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EFFECTS OF RESOURCE ACQUISITIONS ON ELECTRIC-UTILITY SHAREHOLDERS

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SUMMARY

Integrated resource planning seeks to identify the mix of resources that can best meet the future energy-service needs of customers (and sometimes of society as a whole). These resources include new sources, types, and owners of power plants plus demand-side management (DSM) programs. However, little explicit attention is given to utility shareholders in the typical resource-planning proceeding.

Because of the complexity of state regulatory practices and tax policies, it seems unlikely that different resources that provide comparable services to customers will yield comparable returns to shareholders. This study examines a typical investor-owned utility's financial operations and performance using a spreadsheet model we developed for this project. The model simulates an electric utility's financial operations and produces an annual income statement, balance sheet, and cash-flow statement.

The purpose of this study is to see how shareholders fare when the utility acquires different kinds of resources. The resources considered are utility-built, -operated, and -owned power plants with different combinations of construction and operation costs; purchases of power; and DSM programs. We calculated the net present value of realized (cash) return on equity as the primary factor used to represent shareholder interests.

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

The tax policies we studied 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 overall inflation rate, load-growth rate, escalation in nonproduction expenses, and nongeneration construction (capital) requirements.

Finally, given the increasingly competitive nature of electricity markets, we briefly considered alternatives to traditional cost-of-service regulation. We examined shareholder returns for the resources described above in an environment where the utility competes with other suppliers solely on the basis of electricity price.

Figure S-1 summarizes some key results from this study. It shows the incremental cash return on equity for the new resource being examined, relative to a case that includes short-term purchases only. The results assume that rate cases, based on a historic test year, are held every four years. The base-case results assume that there are no uncertainties in the construction or operating costs of these resources. The three other sets of bars show the effects on shareholder earnings if the state regulator disallows 10% of the plant's construction cost, does not allow between-rate-case increases in fuel costs to be recovered from customers, or delays the planned 1998 rate case by one year.

These results show that, under traditional cost-of-service regulation, the more money a utility invests in a resource, the higher return its shareholders earn over the life of the resource. Thus, the incremental return on equity increases in going from purchased power to gas, coal, renewable, or DSM plants.

However, disallowances of fuel or capital costs or delays in conducting the rate case that includes the new project in the ratebase change that conclusion. High-capital-cost projects are most at risk from disallowances and rate-case delays. High-fuel-cost projects are most at risk from reductions in the fuel-adjustment clause. For example, a one-year delay in the rate case or a disallowance of 10% of the plant's capital cost hurts shareholders most for the renewable and DSM plants but very little for the gas plant. The reverse is true for removal of the fuel-adjustment clause, which penalizes shareholders most for the gas plant. Thus, current regulation and tax policy are unlikely to yield resource selections that best meet the needs of both utility

Fig. S-1. Incremental return on equity (relative to a base case that does not include the new resource) for different resources as a function of regulatory treatment.

customers and shareholders. These results are robust across different utility environments. The results are also largely unaffected by changes in tax rates, except for provision of an investment tax credit, which further boosts the incentive to build capital-intensive projects.

If price is set by competitive markets rather than by state regulators, shareholder returns are largely independent of capital costs. Instead, returns depend on the overall cost (both operating and construction) of the resource relative to the market price of electricity. If competition drives decisions to focus more on time horizons less than the operating life of the plant, low-capital-cost projects will benefit shareholders most. DSM programs in a price-competitive environment seriously hurt shareholders because they reduce electricity sales and revenues.

Utilities and their state regulators should consider alternative forms of regulation that reward shareholders for providing valued services to customers at low cost, rather than for spending money on construction projects. Various forms of incentive regulation, including price caps, might help to simplify state regulation of utilities and to treat all supply resources consistently. However, DSM programs are likely to fare poorly under either price caps or competition based primarily on electricity price. Therefore, other solutions are needed to preserve the benefits of DSM programs.

LIST OF ACRONYMS

AFUDC	Allowance for funds used during construction
CWIP	Construction work in progress
DSM	Demand-side management
EEI	Edison Electric Institute
EIA	Energy Information Administration
FAC	Fuel-adjustment clause
FTY	Future test year
HTY	Historic test year
IRP	Integrated resource planning
IRR	Internal rate of return
NARUC	National Association of Regulatory Utility Commissioners
NLRA	Net lost revenue adjustment
NPV	Net present value
O&M	Operations and maintenance
ORFIN	Oak Ridge National Laboratory Financial Model
PUC	Public utilities commission
ROE	Return on equity
RR	Revenue requirements

INTRODUCTION

Electric utilities and their regulators increasingly use integrated resource planning (IRP) methods. The key purpose of this approach is to meet the future energy-service needs of customers at the lowest total cost to customers. 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 ownerships.

Because IRP focuses on customers (and sometimes on society as a whole), the interests of utility shareholders may not get sufficient attention during the process. The purpose of the present analysis, therefore, is to ask whether IRP can ensure that the utility's decisions and actions are consistent with customer interests. If shareholder earnings differ with acquisition of different kinds of resources, then IRP may be necessary but not sufficient to ensure that resource acquisitions truly meet 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 from other entities, then it may want to build plants regardless of what its IRP suggests. More likely, it will modify the many assumptions in its analyses to yield results consistent with shareholder interests. That is, current IRP and regulatory practices could create situations in which the interests of utility customers and shareholders conflict.

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

The Commission's performance-based approach to utility DSM [demand-side management] 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.

Moreover, no comparable mechanism exists that provides the utility an incentive to perform well in purchased-power 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.

The New Jersey Advisory Council on Electricity Planning and Procurement (1993) viewed the situation even more broadly:

Six primary options exist for matching supply with demand, as follows: 1) construct new capacity; 2) purchase capacity and/or energy from other utilities; 3) purchase capacity and/or energy from non-utility generators such as cogenerators or small power producers, which are PURPA Qualifying Facilities or from independent power producers; 4) implement conservation or demand side management programs; 5) purchase DSM implemented by third parties; 6) rehabilitate or upgrade existing facilities; or any combination of the above.

Each of the above supply/demand options will have different impacts on rates, revenue requirements, and the financial health of the utility and each will expose ratepayers and shareholders to different levels of risk.

Consider, as a specific example, Public Service Company of Colorado (1993). The key resource in the company's resource plan is conversion of its Ft. St. Vrain facility (a recently shutdown nuclear plant) to a series of combustion turbine and combined-cycle units. The company's IRP showed that the location of this site (close to the Denver load center), its use of a clean fuel (natural gas) for a utility almost 100% dependent on coal (promoting fuel diversity), and its modular nature make this project attractive to the utility's customers. However, the fact that Public Service Company currently has \$60 million of undepreciated investment in the original Ft. St. Vrain plant not in its ratebase complicates consideration of this resource. Some parties view with skepticism the utility's analysis of the Ft. St. Vrain conversion, wondering whether it is motivated more by shareholder interests (to put that \$60 million back into its ratebase so that shareholders can earn a return on and of that investment) than by customer interests. Thus, the lack of explicit attention to shareholder considerations, which is typical of IRP rules and processes, led to complications in this case.

To explore the effects on utility shareholders of different types of resource acquisitions, we constructed a spreadsheet model that simulates an electric utility's financial operations and performance; the model is called ORFIN (Oak Ridge National Laboratory Financial Model). ORFIN produces an annual income statement, balance sheet, and cash-flow statement. We used ORFIN to examine how a utility's financial situation depends on the types of resources acquired. We considered utility-built and -operated power plants with different combinations of capital and operating costs, purchases of power from others, and operation of DSM programs. We used, as a starting point for this model, the model that Hadley et al. (1993) developed to examine the tax and regulatory treatment of various renewable and traditional power-supply resources.

We examined shareholder returns for these alternative resources as functions of PUC regulation, taxes, and the utility's operating environment. Our treatment of PUC regulation considers:

- frequency and type (future vs historic test year) of rate cases;
- inclusion of construction work in progress (CWIP) in ratebase vs allowance for funds used during construction (AFUDC);

- ratebase vs expensing of DSM programs;
- book and tax depreciation schedules;
- possible disallowances of “excess” capital; and
- possible lack of adjustment for “excess” fuel or purchased-power costs.

We also studied how shareholder returns depend on the types and magnitude of taxes as well as on the economic and operating environment of the utility. Tax policies include the existence and rates for property, sales, and income taxes and the existence and regulatory treatment of deferred taxes. [Although ORFIN can either flow-through or normalize the benefits of deferred income taxes, we focus on normalization because it is required by federal law (Hyman 1992).] The utility’s operating environment includes the overall inflation rate, load-growth rate, escalation in nonproduction expenses, and nongeneration construction (capital) requirements.

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

Chapter 2 provides background on IRP and on current regulatory practices and tax policies that affect electric-utility shareholders. Chapter 3 summarizes ORFIN’s operation. Chapter 4 defines our base-case utility, based primarily on U.S. utility data from the Energy Information Administration (EIA) and Edison Electric Institute (EEI). Chapter 5 presents the key results developed here under traditional regulation, and Chap. 6 shows how these results might differ in a fully competitive environment. Chapter 7 presents our findings and conclusions and offers suggestions on additional work. Appendix A explains the details of ORFIN’s operation, including the various assumptions and simplifications we made. Finally, Appendix B shows annual outputs from ORFIN for a few of the cases presented in Chaps. 5 and 6.

BACKGROUND

INTEGRATED RESOURCE PLANNING

The *Energy Policy Act of 1992* (U.S. Congress 1992) defines integrated resource planning as:

a planning and selection process for new energy resources that evaluates the full range of alternative energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. The process shall take into account necessary features for system operation, such as diversity, reliability, dispatchability, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis.

Traditionally (say before 1980), utilities met the growing demand for electricity by building and operating power plants. Since then, utilities increasingly have focused on customer demands for electric-energy services (rather than just the kWh and kW commodity); see Hirst (1992) for more information on electric-utility IRP. This more expansive scope includes energy-efficiency and load-management programs as alternatives to power plants.

In addition, utilities today consider a much broader array of supply resources, including potential changes to existing power plants, such as life extension, fuel switching, or repowering; purchases from other entities, including qualifying facilities, independent power producers, and other utilities; as well as new utility-owned power plants. For various reasons, including environmental quality and risk management, utilities today consider a diversity of resources. These alternatives include different fuels (including renewables, such as biomass) and technologies (including photovoltaics and wind, as well as steam boilers and combustion turbines).

UTILITY REGULATION

Investor-owned utilities account for approximately three-fourths of the electricity sold in the United States, with various types of government and consumer owned utilities comprising the remainder (EEI 1993b). Investor-owned utilities, the focus of this study, are tax-paying

corporations, financed by the sale of bonds and stock. Shareholders elect the company's board of directors, who in turn select the company's executives.

Given the diversity of possible resources and the complexity of regulatory practices and tax policy, it would be a remarkable coincidence if shareholders were indifferent to these resource choices. Shareholders are most affected by changes in utility revenues and costs because they are residual owners whose claims to income and assets are subordinate to other claims (e.g., bondholders). Thus, small changes in any income statement or balance sheet accounts can have large effects on shareholder returns.

