Regulatory and Tax Treatment of Electric Resources

Stan Hadley and Eric Hirst, Oak Ridge National Laboratory

Integrated resource planning (IRP) focuses on providing customer energy-service needs at the lowest cost. This paper addresses the flip side of IRP, how shareholders fare when utilities build power plants with different capital and operating costs, buy power from others, or run demand-side management (DSM) programs. In general, shareholder earnings are related to the capital cost of the project. However, the risk of a disallowance, delay in the rate case, or retail-price competition all change that conclusion. DSM programs, in spite of their capital-intensive nature, are especially harmful to shareholders for utilities that do not have a lost-revenue adjustment mechanism or that face price competition from other suppliers.

Introduction

Electric utilities and their regulators increasingly use IRP methods to meet the future energy-service needs of customers at the lowest total cost. This objective is met by considering all feasible supply and demand options that could reasonably fulfill those needs. The range of resources considered in IRP encompasses various fuels, technologies, and ownership.

Because IRP focuses on customers, the interests of utility shareholders may not get enough attention. The present analysis, therefore, asks whether IRP is sufficient to ensure that the utility's decisions and actions are consistent with customer interests. If utility shareholders earn more (or less) by acquiring particular kinds of resources, then IRP may be necessary but not sufficient to ensure that resource acquisition really meets the long-term needs of customers. For example, if a utility earns more money by building its own power plants than it does by purchasing power, then it may want to build plants regardless of what its IRP suggests.

To illustrate this point, consider the following statement from the California Public Utilities Commission (1993):

> The Commission's performance-based approach to utility DSM is a first step toward eliminating the bias between the utility's incentive to build and its incentive to invest in efficiency. Despite this move, the cost-plus treatment of utility investment in plant and equipment and the performance-based treatment of DSM investment is likely to continue to bias utility decisions governing investment dollars.
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> Moreover, no comparable mechanism exists that provides the utility an incentive to perform well in power purchase activities. Three wholly different mechanisms governing investment in generation, energy efficiency, and purchased power translates to an imbalance in regulatory incentives. That imbalance is likely to lead to less than optimal utility operation and investment decisions.

To explore the effects on utility shareholders of different types of resource acquisitions, we constructed a model, called ORFIN (Oak Ridge National Laboratory Financial Model), which simulates an electric utility's annual income statement, balance sheet, and cash-flow statement (Hirst and Hadley 1994). We used ORFIN to examine how a utility's financial situation depends on the types of resources acquired. We considered utility-built power plants with different combinations of capital and operating costs, purchases of power from others, and operation of DSM programs. This study focuses on investor-owned utilities, which account for about three-fourths of U.S. electricity sales (Edison Electric Institute 1993).

We examined shareholder return on equity (ROE) for these alternative resources as functions of public utility commission (PUC) regulation, taxes, and the utility's operating environment. Our treatment of PUC regulation considers the frequency and type (future vs historic test year) of rate cases; inclusion of construction work in progress (CWIP) in rate base vs allowance for funds used during construction (AFUDC); ratebase vs expensing of DSM programs; book and tax depreciation schedules; and possible disallowances of "excess" capital, fuel, or purchased-power costs.

Tax policies include the existence and rates for property, sales, and income taxes and the existence and regulatory treatment of deferred taxes. The utility's operating environment includes the inflation rate, load-growth rate, escalation in nonproduction expenses, and nongeneration construction requirements.

Finally, given the increasingly competitive nature of electricity markets, we briefly consider alternatives to traditional cost-of-service regulation. In particular, we examine shareholder returns for the resources described above in an environment where the utility's retail monopoly franchise no longer exists. Here we assume that the utility competes with other suppliers solely on the basis of a market-determined price.

Financial Model

ORFIN includes the basics of a utility income statement, balance sheet, and cash flow statement. These financial statements are computed annually for 36 years, from 1994 through 2029. We chose this time period to allow for construction and full-lifetime operation of a new resource.

Financial Statements

The income statement is a financial report showing the results of a company's operations for a particular time period, a calendar year in ORFIN. The income statement has three parts, revenues, expenses, and income; income is equal to the difference between revenues and expenses.

