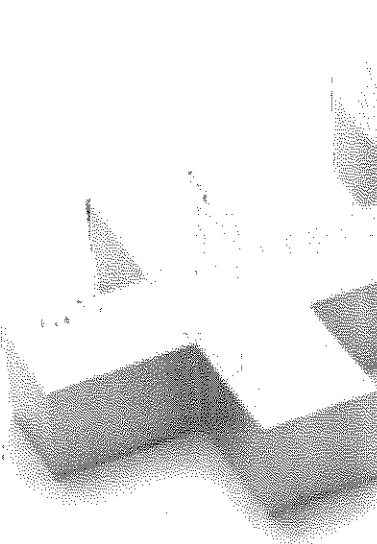
By Frank Graves, Philip Q. Hanser, and Gregory Basheda





Today, many U.S. electric utilities are seeking rate increases; in some cases, very substantial ones. This is occurring in all regions of the country and in states with traditional regulation as well as those with retail access. (See Figure 1.) And no state or utility is immune from the cost pressures that are causing rates to increase.

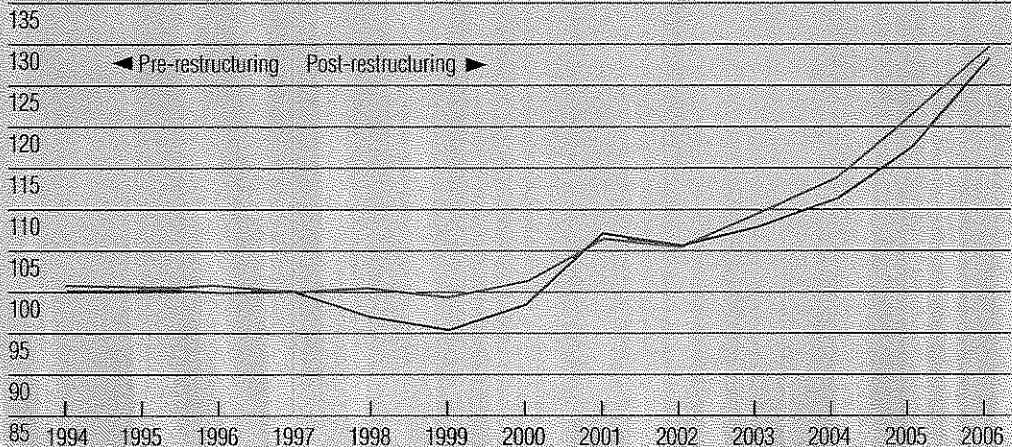
Those pressures are high. Input costs, particularly for fuel and purchased power, have risen substantially over the last few years. [See “Behind the Rise in Prices,” in the July/August 2006 *Electric Perspectives*.] Moreover, increasing demand and aging infrastructure require significant new generation, transmission, and distribution construction, as well as investment in energy efficiency programs and technologies. Electric companies also will require additional investment to comply with known and still uncertain but tightening environmental mandates.



Some recent rate increases, particularly those requested by utilities in retail-access states, stem from the expiration of multi-year rate freezes or rate caps, implemented at the start of the state’s “transition period” to retail competition. Since wholesale prices have increased significantly in the last few years, the transition from frozen, 1990s-vintage cost-based generation rates to current prices has led to significant rate shock in many states. In some, utilities have requested rate increases as large as 70 percent. In addition, not all retail-access states have reached the end of their

FIGURE 1
AMOUNT OF RATE INCREASES IN RESTRUCTURED AND
NONRESTRUCTURED STATES

Percentage
 (base 1997=100 percent)



Source: Energy Information Administration

transition period, so many customers could face comparable rate shock over the next few years.

This upward pressure on electric rates is occurring at a time when the electric utility industry's average return on equity (ROE) is trending downward. Also, while the industry's overall financial condition is sound, the typical utility credit rating has dropped from A to BBB over the last five years, increasing the expense to borrow money for needed investment. Only about 45 percent of all utilities currently main-

of baseload generation drove rate increases—and many state commissions considered ways of moderating the rate impact associated with large new power plants in a utility's rate base.

Operating cost pressures may be the primary reason for today's rate increases. Yet the utility's and regulators' underlying desire to moderate those increases is the same as before. If the goal is to lessen rate shock for the customer, there are several options for the utility and the regulator.

Regulation does not guarantee full cost recovery: It simply gives a utility an unbiased opportunity to recover its prudently incurred costs.

tain ratings of BBB+ or above, down from 75 percent in the late 1990s. Moreover, utility cash flows were about \$10 billion less than the sum of operating and capital costs in 2005. This gap could widen significantly during the next several years as utilities undertake expenditures for infrastructure development, energy efficiency, and environmental improvements. Rejected or delayed rate relief would, of course, only worsen the situation.

Ironically, most electricity rates have decreased in real terms over the last 20 years. Moreover, recent electricity rate increases have been modest compared to the sharp percentage increases in prices for other consumer energy products, such as gasoline. But historical perspective provides little

Frank Graves and Philip Hanser are principals at The Brattle Group in Cambridge, MA; Greg Basheda is a senior consultant in the group's Washington office.

What's a Utility's Rate Base Worth?

A primary goal of ratemaking is to give a franchise utility a fair opportunity to recover its costs, including a return of and on capital invested in utility service. Without a fair opportunity to recover its costs, a utility would have trouble raising the capital it needs to provide adequate and reliable service (or have trouble raising capital at a reasonable cost). It is important to note that regulation does not guarantee full cost recovery: It simply gives a utility an unbiased opportunity to recover its prudently incurred costs, which means that the utility has an equal opportunity to earn more or less than its cost of service.

In simple terms, a utility's cost-of-service (or revenue) requirement has three elements:

- coverage of operating costs, such as fuel, purchased-power, operations-and-maintenance, and customer-service costs;

solace to electricity customers facing significant rate hikes.

To reduce the customer's pain associated with large rate increases, state regulators are considering various methods of deferring or phasing-in rate increases. Not surprisingly, such alternative approaches also received consideration when the industry faced significant rate increases in the past. From the mid-1970s through the mid-1980s, for example, fuel price increases and the completion of the last major construction cycle

- a return of the capital cost, otherwise known as depreciation expense; and
- a return on capital cost, including applicable income taxes.

The public service commission must deem these costs to be “prudently incurred” in order for the utility to recover them. Often the commission determines the allowed costs over a historical or projected 12-month “test period” to establish a utility’s revenue requirement. Then, rates remain fixed until the next rate hearing, though most utilities have adjustment clauses that allow them to modify the rates—up or down—to recover fuel and other volatile operating costs on a more frequent basis.

In the early history of the electric power industry, both regulators and the courts grappled with the problem of how to set utility rates and, in particular, how to “value” a utility’s investment in infrastructure. In nonregulated industries, this

exercise is relatively straightforward—an asset’s economic value to investors is equal to the net present value of the expected cash flows generated by the asset. This is difficult to apply in the context of regulated utilities, because an asset’s expected cash flow is itself determined by the regulator. In a regulated industry, rates cannot be set at levels that are consistent and fair in relation to the market value of the firm’s assets, because that market value is affected by the allowed rates. There is an obvious conundrum in the valuation of a utility’s “rate base.”