Electric utilities are legal monopolies, with the monopoly status granted by state legislatures or PUCs. This status grants the utility an exclusive right to serve all customers within a certain geographic area. In return for that monopoly franchise, utilities have an obligation to serve, which includes four elements. First, the utility must serve any qualified customer who applies for service within the designated service area. Second, the utility must provide a reasonable quality of service at a reasonable price. Third, it must not unduly discriminate in price or service against any customer. Finally, the regulatory commission determines the rates the utility can charge different classes of customers and the types of (minimum) services it must provide those customers (Reeser 1992).

A rate case is the formal process used to determine the rates a utility is allowed to charge its customers for energy, demand, and other utility services. The PUC establishes the total annual revenue requirement so that the utility will earn its authorized return on equity (ROE). The PUC then sets prices so that the revenue requirement is met using test-year sales figures. The amount of revenue a utility actually receives depends on the amount of electricity actually sold.

In a simplified manner, utility revenue requirements are:

Revenue requirements = Operating expenses + Return on investment ,

where operating expenses include the costs of fuel, labor, materials, taxes, and depreciation. Return on investment is the product of ratebase and rate of return on investment. Ratebase reflects the assets the utility uses to provide services to its customers, including power plants, transmission lines, substations, meters, cars and trucks, office buildings, and computers; it is the PUC's determination of the utility's property that is used and useful in providing customer services. The rate of return on investment is the weighted average cost of debt and equity, based on the utility's mix of bonds, common stock, and preferred stock.

A rate case involves careful examination of a utility's costs, revenues, and capital structure for a specified period, usually a year. The purpose of a test year is to develop a representative cost of service reflecting sales, revenues, operating and maintenance costs, depreciation, taxes, and a fair return on ratebase. The PUC determines the utility's allowed rates, based on the costs for the test year.

Although PUCs vary in their selection of a test year, the two typical choices are a historic test year (HTY, usually the 12-month period immediately preceding the utility's rate-case filing) or a future test year (FTY). Some cost adjustments are typically allowed with an HTY, generally for costs that are known to change in the future. For example, the utility may have signed a contract recently with the labor union, which includes provisions for wage increases in the following year. Such changes in labor costs from the historic test year may be allowed in a rate case. With a future test year, all the sales, revenue, and cost figures identified above are forecast for a future time period, generally beginning on the date that the rates are to go into effect. The majority of states use an HTY, probably because it is less subject to controversy than an FTY (NARUC 1992). Just as actual revenues may differ from authorized revenues, actual costs in a given year will differ from the amounts used in calculating revenue requirements in the rate case.

The ratebase is the PUC's assessment of the total value of the utility's property used to provide services to customers. Generally, this assessment is based on the original cost of the property, adjusted for depreciation. Alternative approaches, much less widely used, include the reproduction cost approach, in which the utility's assets are valued at the cost required to replace these assets; and the market-value approach, which seeks to value these assets at the prices they would receive if sold in the marketplace. As with revenues and costs, the actual ratebase and equity investment in the utility will differ from the values used in the rate case.

In many jurisdictions, PUCs allow adjustments to a utility's rates between formal rate cases. The most common type of adjustment is the fuel-adjustment clause (FAC). These clauses are used to reconcile actual fuel costs (and often purchased-power costs also) to revenues, ensuring that customers bear all or most of the risks of changes in fuel costs (Morgan 1993). Typically, base fuel and purchased-power costs are set in a rate case. The FAC then collects or refunds any deviations from the utility's actual fuel and purchased-power costs (NARUC 1992).

Figure 1 summarizes the various costs and revenues that are considered in a typical rate case. Essentially, the PUC sets electricity prices so that the utility's revenues should cover costs, including enough net income to provide shareholders with the authorized ROE. Thus, actual ROE will differ from authorized ROE because sales, revenues, and costs will all differ from their test-year values.

RESOURCES EXAMINED

In carrying out this analysis, we considered the different regulatory and tax treatments that might be applied to the different types of resources a utility might acquire to meet the future energy-service needs of its customers. Consistent with the diversity inherent in IRP, these resources include:

Fig. 1. Schematic of the revenue and cost streams that utilities face.

- Utility-built power plants with different capital and operating costs. We consider very-high-capital, zero-operating-cost plants (e.g., renewables, such as wind); high-capital, low-operating-cost plants (e.g., coal); and low-capital, high- and increasing-operating-cost plants (e.g., natural gas). We consider two types of financial treatment of the construction costs:
 - AFUDC, in which the utility customers pay nothing for the plant until it comes on line and a rate case is conducted. After the rate case, the utility depreciates the cost of the plant, including the carrying costs,* and earns a return on the investment (including a return on the carrying costs it accumulated during construction).
 - CWIP, in which the carrying costs of the plant's construction are charged to customers in the year they occur.# After the rate case, the utility earns a return on and depreciation of its investment in the plant.
- Utility DSM programs with three types of cost recovery:

*Carrying costs include interest on debt plus return on common equity.

#Implicitly, this assumes that the PUC conducts a mini-rate case each year during construction, the sole purpose of which is to include in the ratebase construction costs as they occur.

- DSM that is expensed. The costs to run these programs are recovered from customers on a dollar-for-dollar basis in the year that they are incurred.
- DSM that is ratebased. In this case, the utility costs are capitalized, added to the ratebase, and earn a return on and depreciation of investment. Until the next rate case, the utility earns a return on its DSM investment at its weighted average cost of capital. After the rate case, it begins to depreciate the investment.
- DSM that is ratebased with the investment capitalized, with AFUDC added to income each year until the next rate case.

We consider the provision of a net lost revenue adjustment (NLRA) for the utility but not a financial incentive for running DSM programs. NLRA mechanisms are used to ensure that, between rate cases, the utility does not lose money because it ran DSM programs that cut sales and revenues. Some PUCs offer an extra financial incentive for utility shareholders, to reward the utility for running exemplary programs.

- Purchased power. In this case, the utility signs a long-term contract to purchase energy (¢/kWh) and capacity (\$/kW-year) from another entity. The costs of this purchase flow through the utility's FAC and have no effect on its balance sheet. Although some rating agencies treat purchased-power contracts as the equivalent of long-term debt, we did not do so in this analysis.

REGULATORY AND TAX TREATMENT OF RESOURCES

Regulatory commissions conduct rate cases in response to a request from the utility (generally seeking an increase in rates) or from another party (generally seeking a decrease in rates). In some states, utilities file rate cases on a regular cycle (e.g., California's three-year cycle). Upon completion of a major construction project, the utility will file a rate case to recover the costs of that project in rates. Shareholder earnings will likely depend on whether the rate cases use an HTY or FTY, whether the carrying charges during construction are treated as AFUDC or CWIP, whether the rate case is conducted when the plant comes on line or is delayed, whether the PUC disallows any of the construction costs, whether the utility has an FAC, and how frequently the PUC conducts rate cases.

With AFUDC, the utility reports its interest charges and authorized ROE as noncash income during construction of the resource. When the plant comes online, the PUC includes in the ratebase the accumulated carrying charges as well as the direct costs to build the plant. Alternatively, if the PUC allows CWIP in the ratebase, the utility collects from its customers these carrying charges as they occur. In that case, the PUC includes in the ratebase only the direct construction costs of the plant. On a net-present-value (NPV) basis, shareholders are indifferent between CWIP and AFUDC. However, because of the timing differences in cash flows, shareholders prefer CWIP if they are uncertain about possible disallowances or delays in the rate case. If the new plant represents a sizable fraction of the utility's assets such that the AFUDC income is a nontrivial part of revenue, the financial markets may worry about the

quality of the utility's earnings. In such a case, the financial-rating agencies might downgrade a utility's bond ratings, thereby increasing its cost of capital. Similarly, stock prices might fall if AFUDC earnings become too large. (ORFIN does not incorporate these possible changes in the costs of debt and equity capital.)

In addition to these regulatory practices, shareholder earnings may depend on tax policies, including the existence and magnitude of property, revenue, and income taxes. A key issue concerning federal income taxes is the provision for accelerated depreciation relative to book depreciation. This difference between book and tax depreciation is equivalent to an interest-free loan from the U.S. Treasury to utility shareholders and customers.

FINANCIAL MODEL

ORFIN is a simplified version of a utility financial-planning model, the details of which are in Appendix A. ORFIN includes the utility income statement, balance sheet, and cash-flow statement. These financial statements are based on user inputs for 1993 and are then computed annually for 36 years, from 1994 through 2029. We chose this period to allow for construction and full-lifetime operation of a new resource.

The income statement shows the results of a company's operations for a calendar year. 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 shareholders' equity as of the end of a calendar year. 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.

ORFIN is structured to allow analysis of a single major resource addition superimposed on a "base-case" utility (described in Chap. 4). 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? Generally, we added a 200-MW resource on January 1, 1998, and had a rate case and PUC order that day.

This single resource is added to a base-case utility system. The base case is characterized simply on both the demand and supply sides. 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 for the utility's single customer class. These inputs determine peak demand and electricity sales for each year of the simulation.

On the supply side, the base-case utility begins, in 1993, with user-specified amounts of generating capacity and long-term purchased-power contracts. For the next several years, the utility meets additional demands with annual power purchases, the costs of which are user inputs. Beginning on a date specified by the user, the utility meets a certain percentage of future

load growth by building small power plants (with the remainder continuing to be met by purchases). For analytical convenience, these plants are assumed to be modular and constructed within one year. Thus, the utility builds plants to exactly match load growth from year to year.

BASE-CASE UTILITY

We began the analysis by creating a company that is roughly typical of U.S. investor-owned electric utilities. We used historical data on utility financial indicators from EEI (1993b) and EIA (1993a and b). Table 1 shows data for 1991 and 1992 and our base case for 1993 (the initial year of analysis).

Table 1. Financial statistics on U.S. electric utilities and ORFIN base case

	1991	1992	1993 base case
Electricity price, ¢/kWh	6.8	6.8	7.3
Equity/capitalization	0.44	0.44	0.45
Long-term debt/capitalization	0.49	0.49	0.55
Operations and maintenance/revenue	0.55	0.55	0.53
Operating income/revenue	0.21	0.21	0.23
Net income/revenue	0.09	0.10	0.13
Assets/revenue	3.1	3.2	2.6
Construction/assets	0.046	0.044	0.053
Bond rate, %	9.1	8.1	7.5
Return on equity, %	-	11.3	11.0

Sources: EEI (1993b) and EIA (1993a).

As of 1993, the utility had total sales of 17,500 GWh and revenues of \$1.27 billion, yielding an electricity price of 7.3¢/kWh (Table A-1). The utility's capacity and generation were 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 was 2.0¢/kWh. Electricity production [fuel, power purchases and power-plant operations and maintenance (O&M)] accounted for 38% of total revenues.

