Save Now, Freeze Later

The Real Price of Cheap Electricity

Peter Navarro

FOR THE LAST TEN YEARS, electricity rates in most states have fallen short of the true market cost of generating electricity. This so-called rate suppression, which is primarily the result of faulty regulation, has been a windfall to consumers so far. But because it distorts the investment and operating strategies of the utility industry, rate suppression imposes penalties on consumers that are now about to come due. Consumers will soon be paying these penalties in the form of dramatically higher rates for less reliable service.

The Averch-Johnson Effect Revisited

Over 80 percent of the electricity generated in the United States is provided by private, investor-owned electric utilities that are regulated by state public utility commissions (PUCs). Under the regulation, the utilities must provide reliable service at low cost, and the PUCs, in turn, must allow the utilities to earn a "fair and reasonable return" on their investments. According to several Supreme Court decisions, this "fair and reasonable" standard amounts to letting utilities earn enough to cover the market costs of capital on their investments. These costs include both the interest payable on debt capital and the return (for example, dividends) on equity capital.

Economists Harvey Averch and Leland Johnson argued in the 1960s that a utility allowed to earn a return that is *higher* than its market cost of capital will overinvest in new capacity. The logic behind the so-called AJ effect is that such a return provides an incentive for the utility to increase its use of capital—so that it tends to build more capacity than it needs to provide service at least cost to consumers. The AJ effect was relevant during that decade: technological advances were making it possible for utilities to realize increasing economies of scale, inflation and energy prices were low and stable, and environmental and safety regulations imposed few costs. The predictions of Averch and Johnson seemed to be borne out when, during the 1960s, many utilities earned more than their regulators intended them to, and power-plant construction boomed.

It is understandable that the literature of that time failed to ask what would happen if a utility earned a return *lower* than its market cost of capital. It was assumed that any firm in that position would simply withdraw from the

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market. In making that assumption, however, researchers failed to acknowledge some important facts about the electric utility industry. First, a utility is obliged by its mandate to provide service to customers. Second, the industry is characterized by large, capital-intensive power plants that have few alternative uses. Thus, dropping out of the market is not a feasible choice even for a financially troubled utility—and today many utilities are troubled.

Sources of Rate Suppression

Since the 1973 Arab oil embargo and the subsequent dramatic increases in the costs of energy and capital, the electric utility industry's rate of return on investment has consistently been well below its market cost of capital. For example, one recent study estimates that the industry has earned roughly 3 percentage points less than the 7 percent real (inflation-adjusted) return that represents its cost of equity capital (Eugene Brigham and Dilip Shome, 1982). Another study has found that the industry's average equity earnings since the embargo have been 40 percent "too low" (Howard Thompson, 1983). While utility executives have made their share of mistakes since the embargo, the root of this rate suppression is that the current regulatory mechanism simply cannot function properly, given the political, institutional, and ideological environment in which public utility commissions (PUCs) are forced to operate. (For further discussion of this environment, see my article, "Electric Utility Regulation," in *Regulation*, January/February 1981.)

The political problem is the most obvious. During an era of rapidly rising energy and capital costs and attendant rate hikes, irate consumers are far more likely to mobilize effectively against the interests of utility shareholders than in easier times. In our democratic system where utility commissioners are directly elected by the people (as they are in eleven states) or appointed by elected officials (as they are in the remaining states), the threat of ballot box reprisals greatly favors the consumerist platform of rate suppression.

Similarly, institutional limitations—meaning small budgets and staffs, as well as inadequate computer technology and expertise in many cases—keep even the best-intentioned of commissions from raising rates as fast as costs are going up. Dust gathers on backlogs of rate cases, and in the course of the resultant "regulatory lag," the real value of any eventual rate hike is eroded by inflation.

Most subtly, there is ideological rate suppression—the effect on the PUCs of the ideological mindset that views regulation as a way not only to prevent monopoly profits but also to redistribute income. Utility commissioners in some states appear sympathetic to the claim that, since utility shareholders are wealthier than consumers (a statistically unfounded notion), it is only "fair" that they should shoulder a bigger share of rising electricity costs. This, too, has contributed to the steady erosion in utility stock values we have seen in the recent decade of rate suppression.

Sometimes a PUC will suppress rates directly by setting the allowed rate of return so low that the utility cannot attract capital and maintain its financial integrity. But more often, the low return is an indirect result—sometimes intended, sometimes not—of other commission policies. For example, the use of a "historic test year" in ratemaking, which bases next year's rates on last year's costs, means that utility revenues always chase, but never catch up to, inflation. Failure to allow utilities to adjust rates automatically when the cost of fuel or purchased power rises can also result in real earnings that are lower than those the PUC ostensibly allows. Other sources of rate suppression include the aforementioned regulatory lag, the disallowance of certain operating and maintenance expenses, and the refusal to include capital investment in the rate base.