In the first half of the 20th century there was a vigorous debate (which continues today to some extent) between those who argued that a utility’s rate base should be valued at its original cost and those who argued that the rate base should be valued at its “replacement” (using similar technology) or “reproduction” (using identical technology) cost. Valuing a rate base according to its replacement or repro-

duction cost also is known as a “fair value” rate base. The primary advantage of using original, historical cost is that the value is certain and measurable: A utility provides the data for the construction cost of an asset, such as a generating plant. The advantage of using replacement or reproduction cost is that it is more consistent with an asset’s economic value—that is, rates reflect the current cost of building or replacing the asset in current dollars. The primary disadvantage of valuing assets on the basis of their replacement cost is that replacement cost is subject to estimation error and controversy.

An early U.S. Supreme Court decision (*Smyth v. Ames*, 1896) found that both original cost and replacement cost were valid ways of setting a utility’s rate base. The Supreme Court’s views fluctuated over the next 50 years, but in the 1944 *Hope Natural Gas* case finally put the issue to rest. The court decided, in effect, that the reasonableness of the ultimate result, rather than

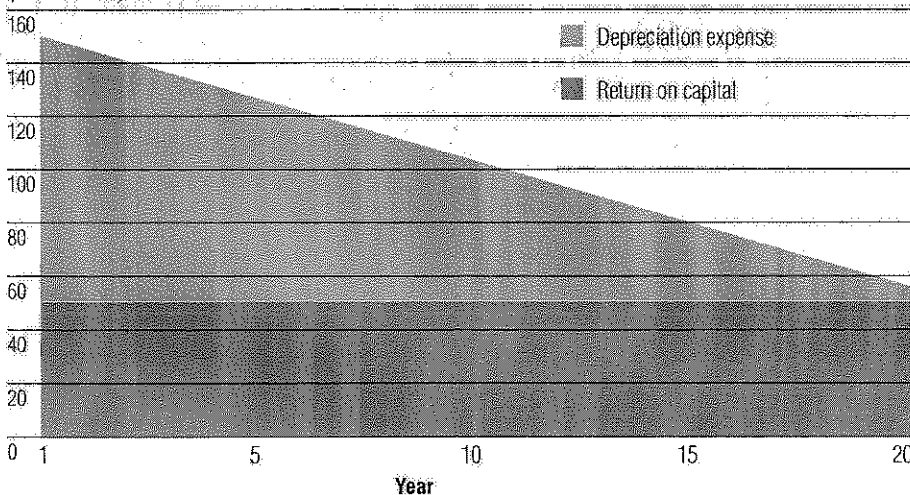
Starting High

A utility brings into service a new power plant, with an original construction cost of \$1 million and an expected operating life of 20 years. The utility’s cost of capital (debt and equity) is 10 percent. In the plant’s first year of operation, its revenue requirement is that cost of capital and the depreciation expense: \$100,000 (10 percent of \$1 million) plus \$50,000 (\$1 million divided by 20), totaling \$150,000. (The plant also would have associated operations, maintenance, and fuel costs but our focus here is solely on capital recovery.) In year two of its operation, the plant’s revenue requirement would be \$95,000 (return on capital) plus \$50,000 (depreciation expense) for a total of \$145,000. In year 10, the total revenue requirement would be \$100,000. As the undepreciated portion of the plant declines, the associated return on capital declines, because the rate of return is applied to a declining plant value. Since depreciation expense remains constant over time, the annual revenue requirement associated with the plant’s capital recovery necessarily declines. The capital recovery method is front-loaded because recovery is greatest in the early years of the plant’s operation.

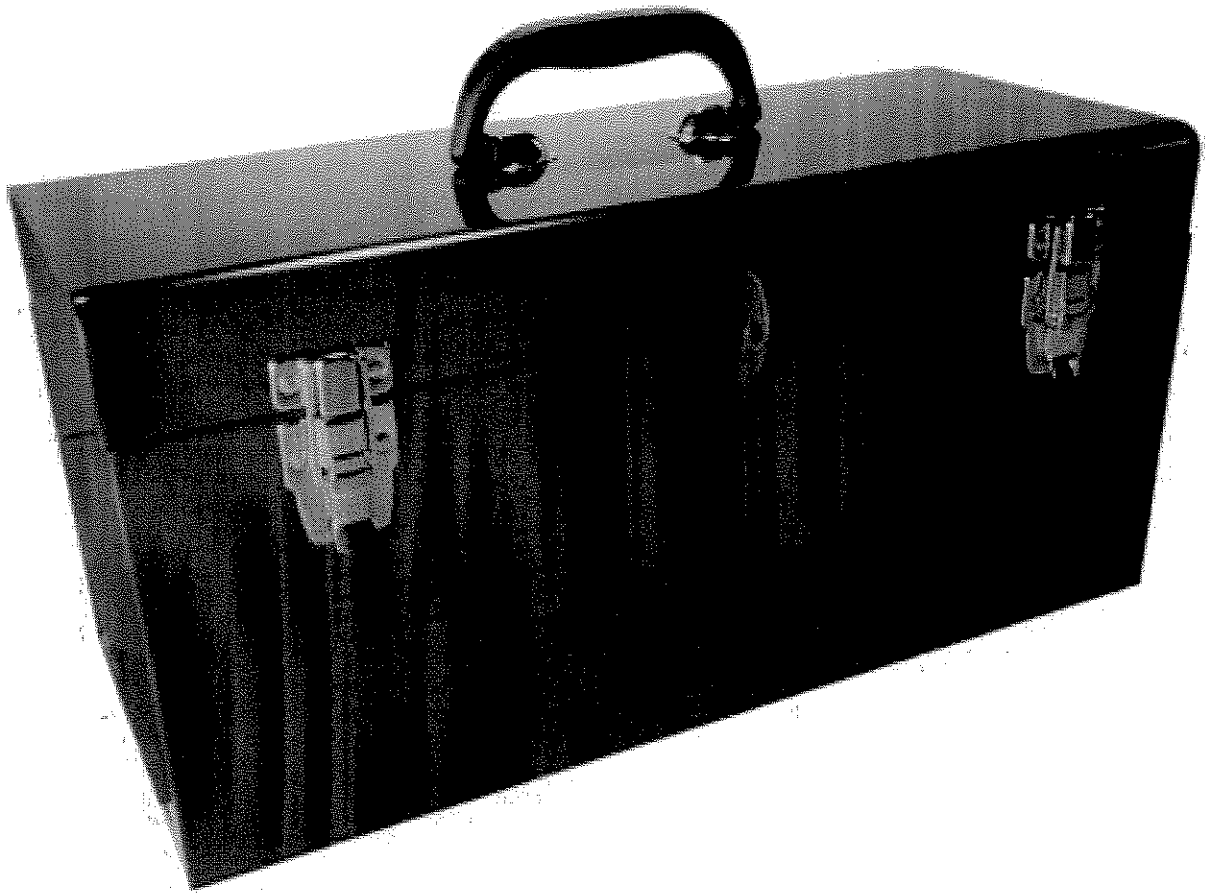
REVENUE REQUIREMENT WITH DEPRECIATED ORIGINAL COST RATEMAKING

A \$1 million asset depreciated over 20 years.