The utility is capitalized with long-term bonds and common equity in the ratio of 55%:45% (Table A-2). (ORFIN does not include preferred stock or short-term bonds.) 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, with growth in the number of customers at 1.0% and growth in per-customer electricity use at 1.1%. This growth rate is higher than the 1.6% projected by EIA (1993b) but about equal to the 2.0% projected by *Electrical World* (1993).

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%). For simplicity, we assume that the utility builds modular power plants each year to exactly match load growth. Figure 2 shows the resource classes considered, including the particular resource for which the financial implications were analyzed.

The utility invests in its system each year for three purposes: (1) replacement of the original (1993) capital stock that has worn out, (2) construction of new nongeneration assets required to meet growth in the number of customers, and (3) construction of small power plants beginning in the year 2000 to meet 75% of load growth. Together, these expenditures increase utility assets over time (Fig. 3). Although the utility's assets increase, the capital component of electricity price decreases over time, consistent with the EIA (1993b) projection. Fuel costs increase, leading to an increasing fraction of total costs devoted to fuels and purchased-power, from 30% in 1993 to 44% in 2010 (similar to EIA's projected change from 26 to 39%).

The utility's PUC holds rate cases every four years beginning in 1994. The commission uses an HTY for these cases. During the years between rate cases, the utility's actual ROE declines (Fig. 4). These declines, a consequence of the user inputs, 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. (With a low inflation rate, high load growth, and modest changes in other input assumptions, actual ROE would exceed authorized ROE; see discussion in Chap. 5 of a different utility environment.)

Between 1998 and 1999, as an example, shareholder equity increases by 3.4%. Total expenses, except for fuels and purchased-power (which flow through the FAC), increase by 3.0%. Base revenues increase only with load growth at 2.1%. Because expenses increase faster than revenues, net income declines 2.0%. As a consequence, ROE drops by 5%: $(100 - 2.0\%)/(100 + 3.4\%)$.

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. Over most of the 1976-to-1990 period that they examined, actual ROE was below authorized ROE; in only two years (1987 and 1988) did actual ROE exceed authorized ROE.

Consistent with the EIA (1993b) projection, electricity prices are roughly constant over the analysis period (Fig. 5). Increases in fuel costs are approximately offset by reductions in non-O&M fixed costs (i.e., the capital-cost component of prices).

DEMAND AND CAPACITY (GW)

Fig. 2. Annual demand and capacity in ORFIN. The utility exactly meets customer loads with a mix of existing (1993) resources, short-term purchases, utility-built modular plants, and a particular resource for which the financial implications are analyzed.

ASSETS (billion 1993-\$)

Fig. 3. Utility base-case assets.

Fig. 4. Actual and authorized return on equity for the base-case utility.

Fig. 5. Real electricity prices in the base case. The waveform shape is a consequence of the assumed rate cases held every four years.

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 that analysis by assuming that traditional cost-of-service regulation prevails. In Chap. 6, we examine shareholder performance for these resources 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 purchased-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 to customers (i.e., net present value of revenue requirements over the full 36-year analysis period) (Table 2); we used the utility's cost of capital (9.1%) as the discount rate. However, the timing of cost impacts to the customer is different, depending on the construction and operating costs of the resource, as well as the applicable tax and regulatory policies. We make this assumption to see how utility shareholders fare when the IRP process makes no distinction among resource choices. Later in this chapter, we relax this NPV-RR constraint.

Table 2. 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 ^c	2475	---	---
DSM	2810	---	---

^aThese resources are all constructed in 1995, 1996, and 1997 and are online as of January 1, 1998. These capital and operating costs are set so that customer costs (i.e., the NPV-RR) are the same for all resource choices.

^bBased on an annual cost of \$126/kW-year, a 32-year contract life, and a real discount rate of 5.7% (equivalent to the utility's nominal weighted average cost of capital of 9.1%).

^cThis resource includes renewables, such as wind or photovoltaics, that consume no fuel.

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 also computed the internal rate of return on equity cash flow, but we do not report these results because they are entirely consistent with the incremental realized ROE results.

We examined incremental ROE for three time periods: 1994–2003, 1994–2013, and 1994–2029. The initial ten-year period covers the plant's construction plus its 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 (through 2029).

INITIAL RESULTS

Figure 6 shows results for the resources considered here under traditional cost-of-service regulation, presented as incremental ROE for the three periods. The capital investments for the resources receive AFUDC during construction, and rate cases are conducted every four years with a historic test year. The individual resources operate for 32 years. Book and tax depreciation lifetimes are 32 and 16 years, respectively.

Fig. 6. Incremental return on equity (relative to the Chap. 4 base case) for different resources. See Table B-1 for additional detail on these cases.

These results show that the 36-year incremental ROE to shareholders increases with increasing capital investment. Shareholders neither gain nor lose with a purchased-power contract because there is no investment at all. As the initial cost of the power plant increases from gas to coal to renewables, incremental ROE increases. Because the DSM program is roughly as capital intensive as the renewable resource, shareholder returns are almost identical for these two resources.

The DSM case discussed above includes an NLRA to compensate the utility for the revenues it would otherwise have lost between rate cases (in 1995, 1996, and 1997 in this example). The NLRA ensures that utility shareholders lose no money because the utility runs DSM programs that reduce sales (Hirst 1993); such mechanisms are in place in about 20 states. 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 (equivalent to 0.16 to 0.05 percentage points).

The differences in ROE across the three time periods are consistent for all resources. Incremental ROE is lowest for the initial 10-year period, primarily because of the plant's construction. Incremental ROE is negative while the plant is under construction because our measure of ROE does not recognize AFUDC income. Incremental ROE is highest for the 20-year period because this period corresponds to that of the deferred tax benefits associated with accelerated depreciation.

Two factors account for the positive incremental ROE values in Fig. 6. The primary factor 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 HTY cases shown here). However, because of book depreciation, the asset associated with the new resource and the interest payment decline each succeeding year. Of course, at the time of the next rate case, the amount of assets remaining is adjusted again.

The second factor contributing to this positive ROE is the benefit of accelerated tax depreciation. However, this effect is only temporary. Shareholder earnings are higher during the period that income taxes are deferred and then lower during the second half of the book lifetime of the resource. The net effect on ROE is zero over the course of the full 32-year operating lifetime for the resource.

These results are consistent with the well-known Averch-Johnson (1962) thesis, which says that regulated utilities have an incentive to rely more on capital and less on labor and other inputs to production. This bias towards capital-intensive modes of production is a consequence of the firm's incentive to maximize total profits under rate-of-return regulation. Although our results are consistent with their thesis, the reasons for increasing returns with investment are different. We focus on profits as a percentage of investment (return on equity) rather than on total profits. And our results are based primarily on the effects of regulatory lag on changes in incremental ROE.

Figure 7 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 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. As with HTY rate cases, increasing the time between cases allows regulatory lag to reward shareholders. Even though lengthening the time between rate cases improves the *incremental* ROE associated with a new power plant, the overall ROE gets worse (Fig. 4). With a new plant online, the drop in ROE is just not as much as it would otherwise have been.

Fig. 7. Incremental return on equity for a coal plant that comes online in 1998 as a function of frequency of rate cases, with historic and future test years.

DIFFERENT REGULATORY TREATMENTS

Regulators are not limited to the use of AFUDC and FACs; they can choose from a variety of regulatory approaches, the effects of which we examine below. These regulatory alternatives change the cost to customers of meeting energy-service needs with the resources considered. Thus, our original assumption of fixed NPV-revenue requirements is no longer maintained.

The cases discussed above all assumed that the utility booked AFUDC during the three-year construction period for each resource. Alternatively, the commission could have allowed

CWIP. Although the timing of returns to shareholders differs (Fig. 8), the net effect over the 36-year analysis period is identical. The extra earnings associated with CWIP during the construction period are exactly offset by the lower equity during the operation period.

Fig. 8. Incremental return on equity for a coal plant that comes online in 1998 with rate cases held every four years with an HTY.

The preceding cases all 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 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 affect shareholders depends on the relationship between capital and operating cost for the particular resource (Fig. 9). A 10% 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.* (For the purchased-power case, there is no change in earnings because there is no investment.) 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). Loss of the FAC has a small adverse effect for the coal plant for which the fuel price increases only with inflation and has no effect for the renewable plant or DSM program (which have no fuel costs). Loss of the FAC hurts utility shareholders (a loss of 7 basis points over the full 36-year analysis period) if the utility signed a purchased-power contract that includes increasing costs. Thus, the risks to shareholders of a purchased-power contract under current regulation are asymmetric. Shareholders cannot earn more money because there is no investment, but they can lose money if purchased-power costs increase and there is no FAC that allows them to pass on these increased costs to its customers. However, if purchased-power costs decline, shareholders will earn money with no FAC.

Fig. 9. Incremental return on equity (relative to Chap. 4 base case) for different resources as a function of changes in regulatory treatment. Base-case results are the same as the 36-year results shown in Fig. 6.

*Under base-case conditions, shareholders are indifferent to the treatment of construction costs, CWIP vs AFUDC (Fig. 8). However, a disallowance of construction costs or a delay in holding the rate case hurts shareholders more with AFUDC than with CWIP because more money is at risk with AFUDC.

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 the 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 because 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 renewables. A one-year delay in gaining that price increase cuts ROE in 1998 by 1.1 percentage points more for DSM than for renewables. 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 ratebase (and into rates), they should avoid high-capital-cost projects.

The results presented earlier in this chapter (Fig. 6) suggest that utilities should aggressively pursue renewables and DSM, the most capital-intensive and therefore the most profitable resources. However, the results shown in Fig. 9 explain some of the factors that might lead to a utility's reluctance to pursue these resources. In addition to the risks of a disallowance or delay in rate case, utilities are concerned that renewables are more expensive than other resources. (Recall that we assumed that these resources all had the same overall costs to utility customers.) 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 the threat that some of these expenses will be disallowed. Finally, NLRAs do not operate in all jurisdictions; as shown in Fig. 6, 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 different resources when the tax treatment differs. We assume changes in taxes that affect only the new resource under consideration and have no effect, except for income taxes, on the base-case resources discussed in Chap. 4. Specifically, we analyze the effects of:

- a shorter tax-depreciation lifetime, 8 vs 16 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 (Fig. 10). Thus, the returns for the natural-gas plant are affected only slightly by any of these changes. On the other hand, the returns are affected substantially for the renewables and DSM resources.

Fig. 10. Incremental return on equity (relative to the Chap. 4 base case) for different resources as a function of changes in tax treatment.

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 incremental shareholder earning because of regulatory lag. The four-year cycle with an HTY means that shareholders overcollect from customers for property taxes. Property taxes decline each year as book depreciation on the new plant increases; however, the amount collected from customers for property taxes remains the same until the next rate case.

Lowering the income tax increases shareholder earnings slightly. On the other hand, changing the sales tax (not shown on Fig. 10) has no effect on earnings.

Finally, a 10% investment tax credit has a large positive effect on shareholders for the renewable and DSM plants but only a small positive effect for the gas plant. Again, this effect is related to the size of the initial capital investment; currently, no investment tax credits are available to utilities. The Energy Investment Credit for solar and geothermal resources is available only to nonutility generators.