The balance sheet is a summary of the company's assets, liabilities, and owner's equity as of a particular date (the end of a calendar year in ORFIN). By definition, assets equal the sum of liabilities and equity.

The cash flow statement classifies cash receipts and payments according to operating, investing, and financing activities. This statement discloses the changes from one year to the next in the company's assets, liabilities, and shareholders' equity, thereby indicating the sources and uses of cash.

Resource Characterization

ORFIN is structured to allow analysis of a single major resource addition, superimposed on a "base case" utility. Treatment of a single resource addition, although hardly realistic, allows us to focus on the question this project poses: How do shareholders fare when utilities acquire different types of resources to meet customer energy-service needs? We added a 200 MW resource on January 1, 1998 and had a rate case that day.

The power plant is characterized by the user in terms of its size (MW), the number of years to build the plant, the construction cost ($/kW), the percentage of construction cost expended each year, fuel and O&M costs (both in ¢/kWh), and the real escalation rate in fuel cost (%/year). The user also specifies the operating, book depreciation, and tax depreciation lifetimes for the plant; as well as the property tax rate and any investment tax credit. The user determines various regulatory factors affecting this new resource, including any disallowance of the capital cost, AFUDC or inclusion of CWIP in the rate base for construction financing costs, and the extent (0 to 100%) of a fuel-adjustment clause.

The DSM program is characterized by specifying the number of years the program runs, the percentage of energy and load reductions that occur each year of program operation, the program's maximum effect (in MW), and the utility cost to run the program ($/kW). The user also specifies the same tax and regulatory factors listed above for the power plant. In addition, the user can expense (rather than ratebase) the DSM-program costs and can include a net lost revenue adjustment (NLRA) mechanism. This mechanism returns to the utility the difference between short-term avoided costs and revenues lost because of the DSM-induced sales reduction while the program is in operation, until the next rate case.

The purchase option is characterized by its size, initial year, fixed cost ($/kW), variable cost (¢/kWh), and the real escalation rate in the cost of this purchased power.

General Inputs and Outputs

The single resource discussed above is added to an existing (base case) utility system. The base-case system is characterized very simply. We assume that supply equals demand exactly every year, ignoring excess capacity, reserve margins, outage rates, and reliability. User inputs specify annual growth rates in the number of customers and usage per customer. Together, these inputs plus the user-specified system load factor determine peak demand and electricity sales for each year of the simulation.

On the supply side, the utility begins, in 1993, with user specified amounts of generating capacity and long-term purchase power contracts. These resources are characterized in terms of 1993 fuel and O&M costs, fuel-cost escalation rates, and for contracts the capacity cost. In addition, the user specifies nonproduction costs and the escalation rate in those (non-generation) costs.

For the next several years, the utility meets additional demands with short-term power purchases, the costs of which are, again, user inputs. Beginning on a date specified by the user (e.g., 2000), the utility meets a user specified percentage of future load growth by building small power plants (with the remainder met by purchases). For analytical convenience, these plants are assumed to be modular and constructed within one year. Thus, the utility is able to build plants to exactly match load growth from year to year.

The user specifies the utility's capital structure, which includes the fractions of assets that are long-term bonds and common stock. The user also specifies the long-term bond interest rate, authorized ROE, and annual inflation rate. These financial parameters are fixed throughout the simulation period.

User inputs determine the existence and rates for income, property, and revenue taxes. The user also specifies the frequency of rate cases and whether they use a historic or future test year. Rate cases are assumed to take place on January 1 and to go into effect on that date. The future test year sets rates that yield exactly the authorized ROE for the year that rates first go into effect. The historic test year uses data from the prior year and, therefore, generally does not provide the utility with its authorized ROE.

The primary dependent variable is the average realized return on equity over the short-term (ten years), mid-term (20 years) and long-term (36 years). We use a realized (cash) ROE that adjusts net income and equity for AFUDC and deferred taxes.

Base-Case Utility

We began the analysis by creating a utility that is roughly typical of U.S. investor-owned electric utilities. (Edison Electric Institute 1993; Energy Information Administration 1993).

