EDISON ELECTRIC INSTITUTE

Building Sustainable Efficiency Businesses

Evaluating Business Models

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I. Executive Summary

This report documents the results of the EEI Efficiency Business Models Project, which was undertaken to help members develop new efficiency businesses by illustrating how to evaluate the rate and financial impacts of alternative business models.[1]

Chapter II, *Introduction*, provides context for the discussion of efficiency business models. It explains why rapid, cost-effective efficiency improvement has become a critical priority for the industry and the Nation; namely, because we must reduce carbon emissions, while mitigating the impact of rising rates on consumers and the financial risks associated with massive new infrastructure spending. Chapter II also examines why regulated utilities are uniquely positioned to move electricity markets for rapid efficiency improvement. The reasons are several, including the long-standing relationships of trust that utilities have with their customers, utilities' ability to realize large economies of scope and scale in the delivery of efficiency, and utilities' access to capital on terms that allow longer time horizons for investments compared to other market participants. To bring these strengths fully to bear, utilities need to pursue efficiency on a sustainable business basis. Chapter II closes with four criteria for a sustainable utility efficiency business: (1) well designed and properly funded efficiency programs, which serve the public interest by being cost-effective and applicable to broad classes of customers; (2) timely recovery of efficiency program costs; (3) being kept whole for fixed network costs as power sales volumes decline; and (4) having the ability to earn a profit margin on efficiency products and services.

Chapter III, *Evaluating Alternative Business/Incentive Models*, describes four business models representative of those that state regulators and energy policy makers have approved or are currently considering. The four models, along with simplifying assumptions, have been used to simulate rate and financial impacts. A business model covers both a shareholder incentive mechanism and a complementary approach to recovery of efficiency program costs and, perhaps, lost fixed revenues.[2]

The four business models are as follows:

1. The *Shared Savings Model*, in which the utility deploys efficiency measures and earns a pre-determined share of the <u>net</u> value of the lifetime energy and capacity avoided cost savings, measured after the cost of the utility program and the full cost of the installed measures are deducted. The valuation of avoided costs and the verification of the efficiency savings that give rise to them are important aspects.

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[1] By "efficiency" we mean initiatives to save both energy (kWh) and capacity (kW), that is, energy efficiency programs and demand response programs. One traditional term for this inclusive set of utility programs is "demand side management."

[2] As discussed below, in the first two models, *Shared Savings* and *Capitalization/Bonus Return on Equity*, the utility is assumed to be fully reimbursed for all of its direct costs of implementing the efficiency programs through the use of a tracker/rate adjustment mechanism. In the next two models, *Virtual Power Plant* and *Regulated Energy Service Company*, there is no regulator-approved cost recovery, but rather an opportunity for the utility to generate sufficient revenues to recover direct costs. In some of the models the utility is also reimbursed for the lost fixed revenues from MWh sales reductions, through the use of a recovery mechanism. As discussed below, these two cost recovery issues are important financial considerations, somewhat independent of the shareholder incentives.

2. *The Capitalization/Bonus Return on Equity Model*, in which the utility deploys efficiency measures, and capitalizes (i.e., puts into rate base) program costs, including the cost of incentives paid by the utility to defray customers' installation costs. The utility earns its nominal allowed return, plus a premium return (e.g., 500 Basis Points or 5 percent) on the equity portion of its efficiency regulatory asset.
3. *The Virtual Power Plant Model*, in which the utility is awarded a revenue stream on a pre-determined portion (e.g., 85 percent) of the total avoided costs of capacity and energy for actual savings achieved over the life of the programs. The utility does not separately recover any efficiency program costs. As in a competitive business, all the direct costs to the utility in program overheads, external contractors, and incentive payments to participants must be charged against revenues.[3]
4. *The Regulated Energy Service Company Model*, in which contracts are negotiated with each participating customer. The utility recovers its costs, plus a return, solely from the electric bill savings that are realized by those customers. In practice, this kind of contracting has been used primarily by utilities implementing efficiency retrofits for institutional customers (e.g., schools or government facilities).

The common modeling and assumptions framework used to simulate the rate and financial impacts of all four of these business models is described in Section III.B. This framework is based on a simplified prototype utility and its financial performance baseline and on a prototypical large scale efficiency program.[4] The common modeling framework and simple assumptions help to communicate the essential differences of the models by isolating the differing impacts of the four incentive approaches on the equity earnings, average rates, timing of cash flows, and other financial outcomes. This is a fertile and evolving policy area, and no claims are made that these models exhaust the possibilities for shareholder incentives and cost recovery.

Section C, Analytic Results, and Section D, Conclusions, describe the results obtained, and their provisional interpretations. **We emphasize that our results are generic in nature**, reflecting a uniform efficiency program and a simplified, uniform utility. In practice, different utilities will deploy different technologies and programs; and different utilities will have different cost structures, and different degrees of financial strength. **Our central purpose has been to provide guidance to EEI members in developing their own, utility-specific simulations. Our results are illustrative, not definitive.** With this caveat in mind, and viewing our results as indicative of the kinds of insights that can be obtained from such simulations, our results show that all of the models can work and be successful.

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[3] The Virtual Power Plant model is based on the Duke "Save-a-Watt" model, but does not attempt to fully replicate all of its features. Particularly, the VPP model does not adjust the stream of revenues based on avoided cost savings closer to the early years of heavy program spending. See *Testimony of Stephen M. Farmer for Duke Energy Carolinas*, before the Public Service Commission of South Carolina, Docket No. 2007-358-E, Dec. 10, 2007.

[4] The efficiency program is modeled for five years and the efficiency measures installed each year reduce energy consumption for the succeeding 10 years, creating a total period of 14 years over which to evaluate the financial and rate impacts. In all long-term utility planning models, there are "end of period" model impacts that must be dealt with in some reasonable and transparent fashion. We recognize that a utility will not actually stop its efficiency spending in the sixth year, so its savings impacts will *not* stop in the fifteenth year. However, we put those valid planning concerns to the side, so as to accomplish our goal—to isolate the comparative impacts over time of the four business models.

The Shared Savings Model has larger up-front rate impacts, which stem from the way costs and profits are recovered. Efficiency program costs are assumed to be expensed[5] and lost fixed revenues are assumed to be recovered via annual prospective rate adjustments.[6] After the costs are recovered in the last efficiency program year, efficiency benefits continue, so rates tend to fall. The shareholder incentive is determined at the end of each year's program, as a share of the present value of net avoided cost savings for ratepayers. The before-tax incentive is then collected in two installments: one part in the year after each basis, which is important to investors, and another five years later.[7] The utility positive cash flows tend to be earlier for the utility and its investors for the same reasons. Assuming the shareholder savings share is between 10 percent and 30 percent, this is a reasonable return that leaves the customers with a significant share of the savings. The risks are relatively low for shareholders, if programs are pre-approved after passing cost-effectiveness tests.[8]

The Capitalization with Bonus Return on Equity (ROE) Model moderates the upfront rate impacts to a degree by amortizing the cost recovery over a period of five years. The cash flows are also somewhat delayed. With direct efficiency costs (excluding what participants pay) financed by the utility, the shareholders earn both the allowed rate of return and the bonus rate of return, which flow to the bottom line. The former amount is considered by some to be just recovering the cost of capital. However that is viewed, the bonus is a clearly a shareholder incentive. The bonus incentive may or may not be tied to avoided cost savings or other targets.[9] The utility positive cash flows are later than in the Shared Savings model and therefore the model may have some minor impact on cash flow and credit metrics in early years of the program.

The Virtual Power Plant (VPP) Model has a different risk and reward structure. The utility collects revenues based strictly on the achieved stream of avoided cost savings to the customers. The utility waives the right to collect any costs incurred in implementing the efficiency programs, much like a competitive business. Thus, the utility bears the entire additional cost incurred in implementing a larger, more aggressive efficiency program. At the same time, the utility retains a greater share of the net benefits for each additional dollar of avoided cost created for a given expenditure of money. The utility has a strong incentive to pursue all cost-effective efficiency for its customers. One effect is to smooth the impact on rates, with smaller impacts in the beginning, but rate increases that last as long a period of time as the savings impacts last.[10]

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[5] Shared savings shareholder incentives and the expensing of efficiency program costs are separate policies. We assume that they are both part of the Shared Savings Model, but other assumptions could be made about cost recovery.

[6] The treatment of lost fixed revenue is a key determinant of rate and financial impacts. Our simulation of the Shared Savings Model is based on practices in California, which include revenue decoupling. Nevertheless, the Model can be implemented without decoupling. In South Carolina, for example, a shared savings model has been implemented that relies on explicit recovery of lost fixed revenues.

[7] This is consistent with the practice in California, where part of any shareholder incentive earned is held back for a period of time to allow the conduct of measurement and evaluation studies of the efficiency impacts.

[8] The model assumes perfect ratemaking and does not attempt to model any specific jurisdiction's decoupling or recovery mechanisms. In practice, the details of such mechanisms will impact the risks inherent in each of the models discussed.

[9] With some modifications, the models could be used to compare differences between planned efficiency results and actual results, and the many interesting issues therein. That is not part of this research effort.

[10] This follows from our assumption that the utility payment stream is directly tied to the avoided energy and capacity cost streams, which in turn are tied to the kWh and kW savings streams over the lifetimes of the efficiency measures. As proposed in South Carolina, the model adjusts revenues and expenses to move them forward in time, so that rate impacts are like those of a power plant (except smaller).

The Regulated Energy Service Company (ESCo) Model is supported and paid for entirely by the participants. These participants are likely to have much longer paybacks than participants in the three business models discussed above. Nonetheless, where the Regulated ESCo is successful for the institutional customer segment, the rate impacts are neutral or rate reducing throughout the program period of fifteen years. The cash flow is moderately negative in early years, with recovery limited by how large the bill savings are and desire for the participant to share in the savings. The profit level is generally moderate, since this is a competitive business where the Regulated ESCo may be competing against a variety of vendors of efficiency measures.

Our generic simulations lead to the following illustrative conclusions. Companies with more desire to get pre-approval of efficiency programs and cost recovery, and less capacity for absorbing risk, may want to look at rate basing and/or shared savings approaches. Companies with more ambitious plans for efficiency, and a greater willingness (and ability) to take on risk for more potential return, may wish to consider a more aggressive model such as the Virtual Power Plant. The Regulated ESCo is a proven model for a limited, niche market. Its attractiveness depends on how many institutional customers are being served (schools, hospitals, government, etc.).

Because cash flow patterns and the potential impact on creditworthiness may differ across these efficiency business models, utilities will want to evaluate alternative models in the context of their own systems and circumstances.[11] The generic tool EEI is providing to its members is a good starting point for such analysis. The place to start is the assumptions used to define the prototypical utility and the prototypical efficiency program. Members should test key assumptions, modifying and extending them as needed to reflect their particular circumstances.

Chapter IV, *Appendix*, contains the User Guide for the Excel template that was used for generic simulations discussed in the report. This User Guide includes descriptions of all inputs and the illustrative input data sets. The user can select new values for key parameters of any of the business models and observe the sensitivity of the results change.

[11] We reiterate that the models do not necessarily follow any one specific jurisdiction's regulatory rules or potential rules.

II. Introduction

The EEI Efficiency Business Models Project was undertaken to help members develop new efficiency businesses. It was based on the premises (1) that investor-owned electric utilities need to accelerate and expand efficiency activities, and (2) that such activities need to be pursued on a sustainable business basis. The Project focused on simulating the rate and financial impact of alternative business/regulatory incentive models, because such simulations are important to the development of effective business and regulatory strategy. Members need to perform their own, system-specific simulations in order to have confidence in the results, and the Project provides valuable guidance by developing generic tools and presenting illustrative analyses.

A. Strategic Context

To fully appreciate the need for increased energy efficiency within the electric sector, it is instructive to review the multiple factors shaping the operating, financial, and regulatory environments of investor-owned electric utilities. There are huge challenges involved in building needed new infrastructure in a rising cost environment, meeting mandatory reliability standards, and grappling with global climate change. Chief among these is the need to mitigate impacts on consumers. Increasing cost effective energy efficiency is one action that addresses all of these objectives.

Nationally, the demand for electricity has been growing at a long term rate of about 2.8 percent a year (Figure 1). Without either new capacity or slower growth, the reserve margins in most regions of the U.S. will fall below target reliability levels within just a few years (Figure 2). Thus, the U.S. Energy Information Agency (EIA) projects that about 171,000 MW of new generating capacity will be needed through 2030.[12]

In meeting these needs, utilities and other suppliers face new and unprecedented environmental challenges. Climate change is an issue of global proportions, which seems likely to become a perennial concern for utility planners. EEI members recognize the need to do even more than they already have to reduce greenhouse emissions.[13] We must maximize cost-effective energy efficiency to slow electricity growth, and we must develop and deploy new, low-carbon technologies and fuel cycles.[14]

Unfortunately, commercially available generating technologies all have significant uncertainties and limitations. For example, among clean/advanced coal technologies, ultra-supercritical pulverized coal technology has not been demonstrated on U.S. coals, and vendors of integrated gasification combined cycle (IGCC) technology will not warranty the performance of an entire IGCC system. More advanced carbon capture and storage technologies are not expected to be commercial until 2020–2025. Third generation nuclear designs are available now, but given the lead times to permit and build new plants, nuclear generation cannot make a significant contribution until after 2015 at the earliest. And gas-fired generation entails significant fuel risk. There is no ideal, or unambiguously best, technology for supply projects that need to be started today.

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[12] U.S. Energy Information Administration, *Annual Energy Outlook 2008*.

[13] Since 1994, when EEI jointed the U.S. Department of Energy in the Climate Challenge, the electric utility has led all other industrial sectors in reducing greenhouse gas emissions.

[14] *EEI Global Climate Change Principles*, February 8, 2007.

Utilities must also take account of new financial issues. Creditworthiness among investor-owned electric utilities has declined over the last decade, and investors perceive new risk in terms of challenges to the industry's ability to recover new capital investments fully with minimum delay. The average utility credit rating declined from A- in 1997 to BBB in 2007[15] (Figure 3). New infrastructure spending can be expected to put additional pressure on utility credit ratings, because some on Wall Street expect regulatory lag to depress realized returns.[16]

The impact of rising electric rates on consumers is another critical aspect of utility strategy. Residential rates among U.S. investor owned electric utilities rose 26 percent between 1999 and 2006,[17] driven largely by increases in fuel prices.[18] This is a national average; in some regions, such as New England, the increase was much higher. As we look ahead, infrastructure spending is likely to drive further increases. Rate increases of this magnitude are very difficult for some customers to absorb and, even where low income programs are available, are likely to produce political pushback and risk a regulatory response.

For all of these reasons, increased efficiency has become a high priority for EEI members. Increased efficiency can first and foremost slow the growth in electric demand. This means that customers participating in energy efficiency programs will see their bills decline. Lower growth will reduce and defer needed new investments, lessening the impact of rate increases on consumers and mitigating the financial risks borne by utilities and their investors. Slower demand growth also can reduce carbon emissions and buy time for the development of better generating technologies. Increased demand response, an important part of efficiency, can cost-effectively reinforce grid reliability in regions whose reserve margins are too low.

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[15] Edison Electric Institute classifies IOUs with at least 80 percent of their assets subject to regulation as "Regulated," IOUs with 50 to 79 percent of their assets subject to regulation as "Mostly Regulated," and those with a lower percentage of regulated assets as "Diversified." Figure 3 reflects data for Regulated and Mostly Regulated IOUs, so at least 50 percent of the utilities' assets are subject to regulation, with the average IOU having approximately 83 percent of its assets subject to regulation. See Edison Electric Institute, Stock Performance, Q3, *2007 Financial Update*. The fourth quarter of 2007 saw more downgrades than upgrades within the Regulated and Mostly Regulated segment of the IOUs. See EEI, Q4, 2007 CreditRatings Q4, 2007 Data. Using EEI's Q4, 2007 data, the average credit rating for Regulated electric utilities is a little above BBB, the average for Mostly Regulated IOUs is a little below BBB and the average for Diversified is very close to BBB.

[16] See Lehman Brothers, *Power & Utilities: Capital Complications,* May 22, 2007.

[17] EEI, *Typical Bills and Average Rates Report*,. The average unit revenue for residential customers rose 26 percent. The average unit revenue for all end-use customers rose 32 percent.

[18] The Brattle Group, *Why Are Electricity Prices Increasing?*, prepared for EEI, June 2006.