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.

Changing these factors slows the rate of cost increases and increases revenue (Table 3). If these changes are pushed far enough, earnings remain roughly constant between rate cases (Fig. 11). In this case, the average ROE from 1994 through 2029 is 11.3% (slightly above the authorized 11.0%), compared with 9.7% in the Chap. 4 base case.

Table 3. Factors affecting ROE in original and revised base-case utility

	Original base case	Revised base case
Load growth, %/year	2.1	2.6
Inflation rate, %/year	3.2	2.6
Escalation in fixed costs, %/year	1.0	0.0
Capital additions		
Base plant replacement	90	75
% of new load growth met by construction	75	10
Average return on equity		
10 years (1994 to 2003)	10.0	11.4
20 years (1994 to 2013)	9.8	11.4
36 years (1994 to 2029)	9.7	11.3

How does the addition of a new resource affect earnings when the revised base case is more profitable than the original base case? For all resources, the *incremental* ROE is less than it was 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 4), although the incremental returns are still positive for all cases except for DSM without an NLRA. The effects of changing the base case are greater with an HTY than with an FTY. In part, the reduction in incremental ROE occurs because, with higher load growth, the base utility and its assets are larger. Thus, the new plant represents a smaller share of the total utility than in the cases considered earlier in this chapter.

These results show that our findings concerning the effects on incremental ROE are robust across different utility operating environments. Although the precise effects on realized ROE will vary with operating conditions, the general patterns concerning capital intensiveness and various disallowances are unchanged.

Fig. 11. Annual return on equity for the high-earnings case versus the original base case described in Chap. 4.

Table 4. Effects on 36-year incremental ROE of a base case with higher earnings (basis points)

	<u>Historic test year</u>		<u>Future test year</u>	
	Original base case	Revised base case	Original base case	Revised base case
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

UNEQUAL RESOURCE COSTS

The cases considered so far assumed that the overall revenue requirements for each resource are the same. We also assumed that the operating characteristics (load factor) of each resource are the same. The effects on shareholders of changing initial cost is predictable, based on the cases presented so far. The more capital-intensive the project, the more shareholders earn.

This effect is shown in Fig. 12, which displays the incremental ROE for a plant whose capital cost ranges from zero to \$2000/kW. With either an HTY or an FTY, shareholder earnings increase linearly with increases in initial cost.

Fig. 12. Incremental return on equity for a plant that comes online in 1998 as a function of the plant's capital cost.

RESULTS IN A COMPETITIVE ENVIRONMENT

The cases discussed in Chap. 5 all assumed the continuation of 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, must compete 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. Under these conditions, 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 shown earlier (Fig. 5). Comparison of Figs. 6 and 13 shows how price competition affects shareholders. Whereas under traditional regulation increasing investments led to greater returns, that is not the case under competition. 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 incremental ROE over all three time periods.

Building a coal or renewable plant is profitable only if that investment is held for the full 36-year construction and operation lifetime. Shareholders lose money if the investment is held for only 10 or 20 years. And if the initial cost of a renewables plant is only 10% higher than shown in Table 2, 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 it could under traditional regulation). Unless the utility can *sell* DSM services to its customers, it cannot afford to conduct DSM programs (Hirst 1994).

These results represent an extreme form of competition. In reality, utilities are likely to have some core customers, representing a partial monopoly franchise. Even for noncore customers, utilities will compete with other suppliers on factors other than price, including power quality and DSM. As discussed in Chap. 7, we plan to expand ORFIN to consider various regulatory and competitive alternatives to current utility regulation.

Fig. 13. Incremental return on equity for different resources, assuming that the utility operates in a competitive environment in which it is a price taker. See Table B-2 for additional detail on these cases.

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 in Chaps. 5 and 6 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 (EEL 1993a) and competition. For example, San Diego Gas & Electric (1993) proposed to the California PUC a multipart reform of regulation. This reform includes (1) incentives for efficient electric generation and dispatch (operation of the existing system), (2) competitive energy procurement (acquisition of new resources), and (3) performance-based ratemaking. 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 (e.g., heat rates and capacity factors)
- 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, including shared savings, bonus ROE, and a bounty payment
- Addition of multiple customer classes, one of which might purchase its electricity from other suppliers (to simulate retail wheeling)
- Inclusion of rate tariffs for each customer class, to allow for customer and demand charges
- Treatment of purchased-power contracts as debt equivalents
- Addition of power-plant performance incentives

We also plan to develop recommendations to utilities and PUCs 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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EXPLANATION OF ORNL FINANCIAL MODEL

This Appendix provides detail on our model (ORFIN). We discuss ORFIN's income statement, balance sheet, and cash-flow statement. We also explain ORFIN's characterization of customer demand and the resources used to meet demand, model inputs and outputs, and the model's key assumptions.

INCOME STATEMENT

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 (Table A-1). The income statement has three parts: revenues, expenses, and income; income is equal to the difference between revenues and expenses.

Base revenue is the product of electricity sales (net of DSM) and the electricity price established in the last rate case. The model allows for three adjustments to base rates. The FAC (which the user can set anywhere between 0 and 100%) adjusts the utility's revenue for the difference between the actual fuel and purchased-power costs for that year and those included in base rates. At values less than 100%, stockholders share with customers the risks and rewards of higher or lower fuel prices and changes in power-supply system efficiency.

The DSM and CWIP adjustments are used when the utility builds its own resources (either a power plant or a DSM program) and is allowed CWIP in its ratebase. This adjustment ensures that the utility recovers from customers the DSM-program costs or the carrying costs associated with the program as they occur. Finally, the utility may be allowed to recover from customers the net lost revenues caused by its DSM programs until the next rate case. The sum of the four factors discussed in this and the preceding paragraph is the utility's total revenue.

The next section of the income statement itemizes the utility's operating expenses. Fuel, purchased power, and O&M expenses constitute the total costs of generating electricity. Nonproduction expenses are the costs of operating the utility's transmission and distribution system, customer-service centers, and administrative and general (e.g., corporate headquarters) functions. Book depreciation is used to allocate the cost of the utility's assets to the periods in which the assets produce services. We use straight-line depreciation for book purposes, with the useful lives of the initial assets and additional resources as user inputs (Fig. A-1).

Table A-1. Structure of the utility's income statement^a

	1993	1994	1995	1996	1997	1998	1999	2000
Sales, GWh	17500	17869	18247	18632	19025	19427	19837	20256
Net sales (with DSM), GWh	17500	17869	18247	18632	19025	19427	19837	20256
INCOME STATEMENT (million \$)								
Base revenues	1270.3	1302.8	1330.3	1358.4	1387.1	1630.3	1664.7	1699.9
Fuel adjustment clause		17.4	40.8	71.0	100.1	8.9	46.7	85.9
DSM & CWIP adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lost Revenue Adjustment (DSM)		0.0	0.0	0.0	0.0	0.0	0.0	0.0
REVENUES, total	1270.3	1320.2	1371.2	1429.4	1487.2	1639.2	1711.4	1785.8
Fuel	275.0	286.6	298.8	311.4	324.6	362.9	378.0	407.9
Purchased power	112.3	125.7	144.6	169.8	193.6	174.8	207.5	227.1
O&M, fixed + variable	90.3	93.2	96.2	99.3	102.5	108.2	111.7	115.3
Production expenses - total	477.6	505.6	539.6	580.5	620.6	645.9	697.2	750.2
Nonproduction expenses	225.0	234.5	244.4	254.8	265.6	276.8	288.5	300.7
Book depreciation	73.7	77.2	80.7	84.5	88.3	103.4	107.5	112.9
Revenue sensitive taxes	38.1	39.6	41.1	42.9	44.6	49.2	51.3	53.6
Property taxes	60.2	62.1	64.1	66.1	68.2	80.3	82.2	85.3
Federal income taxes - current	93.0	94.0	91.6	88.3	84.2	109.8	103.5	101.6
Federal income taxes - deferred	0.0	0.0	0.0	0.0	0.0	1.8	6.7	5.7
Expenses - total	967.6	1013.0	1061.7	1117.1	1171.5	1267.2	1337.0	1410.1
Operating income	302.7	307.2	309.4	312.3	315.7	372.0	374.4	375.6
AFUDC (noncash)		0.0	3.1	10.1	20.6	0.0	0.0	0.0
Interest expense	137.5	140.1	146.5	155.3	166.1	174.6	179.5	185.8
Extraordinary item (disallowed)		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Income w/AFUDC, disallowance	165.3	167.1	166.0	167.1	170.2	197.4	194.9	189.8
Dividends	123.9	125.4	124.5	125.4	127.7	148.0	146.2	142.4
Additions to retained earnings	41.3	41.8	41.5	41.8	42.6	49.3	48.7	47.5

^aThese results are for a utility with a coal plant under construction from 1995 through 1997 that is online January 1, 1998. The PUC conducts a rate case on January 1, 1998, using an HTY.

Fig. A-1. Book and tax values of unde depreciated balances for a power plant that comes online in 1998, has a 32-year book life, and has a 16-year tax life.

The next four lines in the operating-expense portion of the income statement deal with taxes. Revenue-sensitive (sales) taxes are based on the utility's total revenues. Property taxes are based on the utility's net plant in service (discussed below, as part of the balance sheet). Federal income taxes are based on the utility's net income (discussed below). Income taxes are split into two parts, that paid to the U.S. Treasury in the current year and that paid in later years. Taxes are deferred during the initial years after a new construction project comes online to reflect the timing difference between book and tax depreciation (Fig. A-1). Two factors account for the differences between book and tax depreciation. First, tax depreciation is calculated with the IRS-approved modified accelerated cost recovery schedule. This approach uses a double-declining balance approach for projects with a tax lifetime of less than 15 years, and a one-and-one-half-declining balance approach for projects with a longer lifetime. Book depreciation is linear. Second, the allowed lifetime for tax depreciation is shorter than that for book depreciation. In later years, these deferred taxes are paid. Thus, the more-rapid depreciation for tax purposes does not affect the total amount of income taxes paid but does affect the timing of those payments.

The difference between revenues and the sum of all the operating expenses is operating income. This income is the amount of money available to compensate investors for the use of their money. AFUDC is the noncash income that PUCs allow utilities to record as compensation for the cost of money while a project is under construction. Interest expenses are the payments on the utility's long-term bonds. An "extraordinary item" is any material gain or loss that is significantly different in character from the typical activities of the company. In ORFIN, the only time an extraordinary item occurs is if the PUC disallows some of the utility's cost of building a new power plant or DSM program.

Net income, the amount of money remaining to compensate common stockholders, is the difference between the sum of operating income and AFUDC minus interest and extraordinary expenses. Net income is shared between dividends paid to shareholders and retained earnings, which the utility uses to finance capital additions. The user sets the dividend payout ratio, which remains unchanged throughout the simulation.

BALANCE SHEET

The balance sheet is a summary of the company's assets, liabilities, and owner's (shareholders') equity as of a particular date (the end of a calendar year in ORFIN, Table A-2). By definition, assets equal the sum of liabilities and equity.