As of 1993, the utility has total sales of 17,500 GWh and revenues of $1.27 billion, yielding an average price of electricity of 7.3¢/kWh. The utility's capacity and generation are met primarily by utility-owned plants (79% of the total) and secondarily by long-term contracts (21%). The average fuel cost in 1993 to operate the system is 2.0¢/kWh. Electricity production (fuel, power purchases and power-plant O&M) accounts for 38% of total revenues.

The utility is capitalized with long-term bonds and common equity, in the ratio of 55%:45%. The bonds have an interest rate of 7.5% and the authorized return on equity is 11.0%. The inflation rate is 3.2%/year.

Loads grow at a fixed annual rate of 2.1%/year between 1993 and 2029. In the base case, this load growth is met entirely by short-term power purchases until the year 2000. Thereafter, load growth is met by a combination of utility-built power plants (75%) and long-term purchases (25 %). Real electricity prices are roughly constant over the analysis period.

The utility's PUC holds rate cases once every four years, beginning in 1994. The commission uses a historic test year for these cases. During the three years between rate cases, the utility's actual ROE declines. These declines occur because of two factors. First, the utility's assets, and therefore equity, increase more rapidly between rate cases than loads grow. Therefore, the denominator in the ROE equation (shareholder equity) grows faster than revenue, which lowers the ROE ratio. Second, nonfuel costs grow faster than sales do (4.2 vs 2.1 %/year), primarily because of inflation. These increases lower the amount of money left for shareholders (net income) during these years. Thus, ROE declines because of increases in the denominator and decreases in the numerator.

ORFIN results are consistent with the historical record on utility earnings relative to authorized earnings. Moyer and Claggett (1993/1994) showed that realized ROE varies inversely with inflation rate and directly with load growth. For all but two years of the 1976-to-1990 period that they examined, actual ROE was below authorized ROE.

Results Under Traditional Regulation

We now turn to the purpose of this study - to examine the effects on shareholders of acquiring different types of resources. We begin by assuming that traditional cost-of-service regulation prevails. In the next section, we examine shareholder performance assuming that utilities operate in a more competitive economic environment.

As noted earlier, we consider three classes of resources: utility-run DSM programs, utility built and operated power plants, and purchase-power contracts. We examine a range of construction and operating costs for the utility power plants. We initially characterize these resources so that they all have the same operating characteristics (i.e., load factor and MW capacity). We also assume that these resources all have the same overall cost (i.e., net present value of revenue requirements over the full 36-year analysis period) to customers (Table 1). We make this assumption to see how utility shareholders fare when customers are indifferent among the resource choices. Later in this chapter, we relax this net present value of revenue requirements constraint.

Table 1. Assumed Capital and Operating Costs for Resources[a]

	Capital cost (1993-$/kW)	Fuel cost in 1998 (1993-¢/kWh)	Real fuel-cost escalation (%/year)
Purchase contract[b]	1835	2.3	1.0
Natural gas	400	2.9	2.8
Coal	1450	2.0	0.0
Renewables	2475	0.0	0.0
DSM	2810	0.0	0.0

(a) These resources are all constructed in 1995, 1996, and 1997, and are online as of January 1, 1998.
(b) Based on an annual cost of $126/kW-year, a 32-year contract life, and a real discount rate of 5.7%.

The primary dependent variable is incremental realized return on equity. We used realized, rather than accounting, ROE to show more clearly the effects on cash flow to shareholders. Realized ROE differs from accounting ROE in its exclusion of AFUDC from net income and equity, its inclusion of deferred taxes in net income, and its addition of accumulated deferred taxes to equity. Incremental refers to the difference between the particular case examined (e.g., construction of a coal plant that comes online in 1998) and the base case discussed in the preceding chapter. We examine incremental ROE for three time periods: 1994-2003, 1994-2013, and 1994-2029. The initial ten-year period covers the plant's construction plus first six years of operation, while the 36-year period covers the construction period plus the full operating life of the plant. In all cases, the resource comes online January 1, 1998 and operates at full output for 32 years (until 2029).