Figure 1: Electricity Demand

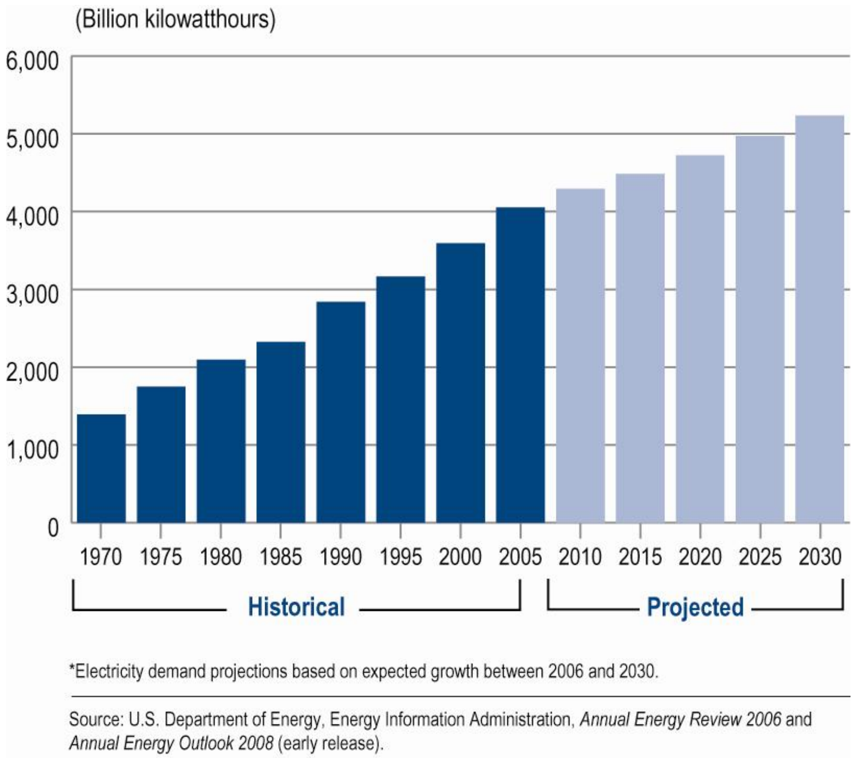


Figure 2: Electricity Supply Margins Projected to Fall Below Minimum Target Levels In Some Areas of North America

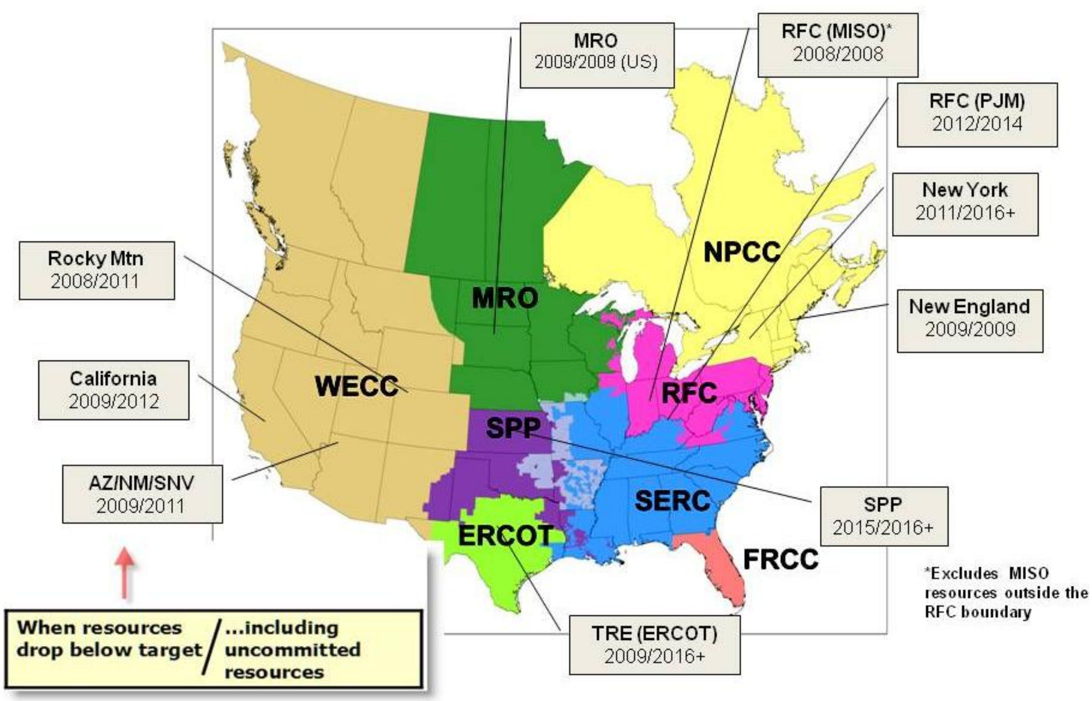
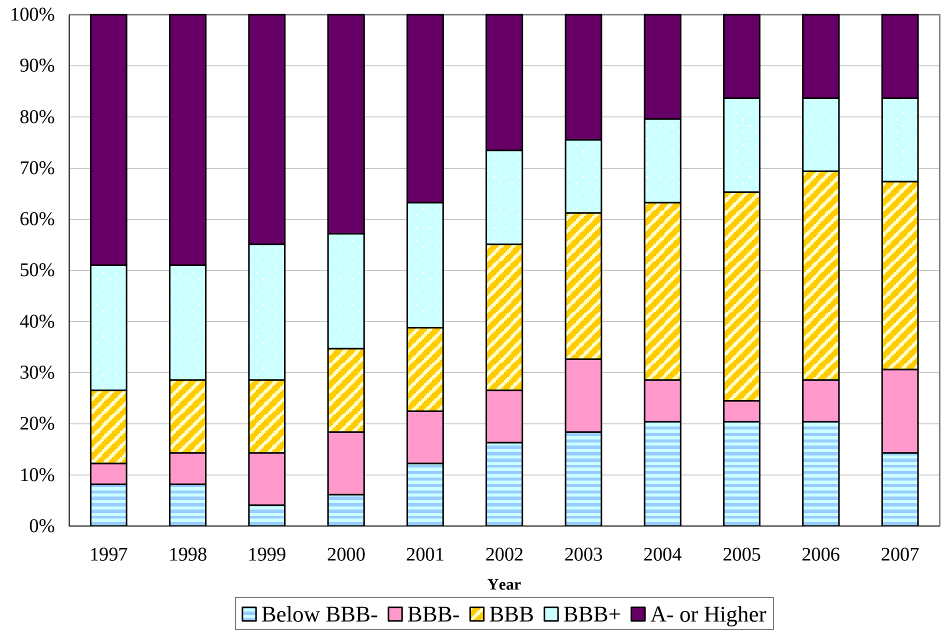


Figure 3: S&P Bond Ranking for Regulated and Mostly Regulated Electric Utilities



Source: Bloomberg and EEI.

B. The Role of the Electric Utility

Given the urgent need to accelerate efficiency improvement, utilities must renew their commitment to programs and activities which help customers reduce electricity consumption overall and particularly on-peak demand during the 100 or so hours of extreme peak demand each year. Utilities are uniquely positioned to move the market, and they must leverage their inherent strengths to help achieve rapid efficiency growth. These strengths include, among others, the potential for large economies of scope and scale. *Scale* economies are cost reductions achieved by serving larger number of customers and are particularly relevant when serving mass market customers. *Scope* economies are savings realized by providing multiple products and services and sharing the required resources (inputs) within one firm. The potential for scope economies in the supply of energy efficiency products and services becomes apparent when we consider that utilities already do load research, rate design, metering, billing, customer interface processes, and maintain customer information systems. The design, delivery, and verification of energy efficiency involves many of these same functions and skills.

Utilities also have long-standing relationships with customers, and are generally trusted as a source of reliable, expert knowledge about energy subjects. This means that consumers may listen more readily to utility explanations and recommendations than to other, unknown entities.

In addition, utilities frequently operate with a lower cost of capital than do their customers or third party efficiency suppliers. This means that utilities can help consumers finance new, more efficient equipment at lower cost. Utilities also can accept longer time horizons for project payback than can other suppliers. This reinforces the consumer benefits of a lower utility cost of capital (relative to what the customer would pay for capital) and means that utilities can structure more attractive efficiency investment opportunities for consumers.

For all of these reasons, utilities must enlist (and must be enlisted) in the campaign to increase energy efficiency in the electric sector.

C. Criteria for Sustainable Efficiency Businesses

New regulatory policies are needed if utilities are to maximize the potential for rapid efficiency improvement. This is because cost of service regulation, as traditionally practiced, creates a conflict of interest for utilities (i.e., between their service obligations to the public and their fiduciary obligations to shareholders). Fortunately, it is possible to adjust the cost of service framework to align customer and shareholder incentives for aggressive efficiency development. Strategies for doing so should be guided by the following four criteria:

1. **Public Interest**—Sustainable energy efficiency programs must meet the expectations of regulators and customers. This can be achieved by designing and implementing portfolios of energy efficiency programs that are well designed and cost-effective and offer efficiency opportunities for all classes of customers. Cost-effectiveness is measured by a standard series of benefit-cost tests, namely, the Total Resource Cost Test, the Participant Test, and the Rate Impact Measure (RIM) Test (see Appendix).

2. **Program Cost Recovery**—The utility needs to recover its efficiency program spending in a timely fashion (e.g., through a demand side management (DSM) tracker, an approved balancing account to be capitalized, or another similarly reliable treatment). Without timely and/or assured cost recovery, any significant increase in efficiency program spending will depress financial performance between rate cases.

3. **Lost Fixed Cost Recovery**—The utility needs to remain whole for the fixed costs that are lost as its volumetric charges go down with efficiency improvements. The more aggressive the efficiency improvement, the greater the loss of fixed costs embedded in volumetric (kWh-based) rates. This can cause shareholders to earn substantially less than their "allowed" return. Decoupling is one way to avoid this problem, although it is not the only way. Reduced reliance of volumetric (kWh) rates to recover fixed costs can achieve the same thing.

4. **Earning a Profit Margin for the Shareholders**—The utility also needs to be able to make a margin on successful implementation of efficiency products and services. This is critical to building a sustainable business. If the Commission agrees to a mechanism for earning a reasonable return (after-tax) for excellent efficiency performance, management will focus on efficiency as a high priority and Wall Street will be less vocal about the lost opportunities to invest in "steel in the ground."

It may not be necessary to include explicit regulatory and rate mechanisms to address each of these each criteria. Dollars are fungible and multiple approaches are possible. Nevertheless, we do believe that sustainability will require these criteria to be satisfied.

D. The EEI Energy Efficiency Initiative

The EEI Energy Efficiency Initiative was organized in the fall of 2006 to address the need to increase energy efficiency in markets served by investor-owned electric utilities, in ways that are cost-effective. Endorsed by the EEI Board of Directors in September 2006, the Initiative is being implemented under the strategic direction of a Task Force of member company CEOs, with day-to-day guidance provided by a Project Review Team of senior executives. (See Appendix A for a list of Task Force and Project Review Team members.) The Initiative is made up of five inter-related action plans, as follows:

1. **Innovative Rate Designs and Regulation**—Which focuses on the need for rate designs that encourage efficient consumption and investment and on new business and regulatory models that will allow utilities to build sustainable businesses delivering efficiency products and services.

2. **Advanced Metering and Infrastructure (AMI)**—Which aims to accelerate the deployment of new metering and related technologies. AMI is needed to support demand-response, the process by which retail consumers adjust their consumption in response to varying short-term price signals. It offers potentially large benefits in terms of reduced peak demand, reduced wholesale power prices, reduced utility operating cost, increased system reliability, and improved service quality.

3. **Smart and Efficient Buildings**—Which aims to increase the efficiency and responsiveness of new and existing buildings by adopting new building codes, expanding the availability of related tax incentives, and raising public awareness of EEI member efficiency programs for residential and commercial buildings.

4. **Smart and Efficient Appliances**—Which aims to increase the efficiency of end-use appliances by adopting new appliance standards, expanding the availability of related tax incentives, and raising public awareness about related member programs.

5. **Plug In Hybrid Electric Vehicles (PHEV)**—Which seeks to support the successful introduction of a PHEV by 2010 by advocating for related legislative and regulatory incentives. (PHEVs are next-generation hybrids that carry a larger battery and so reduce emissions further than today's hybrids.)

This report addresses the first action plan.

III. Evaluating Alternative Business and Incentive Models

EEI members need to take the lead in developing new regulatory policies for sustainable efficiency development. They can do this by filing specific proposals with their commissions. Before they do that, however, we expect they will want to simulate alternative business/regulatory models so they can understand their financial and rate implications. Such simulations can provide an analytic framework for selecting/configuring business models and for developing overall efficiency strategies. They are an essential first step. In this section we describe how to simulate a representative set of business models, using an analytic framework composed of simplified assumptions regarding the utility, the efficiency program, avoided costs, and lost fixed revenues. The framework is implemented in an Excel spreadsheet.

Each business model starts by addressing the classic "disincentives" utilities have to pursuing an enhanced efficiency business, namely:

- Difficulty in getting timely and assured recovery of program costs.
- Financial consequences from loss of fixed revenue recovery from sales reductions that stem from efficiency enhancements.

Each then integrates a positive shareholder incentive for making efficiency a profitable business. Table 1 shows the key features of each model. With the right efficiency programs and appropriate regulatory policies, each model can be a sustainable business for an electric utility.[19]

Table 1: Assumed Treatment of Disincentives and Incentives in Four Business/Incentive Models

Business Model	Recovery of Program Costs	Recovery of Lost Fixed Revenues	Positive Shareholder Incentive
Shared Savings	Recovered annually in Cost Tracker	Recovered annually with LFR Tracker	12% Share of PV of Net Avoided Costs
Capitalization with Bonus RoE	Recovered over time in a Cost Tracker as a capitalized Regulatory Asset	Recovered annually with LFR Tracker	500 Basis Point Bonus amd Allowed Return on Equity for the Regulatory Asset
Virtual Power Plant	No direct recovery. Opportunity in the specific business model	Assumed to not be recovered	Opportunity to collect 85% of Total Avoided Costs
Regulated ESCO	No direct recovery. Opportunity in the specific business model	Recovered Annually with LFR Tracker	Profit in contract after amortized. full cost recovery

[19] While the four incentive approaches are broadly representative of the best efficiency policies in place or being actively pursued in the U.S., there are other variations and models in this fertile area of efficiency policy, so this analysis does not exhaustive the possibilities.

It should be noted that this is how we simulated each model. Of course, other configurations are possible.

The economic benefits of efficiency are composed of the future streams of avoided costs of generating capacity, fuel and other variable costs, and avoided transmission and distribution investments. These benefits come from the reduced kWh and kW and can be anticipated to last over the economic lives of the efficiency measures (high efficiency A/C, motors, lighting, etc.) installed by participants in the efficiency program. In a real application, the avoided cost benefits would come from the utility resource planning process and reflect the characteristics of the particular utility situation. As discussed above in Chapter II, avoided costs are now expected to be increasing because the rising worldwide demand for steel, copper, oil, and other commodities have driven prices of generating capacity and fuel to historic levels.

Against the economic benefits, there must be netted all of the economic costs. These consist of real resources the utility uses in administering and running the programs, as well as the full installed costs of the efficiency measures at the customers' premises. The loss of fixed revenue in base rate when kWh sales fall can be a significant cost to the utility if not ameliorated. Part of the installed or first cost to the participant is often covered by the utility's payment of customer rebates and incentives. We are careful not to double count any incentives paid by the utility. Various net economic benefit measures are developed from the perspectives of society, the participants and the utility in terms of rate impacts. Since benefits, costs, and net benefits are spread over time in different ways, they are evaluated on a present value basis, using an appropriate interest rate that is normally the utility cost of capital.

A. The Incentive Models

1. The Shared Savings Model

The Shared Savings approach starts with the calculation of the gross economic benefits of an energy efficiency (EE) program, determined as the present value of the avoided energy and capacity costs savings coming from load (MW) and sales (MWh) reductions over time. To get net economic benefits, there is a deduction of the total economic costs of the program, consisting of both the utility resources spent in planning and implementing, plus the total installed cost of the efficiency measures (without double counting the utility incentives paid to participants).[20] Shared savings means the utility is allowed to earn a certain percentage of the total net benefits from the EE program. We use the 12 percent share that is currently allowed in California, but this is a user choice in the model. The reward (incentive) may be structured to flow to the utility in a single year or over multiple years. In terms of timing for the incentive collection by the utility, we assume that for each year's program the utility is allowed to recover 70 percent of the incentive in each year of the program after the year is complete (that is, the second through sixth years). The remaining

[20] This is done on a present value basis if the costs are incurred over time, such as in our example of a five-year program. California actually evaluates EE programs on both an annual and three-year cycle basis, for purpose of its shared savings incentive.

30 percent of the 12 percent incentive each year is recovered five years later, in the seventh through eleventh years of the program.[21] In this approach, we also assume that the utility is separately made whole financially by allowing it to expense all program costs and to recover all lost fixed revenues.[22]

2. The Efficiency Capitalization / Bonus ROE Model

Under the second approach, avoided cost benefits are not the starting point, but cost recovery is. The sum of the program administration costs and the utility's portion of the installed measure costs (total cash incentives given out by the utility to increase participation) is capitalized and recovered over a regulatory-approved amortization period. The costs of the efficiency program are treated as an investment, similar to a power plant or substation, and turned into a regulatory asset. The utility must finance this regulatory asset over the amortization period,[23] so the utility will need to recover its cost of capital, including the income taxes owed on the equity return. In addition to the cost of capital, the bonus ROE comes from the Commission approving an additional, annual return on only the unamortized equity portion. Following the precedent in Nevada, this bonus is set at 5 percent or 500 basis points. Moreover, the utility is modeled as recovering its lost fixed revenues.

It should be noted that the length of time over which the capitalized investment is recovered and the magnitude of the bonus return have some effect on the utility's net present value and the customer costs. We assume that this amortization period is four years.[24] Moreover, we assume that lost fixed costs are recovered in rates, modeled as an annual rate rider. Our model's capitalization approach does not deal with the net economic benefits directly. In principle, this is consistent with whatever policy a state would adopt in determining that DSM costs are prudent expenditures and should be given a shareholder incentive.

3. The Virtual Power Plant Model

Under the innovative Virtual Power Plant incentive approach, there is a different risk and reward structure, combining elements of competitive marketing and avoided costs valuation. The utility collects revenues that are set at a fraction of the stream of total avoided cost savings realized through its efficiency activities. Following a current proposal in a VPP proceeding, we set this parameter at 85 percent.[25] The unit avoided costs per kWh and kW are fixed in advance by regulation. The kW and kWh savings realized are based on

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[21] This has been an active area of policy making for the California Public Utility Commission (CPUC) and its Shared Savings incentive. Our model is consistent with the policy, (although in CA the 70 percent has been now changed to 65 percent). This issue is really about so called *ex ante* results determined immediately after the program year is closed and the earnings booked thereon, and the *ex post* results after measurement and evaluation has been completed and whether prior earnings are at risk. These are important shareholder incentive issues, but beyond the scope of this report. See CPUC, *Interim Opinion on Joint Petition for Modification of Decision 07-09-043*, in Rulemaking 06-04-010, Jan. 31, 2008.

[22] This is the case in California, with its strong policy for efficiency. There is no necessary connection, and other states with shared savings incentives may not allow one or the other cost recovery.

[23] The four-year lag is another model user choice. Nevada currently uses three years, but formerly used from three to six years.

[24] Nevada and the Public Utility Commission of Nevada (PUCN) are pioneers in developing the Bonus ROE approach and use a version wherein the amortization period has been longer in the past, but is currently set at three (3) years. Moreover, the policy providing a bonus ROE of 500 basis points or 5 percent is has been reaffirmed in a recent PUCN decision.

[25] This VPP approach has not yet received regulatory approval, despite its very high visibility. The proceeding in South Carolina may the first place it is approved, although Duke is pursuing it in all five of its state retail jurisdictions.

best practices in measurement and evaluation of efficiency programs. With that potential revenue stream as its "objective function," the utility waives the right to collect any costs incurred in implementing the efficiency programs. Much like a competitive business, it is then up to the utility to use good technical advice and marketing to get efficiency measures installed as extensively and as cheaply as possible.

We model the future revenue stream as having the same duration as the kWh and kW savings streams, which are determined by the kinds of programs and measures that are successfully pursued. This makes the utility cash flow picture somewhat backloaded, since costs generally come up front.[26] The customers benefit from paying only their portion of the efficiency measure installation costs, and then saving the remainder of the total avoided cost of supply.[27] The utility is modeled herein as recovering <u>no</u> lost fixed revenues or costs.[28]

4. The Regulated ESCo Model

The final shareholder incentive is different in one essential way. General rates are not used to collect any part of the program costs or shareholder incentives, as they were in all three approaches discussed above. Here, a regulated energy services company (regulated ESCo), on behalf of its parent utility, will design and implement the efficiency program solely through shared savings contracts with the individual participants.[29] We model the efficiency measures, after contracts get participant approval, as being paid for and financed by the utility.

All of the parameters of the savings stream are set in the contract. By virtue of the reduction in kWh and kW usage, the participating customer will have gross bill savings over the lifetime of the measures. Within the contract relationship, the utility recovers its costs from those gross bill savings. The utility incurs its cost of capital in financing the EE investment, similar to the capitalization approach, but over a period determined in the contract. In the Regulated ESCo incentive model, there is a profit margin, but it is not set in terms of a regulated bonus ROE of 5 percent. Rather, the profit margin comes out of sharing the gross bill savings. In our model, the specific contract allows the utility to retain 90 percent of bill savings until all of the amortized costs, including just the cost of capital, are fully paid off. Then the utility continues to collect 10 percent of savings for the rest of the life of the measures. The present value of this 10 percent is the shareholder incentive. Finally, we model the Regulated ESCo incentive as involving the annual recovery of Lost Fixed Revenues. This could be modeled differently with <u>no</u> recovery of lost revenues, since this a business model that is pursued largely outside the regulation of the state. The user can change our assumption by resetting lost fixed revenue, or rate case parameters.