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With rate suppression so common today to be almost the normal condition, there is new interest in how an inadequate earned rate of return will affect utility investment and operating strategy. Indeed, we are now witnessing a *reverse AJ effect:* a utility that earns a rate of return below its market cost of capital underinvests in new capacity and other projects like coal conversion and conservation. In other words, more and more of the utility industry has adopted a strategy of capital minimization in order to reduce the financial losses from rate suppression. This strategy creates three serious "regulatory penalties" that the consumers must ultimately bear. Two of these—the "fuel penalty" and "cost of capital penalty"—will result in higher rates than need be; the "reliability penalty" raises the more serious issue of whether our lights will stay on.

The Reverse AJ Effect and Three Regulatory Penalties

The fuel penalty arises when a utility fails to make otherwise economic investments in such options as coal conversion, conservation equipment, and the construction of new plants to replace existing plants that burn more expensive fuel. This penalty equals the full savings that the utility fails to make when it forgoes such investments. The New England Electric System, for example, has converted its oil plant at Brayton Point to coal, with reported savings to ratepayers of $110 million a year. Consumers would not be reaping these benefits if the utility had been deprived of the capital needed to make the conversion.

Also included in the fuel penalty are the extra costs to the utility of operating old, inefficient plants and of buying power that is more expensive than the power that could be internally generated by new plants. Purchased electric power can be especially costly because the suppliers often link its price to the price of oil, regardless of how the electricity is actually generated. Canada's National Energy Board, for example, has begun to do this.

The cost-of-capital penalty arises in two ways. First, as shown in studies by Robert Trout, Stephen Archer, and others (including my paper with Jeffrey Dubin), investors see rate-suppressed utilities as riskier than others and demand a one to two percentage point "risk premium" when buying the stocks and bonds of such utilities. Thus, when a rate-suppressed utility sells bonds to build a new billion-dollar plant, it will pay $10 to $20 million in additional annual interest expenses—which are passed right through to consumers. A more subtle part of the cost-of-capital penalty is the increase in carrying costs on plant whose construction is cancelled or delayed because of sparse funds.

The reliability penalty manifests itself in more plant breakdowns and a higher probability of brownouts and blackouts. This can occur when the rate-suppressed utility fails to expand to meet load growth or when it finds its rate of return squeezed and therefore trims ordinary operation and maintenance expenses in order to protect its earning and dividend record. (For utilities with nuclear capacity, this "operations and maintenance squeeze" is particularly disturbing.)

Consumers bear the reliability penalty in several ways. Industrial or commercial consumers may respond to the greater likelihood of a supply disruption either by shifting production or plant to other less economic regions where electricity supply is more secure or by using funds they might have invested in modernization or expansion to build their own backup or primary electrical capacity. For residential consumers, blackouts and brownouts mean tremendous inconvenience and discomfort, including the lack of air conditioning or heat in bad weather, refrigerator spoilage, crime in darkened streets, even loss of computer data.

Measuring the Regulatory Penalties

While the consumer clearly bears these costs, the interesting question is whether the costs might be offset by the short-run benefits of rate suppression—lower rates. In other words, are consumers better or worse off?

Design of the Study. To find out if consumers do benefit from ostensibly pro-consumer, rate-suppressive regulation, I computed future electricity rates and reserve margins for a representative sample of six utilities, using a rate-making model that is in wide use among PUCs. The six utilities were selected to ensure a range of variety in load growth, the percent of petroleum in the generation mix, and regional location—the three characteristics most important in determining the magnitude of our three regulatory penalties. The greater a utility's load growth, for instance, the greater will be its need for additional sources of electricity. If the utility builds new plants to meet that growth, the cost-of-capital penalty will be more severe. If instead it purchases power at a cost above what its generating costs would be, the fuel penalty will rise. And if those additional sources of power are unavailable, the reliability penalty will soar. Similarly, the greater a utility's dependence on petroleum-fired power plants, the greater its potential for reducing its petroleum consumption. Thus the fuel penalty is higher for a utility that relies more heavily on power plants that burn oil or natural gas.

Table 1

UTILITY SPENDING UNDER TWO HYPOTHETICAL SCENARIOS
(billions)

	Capital Attraction		Rate Suppression	
Representative Utility	Capital expenditures	Fuel & purchased power expenses	Capital expenditures	Fuel & purchased power expenses
New England	$ 9.9	$ 29.9	$ 4.1	$ 43.2
Midwest	40.6	110.4	23.9	139.4
Southwest	62.8	152.1	64.8	201.0
Southeast	30.5	107.8	8.9	133.6
Pacific Coast	22.1	77.2	12.9	95.3
Rocky Mountain	7.6	35.6	4.8	45.4

Note: Fuel and purchased power expenses are calulated under rising fuel-price assumptions, explained in text.