Initial Results

Figure 1 shows the base-case results for the resources considered here. The capital investments for the resources receive AFUDC during construction, and rate cases are conducted once every four years using a historic test year. Book and tax depreciation lifetimes are 32 and 16 years, respectively.

These results show that incremental ROE to utility shareholders increases with increasing capital investment. Shareholders neither gain nor lose with a purchase-power contract because there is no investment at all. As the initial cost of the power plant increases from gas to coal to renewable, incremental ROE increases also. Because the DSM program is roughly as capital intensive as the renewable resource, shareholder returns are similar for these two resources.

The DSM case discussed above included an NLRA mechanism to compensate the utility for the revenues it would otherwise have lost in 1995, 1996, and 1997. On the other hand, if the utility does not have an NLRA, the revenues lost in 1995, 1996, and 1997 are sufficient to reduce the incremental ROE from 16 to 5 basis points.

The differences in ROE across the three time periods is consistent for all resources. Incremental ROE is lowest for the initial 10-year period, primarily because of the negative effects on ROE of the plant's construction. Incremental ROE is highest for the 20-year period because this period corresponds to that of the tax benefits associated with accelerated depreciation.

The key factor accounting for the positive incremental ROE is regulatory lag associated with infrequent rate cases. At the time of the rate case, prices are set on the basis of interest payments and assets for the test year (the preceding year for the historic test year cases shown here). However, because of book depreciation, the amount of assets associated with the new resources and the annual interest payment decline each succeeding year. Thus, shareholders gain extra income from the revenues collected for interest payment and return on equity that is no longer there. Of course, at the time of the next rate case, the amount of assets remaining is adjusted again.

Figure 2 documents this regulatory-lag phenomenon. It shows incremental ROE for the coal plant as a function of the number of years between rate cases. With annual rate

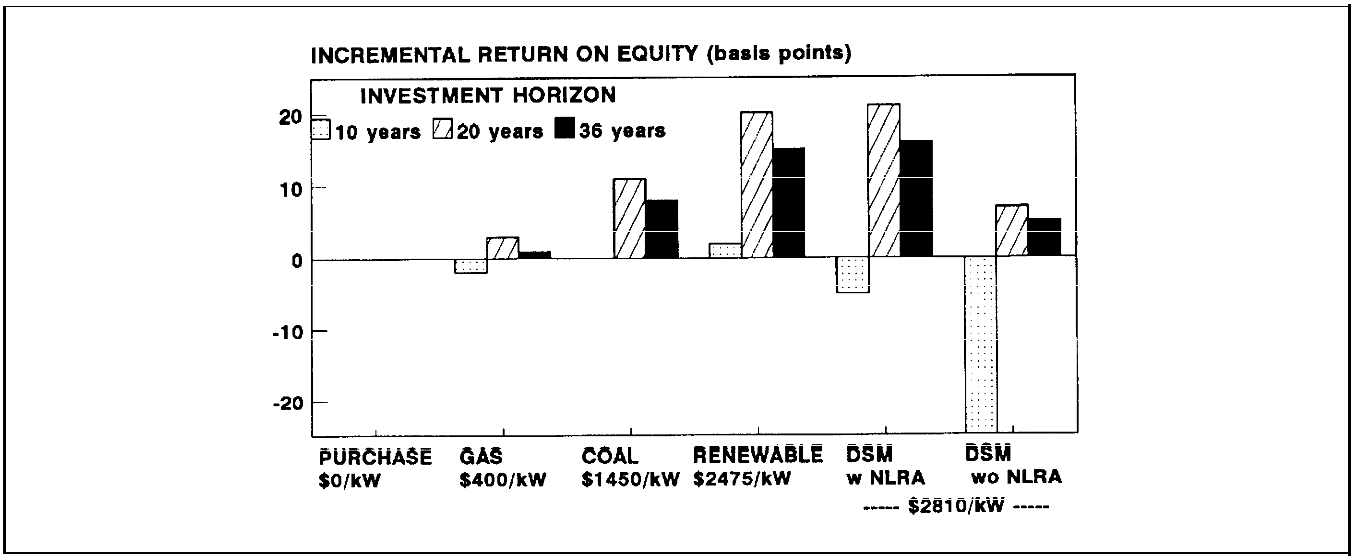

Figure 1. Incremental Return on Equity (relative to base case) for Different Resources