There are many different ways to structure ESCo contracts to recover costs and a competitive profit margin, which is what this efficiency business model is likely to support, because this approach is open to

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[26] As proposed in South Carolina, the VPP Model would improve the cash flow profile by adjusting revenues to move them forward in time like cost of service recovery of capital expenditures. The rate impacts are more like those of a power plant (except smaller).

[27] Since we model all impacts as variances from a "no efficiency" world, we model this as having the utility first distribute the entire avoided costs to its customers through rate change factors and then collecting the 85 percent fixed percentage back.

[28] An alternative treatment of lost fixed costs could be to assume that recovery is not waived or waived for some specified period of time, after which a rate case would be done and collection of lost fixed costs from prior efficiency programs would begin. This is a Model User input.

[29] Unregulated businesses can deliver efficiency using this same, contract-based business model. In this report we are focusing on business models suitable for regulated utilities.

competition. Since the cost recovery and the shareholder incentives and payments are both within the contract, there is no regulatory treatment required. However, there are lost fixed revenues and the utility is modeled as recovering them (again a User Choice), which would require regulatory approval.[30]

B. The Analytic Framework

To simulate the rate and financial impacts of alternative business / regulatory incentive models, we need to make the necessary modeling assumptions. We have tended to simplify these for the purposes of our illustrative analysis. For members, the models with their simplifying assumptions should be a good starting point for developing their own company-specific analyses. We anticipate users will replace some of these assumptions, based on financial and efficiency modeling results that are fitted to their own systems and operating environments.

1. Assumptions on Prototypical Utility and the Efficiency Program

Five Year Program Life. We consider energy efficiency programs to be implemented for five years. Each year's program is identical in nature, with identical energy savings, identical numbers of participants and identical costs (i.e., no inflation). Each year's program creates kWh and kW reducing effects lasting for ten years. The study period thus spans 14 years (i.e., the fifth program year produces impacts for the fifth year and nine future years).[31] Since all efficiency measures last for exactly 10 years, we do not have to deal with filling in the savings from short-lived measures, such as compact fluorescent lights (CFLs).[32]

Customers and Participants. We assume the number of customers to be 1,000,000 in the year before the EE program is implemented. Customers are assumed to grow at an annual rate of 2 percent; 100,000 customers participate in the EE program each year. In the pre-EE world each customer consumes 10,000 KWh of electricity annually. The EE program reduces the electricity usage of participants by 10 percent.

Costs of Measures and Customer Incentives. The utility gives a one-time cash incentive of $200 for each participant to cover the measure installation cost of $350, in each year of the program. The program annual administration cost for the utility is $15,000,000.

Capital Structure. We assume that the percentage share of equity is 50 percent, cost of equity is 11 percent, cost of debt is 6.6 percent, and the corporate tax rate is 40 percent. These values yield an after-tax weighted average cost of capital (ATWACC) of 7.48 percent. We use the ATWACC as the discount rate.

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[30] This is just an assumption and User Choice. We have done no research to determine whether states allow Regulated ESCos to get Lost Fixed Revenue recovery. Typically, unregulated ESCos would not.

[31] The cessation of the efficiency program in the sixth year does create certain "terminal" effects that will appear in the results of the analysis. Utilities in practice are likely to plan to continue efficiency programs far into the future, but this does not represent a real issue. The purpose here is to analyze the discrete effects of efficiency programs, so some cutoff is methodologically necessary. Regulators have come to understand these discrete effects, e.g., the discussion of the California policy on shared savings and the booking of earnings in a footnote of section III.A.1 above.

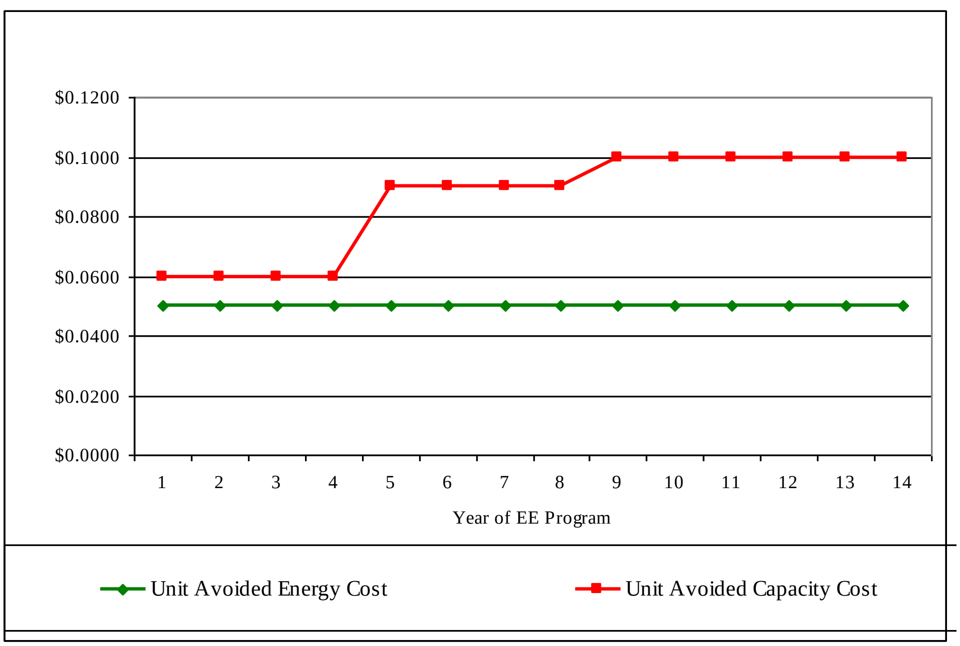
[32] This is a real consideration, which is doable but would require a somewhat more complicated model.

Base Rates. The simple utility model assumes that original base rate is $0.10 per kWh, and would remain fixed if there were no growth in sales. The assumed growth in sales, set at 2 percent per year, requires that new power supplies be procured at higher and higher marginal costs over time, starting at an assumed $0.11 and rising to $0.20, as discussed further below. This combination of system growth and marginal cost above average costs gives rise to an increasing average cost of power per kWh for all customers, in the base case with 2 percent growth case, pre-EE impacts.

2. Assumptions on Avoided Capacity Costs and Lost Fixed Revenues

The subject of avoided cost is complicated and sometimes subject to state regulatory policy decisions. We do not go into these issues, but presume that good avoided cost values will be developed as part of the process of developing a sustainable business model. We assume that the avoided cost of electricity comprises two components—avoided energy cost, and avoided capacity cost. For purposes of the simulation and without claiming any realism, we assume the avoided energy cost is $0.05/kWh, which is not escalated in the base case, but is a user input. The avoided capacity cost would normally be expressed in terms of $ per kW-year and impacts of EE programs developed on a consistent basis. For simplicity, this is not done here. Avoided capacity cost is assumed to start at $0.06/kWh for the first years, and rise to $0.10/kWh by the end of the study period. These numbers are intended to be illustrative, not realistic. As discussed above, the fact that marginal costs exceed average costs is an important aspect of the economic benefits of efficiency. Figure 4 below shows the 14-year stream of unit avoided costs.

Figure 4: Time Profile of Assumed Avoided Capacity and Energy Unit Costs
($ per kWh)



We do not separately model the capacity costs on a per kW basis, but rather assume that these important costs can be modeled on a per kWh basis, similar to the way they would be treated in residential ratemaking. This is another simplifying assumption for our illustrative model and does not in any way imply that the efficiency programs do not reduce kW peak demand. The reduction in peak demand and the avoided capacity costs are very important to the economics of efficiency programs. In real applications, we recognize there would normally be separate treatment of energy costs, per kWh, and capacity costs, per kW-year.

Growth is modeled through an annual increase in the total number of customers, and we do not assume that there is growth in per customer in electricity consumption, but this could be added to the model easily. The total number of units consumed in the "but-for efficiency" world (no efficiency program) is calculated as the number of customers *multiplied times* per customer electricity usage. As an illustrative model, this feature is not important, but we recognize that in an actual application, alternative assumptions may be very important to determining the nature of the rate and financial impacts. In an application, the forecasting of efficiency impacts on a rate class basis may get its own treatment.

Total annual revenue requirement for our prototypical utility in the pre-EE world is calculated as follows. For year zero (i.e., the year before an EE program is implemented), the electricity consumption in that year is multiplied by the rate in year zero (assumed to be $0.10/kWh). For any subsequent year, if the electricity consumption is higher than that in year zero, then we take the previous year's total base revenue requirement and to that we add the revenue requirement for the incremental units of energy consumption. The latter is obtained by multiplying the <u>incremental</u> units of energy use by the marginal cost <u>for the year</u> under consideration.[33]

If the user were to pick parameters so that conservation impacts exceeded "natural" growth, the number of units consumed could be lower than or equal to the number of units consumed in the year zero. Then no incremental units are procured at marginal costs, and no incremental revenue requirements are created.

Average annual rates in the pre-EE world are then calculated by dividing total revenue requirement by total units consumed. The rates in the EE world under various incentive programs and under EE program cost and lost fixed revenue recovery schemes are developed for each case. This could be called the assumption of "perfect ratemaking."

Baseline World of No Energy Efficiency—The Nature of Avoided Costs. All results for the four different incentive schemes are presented relative to the pre-EE world. In the baseline world of no energy efficiency, new plants would have to be built and/or energy and capacity bought to meet the demand. The costs associated with plants that do <u>not</u> have to be built and/or the energy and capacity that do <u>not</u> have to be bought and brought into revenue requirements constitute the "avoided costs" that are used to value energy

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[33] For any year t if the electricity consumption (EC) is more than that in year zero then:

Revenue Requirement in year *t* = Revenue Requirement in year (*t*-1) + (EC_t – EC_{t-1}) x MC_t

If year t electricity consumption is less than that in year zero then:

Revenue Requirement in year *t* = EC_t x Rate in year zero

Given that we hold per customer electricity consumption constant and allow number of customers to grow every year, the later case is not applicable. Note that for year one, "previous year" and year zero are the same, but not so from year 2 onwards.

(and capacity) saved due to the efficiency programs. Avoided costs can also include reduction in transmission and distribution costs associated with energy savings due to the efficiency programs, where such impacts can be identified and measured.

Lost Fixed Revenues and Rate Cases. Lost fixed revenue (also called lost fixed costs, lost base revenues or lost margin) comes from the multiplicative product of two estimated parameters of an EE program:

- Decrease in kWh sales over the lifetime, for each EE Measure installed
- Unit amount ($ per kWh) of fixed or base cost per kWh that is in the volumetric charges of the tariff base rates of the participants in the EE program.

The unit base cost factors are set in general rate cases, so lost fixed revenue is relative to those rates. Lost fixed revenues are created by each year's EE program and can accumulate over the years the EE programs are done. We calculate the amount of fixed revenue lost in any year to be a function of the fixed revenue losses from all of the EE programs which started during or before the year "y" of the most recent base rate factor change and have lifetimes long enough to reach that year "y." Thus, one important parameter is the year in which the last rate case was completed. The model contains a user choice of when a base rate factor change would occur (perhaps by a general rate case or by a separate mechanism), so that all prior sales reductions giving rise to past lost fixed revenues would be washed out, as discussed below.

Each year after a rate case is completed, the utility recovers all of the fixed revenue losses from programs done up to the time of the rate case filing (which is essentially the assumption that forecasts of GWh sales reductions from future EE programs are never factored into the ratemaking). If a rate case is not completed and EE programs continue to reduce kWh sales, the utility is modeled as not recovering the additional fixed revenue loss incurred by new EE Measures that were installed since the most recent rate case.[34]

For example, if the utility completes a rate case in year six (no rate case for first five years), starting in that year and each year thereafter, the utility will recover the current year's fixed revenue losses from the projects done in years one through five. The utility lost revenue is only from years one through five. If and only if the utility completes a rate case each year for years one through five (equivalent to rate case every year), the utility will recover all of the fixed revenue losses resulting from all projects in each year, for the entire 14-year period the model considers. This is our simplified modeling treatment of the complex issue of lost fixed revenue. The subject in a real application would require a treatment of the specific circumstances of the utility and the regulatory policies of the state.

3. *Tests to Evaluate the Cost Effectiveness of the EE Programs*

We discuss three cost effectiveness tests, using the traditional source, the California Standard Practices Manual (CSPM).[35] We are not presuming that any state will or should use the CSPM literally; California policy makers themselves reserve the right to make certain adjustments to fit their needs. We have omitted the fourth standard test found in the CSPM, the Administrator Test, aka the Utility or Revenue Requirements

[34] This is a simple model of lost fixed revenue. It does attempt to be a systematic treatment of impact of regulatory lag on utility revenues.

[35] These tests are based on the "California Standard Practice Manual: Economic Analysis of Demand-side Programs and Projects," October 2001. We make some reasonable, simplifying assumptions when implementing the tests.

Test, in the interests of simplicity. The components for the Administrator test are all in the RIM test, so we feel there is nothing material left out. In fact, we on occasion graph and consider the results of this test.

Our opinion is that the cost effectiveness tests provide useful information and a means to understanding shareholder incentives, cost recovery, lost fixed revenue recovery, and overall rate impacts. For example, the Total Resource Cost (TRC) Test and the Shared Savings approach are very closely tied, so TRC will tell a utility much about that incentive. The RIM Test is an important part of understanding the potential impact on rates. The Participant Test is often seen as an indication of the likelihood of meeting participation and thus GWh savings targets (although efficiency program design is only an assumption in this analysis).

a. Total Resource Cost Test

The TRC Test measures the net present value of the EE program from the perspective of society. The benefits consist of the utility's avoided costs. The costs include program administration costs incurred by the utility and all EE-related expenditures incurred to install the efficiency measures of all participants (whether covered by utility incentive payments or not). A positive net present value (NPV) suggests that the economic benefits of the EE program to the society exceed the combined economic costs and a negative NPV indicates that the costs in relation to the resource benefits are too high. This test includes incentives paid to participants within the total installed cost of the efficiency measures, but not separately, and omits unrecovered revenue requirements that were designed to be recovered through existing rates. Based on the parameters of our hypothetical utility, we calculate the TRC for the five-year utility efficiency program to have an NPV of about $216 million (for a utility with initial market capitalization of $1.5 billion). This is a TRC benefit cost ratio for the EE portfolio of 1.99, which says that $1.99 of gross avoided costs in Present Value (PV) are created for each $1 of "efficiency resource" investment, which is not out of line with actual EE programs being pursued in many states.

b. Participant Test

The Participant Test measures the net present value of the EE program to the participants. In the first instance, the Participant Test provides the net benefits before potential rate impacts signaled by the RIM Test are incorporated. The benefits include bill reductions for the participants attributable to the EE program *plus* total cash incentives paid by the utility to the participants.[36] The costs are composed of the total expenditures on the installed EE-measures and any operating expenses incurred by all the participants. A positive suggests that participants are better off participating in the EE program as compared to the baseline world of no EE program. Based on the parameters of our hypothetical utility we estimate the participant benefit cost ratio of the EE portfolio to be an NPV of about $266 million and a benefit-cost ratio of 2.75. Another common metric for participant benefits is the payback period for the net initial investment in years. The payback period for participants in the EE program is three years. The model also calculates the benefits after rate increases indicated by the RIM Test are put into effect, but before shareholder incentives are incorporated. The NPV is about $267 million, the same as before rate impacts.

[36] Putting the participant incentives received from the Utility as benefits is a convention that affects the test ratio but not the test PV. Incentives to participants could also be thought of as a reduction in participant costs of installing the Measures.

c. Rate Impact Measure Test

The Rate Impact Measure Test (RIM), also called the Non-Participant Test, measures the net present value impact on rates if the utility shareholders were neither harmed nor provided with the opportunity for any profit. The benefits consist of utility avoided costs and are identical to the benefits for the TRC test. The costs include unrecovered revenue requirements due to decrease in energy consumption attributable to the EE program, the program administration costs incurred by the utility, and the total cash incentives paid to all participants. This is all the costs from the EE program, including the ones excluded from the TRC Test. A positive net present value suggests that the electric rates will go down in PV.

Since increasing the participation often involves offering higher participant incentives, it is possible for aggressive EE programs to exhibit a negative NPV of the RIM. This means that electric rates will go up in PV terms, although in particular years rates may be up or down. Without presuming any state policy should or should not promote EE programs that fail the RIM test, we adopt the assumption of a large, RIM-failing efficiency program for our prototype, but note again that this is a user assumption and can be changed. Based on the parameters of our hypothetical utility, we estimate the RIM test for the EE portfolio to have an NPV of about negative $50 million, or a benefit-cost ratio of 0.90. This implies that general rates are increased by the program. It also means that if a utility was basing its EE decisions on RIM, then it would not offer that EE product. The timing of when the rate impacts are positive and negative is also shown in the model and will depend on the incentive and cost recovery schemes. Table 2 shows the results of various Benefit Cost Tests, before and after Shareholder Incentives.

Table 2: Benefit-Cost Test Results with and without Shareholder Incentives

Net Present Value ($ in Millions)

	Efficiency Program Impacts under Expensing before Shareholder Incentives*	Virtual Power Plant	Shared Savings*	Capitalization of EE Costs*	Regulated ESCO*
Participants	$265	$234	$256	$246	$138
Non-Participants	($49)	($63)	($66)	($49)	$66
Utility/Shareholders	$0	$46	$26	$19	$13
Total Resource Net Benefits	$216	$216	$216	$216	$216

* Just these incentives assumed to have effective Lost Fixed Revenue recovery mechanism every year.

4. Assumptions Regarding Financial Modeling

Using the electricity rates determined for each scenario, the financial model translates the results into simplified income and cash flow measures. To do so it is necessary to make several simplifying assumptions. First, we assume that rates and volumes translate directly into revenues for the utility. Second, we assume that the utility maintains the same capital structure throughout the life of the energy efficiency measures. We model this using 50 percent debt and 50 percent equity, so energy efficiency initiatives that are financed by the utility and put on the balance sheet are financed using the 50/50 capital structure. Third, the utility's capital/size grow with the growth in electric revenue.[37] Fourth, the allowed as well as expected return on equity is held constant at 11 percent while the interest rate (cost of debt) is held constant at 6.60 percent. Fifth, we assume throughout that the relevant discount factor is the after-tax weighted cost of capital of 7.48 percent. This is calculated as [11% × 50%] + [6.60% × 50% × (1 – 40%)] where the 40 percent is the tax rate.[38] While these figures are reasonably consistent with the figures observed in the industry at the time of modeling, they are for illustrative purposes only. Each member will need to determine what relevant parameters are for their unique situation. Finally, in modeling income and cash flow, we ignored any tax incentives that may be relevant and simplified the model by assuming that 40 percent was paid on all income or cash flow generated during a specific period.

Baseline Net Income Profile. Using the simplifying assumptions and results on electric rates, the prototype utility has the following Year Zero revenues and cost data, prior to any energy efficiency initiatives.