\$ Thousands, nominal



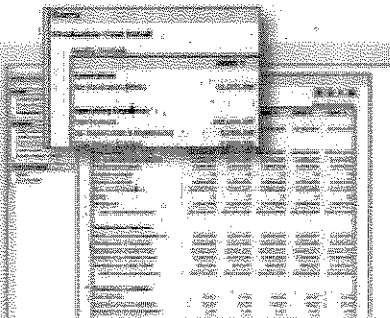
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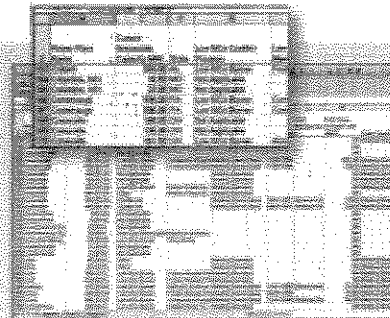
Pictured at right: Power Plant, production cost detail



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Pictured at left: multiple power plant template



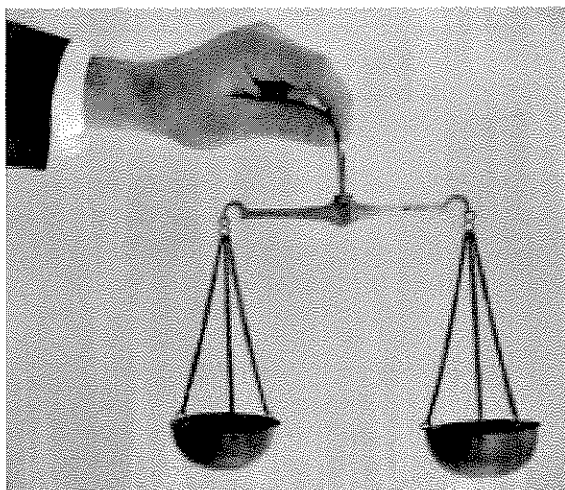
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the method used to set the rate, determined whether the rate was just and reasonable.

A 1992 study by the National Association of Regulatory Utility Commissioners (NARUC) revealed that, as of 1991, 44 regulatory commissions were using original cost, with the remainder either using fair value or having no predetermined method. Hence, setting a utility's rate base equal to original cost less depreciation has become the standard approach to electric ratemaking.



Under replacement cost, the regulator balances the rate with a reduction in allowed returns.

nominal or real terms. Here, the utility annually would recover the same amount of revenue over the asset's operating life. Under real levelization, the annual capital cost recovery would increase every year (in nominal terms) with the rate of inflation, while the allowed return would exclude any allowance for inflation. Levelized rates, whether real or nominal, yield the same discounted lump-sum revenues

Loading Up the Front End

Most utility assets are subject to straight-line depreciation, which means that the generation, transmission, or distribution asset is depreciated at a constant rate over its assumed operating life. Thus, a facility with an original cost of \$1 million and an assumed operating life of 20 years would incur a depreciation expense of \$50,000 per year for 20 years.

Depreciated original cost (DOC) ratemaking leads to cost recovery that is "front-end" loaded—that is, the utility recovers much of the asset's value in the early years of its operating life. (See the sidebar, "Starting High.") But with costs loaded up front, DOC ratemaking can result in an initial rate shock

over the asset's operating life as the utility would earn under DOC, but the pattern of capital recovery is evened out.

Incentive or performance-based regulation (PBR) is another alternative to DOC ratemaking. PBR partially breaks the link between costs and rates by giving utilities an opportunity to earn more or less than their approved return on capital. Utilities that operate efficiently and cut costs can earn more profit; poor-performing companies face financial penalties. The best-known form of PBR is price-cap regulation, in which prices typically are allowed to increase at regular intervals at a percentage of the inflation rate. (Since most assume that the utility under PBR would have productivity gains greater

Several alternatives to DOC ratemaking can yield capital recovery streams that offer the same present value costs to customers and investors as front-loaded ones.

when a new generation, transmission, or distribution asset goes into a utility's rate base. By concentrating capital recovery in the early years of an asset's service life, DOC ratemaking exacerbates any near-term rate impacts (such as volatile fuel costs) associated with new asset, regardless of its cost-effectiveness (or its cost relative to the utility's embedded cost).

Cost-based ratemaking doesn't have to carry that shock, however. Indeed, several alternatives to DOC ratemaking can yield capital recovery streams that offer the same present value costs (and cost recovery) to customers and investors as front-loaded ones. These approaches alter the timing and pattern of capital cost recovery.

One method is simply to *value rate base according to its replacement or reproduction cost*. Under replacement cost, the value of new assets will increase over time (in nominal, inflation-adjusted dollars) rather than decline. In turn, the regulator must balance the rate with a reduction in allowed returns to investors.