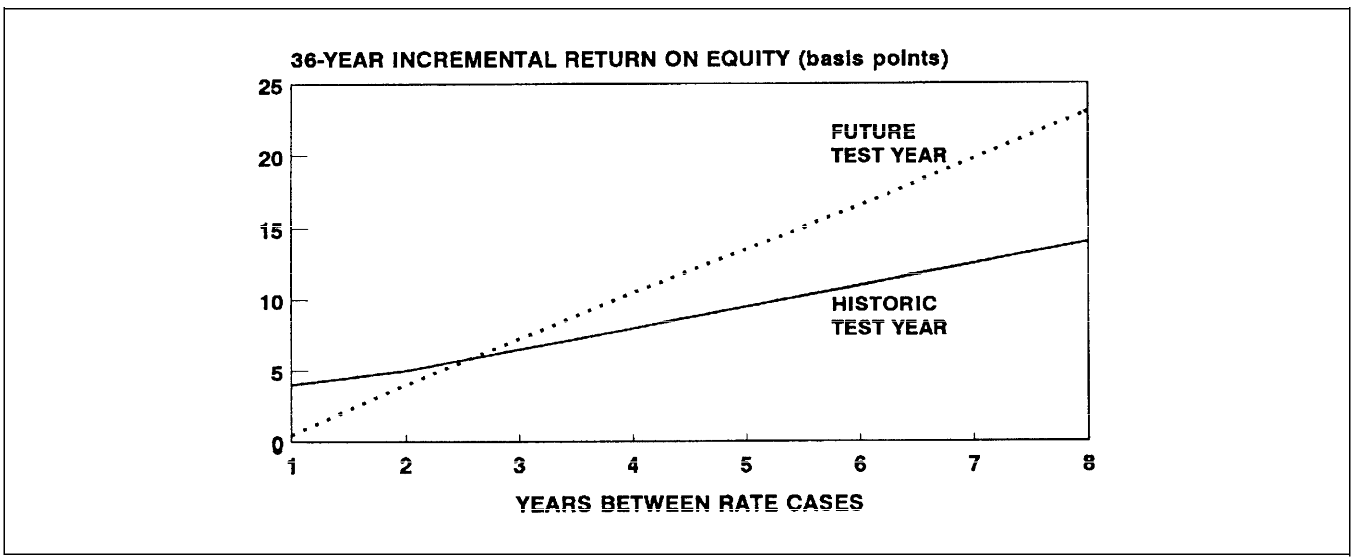

Figure 2. Incremental Return on Equity for a Coal Plant That Comes Online in 1998 as a Function of Frequency of Kate Cases, with Historic and Future Test Years

cases, shareholders benefit only from the one-year difference in the amount of undepreciated assets. However, as rate cases are held less often, the declining interest payments and equity become more important. With a future test year, annual rate cases yield the correct interest payment and equity each year, yielding zero incremental return.

Different Regulatory Treatments

The preceding cases assumed that the utility builds and operates the plant as anticipated, and that regulation works as intended. What happens if these assumptions are relaxed? We examined the following nonbase-case assumptions:

- a 10% disallowance (during the 1998 rate case) of the capital cost of the power plant;
- no fuel-adjustment clause for the new power plant (i.e., the utility is allowed to recover during the years between rate cases only the fuel costs per kWh associated with the fuel costs in the historic test year); and
- a one-year delay in the rate case, from 1998 to 1999.