Table 3: Base Year Net Income for Prototype Utility

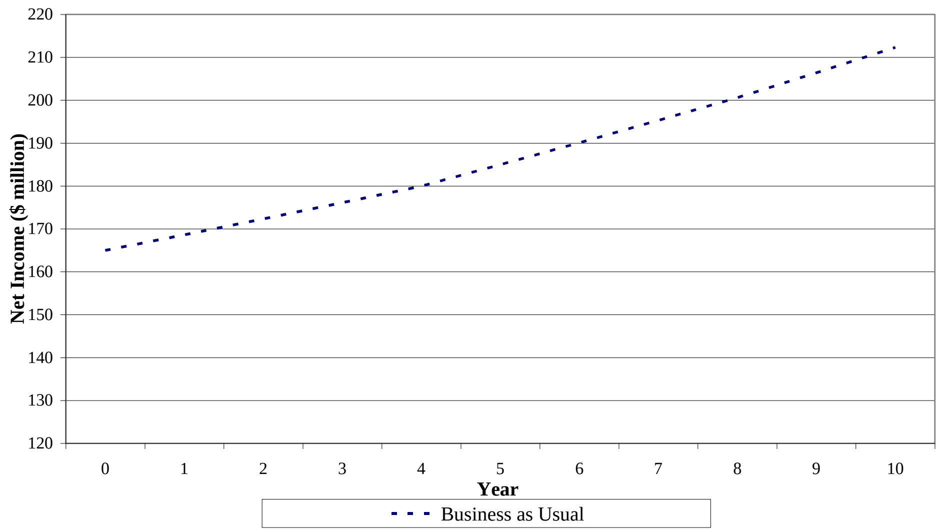
	Base Year (Millions)
Revenue	**$1,000**
Costs	**$ 725**
Tax (40 percent)	**$ 110**
Net Income	**$ 165**

Over time, the net income under Business as Usual, without EE programs, shows a smooth increase.

[37] This is a simplifying assumption that avoids modeling the lumpiness inherent in capital investments.

[38] Using the same discount rate for all streams is a simplifying assumption. From a financial perspective the discount rate needs to be consistent with the inherent risk in the cash flow or income stream that is being discounted. Each member will need to evaluate the risk of the cash flow/income being discounted and pick an appropriate discount rate, which may be higher or lower than the after-tax weighted average cost of capital.

Figure 5: Net Income of Prototype Utility under "Business as Usual"



Note: Absolute scale reflective of prototype model rather than an actual utility.

C. Results of the Analysis

Having simulated four representative business/regulatory incentive models, we turn now to examine how to use the results to find the model (or configuration) that works for a given utility. The models produce results that differ in terms of the timing and magnitude of rate impacts, the magnitude of customer benefits, cost-effectiveness as measured by various standard tests, and the magnitude and timing of impacts on cash flow and net income. We believe that these are among the factors that should be considered in selecting a business model and developing an efficiency strategy.

Before we proceed, it is important to remember that we are *illustrating* how to use simulation results, nothing more. Results that can be relied on as the basis for decisions on efficiency strategy are only available at the cost (in time and effort) of developing detailed, utility-specific simulations. Therefore, any advantages or disadvantages for one model versus another that may appear in the results to follow are illustrative only and may not be valid for any given utility. Remember that in the real world, cost-effective efficiency programs are not homogenous but differ within and among utilities and regions; nor are the baseline rates homogenous.

1. Rate and Total Bill Impacts before Incentives

Cost Recovery that "Makes the Utility Whole" Without Incentives. Before we get to shareholder incentives, for expository purposes, we first consider the rate impacts driven purely by the Rate Impact Measure (RIM) test. We model the case where the net RIM costs (or benefits in other simulations of the RIM) are pushed through to the utility's customers through annual rate changes. The assumption in our simulation is that the EE program has a <u>negative</u> net present RIM value (while it does pass the TRC test). This means that the overall impact is to <u>raise rates</u>, before shareholder incentives are considered. It is easy to simulate a <u>positive</u> net present RIM value with a different EE program that would imply an overall lowering of rates. We use a RIM-failing program only to highlight the rate impacts therein. There is no implication that efficiency programs adopted by any policymakers should pass or fail the RIM test, as there are many considerations in addition to rate impacts.

We also assume that a five-year EE program is carried out in exactly the same way, irrespective of shareholder incentives, and all the same energy impacts and cost expenditures take place. This is for exposition, not presented as a business model, where incentives could play an important role.

We will show the rate impacts over the 14-year period in which there are effects. For expository clarity, we separate the rate impacts into four annual rate change factors:

1. Lost Energy Margin factor (our term for any difference between the Avoided Energy Costs and the Lost or uncollected Energy clause revenues, discussed below);
2. Lost Fixed Revenue, or lost fixed cost, factor ;
3. Avoided Capacity Cost factor; and
4. EE Program Cost Recovery factor, including both administrative and implementation costs, as well as incentives paid by the utility to the participants.

All of the factors are calculated based on the total kWh sales after and reduced by efficiency programs. Before explaining the four factors, it may be useful to see how they change across the 14 years of our analysis. That is portrayed in Figure 6 below.

Take the two positive factors first; that is, the factors that increase the per kWh rate.[39] The Red Line is the EE Program Cost Recovery factor, representing the expensing of EE Program costs, and is positive for the first five years of EE Program spending and then vanishes. (If the program costs were amortized, as in the Capitalization business model, or not recovered at all, as in the VPP business model, this factor would be different.) The Green Line is the Lost Fixed Revenue or fixed cost factor. Base rates set in a general rate case recover fixed costs in volumetric charges. EE programs reduce kWh (or kW) sales and thus reduce fixed-cost recovery. This factor grows as long as the cumulative kWh savings grow and diminish when kWh savings diminish.

The Green Line is the Lost Fixed Revenue or lost fixed cost factor. This factor is assumed to just recover the prudent costs of prior, sunk investments. We assume that base rates, as set in a prior general rate case, were recovering these fixed costs in volumetric charges. EE programs reduce kWh sales (and kW demands, though not modeled here) and thus reduce prudent cost recovery. This factor recovers just the lost fixed revenues and grows as long as the cumulative kWh savings grow with each succeeding year's EE program. The factor diminishes after EE programs cease and the cumulative kWh savings eventually diminish.

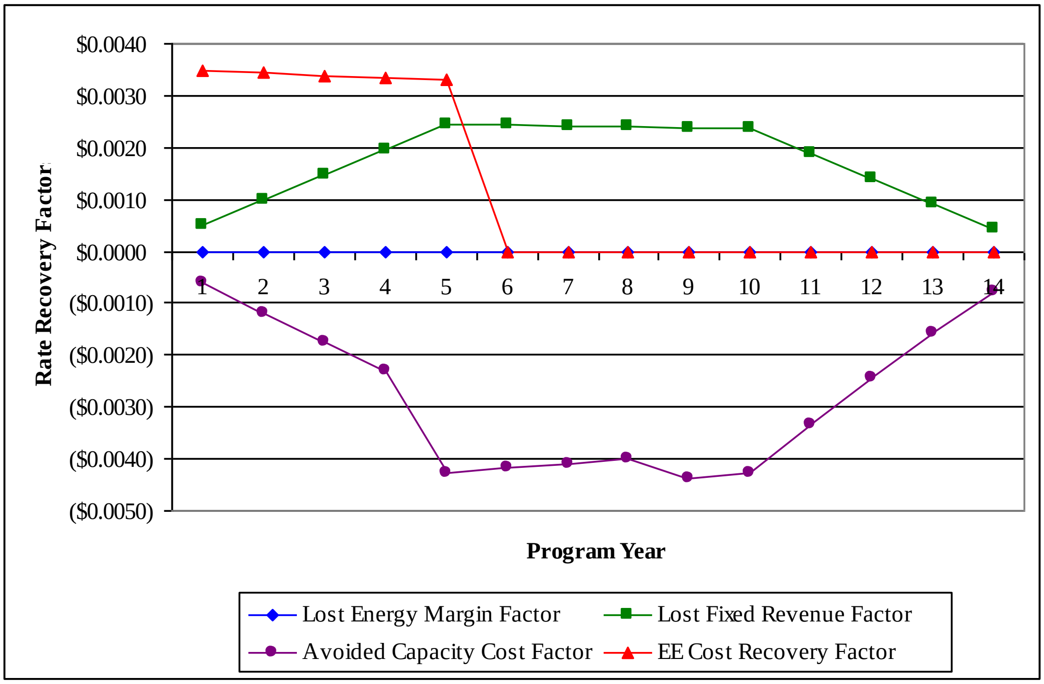
Next look at the "null" factor. The Blue Line is the Lost Energy Margin factor and is identically zero in our model by the simplifying assumption that avoided energy costs always equal uncollected energy revenues, i.e., there is a fuel clause. There are states without a fuel clause, and this could have a rate increasing or decreasing impact, depending on the fuel savings in relation to the fixed energy revenues lost.

[39] Recall that the per kWh rate is the hypothetical rate that would be charged if the five-year EE program were not done, the power plants were built and operated, and all costs were collected.

Finally, the negative or rate-reducing factor is the Purple Line. The Avoided Capacity Cost factor is relatively large, by assumption about increasing future avoided capacity costs. Avoided capacity costs last as long as savings last (just like the Lost Fixed Revenue factor). The shapes of the factors are a function of the assumed relative values for the four costs.

If the kWh savings from installed efficiency measures were known to diminish over time (the so-called "persistence" issue), the capacity and energy savings would decrease, with predictable impacts. The model could be adjusted to incorporate such an assumption.

Figure 6: Comparing the Size and Duration of Four Separate Cost Recovery Factors
($ per kWh)



Note: the EE Cost Recovery Factor is based on the assumption of expensing costs annually.

The assumptions for cost recovery in each sustainable business model determine which rate factors are applicable. Table 4 below summarizes the different factors in terms of whether or not they apply to our four business/incentive models.

Table 4: Rate Change Factors and Incentive Model Factors

	Lost Energy Margin Factor	Lost Fixed Revenue Factor	Avoided Capacity Cost Factor	EE Cost Recovery Factor	Shared Savings Factor	Capitalization Factor	85% Avoided Cost Factor
Utility Made Whole	X	X	X	X			
Shared Savings	X	X	X	X	X		
Bonus RoE	X	X	X			X	
Virtual Power Plant	X	X*	X				X
Regulated ESCO	X	X	X				

* For the purposes of this report, VPP is modeled as having no, or a zero, Lost Fixed Revenue Factor. This is, however, a model user choice.

The first three factors are part of every business model, as we have modeled them, but involve several simplifying assumptions. Whether in a particular situation, the lost energy margin is identically zero, the last revenues can be recovered, and the avoided capacity costs are annually passed back to ratepayers, is something that must be investigated. Table 4 above also shows three new factors, for the recovery of incentives in three incentive models, the shared savings factor, the capitalization factor, and the avoided cost factor. These will be explained below.

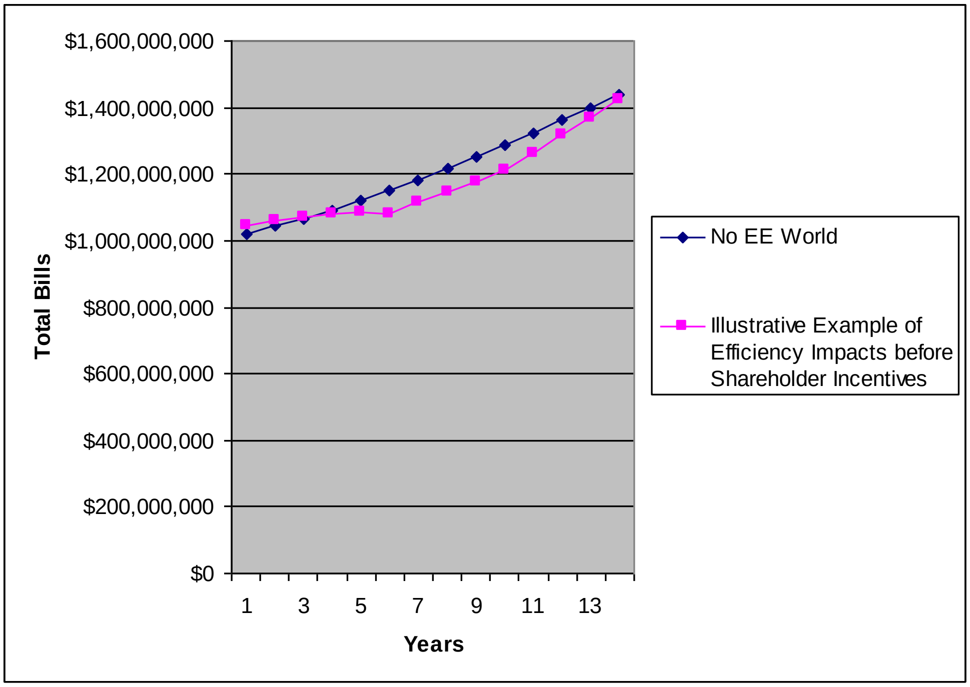
The first line, "utility made whole," is shown only for comparison purposes; it is not put forth as a business model. In our modeling, the EE Cost Recovery is an aspect of only the Shared Savings approach. Shared Savings also has a second factor to recover the incentive. The Bonus ROE model has the Capitalization factor, which recovers the amortized EE program costs, the cost of debt, and the cost of equity, including the bonus ROE on the undepreciated regulatory asset balance. VPP has the 85 percent Avoided Cost Factor only, no cost recovery. Again, Regulated ESCo is assumed to have Lost Fixed Revenue recovery.[40] From the participants, the utility by contract is assumed to receive 90 percent of the Bill Savings for five years, after which the direct costs are all recovered. Then the utility receives 10 percent of bill savings for another five years. Formal definitions and further discussion of the time profiles of all four non-incentive factors are contained in Appendix A.1.

Aggregate customer bill impacts are the product of the efficiency program induced reduction in kWh sales achieved by the participants and the subsequent increase in price per kWh, which applies to all ratepayers. Since the total percentage decrease in kWh sales is greater than the total aggregate percentage increase in rates, the aggregate bills go down by the third year and stay below the baseline aggregate bills. We define "aggregate bill impacts" as the sum of impacts on participants and non-participants. In Figure 7, we shown the time profile of aggregate bills over the 14 years. Again, for a simple illustration, this is shown before the shareholder incentives are recovered, as each shareholder incentive has a somewhat different time profile. The present value of aggregate bill savings is X percent. The participants save 10.0 percent of their baseline,

[40] See discussion above in Section III.A.4.

no EE bills. The non-participants see an increase of 0.6 percent in their baseline bills.[41] (The similar aggregate bill impacts with shareholder incentives are shown below.)

Figure 7: Aggregate Customer Bills with and without Efficiency Programs
(Annual $)



Note that the bill-reducing effects go away in the last four years only because we assume and model just five years of efficiency programs. Real world programs would generally continue beyond the fifth year and continue a commensurate level of bill savings out in time.

2. *Rate and Aggregate Bill Impacts across the Incentive Models*

In this section we present the full aggregate bill and rate impacts under each incentive model, starting with the bill savings. While the business models considerably change the time profiles and the precise nature of the total bill savings, there is a substantial reduction in total bills under all business models. This is shown in Figure 8.

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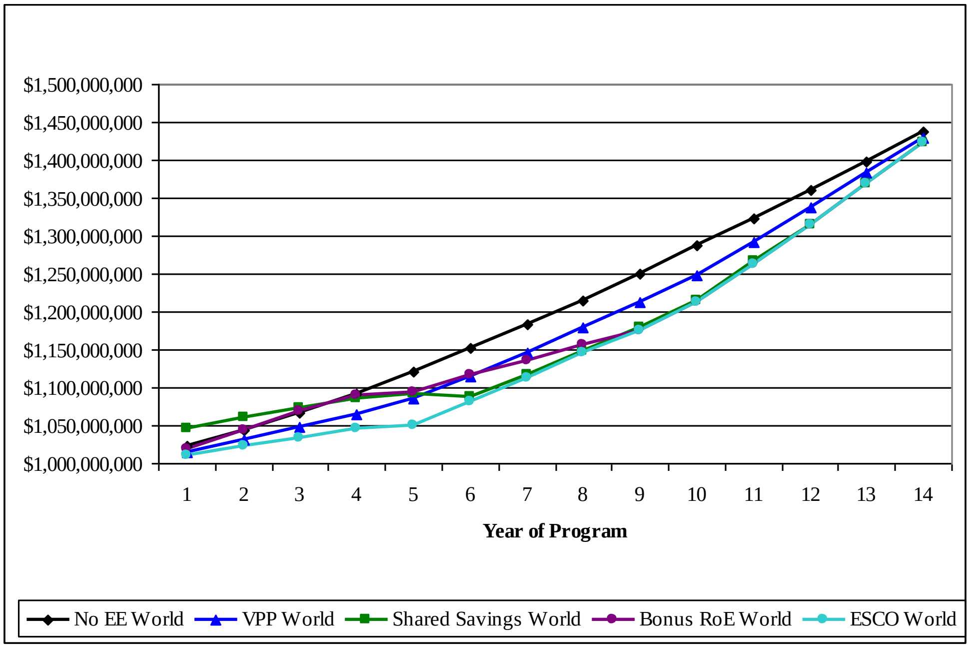
[41] While it is simple to talk about sets of participants and non-participants, these two sets are not disjoint over time and the concepts are actually quite complicated. In this simple model, for example, the distinction is much clearer than in the real world because there is only one program and one measure. The model shows 10 percent of the customers becoming participants in the first year, 20 percent in the second, growing to 50 percent in the last. Therefore, those who join in the fifth year have been non-participants for four years. Any attempt to distinguish impacts on participants must therefore deal with the dynamic nature of this status. In the real world, with multiple programs and multiple measures that are continued for many years, accurately estimating the overall impacts on participants and non-participants may be extremely difficult.

Figure 8: Aggregate Bill Reductions from the Sustainable Business Models
(Annual $)

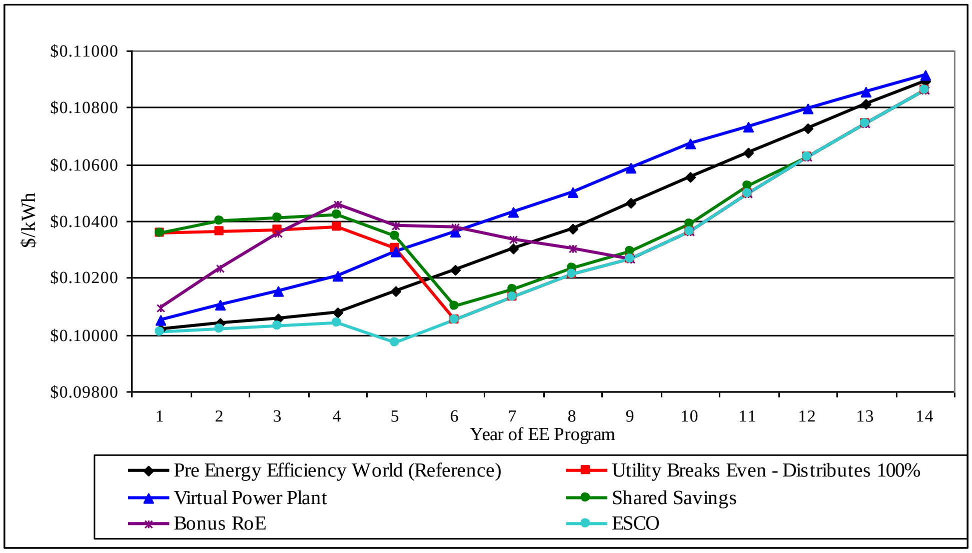


The baseline, no-EE world is shown by the Black Line for comparison. All sustainable business models, notwithstanding the fact that they provide shareholder incentives, provide clear total bill reductions from the third year (until the effects cease by assumption in the fifteenth year). The VPP has a noticeably smooth bill reduction profile from the beginning to the end. The Shared Savings starts with some total bill increases in years one and three but quickly produces total bill reductions that endure. The Bonus ROE world is somewhere in between. Finally, the Regulated ESCo shows the greatest bill reduction, but we have commented above that any direct comparison is questionable, in that this model may be a niche model and unable to attain the same size and scope as the others. These are simulations and would need to have their results revisited in any real application. However, total bill reductions are to be expected from well-designed and implemented efficiency programs that pass the TRC test.