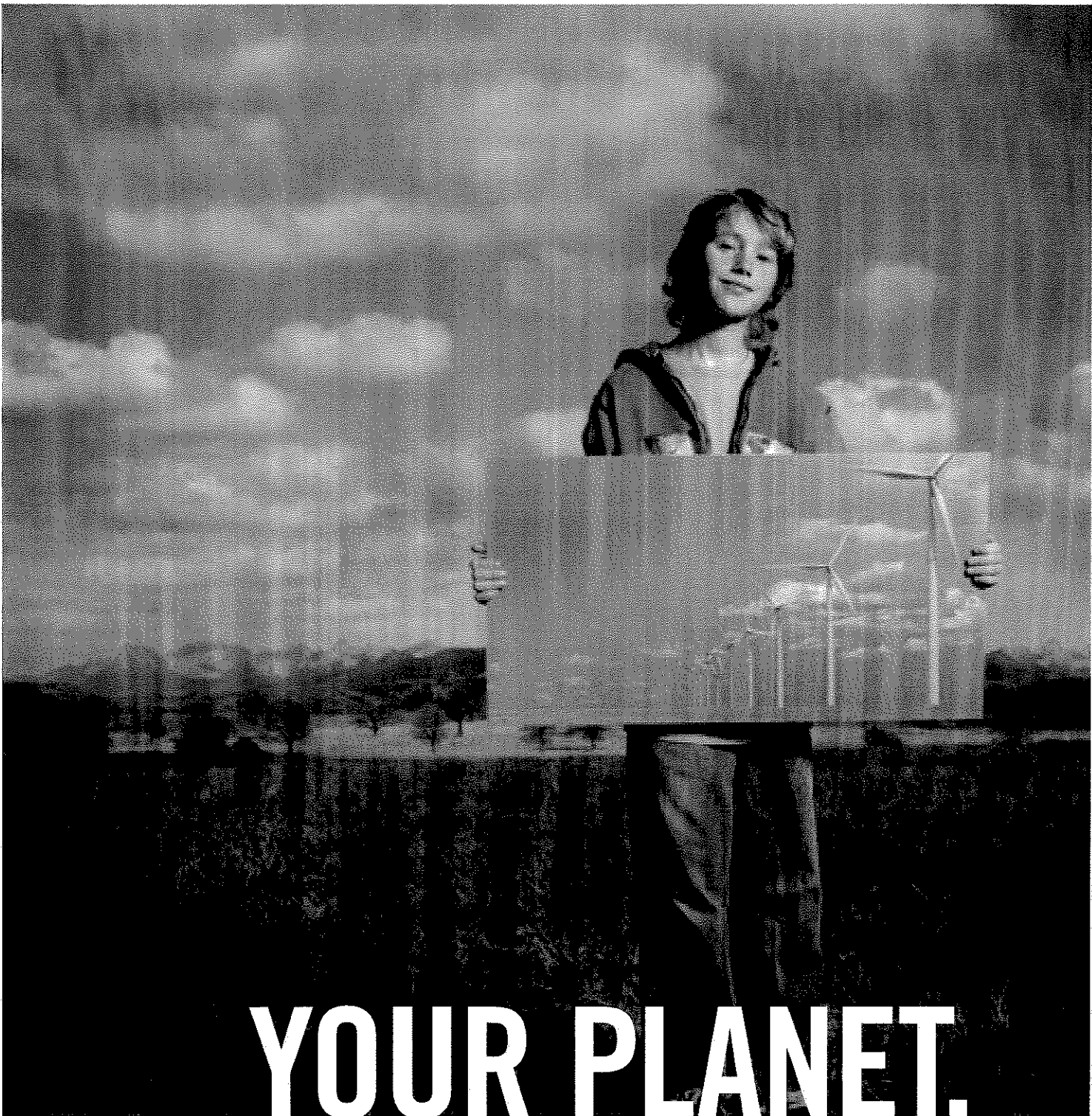
Another approach is to *levelize capital recovery*, either in

than society at large, the rate increase is equal to inflation minus an assumed productivity offset.) A utility that keeps its annual cost increase below the allowed rate increase benefits financially. Depending on its design, PBR could give a utility an incentive to levelize or lengthen the pattern of capital recovery so as to keep its costs at or below the price cap.

Collecting Tomorrow

Those three approaches change the pattern of capital recovery and the calculation of the utility's revenue requirement in a systematic way; and they aren't necessarily used just to mitigate rate shock. Some of them apply specifically to the inclusion of new assets in the utility's rate base, whereas others apply more generically to any new cost.

Rate deferrals, in contrast, are essentially ad hoc, case-specific adjustments to rates to specifically mitigate rate shock. Under this approach, DOC principles underlie the rates, but near-term rates and the timing of capital recovery are adjusted. For example, a utility could "phase in" an asset's



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full revenue requirement, so that the customer rates would not reflect the cost's full impact until several years later. The utility would recover its near-term revenue shortfalls (with an allowed return accruing during the deferral period) in the asset's later years. These deferral methods had their heyday in the 1980s, as the industry completed its last major construction cycle and regulators sought ways to mitigate the rate impacts. The need for these methods lessened over the years, largely due to declining costs through the 1990s, a generation surplus from the 1980s, increased reliance on purchased power rather than self-constructed generation, and industry restructuring. However, several utilities are now phasing in rate increases that would otherwise occur more quickly.

A rate deferral is simply deferred recovery of a utility's prudently-incurred costs. Thus, if \$70 million of an approved \$100 million rate increase is deferred, the utility recovers the \$70 million plus carrying charges at a later time. Otherwise, the utility does not get a fair opportunity to earn its revenue requirement. The deferred amount must

- be a credible regulatory asset,
- have the ability to earn a fair carrying charge; and
- have assurances of being fully amortized.

The \$70 million would become a regulatory asset that would be amortized over a specified, future period. A carrying charge equal to the utility's average weighted cost of capital would be applied to the unamortized balance.

Simple deferrals have at least three drawbacks. First, consumers ultimately pay more in absolute dollars (though not

in present-value terms) than they would have otherwise, because they must pay the utility's carrying charge on the unamortized balance. Second, a deferral could force a utility to borrow a substantial amount of funds to cover the deferral, which could harm its credit rating and cash flow. Third, it may be difficult to assure the reliable future recovery of the deferred amounts, especially in an environment in which costs are expected to rise steadily for several years and the cumulative bill of several rate deferrals becomes prohibitive. In that event, mitigating the initial rate shock of multiple rate filings could result in a more significant shock down the road.

To address such concerns, some utilities securitize, which involves the transfer of a revenue-producing asset to a legally separate special purpose entity (SPE) that will issue debt obligations secured by and payable from the asset's revenue stream. The electric utility industry first used securitization in the 1990s, both to reduce stranded costs (by reducing their associated financing cost) and ensure their recovery by utility shareholders.

Securitization typically authorizes a unique form of irrevocable rate order—and the surcharge to customers pays the debt service on the bond financing. Customers benefit from the SPE's low financing costs (owing to the predictable revenue stream, unhampered by the utility's risks), which will be less than the utility's weighted average cost of capital. Ratings agencies have not treated securitization debt as a borrowing of the utility, so the debt does not depress the utility's ratings. As a result, customers benefit from the fact that