The utilities included here are representative in the sense that they reflect different combinations of conditions typical of the industry as a whole. They come from six major regions of the country—New England, the Southeast, the Southwest, the Midwest, the Rocky Mountains, and the Pacific Coast. Their forecast load growth ranges from 1.5 percent to 4.0 percent a year. And their petroleum dependence ranges from zero to 60 percent.

Each of the six participating utilities was asked to forecast the investment program it would pursue in response to two different hypothesized regulatory climates. The "rate-suppressive regime" was defined as a regulatory climate in which the utility could expect to earn a real (inflation-adjusted) return on common equity of 4 percent, which is three percentage points less than the 7 percent rėal return on equity that would match the estimated market cost of capital for electric utilities in the last decade. This 4 percent rate of return approximates the real return the utility industry has realized in the era of rate suppression since the Arab embargo. The "capital attraction regime" was defined as a regulatory climate in which the utility would be allowed to earn its full cost of capital—that is, a real rate of return of 7 percent.

The Study's Results. When faced with the rate-suppressive regime, each utility said it would continue its current strategy of holding capital expenditures as low as possible. But when faced with the regulatory-reform or capital attraction regime, they all said they would embark on a much more robust program of capital expansion.[1] The figures appear in Table 1.

For example, if the Midwest utility were allowed to earn its market cost of capital, it would spend $40 billion primarily to complete several large nuclear plants without delay and add four additional coal units (over 2,000 megawatts) to meet load growth in the 1990s. In contrast, if its real return on equity were held to 4 percent, it would delay two-thirds of the nuclear capacity for four years, would not start any new projects, and, to meet its expected load, would increase its use of purchased power and existing oil- and gas-burning capacity by $30 billion a year. Similarly, under the capital attraction regime, the Pacific Coast utility would spend $22.1 billion to buy a major share of a coal plant under construction, participate jointly in a coal project, and build transmission lines for purchased power. These three undertakings would be designed to reduce petroleum consumption. But under rate suppression, none of these projects would be undertaken and the retirement of 2,000 megawatts of natural gas- and oil-burning capacity would be deferred. (The project costs reported by each utility were carefully scrutinized for plausibility to avoid any underestimation of power-plant costs.)

For those who follow the Averch-Johnson literature, Table 1 provides strong evidence of the reverse AJ effect, which predicts that as a regulated company's expected return on capital declines, so will its use of capital in the production process. The next question to ask is which mix of capital and other inputs (mostly fuel)

[1] The Southwest utility would appear to be an exception. However, under rate suppression, it delayed many projects it would have undertaken under capital attraction and cancelled others. Because of inflation, the fewer projects actually cost more in nominal dollars when finally undertaken.

is more optimal in the sense of minimizing costs to ratepayers while maintaining reliability of service.

For each of the two investment strategies, I calculated the six utilities' annual electricity rates over the next two decades, using two different assumptions about fuel prices. The "rising fuel price case" assumed a 2 percent real annual increase in the price of oil and natural gas[2] and a 1 percent increase in the price of coal (in line with forecasts of the Department of Energy, the Electric Power Research Institute, and other mainstream observers). The "stable fuel price case," included to allay fears that the results might be driven primarily by this rising fuel price track, assumed *no* increase in real (inflation-adjusted) fuel prices. At the same time, I also calculated reserve margins, which measure how much idle capacity a utility has on hand to protect against an unanticipated loss of power in the system.

Table 2

BENEFITS TO RATEPAYERS FROM ADOPTING CAPITAL ATTRACTION STRATEGY

	Assuming Rising Fuel Costs		Assuming Stable Fuel Costs	
Representative Utility	Net present value of benefits (millions)	Rate of return	Net present value of benefits (millions)	Rate of return
New England	$1,289	40%	$ 513	28%
Midwest	242	16	−279	11
Southwest	2,302	36	995	26
Southeast	2,840	38	1,555	29
Pacific Coast	1,530	20	3	14
Rocky Mountain	607	40	695	41

Note: For definitions of benefits and rates of return, see footnote 3.

As expected, under rate suppression, rates were lower in the early 1980s for both the rising and the stable fuel price cases. Then, as higher fuel costs and carrying charges accumulated, rates eventually "crossed over" for both cases, typically during the mid-1980s, and were consistently higher thereafter. Yet the rate-suppressed utilities were still earning a lower return on investment. The gap widened steadily, so that by the year 2000 rates were dramatically higher under rate suppression than under a capital attraction regime. For example, in the rising fuel price case, electric bills sent to customers ranged from 11 percent higher for the Pacific Coast utility to 33 percent higher for the Southeast utility.