Rate Impacts. Moving to the rate impacts, the model has only one rate in dollars per kWh that is charged to all customers. The rate in the energy efficiency world in each model is obtained by summing the reference or baseline rate in the pre–energy efficiency world with the sum of different cost recovery factors. A different set of factors applies to each incentive model based upon the assumptions of cost recovery in each model, as shown above in Table 4. (Again, these cost recovery factors and their applicability to each incentive model are discussed in Appendix A.1).

Figure 9 below shows the impact of each business model on rates in every year of the simulation. The Black Line represents the reference rate in the baseline, no-energy efficiency world. The impacts associated with each business model are determined by its cost recovery assumptions. The Red Line is there for exposition only, showing the impact of net cost-benefit recovery alone, assuming the expensing of EE program costs and making the utility whole without earning any margin.[42] The relative shapes are explained below for each sustainable business model.

Figure 9: Level and Time Profile of Rate Changes across the Shareholder Incentive Models



Shared Savings. Under the Shared Savings model, the utility is first made whole by allowing the utility to recover/refund the four factors shown in Figure 6 above (lost energy margin, the lost fixed revenue, avoided capacity cost and all program costs incurred by the utility).[43] In addition, the utility is allowed to collect a fixed percentage, 12 percent, of the Total Resource net benefit of each year's program (in present value terms) as incentive payment for its energy efficiency efforts. Of this incentive, 70 percent is recovered by the utility in the immediate or second year after the program and 30 percent is recovered in the seventh year after the program. The Green Line in Figure 9 above represents the resultant rate in the Shared Savings model. The rate impacts are somewhat front-loaded, as all program costs in our model are incurred in the first five years of the study period. In the later years the rate in this model declines relative to the reference rate, because the avoided capacity costs are higher than lost fixed revenues and incentives and all direct costs have been recovered.

Capitalization with Bonus ROE. In the Bonus ROE business model, the utility collects/refunds the lost energy margin, the lost fixed revenue, and the avoided capacity cost just as in the Shared Savings model. However, unlike in the Shared Savings model, program costs are not expensed but are capitalized and recovered over the assumed length of amortization of such costs, here simulated as four years. The incentive to the utility accrues from the 500 basis points that it is allowed to collect on the equity portion of the capitalized program costs. The rate impact is still front loaded compared to the baseline reference rate, but

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[42] Again, making the utility whole is not one of our sustainable business models. This could also be labeled the "RIM Test Rate," for is essentially represents the time profile of what the RIM Test shows in present value.

[43] Just for illustrative purposes, we show the case where the utility breaks even or is made whole with respect to the energy efficiency programs, without any shareholder incentives. The utility is shown recovering or refunding the lost energy margin, the lost fixed revenue, avoided capacity cost, and all program costs it incurs. As discussed above, this has a time profile like the Shared Savings business model. The resultant rate is depicted by the Red Line in Figure 9.

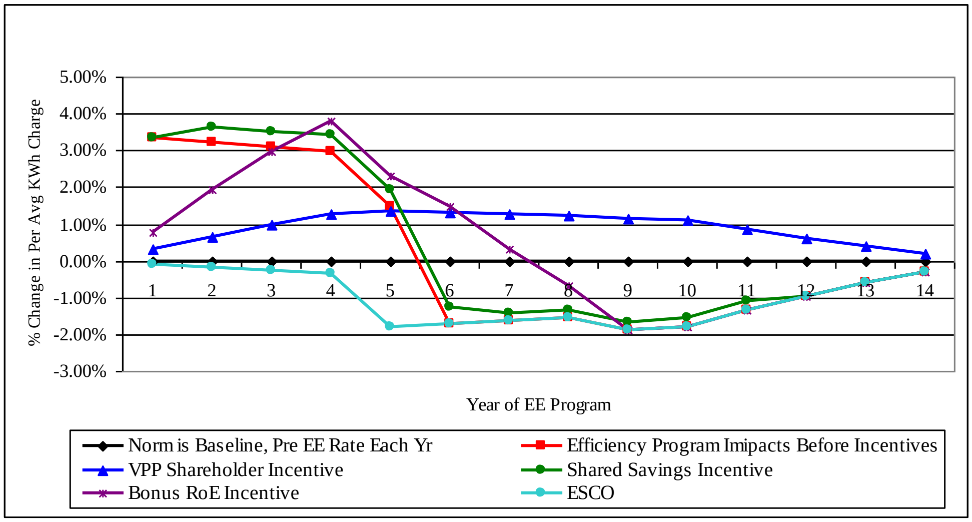
compared to the Shared Savings model, the rate increases are spread out over a longer duration and are of a smaller magnitude in the first three years.

Virtual Power Plant. As in the previous two business models, under the Virtual Power Plant incentive model the utility collects/refunds the lost energy margin and the avoided capacity cost. However, as mentioned before, under this incentive model we assume no recovery of lost fixed revenues. The utility also bears all the program costs, but is rewarded with 85 percent of total avoided costs. This incentive model provides the smoothest trajectory for the overall rate impacts primarily for the simple reason that the customers pay out 85 percent of avoided costs, which are spread out in time. Customers have no responsibility to pay for program costs, which would otherwise be incurred in the first five years. The resultant rate never falls below the reference rate because each year the factor of decrease is the avoided capacity cost, the factor of increase is 85 percent of total avoided cost, and the later is a bit larger than the former. In interpreting Figure 9, remember that there is an important difference between rates and bills. Cost-effective efficiency programs will mitigate participating customer impacts (e.g., allowing customers to realize lower bills), even if they increase unit rates (cents/kWh). This is because cost-effective programs save more than they cost; but they reduce kWh consumption, so costs are spread over fewer kWh.

Regulated ESCo. Finally, in the ESCo model where the energy efficiency programs are implemented by a regulated energy service company, the participants pay for all energy efficiency program costs as well as the shareholder incentives. From the perspective of all ratepayers, this is beneficial. The utility whole collects/refunds the lost energy margin, the lost fixed revenue and the avoided capacity cost. Given our assumption of avoided capacity costs being higher than lost fixed revenues, the average electricity rates fall under this approach relative to the reference world of no energy efficiency. Unfortunately, the Regulated ESCo model would probably be unable to achieve the goals of this simulated efficiency program because of consumer resistance to upfront costs.

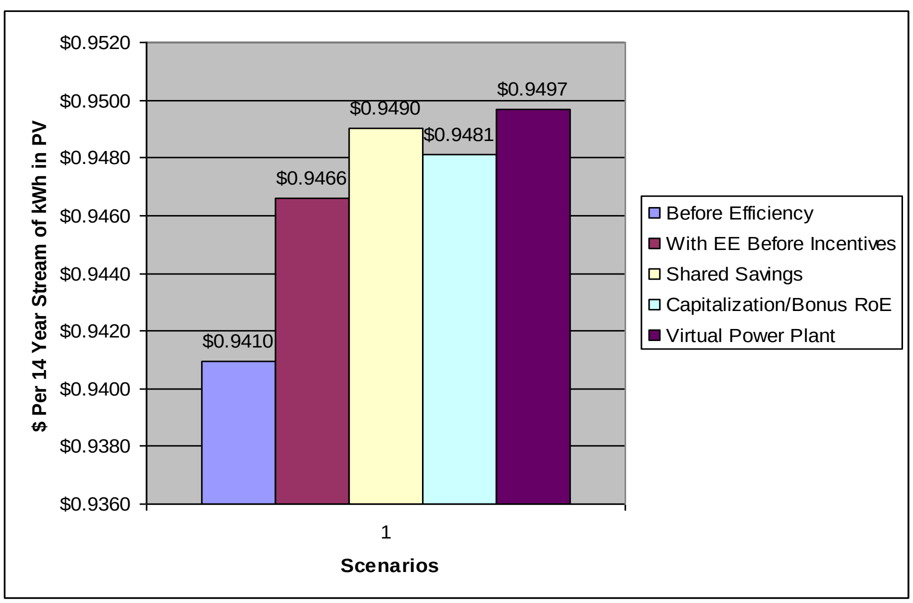
To clarify the relative rate impacts of the business models in this simulation, the following Figure 10 shows the annual percentage change in rates relative to the reference rate in the no-energy efficiency world. The models can be ranked crudely from having the most front loaded rate impacts to the most back loaded rate impacts in this order: Shared Savings, Bonus ROE, and VPP.

Figure 10: Comparison of the Annual Percentage Deviations In Rates across the Shareholder Incentive Models



Another way to see the impact on rates is to examine the present value of the cost of a hypothetical, uniform stream of one kWh per year under the different scenarios. This has the benefit of including the time value of money, which policy makers do consider because efficiency is an investment on behalf of the ratepayers. Figure 11 shows the relative "price" of this 14-year kWh Stream prior to efficiency, after efficiency, and then inclusive of the various shareholder incentives (excluding Regulated ESCo). Since by assumption in this simulation the EE programs do not pass the RIM test, it follows that there will be increasing impacts in present value terms on rates even while the total bills of participants and aggregated bills of all customers are falling.

Figure 11: Comparing the "Price" of a 14-Year Stream of kWh under Scenarios



In aggregate dollar terms (for this prototype utility in this efficiency simulation and before shareholder incentives), the total present value of the participants' bills for 14 years falls by about $330 million. Adding the incentives the participants receive and subtracting total EE measure installation costs they pay, participants' net benefits are about $270 million. On the other hand, the non-participants pay an additional $37 million, or about 0.6 percent due to increased rates.[44]

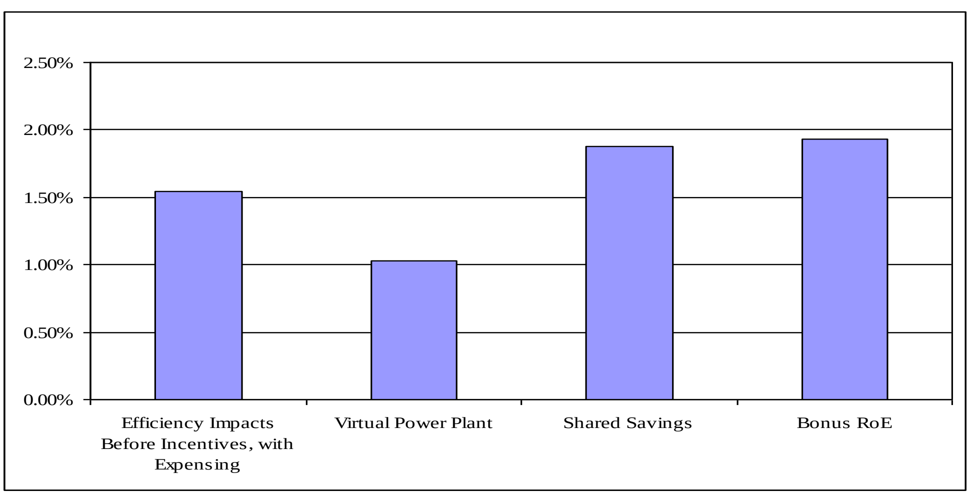
Comparing Near Term with Far Term Rate Impacts. To pursue the timing of rate impacts one more step, we also compare the average annual change in rates for the first seven years versus that for years eight through fourteen.

Under the Virtual Power Plant incentive model, there is the smallest average annual percentage increase in rates compared to the reference case for the first seven years. For the subsequent seven years, VPP continues to increase rates modestly. In present value terms, the early rate moderation has greater impact. The simulated Virtual Power Plant model creates the smoothest trajectory, increasing rates below 1 percent year after year until avoided costs payments and savings end.

The other models cause sharper rate increases in the early years and then lead to rate reductions between five to seven years into the efficiency timeframe, when program costs have all been collected. Under the Shared Savings model the rates are higher in the first seven years on average but are reduced from the reference case on average for the next seven years. Under the Bonus ROE model the rate impacts are less pronounced compared to the Shared Savings model. The rates are higher in the first seven years on average but are lower for the next seven years. (This figure excludes the ESCo model, which is much less applicable to mass market customers.)

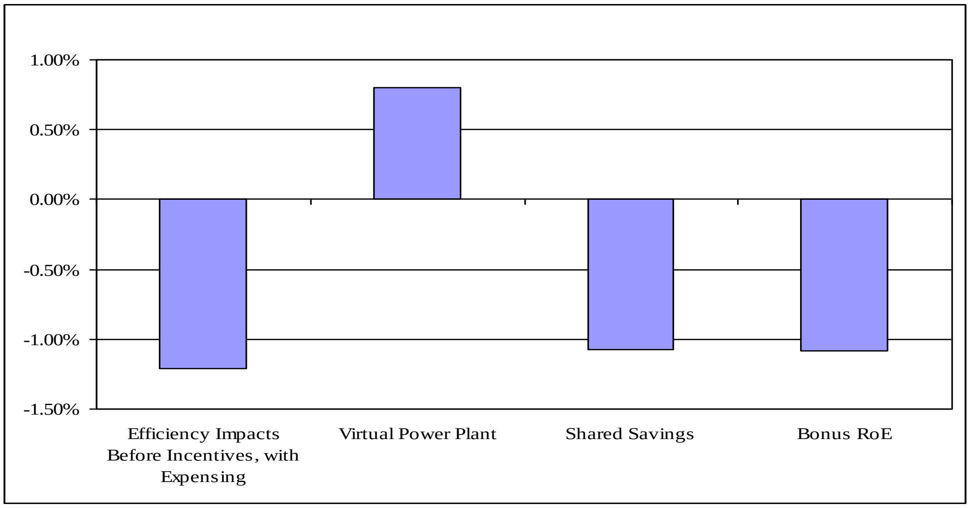
These average annual changes in rates are shown in the Figures 12 and 13 below, for the simulations. (These finding are indicative, but no strong conclusions for utility-specific applications should be drawn.)

Figure 12: Simulated Average Annual Change in Rates for the First Seven Years
(No Present Valuation)



[44] The argument could be made that this $37 million does not include the option value of the efficiency programs that non-participants had the opportunity for but did not join.

Figure 13: Simulated Average Annual Change in Rates for Years Eight through Fourteen
(No Present Valuation)



3. Net Benefits under Different Incentive Mechanisms

As discussed above, the benefit cost test shows that the prototypical EE program of this modeling project, when conducted for five years, creates $216 million in net societal value. That is, the total avoided energy and capacity cost savings of $434 million exceed the real economic costs of $152 million by $216 million. The general public policy norms say that the economic welfare of the customers is important. The sharing of benefits to shareholders is an important means to that end. Competitive industries, without regulation of prices, are assumed to hold down prices and provide quality products "as if by an invisible hand," so that entrepreneurs generate profits at a competitive level in the long run. Here we model the regulatory-authorized earning of a shareholder profit incentives, which can motivate the utility to focus its efforts and achieve greater overall efficiency savings.

There are four business/incentive models. Note again that all comparisons are only for the simulated business models. They do not represent general characteristics of the models, which must always be evaluated in a specific utility situation. Figures 14 to 17 below show the composition of the net resource benefits of the energy efficiency program considered in the model. In each of these figures the first bar represents the total cost avoided due the implementation of the efficiency programs, the second bar represents the total installed cost of the energy efficiency measures, and the third bar represents the real administration and implementation cost related to the running these efficiency programs and installing measures. The magnitude of these first three bars follows from the design of the program and is common across all business models. The difference between the avoided costs and the sum of the costs of the energy efficiency measures and program administration costs represents the total resource net benefit that is shared between the ratepayers and the utility and its shareholders. The simulated shares are shown in the next two bars and their relative magnitudes are driven by the assumptions underlying the different incentive mechanisms. All values in Figures 14 to 17 below represent present values using the ATWACC[45] as the discount rate.

[45] The after-tax weighted average cost of capital (ATWACC) is a standard discount rate used for regulated utilities, and we adopt it.

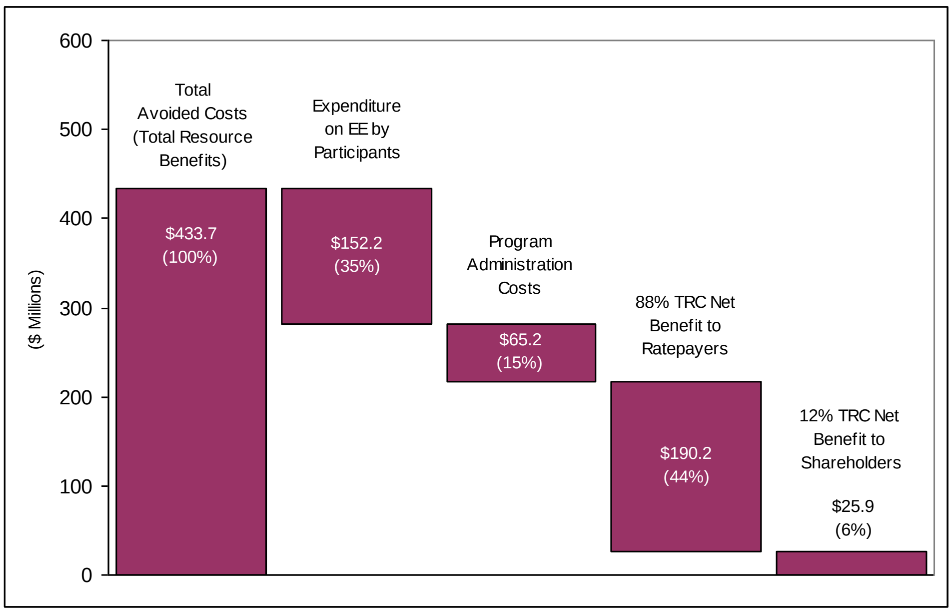
A result common across all models is that the bulk of the share goes to the customers while the utility shareholders retain the smaller share of the net resource benefits.

Shared Savings Model

The Shared Savings incentive is directly derived from the Total Resource Cost test. We assume that utility is ultimately allowed to retain 12 percent of net benefits (in present value terms) from the EE program, as incentive payment for effectively implementing the program. The simple sharing of net benefit impact is that ratepayers' Total Resource benefit is the residual 88 percent, when the utility/shareholders get their 12 percent. The figure below shows the components of the TRC NPV.