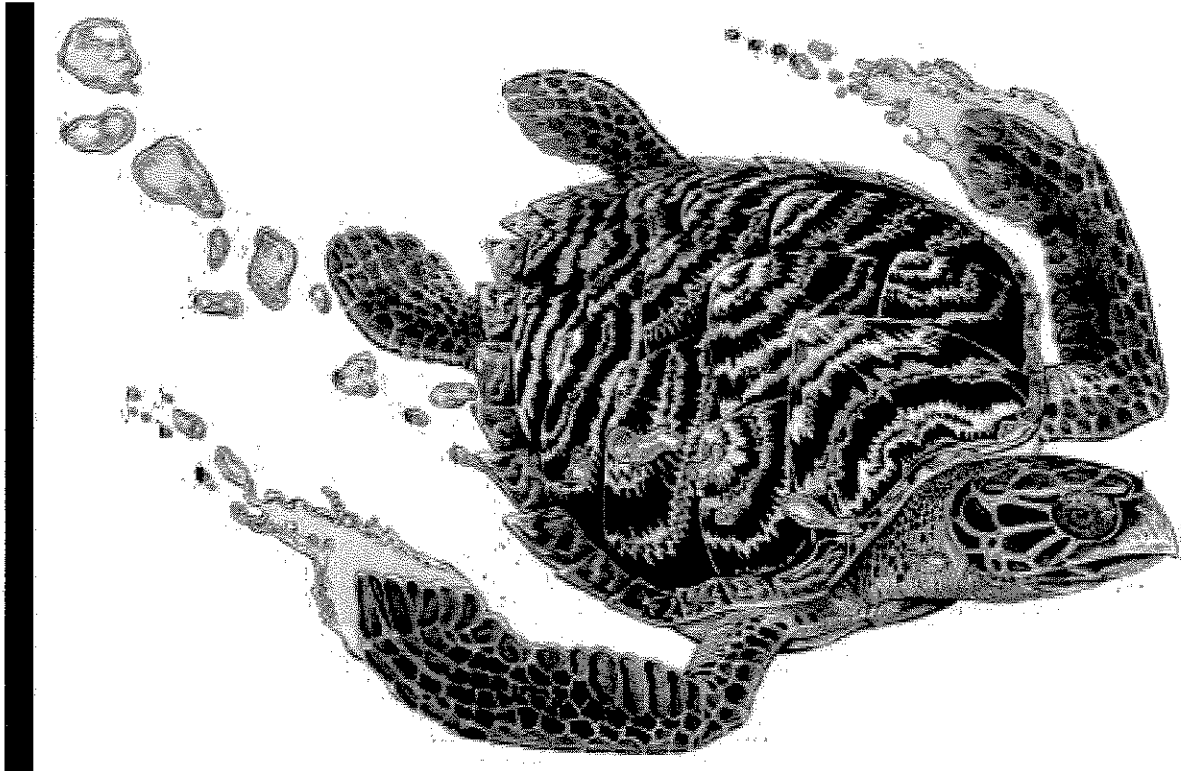
the interest costs are at low rates (thus reducing carrying charges) and at the same time the rest of the utility's borrowings costs less than otherwise.

Securitization is an attractive alternative to utility self-financing of deferred revenues, although it does entail certain transaction and regulatory costs. In addition, legislation must give a state's public service commission the authority to establish the binding rate orders and surcharges

Including "construction work in progress" in rate base enables a utility to recover construction-related financing costs as it incurs them.



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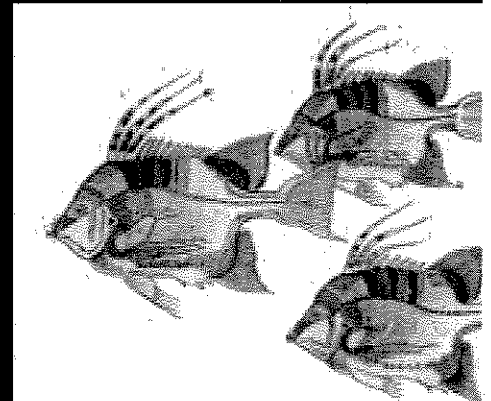
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A Path to Managing Your Carbon Risk: The PI System and Energy Efficiency

It is likely that the single greatest lever an electric utility has to control its carbon emissions is to reduce them at the source via energy efficiency initiatives. The PI System offers the source-level measurement, verification and reporting infrastructure you need to optimize your energy assets and manage your enterprise carbon risk. With energy efficiency as a key component of your carbon management strategy, your organization can significantly reduce your carbon footprint while saving potentially millions of dollars on fuel costs and carbon credits.

As an example, a 1% efficiency improvement on a 500 MW combined cycle facility operating with an 80% capacity factor would result in a savings of over \$1.6 million per year based on a \$6/MMBtu gas price, and a \$25/ton price for carbon credits. And, while you are improving your plant heat rate, the carbon footprint of the plant decreases in direct proportion. Unlike the investment in a "carbon credit," this energy and carbon reduction effort will continue to accrue bottom line savings year after year.

It is generally agreed that emerging state and federal greenhouse gas (GHG) regulation will use a "cap-and-trade" market mechanism for establishing the cost of GHG reduction. This means what was once considered a harmless byproduct of combustion is now a fungible, tradable commodity. As such, carbon lands on the corporate balance sheet and is subject to the rigorous internal controls that govern all values on a corporation's financial statements.

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and carbon accounting system is that PI meets the audit trail and security requirements of Sarbanes-Oxley. In addition, the PI System's real-time platform provides engineering and operations personnel with the detailed asset-level performance information they need to identify and resolve performance shortfalls in your equipment and processes.

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that establish the basis for the revenue-producing SPE asset.

Work in Progress

For many years, it was common practice to include in the rate base an allowance for “overhead” costs during the construction of a utility facility. With the development of the uniform system of accounts, utilities entered all costs incurred during construction. Interest during construction was capitalized and, when the plant went into service, the accumulated interest was added to the book cost of such plant and the total amount over the plant’s useful life. In 1971, the Federal Power Commission (predecessor to the Federal Energy Regulatory Commission—FERC) abandoned the term “interest during construction” and substituted “allowance for funds used during construction” (AFUDC) in its system of accounts.

Starting in the late 1960s, costs of both construction and capital began to increase dramatically, and construction periods lengthened considerably. As a result, AFUDC accounts

their consumption habits and their technologies. Conversely, AFUDC accounting can facilitate a potentially large, sudden increase in rates.

CWIP allows customers to see a gradual rate increase in a timely way, thereby enabling them to adjust their consumption habits and their technologies.

grew large. By 1980, AFUDC had increased to more than 50 percent of the electric industry’s return on common equity. Many electric utilities had dividend pay-out ratios of more than 50 percent, so companies were in effect forced to borrow funds to pay common stock dividends.

Confronted with these problems, many commissions began to permit all or part of “construction work in progress” (CWIP) in rate base. In effect, CWIP enables a utility to recover construction-related financing costs as it incurs them, rather than after the plant goes into service. By the late 1970s, most states allowed CWIP, though actual CWIP amounts and conditions varied considerably.

Allowing CWIP in rate base before a facility is in service or allowing a cash return on CWIP is similar to a phase-in plan that gradually spreads out costs in rates—though CWIP spreads the pain back in time rather than forward. (See the sidebar, “CWIP Controversies.”) Also, CWIP spreads the recovery of new costs over a longer period than would otherwise be the case; it also eliminates the compounding of carrying costs, which in turn alleviates pressure on the utility’s credit ratings. In addition, CWIP allows customers to see a gradual rate increase in a timely way, thereby enabling them to adjust

CWIP Controversies

In the past, consumer advocates and other customer representatives frequently opposed including construction work in progress (CWIP, pronounced “quip”) in electric rates.

One general complaint is that CWIP is inequitable because it forces customers to pay for an asset before they receive any benefits from it. The fact is, though, ratemaking already is inequitable, even using strict depreciated original cost ratemaking—straight-line depreciation does not equal economic depreciation, and regulation must true up many operating costs. Thus, traditional ratemaking does not lead to a temporally perfect match of costs and rates. It is true that increased financing costs (due to a utility’s weak credit rating during major construction) could have an immediate, adverse effect on all customers. But if CWIP generally helps reduce financing costs, the reduction in total lifecycle costs has a positive impact for customers.