To compare one set of costs with another, it is helpful to use net present value discounting. This technique enables us to calculate the present value of the two streams of numbers—the costs in the capital attraction scenario and the costs in the rate suppression scenario. That, in turn, tells us which of the two regulatory schemes costs consumers more overall.

Table 2 provides, for each of our fuel price assumptions, the net present value of total benefits to ratepayers from a policy of capital attraction, along with the rate of return that such benefits would represent.[3] In a situation of moderately rising fuel prices, the benefits to be gained from capital attraction are startling, ranging from $242 million for the Midwest utility to $2.8 billion for the Southeast utility. Moreover, these sums translate into whopping double-digit rates of return. For example, the $1.3 billion that the New England utility's ratepayers would save amounts to an annual return for them of 40 percent on average over the forecast period. Indeed, the ratepayers of four of the six utilities would realize rates of return above 35 percent—roughly three times the annual return on the stock market over the last decade and more than twice the yield of money market funds.

What happens to these whopping benefits and investment returns when we assume that fuel prices will be stable? In particular, does the fuel penalty shrink to the point where rate suppression becomes worthwhile for consumers? The answer is a perhaps surprising *no*. For four of the six utilities (the same four, incidentally), ratepayer benefits, though lower, still range from the hundreds of millions to the billions of dollars and ratepayer returns are above 25 percent. The New England utility, for example, saves its ratepayers $513 million for a return of 28 percent, while Rocky Mountain's return to ratepayers hits 41 percent. For only two

[2] For natural gas, the price rose only after deregulation, assumed to occur in 1985.

[3] The net present value of benefits is calculated by assuming a real discount rate of 6 percent; this means that, at an inflation rate of (say) 8 percent, the discount rate would be 14 percent. The rate of return is what ratepayers would earn on their "investment" by paying slightly higher rates in the earlier years.

utilities does the return provided fall into the range where other kinds of investments in stocks, bonds, and money market might be competitive.

Not unexpectedly, the weakest case turns out to be the Midwest utility, which has the lowest rate of oil consumption (and hence the smallest fuel penalty). Its ratepayers actually *lose* $279 million (in a present value sense) under an improved regulatory climate, though they still earn a positive rate of return of 11 percent. Slightly more robust is the Pacific Coast utility with savings of a scant $3 million and a modest but respectable 14 percent rate of return.

The story is not yet complete, however, because we still have to measure the reliability penalty. Here I found dangerously low reserve margins for four of the six utilities, with the most perilous situation occurring in our "weak" Midwest utility. Under rate suppression, Midwest's reserve margin plunged from 23 percent to a razor-thin 5 percent, well below the 15–20 percent a utility needs to maintain uninterrupted service. Similarly, the reserve margin of the Southwest utility fell from 20 percent to 8 percent.

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The bottom line, then, is that in return for the luxury of lower rates for a few short years in the 1980s, the ratepayers of all six utilities would pay dramatically higher rates over many years, or would have far less reliable service, or both.

Conclusions

Rate suppression is a symptom of a much larger and more pernicious problem that plagues our economy today, the unwillingness to invest in America's infrastructure and long-term future, even though the benefits would be large. By paying 5 to 10 percent more for electricity now, consumers could earn returns of up to 40 percent in a few years. They would also help stave off the risk of future energy shortages. It should be of enormous concern to national energy policy makers that the five petroleum-dependent utilities included in my analysis consumed, under rate suppression, a total of 1 billion additional barrels of oil over the forecast period—twice the projected inventory in our Petroleum Reserve.

The analysis points to an expensive and precarious electricity future if the current trend of rate suppression is not reversed. This appears to be true even if petroleum prices do not resume their rapid rise. To avert this future, we must reduce and, where possible, eliminate the underlying causes of rate suppression. Consumer groups, in particular, should become aware that by using their political clout to keep rates too low, they are working at cross purposes to their real goal of consumer welfare. Similarly, state officials must bite the "Proposition 13 bullet" and realize that, by not giving their PUCs adequate funds and staffs, they are inviting an institutional failure that will drive industry to other states in search of reliable, affordable electricity—with adverse effects on tax revenues and jobs. Finally, those who would like to use regulation to redistribute income must recognize that, at least in the hands of a PUC, redistributive rate suppression is far too blunt a tool to achieve their purpose.

In short, consumers, state officials, and well-intentioned ideologues must learn that rate suppression, though ostensibly aimed at helping consumers, actually hurts *everyone* in the end—consumers, industry, and the nation. ■

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