Gross plant equals the original, undepreciated costs of the land, buildings, and equipment used by the utility to provide electric services to its customers. Accumulated depreciation is the sum of the annual amounts of book depreciation of the land, buildings, and equipment included in gross plant. Net plant (sometimes called plant in service) is the difference between gross plant and accumulated depreciation.

CWIP is the sum of all costs associated with constructing new utility facilities until they are in operation, at which time they are included in the ratebase (after approval by the PUC in a rate case).

Table A-2. Structure of the utility's balance sheet^a

	1993	1994	1995	1996	1997	1998	1999	2000
BALANCE SHEET - end of year								
Gross plant	3684	3858	4037	4223	4415	4969	5174	5447
Accumulated depreciation	674	751	832	916	1004	1108	1215	1328
Net plant	3010	3107	3206	3307	3411	3861	3959	4119
CWIP		0	80	186	355	0	0	0
Current assets	328	345	364	384	404	426	449	473
ASSETS, total	3338	3452	3650	3877	4170	4287	4407	4591
Long-term debt	1836	1899	2008	2132	2293	2358	2424	2525
Accumulated deferred income tax	0	0	0	0	0	2	9	14
Common equity	1502	1554	1643	1745	1876	1927	1975	2052
Common stock	1454	1463	1511	1571	1660	1662	1661	1690
Retained earnings	48	90	132	173	216	265	314	361
LIABILITIES and EQUITY, total	3338	3452	3650	3877	4170	4287	4407	4591

^aSee Footnote a, Table A-1.

Current assets represent, in ORFIN, a simplification of several miscellaneous assets. These assets include the difference between amounts owed the utility (e.g., utility bills sent to customers but not yet paid) and the amounts the utility owes others (e.g., accrued taxes and interest not yet paid), working capital (cash), materials and supplies, plant held for future use (e.g., land that might be used later for a power plant), fuel stocks, and capital leases. In ORFIN, current assets are set equal to a fixed, user-specified fraction of annual revenues.

Total assets are the sum of net plant, CWIP, and current assets. The PUC, in a rate case, sets the ratebase equal to assets minus any disallowance of construction costs.

The second half of the balance sheet shows capitalization, which in ORFIN includes only long-term bonds and common stock. ORFIN includes neither short-term debt nor preferred stock. The only other liability included in the model is the accumulation of deferred income-tax benefits, the income-tax effects of the differences between book and tax depreciation (Fig. A-1). In general, current liabilities include debt due within one year as well as short-term debt. User inputs specify the debt and equity capitalization ratios.

CASH-FLOW STATEMENT

The third element of ORFIN is the sources and uses of funds, shown in Table A-3. 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. Cash from operations includes net income and depreciation adjusted for AFUDC and deferred taxes. Cash from financing includes debt and common stock issued. Uses of cash include dividend payments, repurchase of common stock, retirement of long-term debt, construction (investment), and increases in current assets.

Table A-3. Structure of the utility's cash-flow statement^a

	1993	1994	1995	1996	1997	1998	1999	2000
SOURCES: Net Income		167	166	167	170	197	195	190
Depreciation		77	81	84	88	102	106	112
- AFUDC		0	-3	-10	-21	0	0	0
+ Depreciation of AFUDC		0	0	0	0	1	1	1
Provision for Deferred Taxes		0	0	0	0	2	7	6
Disallowance		0	0	0	0	0	0	0
Cash from Operations		244	244	241	238	303	309	308
Debt Issued		63	109	125	161	64	66	101
Common Stock Issued		10	48	60	89	1	0	30
Total		317	400	426	488	368	376	439
USES: dividends		125	124	125	128	148	146	142
Capital Expenditures		174	257	281	340	199	205	273
Increase in Current Assets		18	19	20	21	22	23	24
Debt Retirement		0	0	0	0	0	0	0
Common Stock Repurchase		0	0	0	0	0	1	0
Total		317	400	426	488	368	376	439

^aSee Footnote a, Table A-1.

RESOURCE CHARACTERIZATION

ORFIN is structured to analyze the financial implications of a single resource acquisition, which comes online in the late 1990s. Generally, we added a 200-MW resource on January 1, 1998 and had a rate case and PUC order that day. As noted above, we consider three types of resources: utility-built, -owned, and -operated power plants; DSM programs; or purchased-power contracts.

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 (a dollar-for-dollar reduction in income taxes intended to encourage capital expenditures). The user determines various regulatory factors affecting this new resource, including any disallowance of the capital cost, normalization or flowthrough of the deferred income-tax benefits, AFUDC or inclusion of CWIP in the ratebase for construction financing costs, and the extent (0 to 100%) of a FAC.

The DSM program is characterized in a similar fashion, 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 specify provision of an NLRA mechanism. Until the next rate case, the NLRA returns to

*The DSM program differs from the power plants and power purchases in timing. The DSM resource begins to produce energy savings over several years, typically 1995 through 1997, while the purchases and power plants provide electricity all at once, typically on January 1, 1998.

the utility the difference between short-term avoided costs and revenues lost because of the DSM-induced sales reduction.

The purchase option is characterized by its size, initial year, fixed cost (\$/kW), and variable cost (¢/kWh) and by 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. User inputs characterize the base case. The utility base-case system is characterized very simply, on both the demand and supply sides. We assume that supply equals demand exactly every year, ignoring issues of excess capacity, reserve margins, outage rates, and reliability. User inputs specify annual growth rates in the number of customers and usage per customer for the utility's single customer class. 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 purchased-power contracts. These resources are characterized in terms of 1993 fuel and O&M costs, fuel-cost escalation rates, and the capacity cost for contracts. The user also specifies nonproduction costs and the escalation rate in those (nongeneration) costs.

For the next several years, the utility meets additional demands with short-term (annual) power purchases, the costs of which are, again, user inputs. Beginning on a date specified by the user (e.g., the year 2000), the utility meets a user-specified percentage of future load growth by building small power plants (with the remainder continuing to be 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 return on equity, and annual inflation rate. These financial parameters are fixed throughout the simulation period.

User inputs determine the existence and rates for income taxes, property taxes, and revenue taxes. The user also specifies the frequency of rate cases and whether they use an HTY or FTY. Rate cases take place on January 1 and new rates go into effect on that date. Rates based on a future test year yield exactly the authorized return on equity for the year that the rates first go into effect. Rate cases based on an HTY use data primarily from the prior year and, therefore, generally produce rates that result in the utility's earning more or less than its authorized return on equity.

In addition to the three financial statements discussed above, the model computes various summary statistics (Table A-4). The primary dependent variable is the average realized (cash) return on equity over the short term (ten years), mid term (20 years), and long term (36 years). We use a realized, rather than reported (accounting), ROE to show more clearly the effects on cash flow to shareholders. Realized ROE differs from reported 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:

$$\text{Realized ROE} = \frac{(\text{Net Income} - \text{AFUDC Revenue} + \text{AFUDC Depreciation} + \text{AFUDC Disallowance} + \text{Deferred Taxes})}{(\text{Common Equity} + \text{Accumulated Deferred Taxes} - \text{Net AFUDC Capital})}$$

We show results for three time periods because, according to the Electric Power Research Institute (1993), some utilities emphasize short-term economics that "show a revenue requirement advantage in the first one-fourth to one-third of the alternative's life."

Table A-4. Summary outputs from ORFIN for a coal-fired power plant online in 1998

	1994- 2003	1994- 2013	1994- 2029	Differences from base		
				1994- 2003	1994- 2013	1994- 2029
NPV net income without AFUDC, million \$	1072	1615	1994	43	78	80
NPV adjusted equity, million \$	10708	16357	20297	436	613	650
Weighted Average ROE, %	10.01	9.87	9.82	-0.00	0.11	0.08
IRR on incremental cash, %	-0.80	11.61	12.25	-10.81	1.85	2.51
NPV revenues, million \$	10299	17569	24960	58	39	-49
Average price, ¢/kWh	8.48	10.03	13.30	0.05	0.01	-0.09
NPV cash from operations, million \$	1642	2520	3148	71	127	137
NPV incremental cash flow, million \$	-38	4	9	-38	4	9
% construction internally financed	139.4	146.9	151.2	-10.5	-0.9	0.4
Average interest coverage	2.6	2.6	2.6	-0.0	-0.0	-0.0
Average profit margin, %	11.18	10.38	9.41	0.32	0.42	0.32
Average asset turnover, %	0.39	0.41	0.46	-0.0	-0.0	-0.0
NPV assets, million \$	11019	16745	20738	556	694	706

Other summary variables calculated in ORFIN include financial performance ratios, NPV of assets and equity cash flow, NPV of revenues and income, levelized electricity prices, as well as the year-by-year values of the different costs and revenues. These outputs provide results from various perspectives, including those of shareholders, utility management, and customers for each resource option. ORFIN uses the utility's authorized weighted average cost of capital to compute those summary statistics that reflect the customer perspective (e.g., revenues and prices), and uses the utility's authorized return on equity for those statistics that reflect shareholder interests (e.g., net income, incremental cash flow, and ROE).

The values of net income and equity shown in Table A-4 are consistent with our definition of realized ROE rather than accounting ROE. IRR on incremental cash is the internal rate of return on the difference between cash flows in the "resource case and the base case.

MODEL LIMITATIONS AND ASSUMPTIONS

Like all models, ORFIN is a simplification of, and an abstraction from, reality. Its key assumptions include:

- The economic and tax lifetimes of the initial plant are ignored. Instead of keeping track of each year's capital investments separately, we assume an average lifetime for all the plant in service as of the initial year.

- Changes in base plant (i.e., all investments except those in the single resource that is the subject of analysis) are modeled very simply. We assume that a fixed percentage of initial-year plant is replaced each year, that the amount of investment required per new customer is fixed over the simulation period, and that the cost of the generic modular power plants built to meet a fraction of each year's load growth is either constant or changes smoothly at a fixed exponential rate. Book and tax depreciation schedules for this base plant are identical; that is, there are no income-tax benefits associated with these investments.
- We ignore possible changes over time in inflation rates, long-term bond rates, or authorized levels of ROE. Similarly, we assume that load growth, fuel prices, and other variables all change smoothly at fixed exponential rates over time.
- The details of production costing are largely ignored in ORFIN. It builds or buys capacity to just meet load growth, and the electric system is assumed to operate with no reserve margin or outages.
- The debt:total capital ratio is held constant throughout the simulation period. In addition, the model does not consider preferred stock or short-term debt.
- ORFIN does not calculate current liabilities. Instead, current assets are tracked as *net* current assets and are computed as a simple function of load growth and inflation.
- Dividends are equal to a fixed percentage of net income and do not vary with construction expenditures or other factors.
- The inclusion of CWIP in ratebase does not, in the model, involve a full rate case. Instead, ORFIN allows for annual adjustments to rates to just cover these carrying costs.
- Once debt levels are set by the debt ratio, cash excesses or deficits are reconciled through the purchase or issuance of stock.
- The treatment of income taxes does not distinguish between state and federal taxes.
- Incentives to utility shareholders for DSM programs, purchased-power contracts, and efficient operation of the utility's system are not considered.
- The possible effects of purchased-power contracts on the utility's capitalization ratios are not considered.