The extent to which these changes hurt shareholders depends on the relationship between capital and operating cost for the particular resource (Figure 3). A 10%

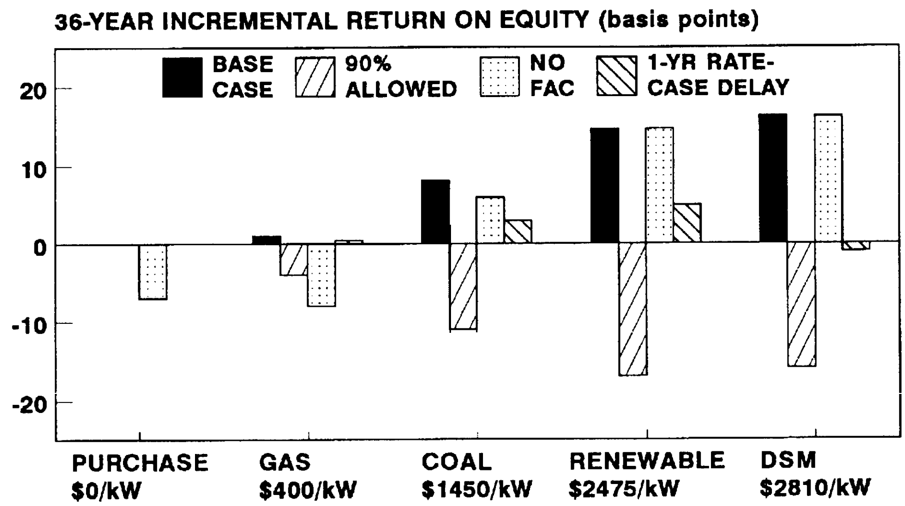

Figure 3. Incremental Return on Equity for Different Resources as a Function of Changes in Regulatory Treatment. Base case results are the same as the 36-year results shown in Figure 1 (FAC is fuel-adjustment clause).

disallowance of the plant's construction cost is most damaging for shareholders if the utility built a renewable or DSM plant. The penalty for a gas plant, with its low initial cost, is much less. However, in all cases, a base-case gain in earnings turns into a loss. Thus, if utilities believe that there is a substantial risk that regulators will disallow even a small portion of the construction costs of a new power plant or DSM program, they will be reluctant to invest in capital-intensive projects.

On the other hand, loss of the fuel adjustment clause severely penalizes shareholders for building the gas-fired plant (with its high and rapidly increasing fuel prices) but has no effect for the renewable plant or DSM program (which have no fuel costs).

A one-year delay in the 1998 rate case has the greatest negative impact for the high-capital cost plants. This effect occurs because the utility must wait a year to recover from customers book depreciation of the plant and a return on that investment. The penalty of this one-year delay is especially severe for the DSM program. This severity is a consequence of the fact that DSM programs reduce sales, which leads to larger price increases at the time of the next rate case. At the time of the 1998 (or 1999) rate case, prices are increased by about 0.5¢/kWh more with DSM than with renewable. A one-year delay in gaining that price increase cuts ROE in 1998 by 1.1 percentage points more for DSM than for renewable. As with the disallowance results, these numbers suggest that if utilities believe there is a substantial risk of a delay in the rate case that allows the new plant's construction costs in rate base (and into rates), they may avoid high-capital-cost projects.

The base-case results presented earlier (Figure 1) suggest that utilities should aggressively pursue renewable and DSM, the most capital-intensive, and therefore, the most profitable resources. However, Figure 3 shows some of the factors that might lead to utility reluctance to pursue these resources. In addition to the risks of a disallowance or delay in rate case, utilities are concerned that renewable are more expensive than other resources (recall that we assumed that these resources all had the same effects on utility customers in terms of revenues collected). Utilities may be concerned that because DSM program costs are generally expensed, they can earn no money on those programs. In addition, if the expenses are deferred until a future date, there is always the threat that some of these expenses will be disallowed. Finally, decoupling or NLRAs do not operate in all jurisdictions; as shown in Figure 1, without compensation for lost revenues, utility shareholders gain little, and only after a long time, with DSM programs.

Different Tax Treatments

Here we consider the effects on shareholders of acquiring these resources when the tax treatment differs. Specifically, we analyze the effects of:

- a shorter tax depreciation lifetime, from 16 to 8 years;
- an increase in property tax, from 3 to 6%;
- a lower income tax rate, from 36 to 32%; and
- a 10% federal investment tax credit for the capital costs of the new plant.