Another criticism is that CWIP reduces a utility’s incentives to control costs. Regulators, however, can restrict CWIP to a predetermined budget of prudent and cost-effective expenditures, with any cost overruns at risk.

One other argument is that if a plant turns out to be excess capacity, CWIP prevents a “used and useful” disallowance. But the used and useful principle arguably is anachronistic in a credit-constrained, highly volatile environment in which significant new infrastructure is needed. CWIP is more likely to foster the right kind of planning discussions before the fact.

Sale and Leaseback

The primary motivation for a sale and leaseback agreement is to transfer a property’s federal tax benefits between two parties without actually transferring property ownership. The lessor can use the federal accelerated depreciation allowances and any other development tax credits on the property. Theoretically, this allows the lessee to receive a portion of the lessor’s tax savings through cash payments or reduced rental charges. So, firms without sufficient federal tax liability (such as a utility with a major expansion plan) can use certain tax benefits immediately to reduce financing costs implicit in the rental payments. The potential advantages are the reduced financing cost resulting from a “flow-through” of tax benefits in the lease price and alleviating the potential rate shock associated with adding a new generating plant to rate base. The primary disadvantage of leasing is that the utility does not earn a return on its investment.

Sale and leaseback transactions are not common. However, in the 1980s, several utilities made sale/leaseback transactions for newly-constructed nuclear power plants. A study of these transactions during the period 1978 to 1990 found that most of them occurred from 1985 to 1987, the period

just prior to the effective date of the Tax Reform Act of 1986, which reduced the effectiveness of such transactions to utilities.

The study also found that most of the firms engaging in sale and leaseback transactions did not have strong financials. Indeed, such transactions are attractive to financially weak firms, possibly due to the less burdensome covenants on lease financing compared to secured borrowing. In other words, mitigating rate shock does not appear to be the primary motivation behind most of the 1980s-vintage sale and leaseback transactions.

That said, lease financing can serve to reduce rate shock—in effect, the regular payments over the life of the lease levelize the revenue requirements, and regulation normally treats these payments as a cost of service. Rates are lower initially.

Moreover, the value of all the lease payments is equivalent to the revenue the utility would have otherwise received under DOC ratemaking, apart from cost savings yielded by a flow-through of tax benefits.

Trended Original Cost Ratemaking

FERC has applied trended original cost (TOC) ratemaking to oil pipelines, but the method has been used little, if at all, in the electric power industry. (See the sidebar, “Following the Trend.”) An advantage of “trended” over “depreciated” original cost ratemaking is that TOC reduces the front-loaded cost recovery associated with DOC, where the rate base declines over time and the present-value equity return is compressed into the early years of the property’s life. TOC ratemaking defers utility income until later years by capitalizing the in-

Following the Trend

The trended original cost (TOC) process determines an allowed, nominal (inflation-included) rate of return on equity that reflects the firm’s cost of capital. Next, the process subtracts the inflation component, producing the “inflation-adjusted” rate of return. Then, it multiplies that rate by the facility’s equity share of the rate base, yielding the annual allowed ROE in dollars. The write-up of the equity rate base is derived by multiplying the equity rate base by the inflation factor. As it would depreciate, the utility writes off that write-up or amortizes it over the remaining life of the property.

Here is an example of TOC ratemaking for a new generating plant with an original equity investment of \$1 million. The total, nominal ROE is 11 percent, which includes 4 percent for inflation. The plant has a 20-year depreciation.

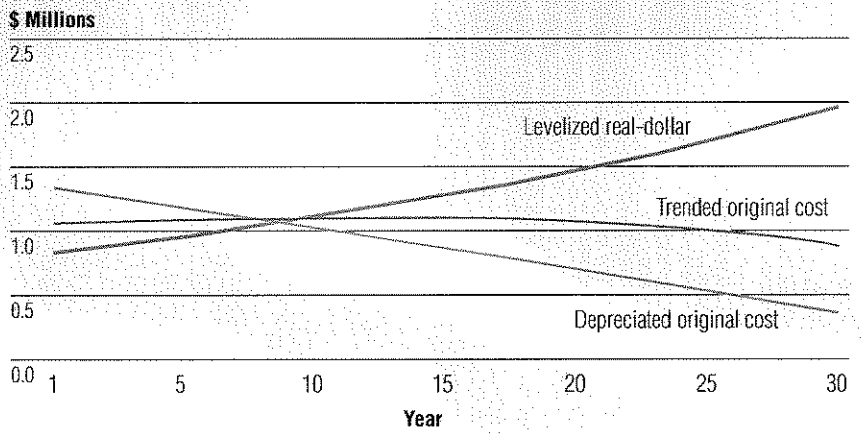
- 7 percent (11 percent minus 4 percent) is the inflation-adjusted rate of return.
- So, in its first year of service, the power plant would be entitled to earn \$70,000 (7 percent of \$1 million).
- In that first year, the inflation total—\$40,000 (4 percent of \$1 million)—would be capitalized into the equity rate base.
- Part of the year’s write-off is the amortization of \$2,000 (\$40,000 divided by 20).
- Another part is the depreciation on the total original equity, or \$50,000 (\$1 million divided by 20).

The equity base at the start of year two would be \$988,000 (\$1 million minus \$50,000 plus \$38,000)—the original cost less depreciation and plus the capitalization of the inflation portion of the return. This process would continue over the life of the property until the rate base (assuming no salvage value) hits zero. Unless changed in a rate case, the real rate of return should be relatively stable. The inflation rate would vary as the chosen inflation index (the rate for U.S. Treasury bonds, for example) varies.

Some regulators, including the Federal Energy Regulatory Commission, believe that trending the entire rate base will give shareholders an unjustified benefit—they would receive a write-up of the portion of the rate base financed by debt. According to this view, equity holders only should be compensated for inflation to the extent that assets are financed by equity. We believe, however, that the entire rate base can (and should) be trended, as long as only a real cost of debt is allowed. Regulation can implement either approach—trending the full rate base or just the equity portion of it—so as to yield the same lifecycle present value revenues, but with different implications for how readily the utility may recover debt service.

PATTERN AND TIMING OF CAPITAL RECOVERY UNDER THREE RATEMAKING METHODS

Annual carrying charges for \$1 million asset with 30-year life and 10 percent weighted average cost of capital. Inflation, 3 percent. Real return, 7 percent.