We believe that these simplifying assumptions have no material effect on the results presented here. In addition, as explained in the Conclusion, we are expanding the model to consider a variety of incentive regulation mechanisms.

SELECTED DETAILS OF MODEL OUTPUTS

This appendix shows annual results from ORFIN for a few of the cases discussed in Chaps. 5 and 6. Table B-1 presents results for the cases that consider traditional cost-of-service regulation for the different resources examined here (Fig. 6). Table B-2 presents results for the cases that consider price competition (Fig. 13).

These tables show annual values for revenues, electricity price, assets, net income, realized (cash) and reported (accounting) returns on equity, before-tax interest coverage, and equity cash flow. Revenues, price, assets, net income, and equity cash flow are all shown in nominal (current year) dollars.

Table B-1. Sample of annual outputs for selected years for the cases shown in Chap. 5

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Base case, 4-year HTY														
Revenues (million \$)	1,315	1,354	1,403	1,437	1,516	1,600	1,688	1,781	1,879	1,982	2,091	2,205	2,326	2,454
Price (¢/kWh)	7.36	7.51	7.75	8.00	8.25	8.52	8.79	9.07	9.36	9.66	9.97	10.29	10.62	10.96
Assets (million \$)	3,452	3,570	3,691	3,815	3,943	4,075	4,270	4,471	4,679	4,893	5,113	5,341	5,576	5,819
Net income (million \$)	164	158	158	155	162	166	170	170	176	182	189	196	203	211
Realized ROE (%)	10.71	10.00	9.67	9.18	9.26	9.21	9.03	8.63	8.53	8.45	8.38	8.32	8.27	8.24
Reported ROE (%)	10.71	10.00	9.67	9.18	9.26	9.21	9.03	8.63	8.53	8.45	8.38	8.32	8.27	8.24
Before tax interest coverage	2.83	2.70	2.65	2.56	2.58	2.57	2.54	2.47	2.45	2.44	2.43	2.42	2.41	2.40
Equity cash flow (million \$)	104	97	95	91	96	98	73	71	73	76	80	83	87	91
Gas														
Revenues (million \$)	1,320	1,371	1,429	1,487	1,611	1,688	1,768	1,856	2,022	2,106	2,194	2,287	2,506	2,610
Price (¢/kWh)	7.39	7.51	7.67	7.82	8.29	8.51	8.73	8.97	9.57	9.77	9.96	10.17	10.91	11.13
Assets (million \$)	3,452	3,570	3,691	3,815	3,943	4,075	4,270	4,471	4,679	4,893	5,113	5,341	5,576	5,819
Net income (million \$)	167	164	161	157	187	183	177	169	216	209	201	193	259	251
Realized ROE (%)	10.94	10.38	9.83	9.28	10.71	10.16	9.42	8.61	10.50	9.70	8.93	8.19	10.55	9.79
Reported ROE (%)	10.94	10.38	9.83	9.28	10.71	10.16	9.42	8.61	10.50	9.70	8.93	8.19	10.55	9.79
Before tax interest coverage	2.86	2.77	2.67	2.58	2.82	2.73	2.60	2.47	2.79	2.65	2.52	2.39	2.79	2.67
Equity cash flow (million \$)	107	103	98	93	120	115	80	70	112	102	91	80	140	129
Coal														
Revenues (million \$)	1,320	1,371	1,429	1,487	1,610	1,682	1,758	1,841	2,009	2,094	2,183	2,276	2,492	2,598
Price (¢/kWh)	7.39	7.51	7.67	7.82	8.29	8.48	8.68	8.90	9.51	9.71	9.91	10.12	10.85	11.08
Assets (million \$)	3,452	3,592	3,742	3,913	4,038	4,167	4,359	4,557	4,761	4,972	5,190	5,414	5,647	5,886
Net income (million \$)	167	164	160	155	189	187	181	174	222	214	207	199	263	255
Realized ROE (%)	10.94	10.33	9.68	9.02	10.64	10.20	9.49	8.69	10.62	9.83	9.07	8.35	10.60	9.87
Reported ROE (%)	10.94	10.38	9.84	9.32	10.55	10.04	9.36	8.60	10.54	9.77	9.03	8.31	10.57	9.84
Before tax interest coverage	2.86	2.76	2.65	2.53	2.79	2.70	2.58	2.45	2.78	2.65	2.53	2.41	2.79	2.67
Equity cash flow (million \$)	107	93	87	76	123	120	85	75	118	108	98	87	145	134
Renewables														
Revenues (million \$)	1,320	1,371	1,429	1,487	1,639	1,711	1,786	1,868	2,033	2,117	2,205	2,297	2,501	2,605
Price (¢/kWh)	7.39	7.51	7.67	7.82	8.44	8.63	8.82	9.03	9.63	9.82	10.01	10.21	10.89	11.11
Assets (million \$)	3,452	3,650	3,877	4,170	4,287	4,407	4,591	4,782	4,978	5,181	5,390	5,607	5,831	6,063
Net income (million \$)	167	163	157	150	200	203	197	189	236	229	222	215	274	267
Realized ROE (%)	10.94	10.20	9.32	8.37	10.71	10.54	9.86	9.11	10.90	10.16	9.45	8.78	10.75	10.07
Reported ROE (%)	10.94	10.39	9.87	9.40	10.38	9.99	9.43	8.77	10.63	9.95	9.29	8.64	10.63	9.97
Before tax interest coverage	2.86	2.74	2.58	2.41	2.76	2.66	2.57	2.46	2.77	2.66	2.55	2.44	2.78	2.66
Equity cash flow (million \$)	107	69	57	31	136	137	103	93	135	125	116	106	158	148

Table B-1. Sample of annual outputs for selected years for the cases shown in Chap. 5 - continued

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
DSM with NLRA														
Revenues (million \$)	1,320	1,371	1,429	1,487	1,654	1,726	1,801	1,883	2,044	2,129	2,217	2,309	2,502	2,606
Price (¢/kWh)	7.39	7.51	7.67	7.82	8.51	8.70	8.89	9.10	9.69	9.87	10.07	10.27	10.90	11.11
Assets (million \$)	3,452	3,707	4,008	4,420	4,530	4,643	4,819	5,001	5,189	5,384	5,586	5,795	6,011	6,235
Net income (million \$)	167	162	155	145	211	218	212	205	250	244	237	231	284	278
Realized ROE (%)	10.94	10.08	8.97	7.79	10.77	10.83	10.20	9.49	11.16	10.46	9.79	9.18	10.88	10.25
Reported ROE (%)	10.94	10.39	9.90	9.48	10.23	9.94	9.49	8.93	10.71	10.12	9.53	8.95	10.69	10.09
Before tax interest coverage	2.86	2.72	2.52	2.30	2.73	2.63	2.56	2.46	2.77	2.67	2.57	2.47	2.76	2.66
Equity cash flow (million \$)	107	45	28	(13)	149	154	120	111	151	142	133	124	171	162
DSM no NLRA														
Revenues (million \$)	1,320	1,361	1,397	1,417	1,666	1,740	1,816	1,900	2,057	2,142	2,232	2,325	2,511	2,617
Price (¢/kWh)	7.39	7.55	7.72	7.88	9.07	9.26	9.45	9.68	10.25	10.44	10.64	10.85	11.46	11.68
Assets (million \$)	3,452	3,694	4,018	4,499	4,606	4,716	4,890	5,070	5,256	5,448	5,648	5,854	6,068	6,290
Net income (million \$)	167	161	148	129	215	224	219	214	256	250	245	240	289	284
Realized ROE (%)	10.94	10.01	8.61	6.88	10.82	11.00	10.42	9.76	11.25	10.61	9.99	9.43	10.94	10.36
Reported ROE (%)	10.94	10.29	9.53	8.74	10.25	10.03	9.65	9.15	10.77	10.24	9.72	9.19	10.74	10.20
Before tax interest coverage	2.86	2.70	2.46	2.15	2.73	2.64	2.57	2.49	2.77	2.68	2.60	2.51	2.77	2.67
Equity cash flow (million \$)	107	48	12	(56)	154	162	129	120	157	149	141	133	176	168

Table B-1. Sample of annual outputs for selected years for the cases shown in Chap. 5 - continued

	2008	2009	2010	2011	2012	2014	2016	2018	2020	2022	2024	2026	2028	2029
Base case, 4-year HTY														
Revenues (million \$)	2,588	2,730	2,880	3,037	3,203	3,563	3,964	4,408	4,903	5,452	6,063	6,741	7,496	7,904
Price (¢/kWh)	11.31	11.67	12.04	12.43	12.83	13.66	14.55	15.49	16.50	17.58	18.72	19.94	21.23	21.91
Assets (million \$)	6,070	6,330	6,598	6,875	7,162	7,765	8,412	9,106	9,852	10,654	11,517	12,447	13,450	13,982
Net income (million \$)	220	229	238	249	259	283	309	339	371	408	448	493	543	570
Realized ROE (%)	8.21	8.20	8.20	8.20	8.21	8.26	8.33	8.42	8.54	8.67	8.82	8.98	9.15	9.24
Reported ROE (%)	8.21	8.20	8.20	8.20	8.21	8.26	8.33	8.43	8.54	8.67	8.82	8.98	9.15	9.24
Before tax interest coverage	2.40	2.39	2.39	2.39	2.40	2.40	2.42	2.43	2.45	2.47	2.50	2.53	2.55	2.57
Equity cash flow (million \$)	96	100	106	111	117	130	145	162	182	203	228	255	285	302
Gas														
Revenues (million \$)	2,720	2,836	3,093	3,224	3,361	3,809	4,142	4,684	5,097	5,753	6,266	7,062	7,699	8,042
Price (¢/kWh)	11.36	11.60	12.39	12.65	12.91	14.04	14.64	15.88	16.57	17.94	18.74	20.25	21.18	21.66
Assets (million \$)	6,070	6,330	6,598	6,875	7,162	7,765	8,412	9,106	9,852	10,654	11,517	12,447	13,450	13,982
Net income (million \$)	242	233	308	299	289	363	343	427	403	500	473	584	554	536
Realized ROE (%)	9.06	8.36	10.58	9.86	9.16	10.60	9.23	10.62	9.28	10.63	9.31	10.63	9.32	8.69
Reported ROE (%)	9.06	8.36	10.58	9.86	9.16	10.60	9.23	10.62	9.28	10.63	9.31	10.63	9.32	8.69
Before tax interest coverage	2.54	2.42	2.80	2.68	2.56	2.80	2.57	2.80	2.58	2.81	2.58	2.81	2.58	2.48
Equity cash flow (million \$)	117	105	171	159	146	206	177	246	212	290	251	341	295	270
Coal														
Revenues (million \$)	2,709	2,826	3,081	3,213	3,351	3,800	4,138	4,682	5,102	5,764	6,286	7,091	7,741	8,091
Price (¢/kWh)	11.32	11.56	12.34	12.60	12.88	14.00	14.62	15.87	16.59	17.97	18.80	20.34	21.29	21.80
Assets (million \$)	6,134	6,391	6,656	6,930	7,214	7,811	8,452	9,140	9,879	10,675	11,532	12,456	13,453	13,982
Net income (million \$)	247	238	311	302	293	364	343	427	404	499	473	584	553	536
Realized ROE (%)	9.16	8.47	10.61	9.91	9.22	10.59	9.22	10.58	9.27	10.60	9.30	10.61	9.32	8.69
Reported ROE (%)	9.14	8.45	10.60	9.90	9.21	10.61	9.26	10.62	9.30	10.63	9.32	10.63	9.33	8.70
Before tax interest coverage	2.55	2.43	2.79	2.67	2.56	2.80	2.57	2.80	2.58	2.81	2.58	2.81	2.59	2.48
Equity cash flow (million \$)	123	111	175	163	150	209	179	247	214	291	252	342	296	271
Renewables														
Revenues (million \$)	2,714	2,828	3,071	3,201	3,336	3,769	4,099	4,628	5,036	5,680	6,188	6,972	7,601	7,941
Price (¢/kWh)	11.34	11.57	12.30	12.56	12.82	13.89	14.49	15.69	16.37	17.71	18.50	19.99	20.91	21.39
Assets (million \$)	6,303	6,551	6,808	7,074	7,350	7,931	8,556	9,228	9,952	10,731	11,572	12,480	13,461	13,982
Net income (million \$)	260	251	319	311	303	368	346	427	405	499	474	583	554	537
Realized ROE (%)	9.41	8.76	10.69	10.03	9.38	10.55	9.19	10.50	9.24	10.54	9.28	10.58	9.31	8.70
Reported ROE (%)	9.32	8.69	10.64	9.99	9.35	10.64	9.34	10.64	9.35	10.64	9.36	10.64	9.36	8.74
Before tax interest coverage	2.55	2.45	2.77	2.67	2.56	2.78	2.58	2.80	2.59	2.81	2.59	2.81	2.60	2.49
Equity cash flow (million \$)	137	126	186	175	162	215	184	250	217	294	256	343	299	274