Figure 14: The Simulated Benefits and Costs under Shared Savings Business/Incentive Model

($ PV Millions)



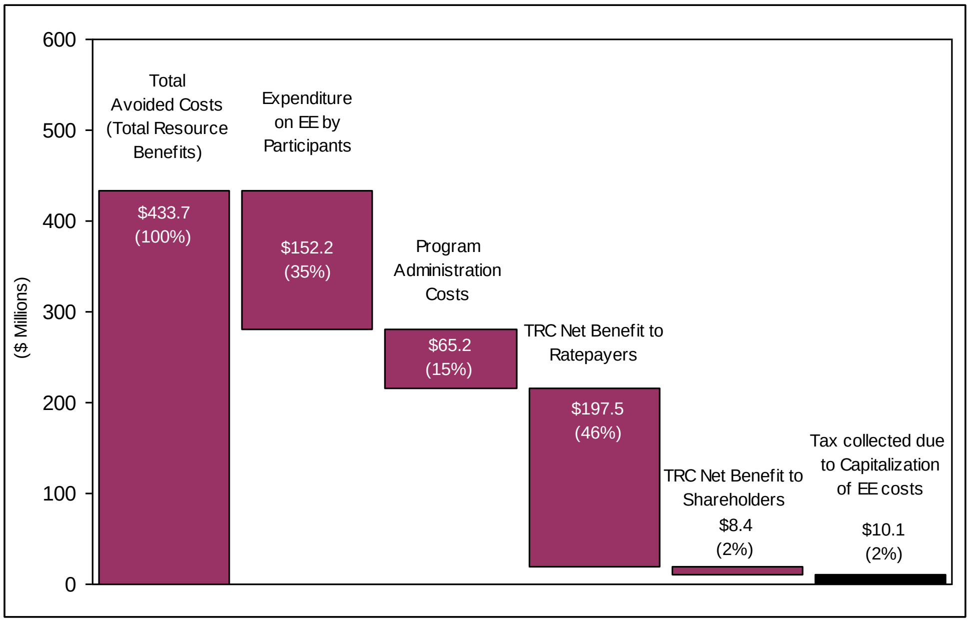
The Ratepayers get the largest share of total benefits at 44 percent.

Bonus Return on Equity Approach under Capitalization of Costs

The figure below shows the components of the TRC NPV. Note that the NPV to the utility shown in the figure below only accounts for the bonus return on the EE costs incurred by the utility and treats the regulated return on equity and debt used to finance the regulatory asset as a cost (opportunity cost) of doing the EE program.

Figure 15: The Simulated Benefits and Costs under Capitalization With Bonus ROE Business/Incentive Model

($ PV Millions)



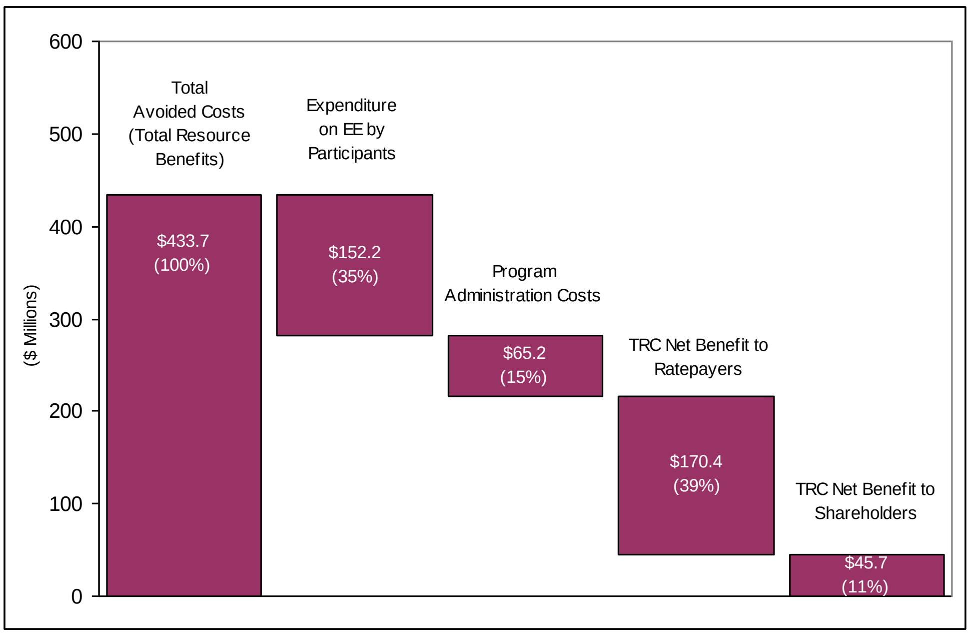
The before tax component of the return on the capitalized energy efficiency, regulatory asset (except the bonus ROE), is not accounted for by the present value of the return to shareholders. This is shown by the black bar in the figure above.[46]

[46] This discrepancy results from the choice of ATWACC as the discount rate and collection of return on the capitalized energy efficiency asset on a before tax basis, where ATWACC = (1-tax rate)*BTWACC, whereas in the calculation of the net resource benefits these program costs are discounted using ATWACC.

Virtual Power Plant

As mentioned before, under the Virtual Power Plant incentive mechanism we assume no recovery of Lost Fixed Revenues. Hence, the Lost Fixed Revenue factor is zero for all years.[47] The figure below shows the components of the TRC NPV under the Virtual Power Plant incentive mechanism.[48] In interpreting Figure 16, remember that for the purposes of our demonstration we have assumed that all business models produce the same level of efficiency investment and savings. In reality, because the VPP model may contain stronger incentives than the others, it may produce greater investment, and greater savings. As a result, customers could well enjoy a greater total bill savings under VPP than they would under other business/incentive models. Again, the point of this exercise is to illustrate *how* to use the results of utility-specific simulations to frame decisions about efficiency strategy. These generic, simplified results should not be taken as representative, or reliable, for any real world utility.

Figure 16: The Simulated Benefits and Costs Under Virtual Power Plant Business/Incentive Model
($ PV Millions)



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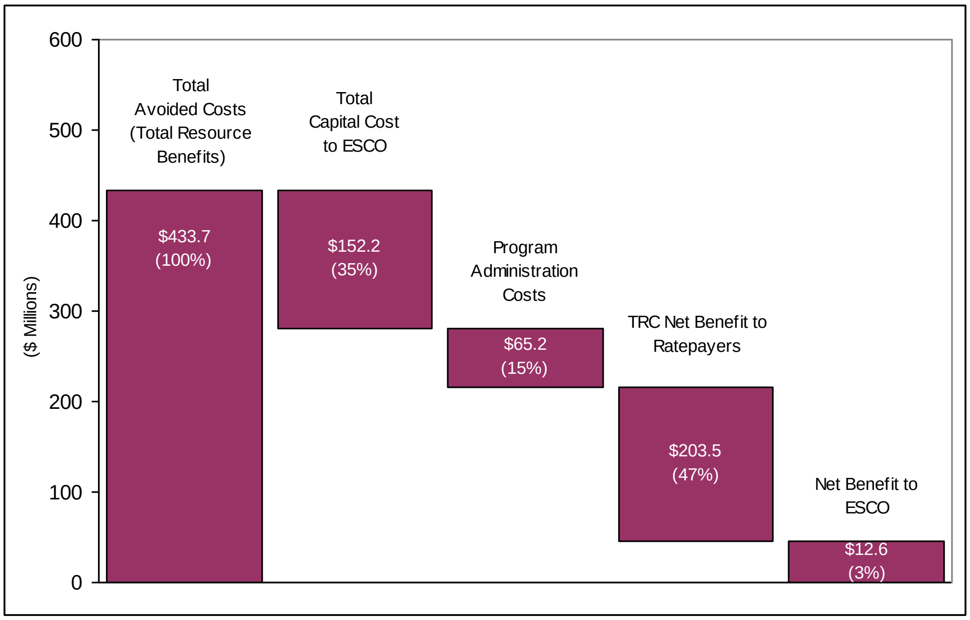
[47] Given that recovery of lost fixed revenues is assumed to be a function of years in which rate cases are completed, we model this by assuming no rate case is completed in any of the 14 years of the study period.

[48] Stated alternatively, under the VPP incentive mechanism (where LFR is "lost fixed revenue"): Utility/Shareholder NPV = 85 percent avoided costs – Incentives to Participants – Program Administration Costs – LFR; Ratepayers' NPV = 15 percent avoided costs + LFR + Incentives – EE-related expenditure**.**

Regulated ESCo Approach
Under this approach the EE programs are implemented by a regulated energy service company (ESCo) while the utility is made whole with respect to the EE program impacts in terms of lost fixed revenues. The figure below shows the components of the TRC NPV under this approach. We assume in our simulation that lost fixed revenue is recovered (this is a user option).

Figure 17: The Simulated Benefits and Costs Under Regulated ESCo Business/Incentive Model
($ PV Millions)



The net benefits to general ratepayers are large in this business model because the participating customers pay a greater share of installed measure costs. Again this may well mean that the scope of the Regulated ESCo model is inherently smaller (although for comparability, we model it for the same sized efficiency program).

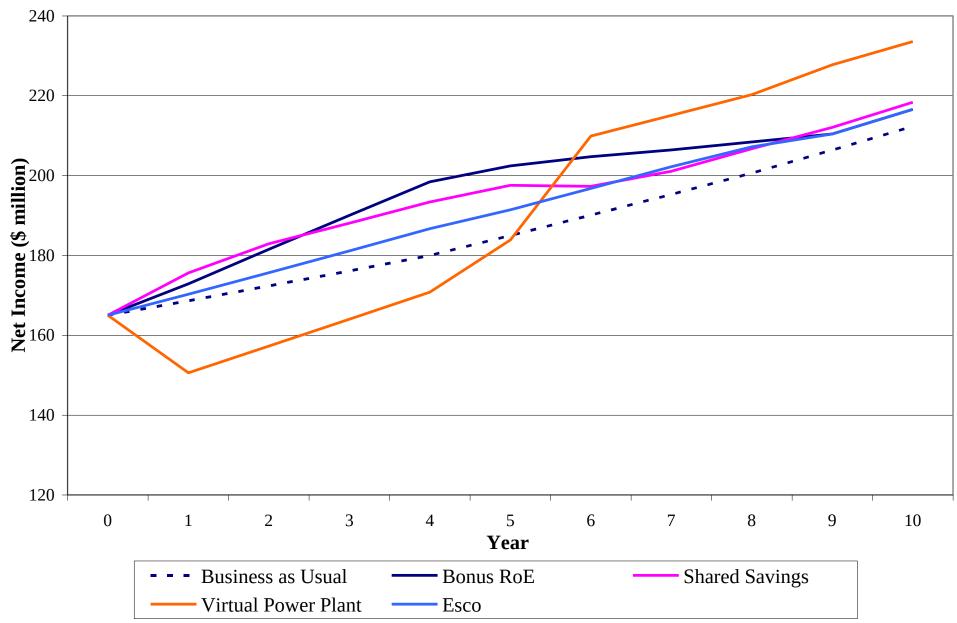
In summary, the greater share of benefits goes to the customers while there is a moderate level of benefit, or profit, left to the shareholders.

4. Financial Impacts of Efficiency Programs and Incentives

In our baseline no-EE program, the income of the prototype utility grows steadily. This can therefore serve as a benchmark against which to evaluate the merits of each model. One caveat when using the prototype utility's growth without energy efficiency is that it models growth simply as a growth in operating costs that are then recovered in revenue. Further, we assume that growth occurs smoothly over time and that growth in assets is financed similarly to historical assets, so the model does not consider the changing cost environment or financing issues.

The Shared Savings model starts sharing in obtained savings and sees its revenue and hence income grow over a number of years up front, after which it tapers off as energy efficiency savings taper off. Similarly, the Capitalized Efficiency/Bonus ROE model recovers a return on and of efficiency costs in early years and then sees a decrease as the regulatory assets of capitalized costs is depreciated. The Regulated ESCo finances energy efficiency initiatives in early years and also receives a large share of bill savings in early years and a smaller share in later years. With the model's parameters, this appears as a fairly smooth income stream. Finally, the Virtual Power Plant model[49] requires the utility to incur large up-front expenses which show up as a decline in income and cash flow. After year five, the utility continues to receive 85 percent of the long-lived avoided costs and therefore sees its revenue and income increase substantially. These patterns are shown for the first 10 years in Figure 18 below.

Figure 18: Net Income under Different Shareholder Incentive Scenarios



Note: Absolute scale reflective of prototype model rather than

From Figure 18, it is evident that for the prototype utility the Virtual Power Plant model gives rise to a more volatile income stream over time than do the other models. While the particular location of the graphs depend on the parameters with which we implement the model, the degree to which income is postponed and varies is a unique feature of the Virtual Power Plant model, as we have modeled it. This Virtual Power Plant model exposes the utility to more risks than the other methods.[50]

Both shareholders and creditors are concerned with measures of financial health other than earnings (income). One such measure which is of substantial importance to both shareholders and creditors is the utility's cash flow. Cash flow is typically more variable than is earnings regardless of whether the utility undertakes energy efficiency initiatives or not. From a credit worthiness perspective, a substantial reduction

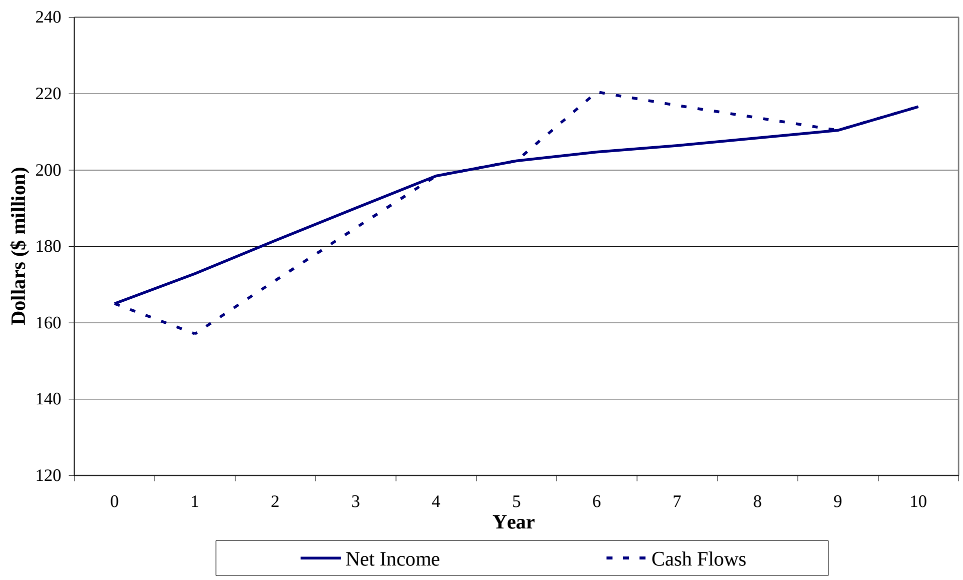
[49] As discussed above in the Executive Summary, footnote 2 and Section III.C.3, the treatment of VPP in this report ties revenue to the actual long-term flow of total avoided cost savings and does not attempt to bring the revenue forward in time, as one visible, current proposal for the VPP method does.

[50] Because a basic principle in finance is that there is a tradeoff between the risks and returns of an investment, our assumption that the return on capital is the same all under all five models is probably a simplification.

in cash flow may impact the utility's credit metric and ultimately its credit rating.[51] It is therefore important to look to the timing and the size of impact on cash flow of any energy efficiency initiatives the utility is considering.

Figure 19 below shows the net income (earnings) and cash flow associated with the Capitalized Efficiency/Bonus ROE model when a 5 percent Bonus ROE is in place. Because the costs of energy efficiency measures are capitalized when incurred and expensed in subsequent years, the utility's income statement shows less volatility than does the cash flow. The cash outflow occurs up front while expenses spread out in time and recouped later as depreciation. In addition, the Bonus ROE is applicable over the four-year period that is used to depreciate the measures. In the model, all other differences between the utility's income and cash flow were assumed constant.

Figure 19: Net Income and Cash Flow of Bonus ROE Model



Note: Absolute scale reflective of prototype model rather than actual utility.

Similarly, both the VPP and the Regulated ESCo models give rise to delayed cash flows because the utility finances the energy efficiency measures up front but recovers its costs and incentive payment at a later date.

5. *Impact of Lost Fixed Revenue*

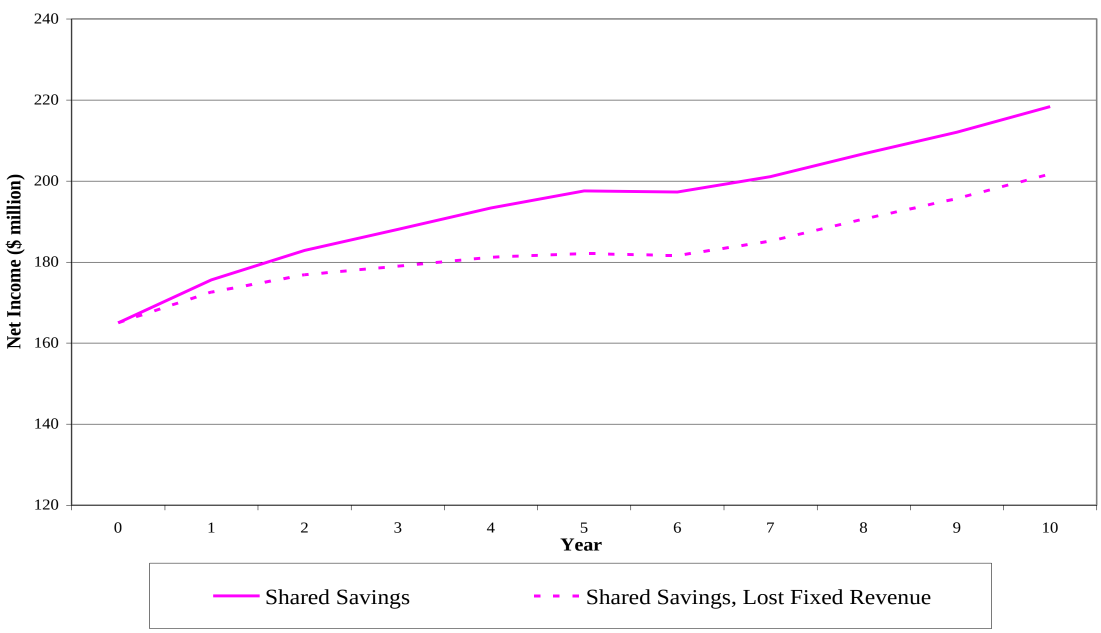
Lost fixed revenue (lost base revenues or lost margin) is caused by the fact that, all other things being equal, energy efficiency decreases the kWh sales. Because fixed or sunk costs are included in the volumetric

[51] Standard & Poor's (S&P), which is one of the major credit rating agencies, looks at two cash flow based measures when assigning credit ratings, among other factors. According to S&P, key measures they review are the Funds from Operations to Interest Expense, Funds from Operations to Total Debt, and Total Debt to Total Capital. Funds from Operations is closely linked to cash flows generated from operations. See, for example, Standard & Poor's, *Corporate Ratings Criteria 2006*. A utility's credit rating affects its debt cost (interest) and its ability to access credit markets, particularly during times of less liquidity as experienced during the recent subprime crisis.

charge per kWh, a reduction in kWh reduces the recovery unless an adjustment is made to rates. We calculate lost fixed revenues for each year the energy efficiency program is in effect. Thus, the lost fixed revenue in year *t* is the sum of the lost fixed revenues that is created by energy efficiency programs stated in year *t* or earlier. This loss can be offset by adjusting rates upwards to recover these losses. The model adjusts the rates exactly enough to offset these losses and the adjusted rates are then reflected in revenues in scenarios with lost fixed revenue recovery.