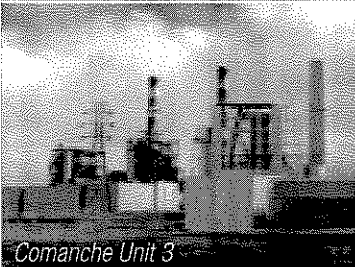




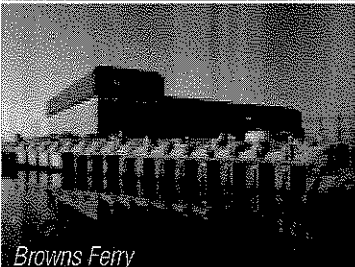
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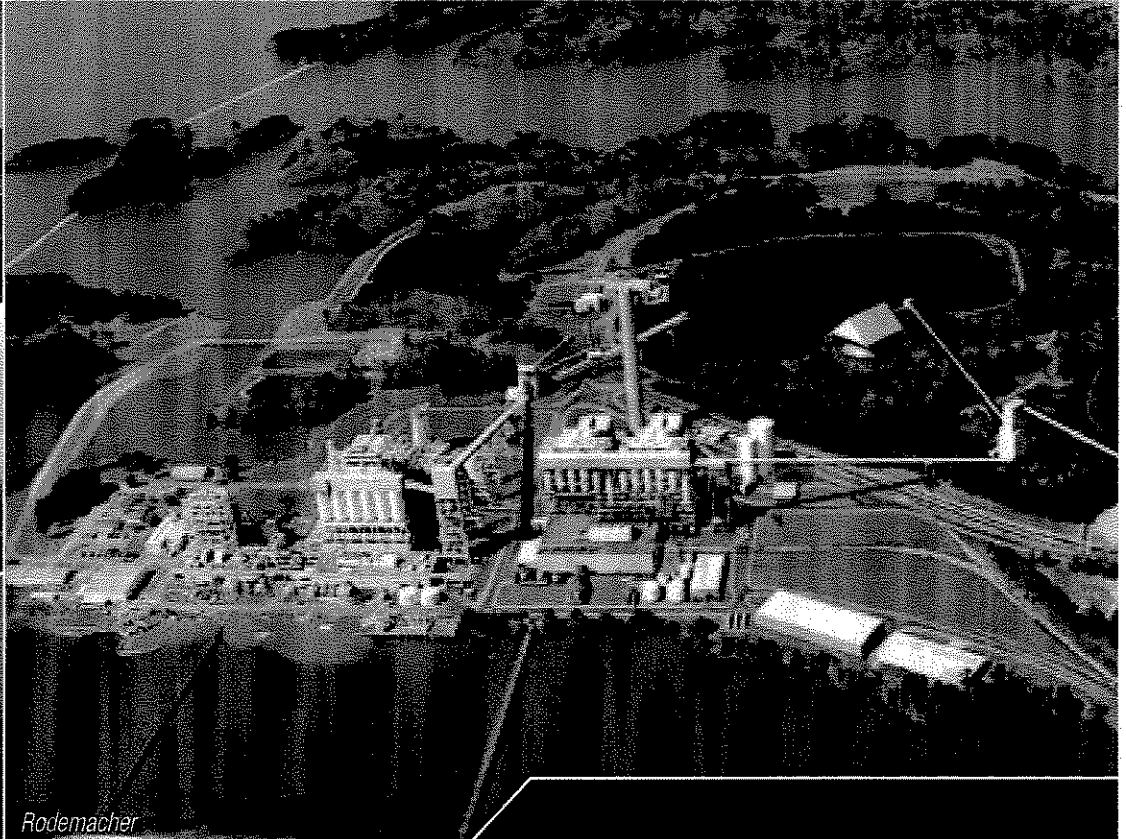
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flation factor into the equity rate base. As time goes on and prices rise due to inflation, the company can raise its rates to recover the deferred income. While investors receive a higher initial cash return under DOC, the present values of the cash returns generated over the life of an asset are identical under DOC or TOC regulation: The time patterns differ but the values are the same.

recovery similar to TOC. Indeed, it is unusual for a long-term power contract to have front-loaded capacity payments. So purchasing new generating capacity is another means of mitigating the initial rate shock associated with the addition of new assets.

Of course, a utility and its state regulators take into account many other factors in the buy or build decision. But

Purchasing may allow a better matching of capacity to the utility's resource needs, while outright ownership of a large plant may be more "lumpy."

Another advantage of TOC is that it comes closer to pricing found in unregulated industries whose assets typically depreciate at a slower rate. When inflation is rapid, DOC regulation can lead to consumer prices far out of line with what a competitive firm would charge—values based on historical costs can be grossly misleading when inflation is rapid, particularly for long-lived assets. TOC also arguably provides for greater intergenerational equity: Successive generations of ratepayers will pay more in nominal dollars, but the dollars will be cheaper because of inflation.

Buy v. Build

Long-term power purchases, either from merchant generators or other utilities, are another way of levelizing the timing and pattern of capital recovery. While the terms of such contracts can and do vary widely, the demand charges they establish often are either constant or rise at a predetermined escalation rate (such as the inflation rate). These contracts, in other words, often have real or nominal levelized capacity payments that result in a timing and pattern of capital

one possibly overlooked benefit of buying power is that it typically leads to levelized capital recovery without requiring changes in ratemaking methodology. Purchasing also may allow a better matching of capacity to the utility's resource needs, while outright ownership of a large plant may be more "lumpy"—that is, have unaccounted-for peripheral costs.

Preventing Future Shocks

The ideal, though unattainable, solution to "rate shock" would be to develop a perfectly timed, dynamically evolving portfolio of both owned assets and power purchases, coupled with a risk management policy that gives a company virtually bulletproof protection against large price increases.

Of course, there is no fullproof way of avoiding rate shocks, at least no way that is not actually prohibitively expensive (such as building so much baseload capacity that the company almost never has to dispatch or purchase gas- or oil-fired generation). A utility can hedge fuel price exposure over a couple of years, but the cost of hedges will track rising fuel prices (and fuel price volatility). All utilities are exposed to volatile wholesale prices to one degree or another. Similarly, utilities cannot fully hedge themselves against volumetric risk, weather, and other operating risks. In short, there will always be some risk of rate shock, given that certain significant input costs are largely or totally beyond a utility's control.

That said, a utility certainly can meaningfully reduce its exposure to rate shock through effective resource planning and well-designed risk mitigation policies. For example, if a utility is self-building its supply, it can lessen the possibility of rate shock through the construction of smaller assets. This also allows a utility to better match supply with load growth.