Table B-1. Sample of annual outputs for selected years for the cases shown in Chap. 5 - continued

	2008	2009	2010	2011	2012	2014	2016	2018	2020	2022	2024	2026	2028	2029
DSM with NLRA														
Revenues (million \$)	2,715	2,829	3,062	3,191	3,326	3,749	4,076	4,598	5,004	5,641	6,146	6,922	7,548	7,886
Price (¢/kWh)	11.34	11.57	12.27	12.52	12.78	13.82	14.41	15.58	16.27	17.59	18.38	19.85	20.76	21.24
Assets (million \$)	6,467	6,708	6,957	7,215	7,483	8,049	8,658	9,314	10,022	10,786	11,611	12,504	13,469	13,982
Net income (million \$)	272	264	327	320	312	371	348	427	406	498	475	582	554	537
Realized ROE (%)	9.64	9.03	10.76	10.14	9.53	10.51	9.15	10.41	9.21	10.49	9.27	10.54	9.31	8.70
Reported ROE (%)	9.50	8.91	10.69	10.08	9.49	10.67	9.41	10.65	9.39	10.65	9.40	10.65	9.39	8.78
Before tax interest coverage	2.56	2.47	2.76	2.66	2.56	2.77	2.59	2.80	2.59	2.81	2.60	2.82	2.61	2.50
Equity cash flow (million \$)	152	141	197	186	174	220	189	252	221	296	259	345	302	277
DSM no NLRA														
Revenues (million \$)	2,727	2,843	3,069	3,199	3,336	3,753	4,084	4,600	5,011	5,642	6,151	6,922	7,552	7,892
Price (¢/kWh)	11.91	12.15	12.84	13.09	13.36	14.39	14.99	16.17	16.87	18.19	18.99	20.47	21.39	21.88
Assets (million \$)	6,519	6,757	7,004	7,260	7,525	8,086	8,690	9,341	10,044	10,803	11,624	12,511	13,472	13,982
Net income (million \$)	278	272	330	325	318	373	352	427	410	499	478	583	558	543
Realized ROE (%)	9.80	9.24	10.80	10.22	9.66	10.51	9.22	10.41	9.27	10.49	9.33	10.55	9.37	8.79
Reported ROE (%)	9.66	9.12	10.73	10.18	9.63	10.71	9.53	10.68	9.49	10.68	9.48	10.68	9.47	8.88
Before tax interest coverage	2.58	2.49	2.76	2.67	2.57	2.77	2.60	2.80	2.61	2.81	2.62	2.82	2.62	2.52
Equity cash flow (million \$)	159	150	201	191	181	223	193	254	226	297	264	347	306	284

Table B-2. Sample of annual outputs for selected years for the competition cases shown in Chap. 6

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Base case														
Revenues (million \$)	1,315	1,370	1,444	1,521	1,603	1,689	1,780	1,876	1,977	2,083	2,195	2,313	2,438	2,569
Price (¢/kWh)	7.36	7.51	7.75	8.00	8.25	8.52	8.79	9.07	9.36	9.66	9.97	10.29	10.62	10.96
Assets (million \$)	3,452	3,570	3,691	3,815	3,943	4,075	4,270	4,471	4,679	4,893	5,113	5,341	5,576	5,819
Net income (million \$)	164	163	169	178	182	184	185	182	188	195	202	209	217	225
Realized ROE (%)	10.71	10.33	10.37	10.54	10.44	10.21	9.84	9.26	9.14	9.04	8.96	8.89	8.83	8.79
Reported ROE (%)	10.71	10.33	10.37	10.54	10.44	10.21	9.84	9.26	9.14	9.04	8.96	8.89	8.83	8.79
Before tax interest coverage	2.83	2.76	2.77	2.80	2.78	2.74	2.68	2.58	2.56	2.54	2.52	2.51	2.50	2.50
Equity cash flow (million \$)	104	102	106	113	115	115	88	82	85	89	92	96	100	105
Purchased-power														
Revenues (million \$)	1,315	1,370	1,444	1,521	1,603	1,689	1,780	1,876	1,977	2,083	2,195	2,313	2,438	2,569
Price (¢/kWh)	7.36	7.51	7.75	8.00	8.25	8.52	8.79	9.07	9.36	9.66	9.97	10.29	10.62	10.96
Assets (million \$)	3,452	3,570	3,691	3,815	3,943	4,075	4,270	4,471	4,679	4,893	5,113	5,341	5,576	5,819
Net income (million \$)	164	163	169	178	179	183	187	188	194	201	208	215	223	231
Realized ROE (%)	10.71	10.33	10.37	10.54	10.23	10.17	9.97	9.55	9.42	9.32	9.22	9.14	9.08	9.03
Reported ROE (%)	10.71	10.33	10.37	10.54	10.23	10.17	9.97	9.55	9.42	9.32	9.22	9.14	9.08	9.03
Before tax interest coverage	2.83	2.76	2.77	2.80	2.74	2.73	2.70	2.63	2.60	2.59	2.57	2.56	2.54	2.54
Equity cash flow (million \$)	104	102	106	113	112	115	90	88	91	94	98	102	106	110
Gas														
Revenues (million \$)	1,315	1,370	1,444	1,521	1,603	1,689	1,780	1,876	1,977	2,083	2,195	2,313	2,438	2,569
Price (¢/kWh)	7.36	7.51	7.75	8.00	8.25	8.52	8.79	9.07	9.36	9.66	9.97	10.29	10.62	10.96
Assets (million \$)	3,452	3,592	3,742	3,913	4,038	4,167	4,359	4,557	4,761	4,972	5,190	5,414	5,647	5,886
Net income (million \$)	164	163	168	176	185	192	195	196	202	208	215	222	229	238
Realized ROE (%)	10.71	10.29	10.22	10.26	10.42	10.44	10.23	9.79	9.65	9.52	9.42	9.33	9.25	9.18
Reported ROE (%)	10.71	10.34	10.38	10.55	10.32	10.28	10.10	9.69	9.57	9.47	9.37	9.29	9.21	9.15
Before tax interest coverage	2.83	2.75	2.74	2.74	2.76	2.74	2.71	2.64	2.62	2.60	2.59	2.57	2.56	2.55
Equity cash flow (million \$)	104	89	81	68	119	124	99	96	99	102	105	109	113	117
Coal														
Revenues (million \$)	1,315	1,370	1,444	1,521	1,603	1,689	1,780	1,876	1,977	2,083	2,195	2,313	2,438	2,569
Price (¢/kWh)	7.36	7.51	7.75	8.00	8.25	8.52	8.79	9.07	9.36	9.66	9.97	10.29	10.62	10.96
Assets (million \$)	3,452	3,650	3,877	4,170	4,287	4,407	4,591	4,782	4,978	5,181	5,390	5,607	5,831	6,063
Net income (million \$)	164	162	166	171	178	189	193	194	201	208	216	225	235	245
Realized ROE (%)	10.71	10.16	9.84	9.56	9.52	9.83	9.69	9.35	9.28	9.23	9.20	9.21	9.22	9.24
Reported ROE (%)	10.71	10.34	10.39	10.57	9.20	9.29	9.26	9.00	9.01	9.03	9.04	9.07	9.10	9.13
Before tax interest coverage	2.83	2.73	2.67	2.61	2.56	2.54	2.54	2.50	2.50	2.51	2.51	2.51	2.52	2.52
Equity cash flow (million \$)	104	66	59	37	115	124	100	98	102	106	110	116	121	127

Table B-2. Sample of annual outputs for selected years for the competition cases shown in Chap. 6 - continued