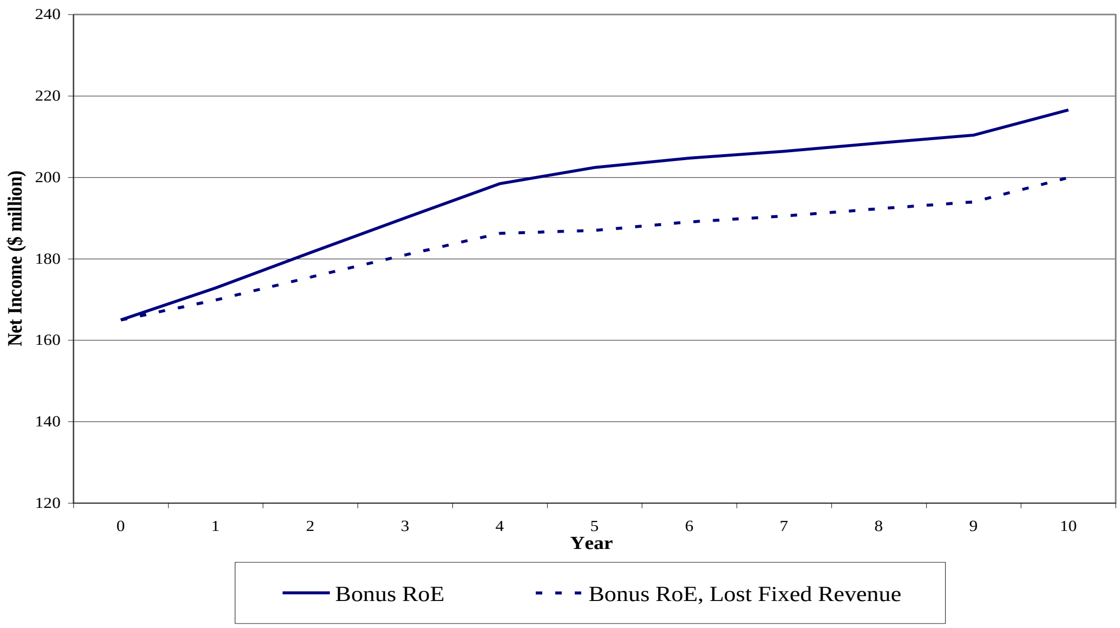
For simulation purposes, we assume that lost fixed revenues may be recovered in the Shared Savings, Capitalized Efficiency/Bonus ROE, and Regulated ESCo models, while the VPP model does not assume lost fixed revenue recovery. In the financial model we estimate the additional income that flows to the utility as a result of lost fixed revenue recovery. This amount can be quite substantial. Figures 20, 21, and 22 below depict net income with and without lost fixed revenue recovery for the Shared Savings, the Capitalized Efficiency/Bonus ROE, and Regulated ESCo, respectively. As can be seen from the figures below, allowing electric utilities to recover lost fixed revenue can be very important, as it can substantially affect the profitability of the utility. It is therefore important that a utility and jurisdiction that consider enhancing the energy efficiency programs in their service territory not only consider shareholder incentives but also the treatment of lost fixed revenue. Thus, the model assumes there are not revenue requirement true-ups during the planning horizon.

Figure 20: Shared Savings—The Impact of Lost Fixed Revenue Recovery



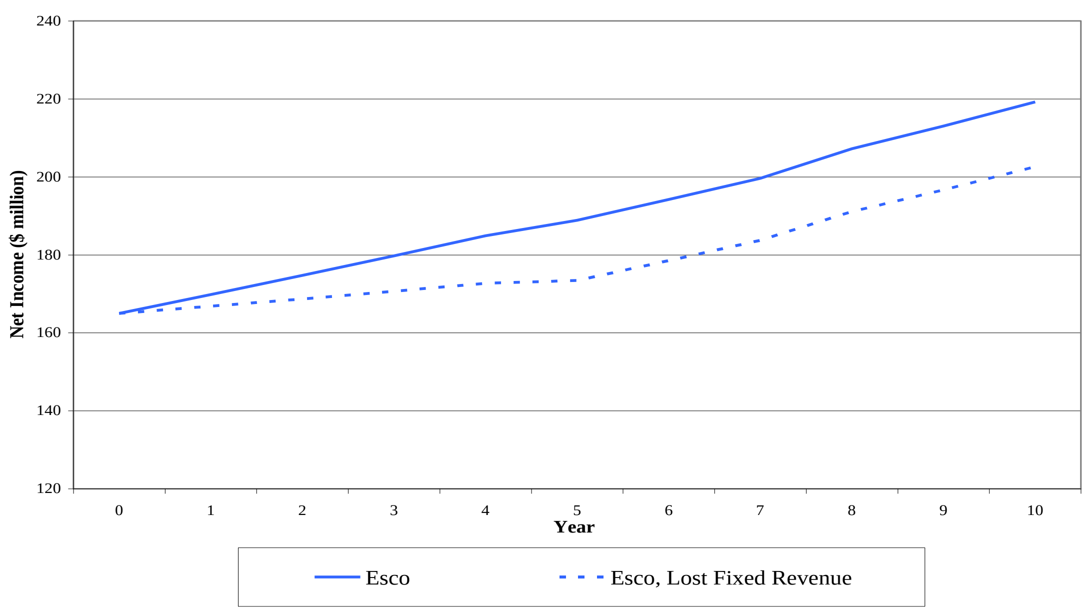
Note: Absolute scale reflective of prototype model rather than actual utility.

Figure 21: Capitalized Efficiency/Bonus ROE—The Impact of Lost Fixed Revenue Recovery



Note: Absolute scale reflective of prototype model rather than actual utility.

Figure 22: Regulated ESCo—The Impact of Lost Fixed Revenue Recovery



Note: Absolute scale reflective of prototype model rather than actual utility.

The impact on cash flow from lost fixed revenue is the same for all models and comparable to the net income impact shown above. While the cash flow is delayed compared to revenues, the impact on cash flow over the life of the energy efficiency programs is exactly the same as the impact on net income.

D. Conclusions

1. Illustrative Differences/Tradeoffs among Different Business Models

The business/incentive models that have been discussed do not attempt to capture the details of any one company's circumstances, be they operational, financial, or jurisdictional. However, we believe the models do provide valid insights into some tradeoffs and key aspects of energy efficiency initiatives. Some key elements are discussed below.

Energy Efficiency Initiatives May Affect Income (Earnings), Cash Flow, and Customers' Rates Differently, and All Measures Are Important

As illustrated in the figures just above, the income and cash flow pattern differ across the shareholder incentive models. Specifically, the Capitalized Efficiency/Bonus ROE, VPP, and Regulated ESCo incur cash costs up front that only later are recovered in rates. Therefore, the positive cash flow tends to be delayed. The Shared Savings model does not have this feature. The timing of impacts on customer rates was discussed above. Cash flow impacts and rate impacts tend to move together in time but with opposite pressures on the utility.

In the model, the VPP exhibits the most delay in cash flow and income. (We do understand that the VPP model as recently proposed in South Carolina intends to move positive cash flow up in time; so as to better match the cash outflow, this was not captured by our model.) Because both income and cash flow matters to investors, any incentive scheme need to consider both the impact on cash flow and income. Rate impacts are important to manage as well.

The Impacts on Customer Rates Differ

In the Shared Savings model, the rate impacts are somewhat front-loaded, as all program costs in our model are incurred in the first five years of the study period. In the later years the average rate in this model declines relative to the reference rate, because the avoided capacity costs are higher than lost fixed revenues. In the Capitalization with Bonus ROE model, the rate impacts are of a smaller magnitude in the first few years but are spread out over a longer duration compared to the Shared Savings model. In the VPP, we find the smoothest rate impact profile. VPP has the lowest rate impacts in the first five years, but there is positive upward pressure on rates (as distinct from bills) over a considerably longer period.

These rate impacts are calculated for the same EE program impacts. The overall assessment of the rate impacts would be more complicated if the incentive were simulated as having an impact on program success. This may be something that future users will investigate.

The Inherent Risks in the Models Differ

Only the Shared Savings model does not require an up-front cash commitment from the utility, because it assumes expensing of all utility costs. It therefore has less risk of "stranding costs" than do the other models from future changes in regulatory policy. The VPP model has the largest up-front commitment of costs from the utility relative to when the revenues are to be received, and therefore a larger inherent risk of stranding costs. The Capitalized Efficiency/Bonus ROE and the Regulated ESCo models both have some up-front cash commitment from the utility and sit between the Shared Savings and the VPP models.

Because the timing of the cash/income recovery of the models differs, so does the value of the positive cash flow. Everything else being equal, cash today is more valuable than (the same amount of) cash tomorrow. The degree to which a delay in positive cash flow matters to a utility will depend on many factors, but for utilities that are more cash constrained, have less capital market access, or are closer to a governance constraint or credit metric constraint (e.g., nearing the lower bound of one of S&P's ratio benchmarks), the more important timely income and cash flow are likely to become. As the delay between a utility's outlays for energy efficiency initiatives and the positive cash increases, the importance of strong regulatory pre-approval increases.

In sum, it is highly unlikely that there is one model that will fit all electric utilities. Instead, the choice of mechanism will depend on the utility's specific circumstances as well as its jurisdiction.

Recovery of Lost Fixed Revenue Can Be Very Important

As illustrated above, the recovery of lost fixed revenue is important and in many instances at least as important as is shareholder incentives. The importance is likely to be situational dependent, perhaps a complex function of the growth in revenues from all sources, the growth in revenue requirements, and the planning for rate cases. The simple prototype models are not designed to deal with this issue. However, without an adequate recovery of lost fixed revenue in a given situation, revenues and thus net income and cash flow may decline. The utility could be creating a larger shareholder value without energy efficiency than with energy efficiency plus shareholder incentives alone.

A Shareholder Incentive is Important

In all models, shareholder incentives improve income and cash flow over their absence and serve as an offset to the lost opportunity for investment in new power plants and infrastructure. However, we have not investigated the degree to which the offset in any of the shareholder incentives is commensurate in present value dollars. Moreover, lost revenues from energy efficiency initiatives if not fully collected can further erode earnings. In other words, utilities are facing a tradeoff between income created through growth in energy consumption and income from incentives to conserve energy.

Across the business/incentive models, the VPP model has a somewhat larger potential shareholder incentive. It is common practice in competitive markets to reward higher risks with higher returns. Not surprisingly, we find that VPP has the largest up front cash outlay and a longer delay until there is positive cash flow (as we have modeled VPP). As we have modeled it, VPP cash at risk is somewhat larger in this simulation than in other shareholder incentives. [52]

[52] Again, we understand that the VPP model that currently is being considered in SC does improve the cash flow, but treating the total avoided cost stream as a regulatory asset to be amortized. The model can be extended to look at the simulated results.

2. Developing Company-Specific Analyses

As noted above, no one business model is likely to work for all utilities. Each model has its own risk and reward tradeoff. For example, the timing of cash outlays and earnings differ, as do the magnitude thereof. Therefore, each utility will need to make a company-specific evaluation of the risk and potential return taking into account its unique circumstances. In doing so, it is important that the utility consider the treatment of lost fixed revenue in its jurisdiction as well as shareholder incentives.

IV. Appendix

A. CEO Energy Efficiency Task Force

Michael J. Chesser
Chairman and CEO
Great Plains Energy

Peter A. Darbee
Chairman, CEO, and President
PG&E Corporation

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President and CEO
Duke Energy

Dennis R. Wraase
Chairman, President and CEO
Pepco Holdings, Inc.

Patricia K. Vincent
President and CEO
Public Service Co. of Colorado

John B. Ramil
President and COO
TECO Energy, Inc.

David M. Ratcliffe
Chairman, President and CEO
Southern Company

Jeffry E. Sterba
Chairman, President and CEO
PNM Resources, Inc.

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National Grid USA

Michael T. McCall
Chairman and CEO
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Florida Power & Light Company

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CMS Energy Corp.

James S. Haines
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Westar Energy

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PG&E Corporation

Dee Brown
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Tampa Electric Co

Joseph G. Belechak
Senior Vice President and COO
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Pepco Holdings, Inc

Thomas R. Standish
President, Regulated Operations
CenterPoint Energy, Inc.

David M. Sparby
Vice President, Govt. & Regulatory Affairs
Xcel Energy

Hank Courtright
Sr. VP, Member Services & Environment
EPRI

B. The Rate Change Factors

The change in rates to all customers is closely linked to the framework and design of the different incentive models. To illustrate this point, consider the recovery of program costs. In the Shared Savings model these costs are expensed and recovered through rates in the year in which they are incurred. In the Bonus ROE model each year's program costs are capitalized and recovered over the assumed length or period of amortization of such costs. Finally, in both the Virtual Power Plant model and the ESCo model these costs do not affect the rates, as they are borne by the utility and the ESCo respectively and covered by the revenue earned, as in any competitive, unregulated business. While there are differences, some common issues, such as dealing with lost fixed revenues margin, apply to all business models.

To study the overall impact on rates, we calculate causal factors that affect rates for different cost recovery aspects of the incentive models. Given the inherent differences in these business models, different sets of factors apply to each model. For expository convenience, we first describe the different factors considered and then discuss the applicability of these factors under each incentive model.

Avoided Capacity Cost Factor. The Avoided Capacity Cost factor distributes the costs attributable to avoided fixed costs to all ratepayers. The intuition is that all fixed costs avoided due to conservation that are reflected in the fixed rates in the no energy efficiency world are adjusted to reflect the fact that those costs were not incurred in a world with conservation. This factor is calculated by dividing the fixed avoided costs by the total number of units consumed by all customers in the energy efficiency world. The shape of the curve follows the time profile of the energy savings (MWh) created by the energy efficiency programs and the assumed avoided capacity cost per kWh.

Lost Energy Recovery Factor. In the general case,[53] the Lost Energy Recovery factor recovers the losses (or distributes the gains) due to any difference in utility's energy component of avoided costs and the energy component of rates. It is calculated by dividing the difference between the aggregate allowed revenues to recover cost of energy, which is included in the pre–energy efficiency reference case, and the cost of energy, which is avoided through efficiency improvement by the total number of units consumed by all customers in the energy efficiency world. However, our example is simpler, because we assume the equality of variable energy rates and energy avoided costs. In this case, this factor is zero and there is no energy impact on rates.

EE Cost Recovery Factor. The EE Cost Recovery factor collects from all ratepayers the sum of the program administration costs and cash incentives given by the utility to all participants. It is calculated by dividing the sum of program administration costs and cash incentives given by the utility to all participants by the total number of units consumed by all customers in the energy efficiency world.

Lost Fixed Revenue Factor. The Lost Fixed Revenue factor recovers the costs attributable to lost fixed revenue from energy efficiency sales reductions. As mentioned above, without a factor, the actual loss would take place between the rate case years. "Decoupling" is sometimes used to describe the issue we are dealing with, but involves many other issues such as the effect of weather on sales that are not part of our modeling effort. Therefore, we adopt this terminology of "lost fixed cost recovery." Under this scenario we assume perfect annual ratemaking (i.e., we adjust rates at the beginning of every year to recover fixed costs that

[53] The situation might arise where the difference was material, if the energy efficiency measure saved primarily summer, on-peak, expensive natural gas costs, and the fuel clause was independently recovering a broad annual average fuel factor including coal.

otherwise would be stranded by declining kWh sales). We calculate this factor by dividing the lost fixed revenue by the total number of units consumed by all customers in the energy efficiency world. Under the assumption of perfect annual ratemaking, this factor rises for the first five years when the energy efficiency programs are conducted and new customers enroll each year, thereby raising the total lost fixed revenues. For the next five years it remains at nearly the same level (affected by rising sales units and rising base rates) as no new programs are implemented after the fifth year.[54] From years 11 through 14 this factor declines due to the decline in the units of energy conserved as programs sequentially reach the end of their lives. Lost Fixed Revenues are in a sense the mirror image of the Avoided Capacity Costs, only smaller. Both value streams last as long as the energy efficiency MWh savings stream lasts. The Avoided Capacity cost stream is larger, in conformance with the expectation that the next generation of infrastructure investments, especially power plants, are more expensive than the sunk costs of yesterday's infrastructure investment.

As mentioned before, under the Virtual Power Plant incentive mechanism we assume no recovery of Lost Fixed Revenues. Hence, under this incentive model the Lost Fixed Revenue factor is zero for all years.[55]

Shared Savings Factor. The reward to the utility and its shareholders for engaging in energy efficiency efforts in the Shared Savings incentive model is earned through the Shared Savings factor. This factor is calculated by dividing the incentive payment the utility receives in the form of Shared Savings by the total number of units consumed by all customers in the energy efficiency world. We assume that the utility is allowed to collect 12 percent of Total Resource net benefit (in present value terms) from any energy efficiency program as incentive payment for implementing the program. Of this amount, as previously discussed, 70 percent is recovered by the utility in the second year of the program and 30 percent is recovered in the seventh year of the program.

Capitalization Factor. In the Bonus ROE incentive model each year's program costs are capitalized and recovered over the assumed length or period of amortization of such costs. Under this incentive mechanism, as discussed before, the utility is allowed to earn extra 500 basis points on its equity portion of the total program costs. The Capitalization factor is calculated by dividing the sum of amortization of the capitalized asset, before tax return on debt and before tax return on equity (including the bonus return) by the total energy consumption.

85 Percent Avoided Cost Factor. The Avoided Cost factor (that collects 85 percent of total avoided costs) rewards the utility in the Virtual Power Plant incentive model for its energy efficiency efforts. It is calculated by dividing the total avoided costs (fixed and fuel) by the total number of units consumed by all customers in the energy efficiency world. This factor rises for the first five years as a new energy efficiency program is implemented in each of the first five years and new customers enroll thereby raising the total avoided costs. For the next five years it remains almost at the same level (with some fluctuations caused by avoided fixed costs rising from 9 cents per kWh in the eighth year to 10 cents per kWh in the ninth year and total consumption in the energy efficiency world also gradually rising due to the growth in the number of total customers). After the tenth year this factor falls every year as programs sequentially reach the end of their lives.

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[54] This factor falls only slightly between the sixth and the tenth years. The total lost fixed revenues go up due to a small increase in the base rates (note that units of energy conserved between these years remains constant). However, total units of energy consumed by all ratepayers go up during these years due to increase in the number of customers. The net effect of the two opposing forces is to slightly lower the Lost Fixed Revenue factor.

[55] Given that recovery of lost fixed revenues is assumed to be a function of years in which rate cases are completed, we model this by assuming no rate case is completed in any of the 14 years of the study period.

Rate Recovery Factors and Incentive Models

As discussed previously, based on the assumptions of cost recovery in each incentive mechanism a different set of factors applies to each business model. The table below shows the different factors and whether or not they apply to each incentive model.

Table 5: Rate Change Factors and Incentive Models

	Lost Energy Margin Factor	Lost Fixed Revenue Factor	Avoided Capacity Cost Factor	EE Cost Recovery Factor	Shared Savings Factor	Capitalization Factor	85% Avoided Cost Factor
Utility Made Whole	X	X	X	X			
Shared Savings	X	X	X	X	X		
Bonus RoE	X	X	X			X	
Virtual Power Plant	X	X*	X				X
Regulated ESCO	X	X	X				

Note: (*) Under the Virtual Power Plant incentive model we assume no recovery of Lost Fixed Revenues, and hence this factor is zero in all years.