Similarly, for utilities that rely primarily

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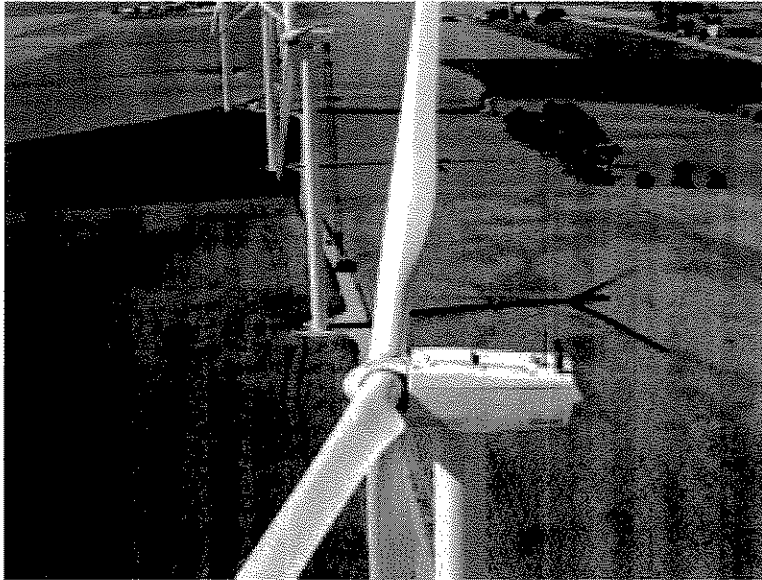


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Fuel and technology diversification is another way to reduce the risk of rate shock.

on power purchases, “staggered” procurement will have lower rate shock risk than buying 100 percent of power supply at one time. The latter approach obviously exposes the utility to the risk that it might inadvertently procure its supply in a high-priced market. In addition, procuring all supply at once may make it



harder to get a good price, to the extent the large purchase “moves the market” and potentially excludes small suppliers who cannot fill a significant portion of the utility’s requirements. This is one reason that many retail-access states have implemented a “laddered” procurement approach for standard offer or provider of last resort (POLR) service—including

management programs that reduce customer demand during peak periods) are another way to reduce rate shock. Demand-side management (DSM) is a flexible resource that can be added in small increments to track growing load requirements. Load management programs could enable a utility to significantly reduce its exposure to expensive gas- and oil-fired generation. In addition, by reducing energy usage, DSM also helps reduce the cost and risk associated with environmental compliance, particularly given the possibility of regulations targeting climate change. If and when such regulation is imposed, it will likely entail a protracted period of rate increases, against which efficiency may be the best resource.

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some states that initially directed their utilities to procure 100 percent of POLR generation requirements at one time.

Fuel and technology diversification is another way to reduce the risk of rate shock, though diversification, in and of itself, does not necessarily reduce price risk cost-effectively. A utility’s resource diversification is quite different from financial diversification in portfolio management: Financial assets are substitutes for each other, while utility assets are much more complex and multidimensional; and the differences among generation asset types and power purchase contracts often cannot be simply reduced to monetary dimensions. Moreover, portfolio management in financial markets presumes free disposability of assets, which does not apply to generation plants and power purchase agreements.

Still, a utility can use portfolio management ideas to a greater degree when it primarily relies on power purchase agreements, because these are financial instruments. The industry already uses most of the directly applicable techniques from financial portfolio management in managing purchased power portfolios.

Finally, demand-side resources (including both conservation programs that reduce overall consumption and load

Future Shock

The electric utility has entered an era of rising input costs and infrastructure needs, forcing many utilities to seek rate increases. Through its resource planning and risk management practices, a utility can reduce, though certainly not eliminate, society’s exposure to rate shock. At the same time, utilities and their regulators can employ various ratemaking methods to change the timing and pattern of capital recovery in a way that reduces the near-term rate impact associated with a new asset.

But a key criterion for the legitimacy of all rate deferral or alternative ratemaking methods is that they hold the utility financially harmless—that is, the discounted present value revenue stream should be identical to the discounted present value revenue stream provided under traditional ratemaking. Otherwise, the utility will find its financial health undermined and its financial flexibility reduced, leaving it with few or no good options.

In the end, there is no magic bullet for the rate shock problem. But there are sound ratemaking and planning approaches that can provide near-term relief and reduce the possibility of rate shocks in the future. ♦

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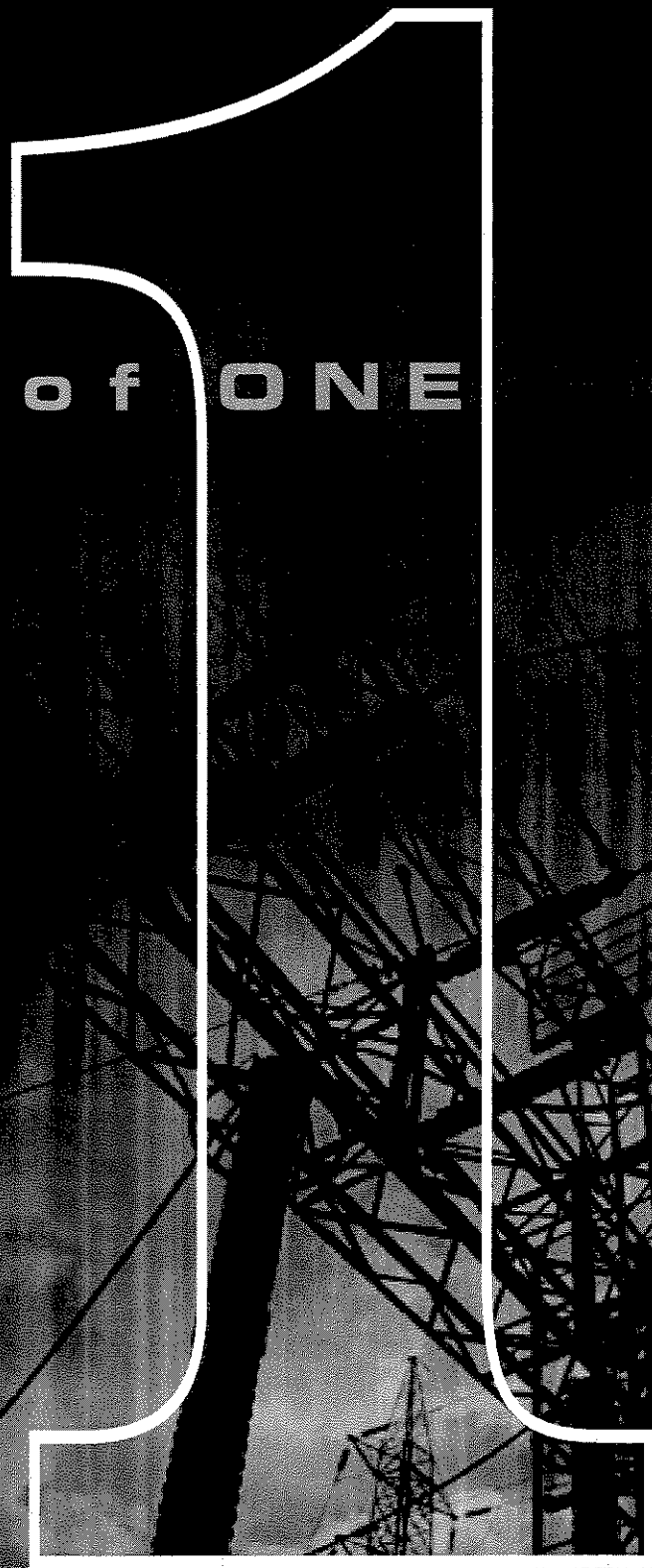
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