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Renewables														
Revenues (million \$)	1,315	1,370	1,444	1,521	1,603	1,689	1,780	1,876	1,977	2,083	2,195	2,313	2,438	2,569
Price (¢/kWh)	7.36	7.51	7.75	8.00	8.25	8.52	8.79	9.07	9.36	9.66	9.97	10.29	10.62	10.96
Assets (million \$)	3,452	3,707	4,008	4,420	4,530	4,643	4,819	5,001	5,189	5,384	5,586	5,795	6,011	6,235
Net income (million \$)	164	161	163	166	179	195	199	200	208	215	224	234	244	255
Realized ROE (%)	10.71	10.04	9.49	8.93	9.16	9.70	9.60	9.29	9.26	9.24	9.25	9.30	9.35	9.41
Reported ROE (%)	10.71	10.35	10.41	10.59	8.67	8.83	8.89	8.73	8.81	8.90	8.98	9.06	9.15	9.24
Before tax interest coverage	2.83	2.71	2.60	2.49	2.46	2.44	2.45	2.43	2.45	2.47	2.48	2.49	2.51	2.52
Equity cash flow (million \$)	104	44	37	7	119	133	108	107	111	115	120	126	133	140
Renewables, 10% more expensive														
Revenues (million \$)	1,315	1,370	1,444	1,521	1,603	1,689	1,780	1,876	1,977	2,083	2,195	2,313	2,438	2,569
Price (¢/kWh)	7.36	7.51	7.75	8.00	8.25	8.52	8.79	9.07	9.36	9.66	9.97	10.29	10.62	10.96
Assets (million \$)	3,452	3,720	4,040	4,481	4,588	4,699	4,873	5,054	5,240	5,433	5,633	5,840	6,055	6,277
Net income (million \$)	164	161	163	165	176	192	197	198	205	213	221	231	242	253
Realized ROE (%)	10.71	10.01	9.41	8.78	8.89	9.48	9.38	9.09	9.06	9.05	9.07	9.13	9.20	9.27
Reported ROE (%)	10.71	10.35	10.41	10.60	8.36	8.54	8.62	8.48	8.58	8.68	8.78	8.88	8.98	9.08
Before tax interest coverage	2.83	2.70	2.59	2.46	2.41	2.39	2.40	2.38	2.40	2.42	2.44	2.46	2.47	2.49
Equity cash flow (million \$)	104	39	31	(0)	117	131	107	105	109	113	118	125	131	138
DSM														
Revenues (million \$)	1,315	1,354	1,403	1,437	1,516	1,600	1,688	1,781	1,879	1,982	2,091	2,205	2,326	2,454
Price (¢/kWh)	7.36	7.51	7.75	8.00	8.25	8.52	8.79	9.07	9.36	9.66	9.97	10.29	10.62	10.96
Assets (million \$)	3,452	3,694	4,018	4,499	4,606	4,716	4,890	5,070	5,256	5,448	5,648	5,854	6,068	6,290
Net income (million \$)	164	156	152	142	122	138	140	139	145	151	157	165	174	183
Realized ROE (%)	10.71	9.74	8.82	7.55	6.16	6.74	6.65	6.38	6.37	6.38	6.42	6.50	6.58	6.67
Reported ROE (%)	10.71	10.02	9.75	9.40	5.72	5.87	5.94	5.80	5.91	6.02	6.13	6.24	6.36	6.47
Before tax interest coverage	2.83	2.66	2.49	2.26	1.96	1.93	1.95	1.93	1.96	1.98	2.00	2.02	2.04	2.06
Equity cash flow (million \$)	104	49	32	(7)	66	80	53	50	52	55	58	62	67	72

Table B-2. Sample of annual outputs for selected years for the competition cases shown in Chap. 6 - continued

	2008	2009	2010	2011	2012	2014	2016	2018	2020	2022	2024	2026	2028	2029
Base case														
Revenues (million \$)	2,707	2,853	3,006	3,168	3,338	3,707	4,117	4,571	5,076	5,637	6,260	6,951	7,719	8,134
Price (¢/kWh)	11.31	11.67	12.04	12.43	12.83	13.66	14.55	15.49	16.50	17.58	18.72	19.94	21.23	21.91
Assets (million \$)	6,070	6,330	6,598	6,875	7,162	7,765	8,412	9,106	9,852	10,654	11,517	12,447	13,450	13,982
Net income (million \$)	234	244	254	264	275	300	327	357	390	428	469	515	566	594
Realized ROE (%)	8.76	8.73	8.72	8.71	8.72	8.75	8.80	8.88	8.98	9.10	9.23	9.38	9.53	9.62
Reported ROE (%)	8.76	8.73	8.72	8.71	8.72	8.75	8.80	8.88	8.98	9.10	9.23	9.38	9.53	9.62
Before tax interest coverage	2.49	2.49	2.48	2.48	2.48	2.49	2.50	2.51	2.53	2.55	2.57	2.59	2.62	2.63
Equity cash flow (million \$)	109	114	120	126	132	146	162	180	200	222	248	276	307	324
Purchase-power														
Revenues (million \$)	2,707	2,853	3,006	3,168	3,338	3,707	4,117	4,571	5,076	5,637	6,260	6,951	7,719	8,134
Price (¢/kWh)	11.31	11.67	12.04	12.43	12.83	13.66	14.55	15.49	16.50	17.58	18.72	19.94	21.23	21.91
Assets (million \$)	6,070	6,330	6,598	6,875	7,162	7,765	8,412	9,106	9,852	10,654	11,517	12,447	13,450	13,982
Net income (million \$)	240	250	260	270	281	306	333	363	396	434	475	520	571	598
Realized ROE (%)	8.98	8.95	8.93	8.92	8.91	8.93	8.97	9.03	9.12	9.22	9.34	9.47	9.61	9.69
Reported ROE (%)	8.98	8.95	8.93	8.92	8.91	8.93	8.97	9.03	9.12	9.22	9.34	9.47	9.61	9.69
Before tax interest coverage	2.53	2.52	2.52	2.52	2.52	2.52	2.52	2.53	2.55	2.57	2.59	2.61	2.63	2.65
Equity cash flow (million \$)	115	120	126	132	138	152	168	185	205	228	253	281	312	328
Gas														
Revenues (million \$)	2,707	2,853	3,006	3,168	3,338	3,707	4,117	4,571	5,076	5,637	6,260	6,951	7,719	8,134
Price (¢/kWh)	11.31	11.67	12.04	12.43	12.83	13.66	14.55	15.49	16.50	17.58	18.72	19.94	21.23	21.91
Assets (million \$)	6,134	6,391	6,656	6,930	7,214	7,811	8,452	9,140	9,879	10,675	11,532	12,456	13,453	13,982
Net income (million \$)	246	255	264	274	285	306	330	358	388	421	457	496	540	563
Realized ROE (%)	9.12	9.07	9.03	8.99	8.96	8.90	8.87	8.87	8.90	8.93	8.98	9.03	9.09	9.12
Reported ROE (%)	9.09	9.05	9.01	8.98	8.96	8.92	8.91	8.91	8.93	8.96	9.00	9.05	9.10	9.13
Before tax interest coverage	2.54	2.53	2.52	2.52	2.51	2.51	2.51	2.51	2.52	2.52	2.53	2.54	2.55	2.55
Equity cash flow (million \$)	122	126	131	137	142	154	166	181	198	217	237	259	283	296
Coal														
Revenues (million \$)	2,707	2,853	3,006	3,168	3,338	3,707	4,117	4,571	5,076	5,637	6,260	6,951	7,719	8,134
Price (¢/kWh)	11.31	11.67	12.04	12.43	12.83	13.66	14.55	15.49	16.50	17.58	18.72	19.94	21.23	21.91
Assets (million \$)	6,303	6,551	6,808	7,074	7,350	7,931	8,556	9,228	9,952	10,731	11,572	12,480	13,461	13,982
Net income (million \$)	256	267	278	291	304	329	357	391	430	472	519	570	627	657
Realized ROE (%)	9.26	9.29	9.33	9.37	9.42	9.43	9.48	9.63	9.80	9.97	10.16	10.35	10.54	10.64
Reported ROE (%)	9.18	9.22	9.27	9.33	9.39	9.52	9.64	9.77	9.91	10.07	10.23	10.41	10.59	10.68
Before tax interest coverage	2.53	2.54	2.55	2.55	2.56	2.60	2.63	2.65	2.68	2.71	2.74	2.77	2.81	2.82
Equity cash flow (million \$)	134	140	148	155	163	178	194	216	241	268	298	331	368	388

Table B-2. Sample of annual outputs for selected years for the competition cases shown in Chap. 6 - continued

	2008	2009	2010	2011	2012	2014	2016	2018	2020	2022	2024	2026	2028	2029
Renewables														
Revenues (million \$)	2,707	2,853	3,006	3,168	3,338	3,707	4,117	4,571	5,076	5,637	6,260	6,951	7,719	8,134
Price (¢/kWh)	11.31	11.67	12.04	12.43	12.83	13.66	14.55	15.49	16.50	17.58	18.72	19.94	21.23	21.91
Assets (million \$)	6,467	6,708	6,957	7,215	7,483	8,049	8,658	9,314	10,022	10,786	11,611	12,504	13,469	13,982
Net income (million \$)	267	279	292	306	320	345	373	410	451	496	545	600	659	692
Realized ROE (%)	9.47	9.54	9.61	9.68	9.76	9.77	9.81	10.01	10.22	10.43	10.65	10.87	11.09	11.20
Reported ROE (%)	9.33	9.43	9.52	9.62	9.72	9.92	10.08	10.24	10.42	10.60	10.78	10.98	11.17	11.27
Before tax interest coverage	2.54	2.55	2.57	2.58	2.60	2.65	2.70	2.73	2.76	2.80	2.84	2.87	2.91	2.93
Equity cash flow (million \$)	147	155	163	172	181	196	212	237	263	293	326	362	402	424
Renewables, 10% more expensive														
Revenues (million \$)	2,707	2,853	3,006	3,168	3,338	3,707	4,117	4,571	5,076	5,637	6,260	6,951	7,719	8,134
Price (¢/kWh)	11.31	11.67	12.04	12.43	12.83	13.66	14.55	15.49	16.50	17.58	18.72	19.94	21.23	21.91
Assets (million \$)	6,507	6,746	6,993	7,249	7,515	8,077	8,683	9,335	10,039	10,799	11,621	12,509	13,471	13,982
Net income (million \$)	265	277	290	303	318	342	370	407	448	493	543	598	658	690
Realized ROE (%)	9.34	9.41	9.49	9.58	9.66	9.67	9.71	9.93	10.15	10.37	10.60	10.83	11.06	11.17
Reported ROE (%)	9.18	9.29	9.40	9.51	9.62	9.83	10.01	10.18	10.36	10.55	10.75	10.95	11.15	11.25
Before tax interest coverage	2.51	2.52	2.54	2.56	2.57	2.63	2.68	2.72	2.75	2.79	2.83	2.87	2.91	2.92
Equity cash flow (million \$)	146	154	162	171	180	194	210	235	262	292	325	361	401	423
DSM														
Revenues (million \$)	2,588	2,730	2,880	3,037	3,203	3,563	3,964	4,408	4,903	5,452	6,063	6,741	7,496	7,904
Price (¢/kWh)	11.31	11.67	12.04	12.43	12.83	13.66	14.55	15.49	16.50	17.58	18.72	19.94	21.23	21.91
Assets (million \$)	6,519	6,757	7,004	7,260	7,525	8,086	8,690	9,341	10,044	10,803	11,624	12,511	13,472	13,982
Net income (million \$)	192	202	213	224	236	255	277	308	343	381	424	471	522	550
Realized ROE (%)	6.76	6.86	6.95	7.05	7.15	7.19	7.26	7.50	7.75	8.01	8.27	8.52	8.78	8.91
Reported ROE (%)	6.59	6.71	6.83	6.95	7.07	7.32	7.53	7.74	7.96	8.18	8.41	8.64	8.88	9.00
Before tax interest coverage	2.07	2.09	2.11	2.13	2.15	2.21	2.27	2.31	2.35	2.39	2.44	2.48	2.52	2.54
Equity cash flow (million \$)	77	83	89	96	103	111	122	141	162	186	212	241	273	291

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