As with the previous cases, the extent to which these changes affect shareholder returns depends primarily on the capital cost of the resource. Thus, the returns for the natural-gas plant are affected only slightly by any of these changes.

Decreasing the tax life raises shareholder earnings, because the effective amount of the zero-interest loan from the U.S. Treasury increases with larger differences between book and tax lives. Raising the property tax also increases shareholder earning, because of regulatory lag. The four-year cycle with a historic test year means that shareholders overcollect from customers for property taxes. Property taxes decline each year as book depreciation increases; however, the amount collected from customers for property taxes remains the same until the next rate case.

Lowering the income tax rate increases slightly shareholder earnings. On the other hand, changing the sales tax has no effect on earnings. Finally, a 10% investment tax credit has a large positive effect on shareholders for the renewable plant but only a small effect for the gas plant. Again, this effect is related to the size of the initial capital investment.

In general, tax changes (except for provision of an investment tax credit) have much less effect on shareholders than do state regulatory practices.

Different Utility Environment

Increasing load growth, lowering the inflation rate, lowering the escalation in nonproduction fixed costs, and reducing the rate of capital additions all increase base-case ROE. If these changes are pushed far enough, earnings remain roughly constant between rate cases. In this case, the average ROE from 1994 through 2029 is 11.3%, compared with 9.7% in the earlier base case.

How does the addition of a new resource affect earnings when the base case (without that resource) is more favorable to shareholders than the original base case? For all resources, the *incremental* ROE is less than with the original base case. As usual, the effect on shareholders depends on the initial capital investment. The incremental returns associated with the most capital-intensive resources are cut the most by this change in base case (Table 2), although the incremental returns are still positive for all cases except DSM without an NLRA. The effects of changing the base case are greater with a historic than with a future test year.

Results in a Competitive Environment

The cases discussed above all assumed a utility that is a regulated entity with a retail monopoly franchise. What happens to shareholders if the utility no longer has a monopoly and, instead, competes with other suppliers? What happens if that competition is based entirely on the price of electricity? In this case, the PUC cannot impose cost-of-service regulation on the utility's customers, because they are free to buy electricity from whomever they desire. Thus, the utility is a price taker.

In the cases considered below, rate cases are replaced with an exogenously specified price. For simplicity, we consider a constant real electricity price of 7.10¢/kWh, roughly equivalent to the base case price. Comparison of Figures 1 and 4 show how price competition affects shareholders. Results are dramatically different. Under traditional regulation, increasing investments led to greater returns, but under competition, utility shareholders do best with low-capital-cost projects, i.e., purchased power or natural gas. Indeed, these are the only two resources that show positive ROE over all three time periods.

Table 2. Effects on 36-year Incremental ROE of a Base Case With Higher Earnings (basis points)

	Historic Test Year		Future Test Year	
	Original base	New base	Original base	New base
Natural gas	1	0	3	3
Coal	8	5	11	10
Renewables	15	9	18	16
DSM	16	10	17	15
DSM without NLRA	5	-3	6	1

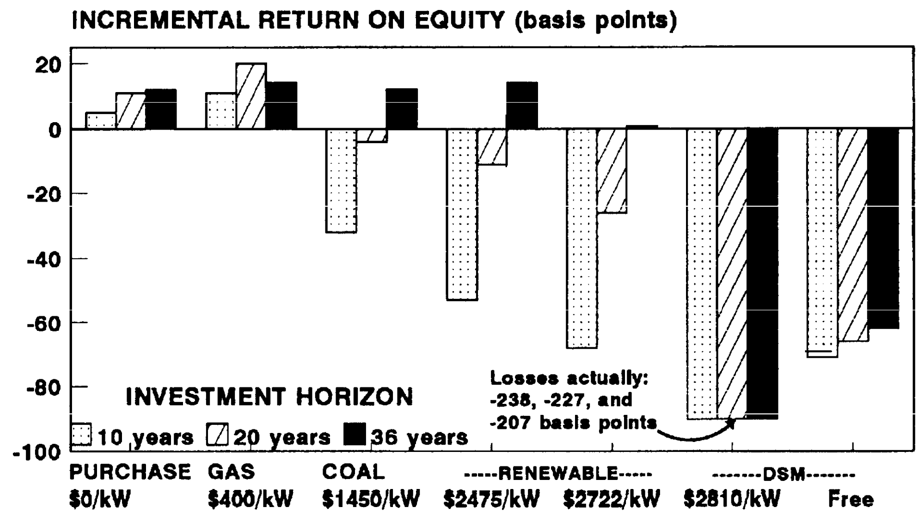

Figure 4. Incremental Return on Equity for Different Resources, Assuming that the Utility Operates in a Competitive Environment in Which it is a Price Taker

Building a coal or renewable plant is profitable only if that investment is held for the full 36-year construction and operation lifetime. And if the initial cost of a renewable plant is only 10% higher than shown in Table 1, it is just barely profitable.

Finally, running DSM programs hurts shareholders under all circumstances. Even if the utility can provide energy and load reductions at *no* cost, shareholders still lose money. This loss occurs because DSM reduces sales, which reduces revenues. This revenue reduction cannot be offset by higher electricity prices (as could occur under traditional regulation). Unless the utility can *sell* DSM services to its customers, it cannot afford to conduct DSM programs (Hirst 1994).

Conclusions

In a reversal of the typical IRP analysis, which focuses on optimal resource selection from the customers' perspective, we examined how acquiring different types of resources affect utility shareholders. Not surprisingly, we find that current regulation and tax policies do not provide a "level playing field" for all resources.

On the contrary, under typical conditions (i.e., rate cases conducted every several years using a historic test year), shareholder returns are directly proportional to the capital investment. On the other hand, if there is a threat of capital-cost disallowance or delay in the rate case, utilities should avoid capital-intensive projects. And if the regulatory commission does not allow use of a fuel-adjustment clause, projects that use a fuel whose price might increase between rate cases (such as natural gas) can penalize shareholders.

Changes in the rates for property, income, or sales taxes have much less effect on shareholder returns than do changes in PUC regulation. Only provision of an investment tax credit, which again encourages investment in capital-intensive projects, has a substantial effect.

If retail competition increases in the utility industry, prices may be set by the market rather than by regulation. In such a scenario, shareholder returns no longer depend solely on capital cost; instead, they depend on the overall cost (both fuel and capital) of the resource relative to electricity price. However, to the extent that a competitive market drives decisions to focus on shorter time horizons (e.g,. 10 or 20 years, rather than the assumed construction and operating lifetime of 36 years), low-capital-cost projects will most benefit shareholders given equal long-term costs. Alternatively, utility shareholders and bondholders will require higher returns to compensate them for the greater risk of operating in a competitive environment. These higher discount rates will also shift preferences among resources.

DSM programs, because they reduce electricity consumption and utility revenues, hurt shareholders in a competitive environment. Even under regulation, shareholders benefit from investment in DSM only if the commission allows the utility to recover the net lost revenues between rate cases.

The results presented here show that shareholder returns are often independent of customer benefits. Under cost-of-service regulation, utility shareholders earn more money when utilities invest in capital-intensive projects. However, the risk of disallowances might dissuade them from doing so. Under price competition, utilities will avoid DSM programs. These results suggest a need to modify state regulation to align better the interests of utility customers and shareholders.

We plan to continue these analyses, focusing next on various forms of incentive regulation and competition. The changes to ORFIN we are exploring include: modification of the fuel-adjustment clause to encompass separate treatment of fuel price and power-plant performance; modification of the fuel-adjustment clause to treat separately fuel costs, purchased-power capacity costs, and purchased-power energy costs; addition of various DSM incentives to shareholders; addition of multiple customer classes, one of which might purchase its electricity from other suppliers (to simulate retail wheeling); and inclusion of rate tariffs for each customer class, to allow for customer and demand charges. We also plan to develop recommendations on how to structure regulation in an increasingly competitive environment so that resource choices truly meet customer needs at least cost.

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