The first three listed factors, Lost Energy Margin, Lost Fixed Revenue, and Avoided Capacity Cost factors, apply to each incentive model. Note, however, that based on the assumption of no recovery of lost fixed revenues in the Virtual Power Plant business model, the Lost Fixed Revenue factor is zero in all years in that model. The total program cost incurred by the utility is recovered through the EE Cost recovery factor in the approach where the utility is made whole or breaks even and in the Shared Savings business model. The incentives paid to the utility in the Shared Savings model is collected through the Shared Savings factor. In the Bonus ROE model, the Capitalization factor not only recovers the program costs incurred by the utility but also collects the incentive paid to the utility for engaging in energy efficiency efforts. In the Virtual Power Plant model, the 85 percent Avoided Cost factor is designed to collect the incentives for the utility under this business model. As discussed before, in this business model the utility bears all the program costs. In the regulated ESCo model the utility is made whole and the ESCo bears all the program related expenses. Hence, from the perspective of factors that affect rates, in order to make the utility whole, we calculate three rate change factors; namely, the Lost Energy Margin factor, the Lost Fixed Revenue factor, and the Avoided Capacity Cost factor. The graphs below show the time profile of the different factors under each business model.

Figure 23: Rate Adjustment Factors in the Case where the Utility Is Made Whole

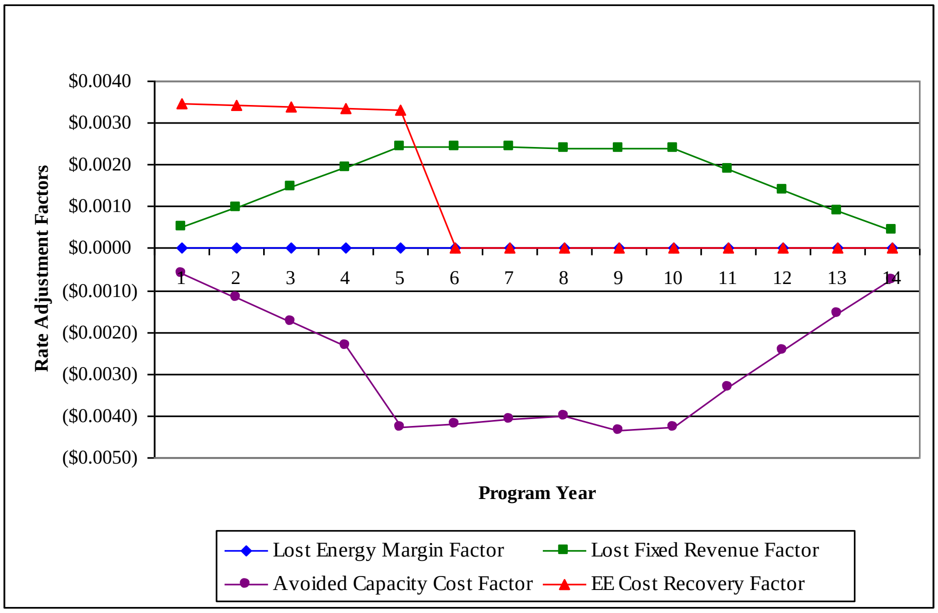


Figure 24: Rate Adjustment Factors in the Shared Savings Incentive Model

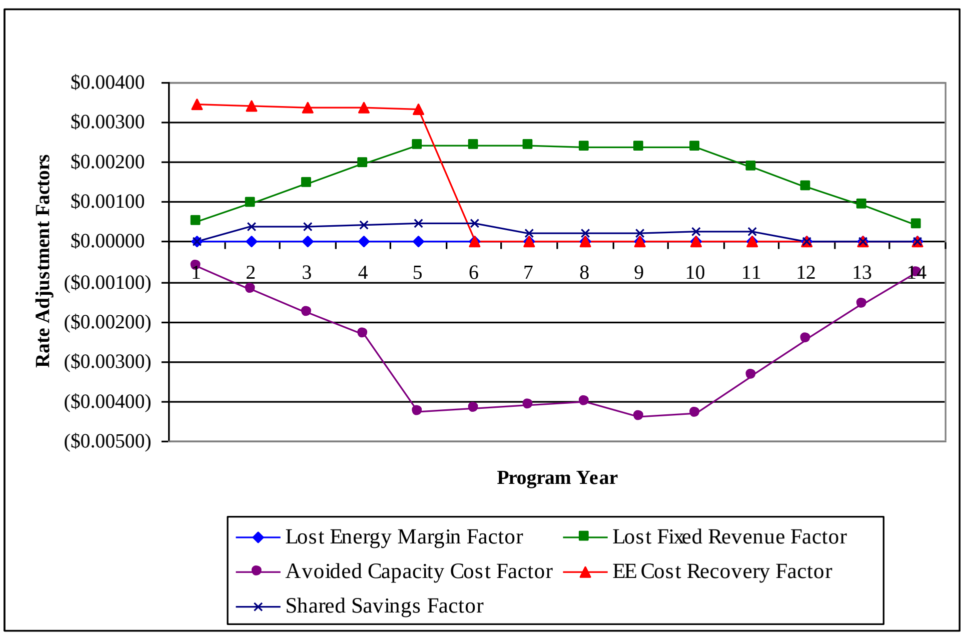


Figure 25: Rate Adjustment Factors in the Bonus ROE Incentive Model

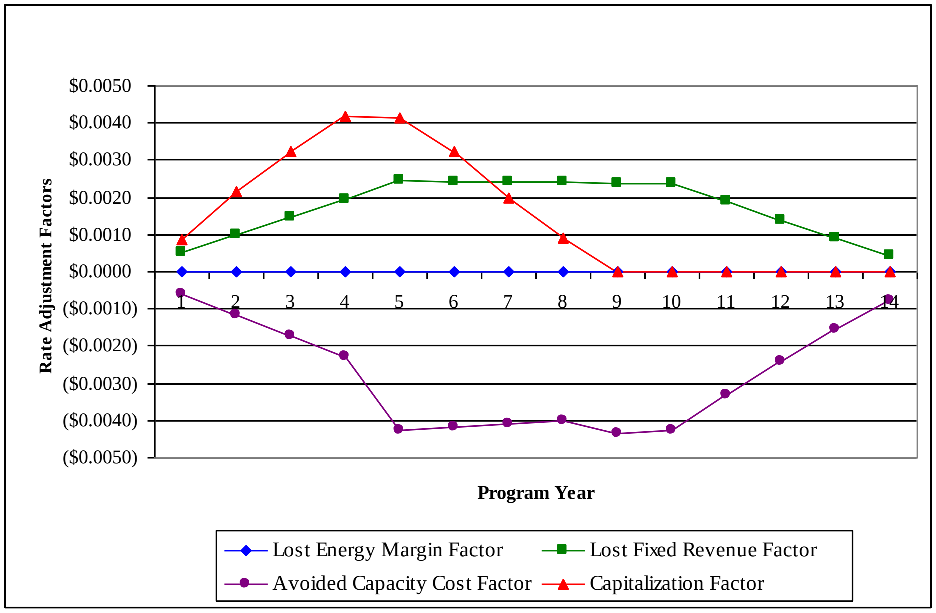


Figure 26: Rate Adjustment Factors in the Virtual Power Plant Incentive Model

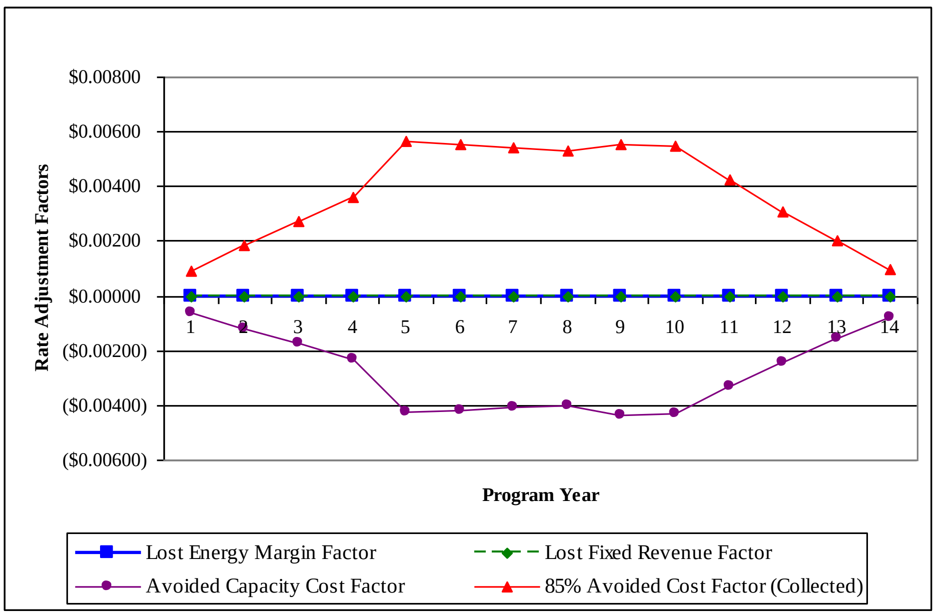
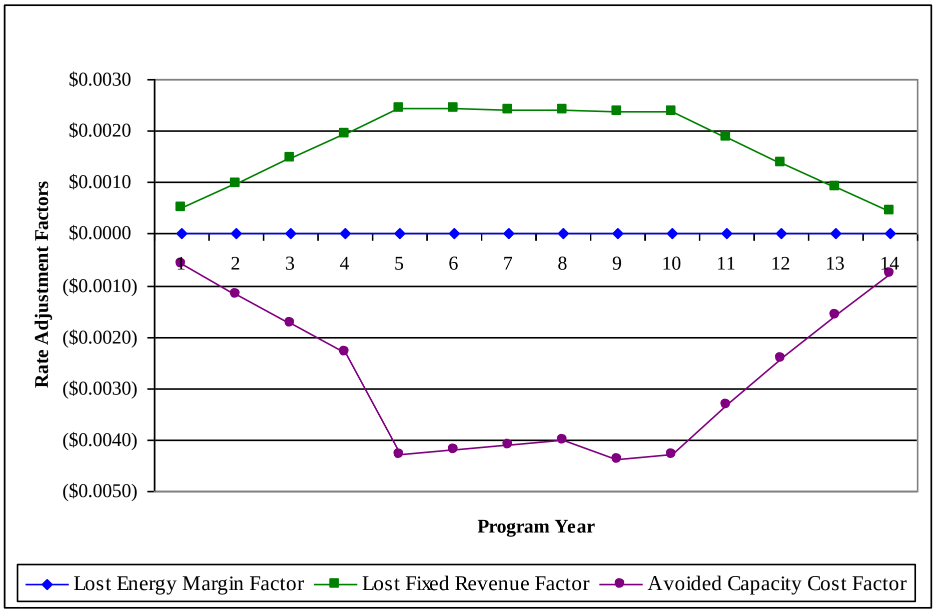


Figure 27: Rate Adjustment Factors in the Regulated ESCo Incentive Model



C. The User's Guide for Shareholder Incentive Model ("ShareIM")

Disclaimer. This is the User's Guide for the beta version of the Shareholder Incentive Model (ShareIM). All results are derived from a hypothetical modeling exercise and are based on assumptions made. When users of the model want to draw conclusions relevant to their own situations, they should take responsibility for determining all relevant inputs and validating all results. The results of the shareholder incentive mechanisms of this simplified model are not necessarily descriptive of the approaches adopted by various states, which can vary in the details and frequently change. All results must be judged on specific circumstances and state policy considerations.

Introduction. The Shareholder Incentive Model (ShareIM) was built as part of the EEI Efficiency Business Models Project to help members build new efficiency businesses. ShareIM evaluates four different, prototypical incentive mechanisms and their financial, rate, and customer impacts. Each business model analyzes an incentive mechanism to reward energy efficiency efforts undertaken by either a utility or a utility-owned, regulated energy service company (ESCo), and an accompanying approach dealing with recovery of program costs and lost fixed revenues as applicable. The details of the business models are discussed in a companion report by Brattle and EEI entitled "Building Sustainable Efficiency Businesses" (Report).

This User's Guide (Guide) to ShareIM is intended to provide the user of the model a description of the general structure of ShareIM and how to run it. There are two general uses to which ShareIM can be put. First, the user would use the model to understand the general principles of shareholder incentives. Reviewing the inputs, the calculations, and the results will provide a quick understanding of the different incentives, cost recovery mechanics, and the subject of lost fixed costs. Simulating different input values for the prototype utility will provide insight into the major shareholder approaches and what drives each. Second, some users would convert ShareIM to represent their own utilities, Demand Side Management programs, and the possible incentives that could be earned at different levels of commitment, budget, and performance. This User's Guide is largely directed at the first purpose. However, the kind of understanding that can be developed from reading the final report and using the model to see how general principles operate in simulation results will be very useful in modeling shareholder incentives for a particular utility.

The User's Guide also spends a little time explaining the Excel techniques used in the development of the model. The user is expected to have staff familiar with basic Excel formulas. The reader of this guide will be referred to various sections of the report when appropriate. Topics discussed at length in the report will not be elaborated upon in this guide, and as such, the report and this guide should be viewed as complementary documents.

The ShareIM is an Excel spreadsheet model and its various components are presented in a number of worksheets. This guide will describe the main contents of each worksheet. To assist the user in navigating through the model, this guide will combine sets of worksheets as appropriate. Throughout the spreadsheet model the following color coding has been used: all inputs are in black, simple cell references are in green, and formulas are in blue. The user of the model can change any of the inputs in black and all the results of the model will be automatically updated.

ShareIM contains the following four main categories of worksheets:

- General Description and Inputs
- Benefit-Cost Tests, including TRC, Participant, and RIM
- Recovery of Lost Fixed Revenues and the timing of general rate cases
- Shareholder Incentive Mechanisms

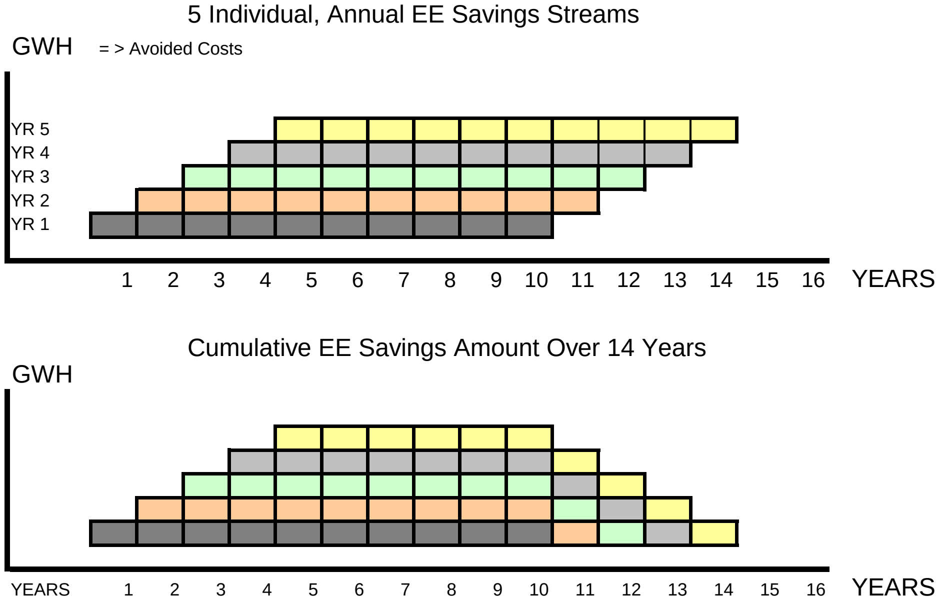
The worksheets that contribute to each of these categories are discussed in the above order.

1. *General Description and Inputs*

The "Read Me" worksheet provides a list of the different worksheets in the model and a corresponding basic overview of each worksheet. The "Notes" worksheet provides some basic notes for the model. The modeling process starts with the "Inputs" worksheet. It contains all the inputs to the model, including, but not limited to, the parameters of the energy efficiency (EE) program, the capital structure of the utility, the reference average electric rates in the "pre-energy efficiency" world, and parameters for the different shareholder business models.

The "MC (Marginal Cost) Inputs" worksheet contains the assumed per unit avoided costs, both capacity and energy, for each year over the planning horizon of ShareIM, which is 14 years. This planning horizon consists of five consecutive years in which the same size EE program is implemented, with assumed results. The lifetime of the EE Measures and thus the energy and capacity savings from each year's program is 10 years long. This makes 14 years altogether, as shown schematically in Figure 28.

Figure 28



Modeled in this way, the finite lifetime effects of the savings streams are clearly seen. However, this is at the cost of some realism, since most utilities have no plans to unwind completely from DSM at any future time. The "Inputs" worksheet also gives the user an option to levelize the unit avoided costs.

The marginal cost inputs are parameterized to increase the MC of capacity significantly and leave the MC of energy constant, in the default parameterization. This is just an assumption, but goes with an insight we are trying to convey. The MC of capacity is an important determinant of potential future electric rate increases. In relation to the factor in base electric rates set to recover the fixed or sunk costs of capacity, the MC of capacity is an important feature we looked at in terms of the RIM test and possible rate impacts.

Since many utilities have automatic fuel and purchased power adjustment clauses that adjust outside the general rate case process, the avoided energy costs may be automatically matched with bill savings of the same size. We feel there can be less interaction and more transparency so we simplified the assumptions. But rising marginal fuel increases would still have a direct impact on rates. The user should judge when or whether this assumption should be changed to simplify user input. For example, if the user wants to model increasing fuel costs because of carbon fees because of carbon taxes or cap and trade systems, the model can accommodate increasing energy costs (but does not have such a module built in).

Another important simplifying assumption is that ShareIM sets the future base electric rates in the "Pre–Energy Efficiency" or "baseline" world (also called the "but for" world) to include the effects of the assumed rising marginal costs of capacity, just to get started.[56] Using simple economic logic, ShareIM and its analytical approach then go about modeling the incremental impacts of the utility EE program, relative to

[56] A user doing a concrete analysis might start with the long term system plan and financial model run before the EE program as the starting point, but we created something simply for our prototypical utility. The way we got to our starting point is not a critical assumption.

what would have happened in the pre-EE world. Electric usage goes down, there are avoided capacity and energy savings, costs of EE programs are collected, etc. Before that, to determine pre–EE baseline electric rates, the marginal costs of capacity in year *t* are applied to the incremental MWh that customers would use in year *t* without EE programs and measures.[57]

The ShareIM assumes in the shared savings approach that the utility will recover its costs (i.e., implementation costs as well as all payments for the installed cost of the EE measure, a user input). There is no switch for combining shared savings and partial or no EE cost recovery. In the capitalization model, the utility EE costs are amortized and fully recovered. The user inputs are the number of years over which the costs are amortized. In the Virtual Power Plant model, by construction, there is no direct recovery of utility EE costs.

Beyond these points, the inputs will not be discussed in detail in this guide. They have been discussed further in the report. The description of the EE program and the associated costs, the number of customers and participants, and the capital structure of the prototypical utility are discussed in Section III.B.1 of the report. The inputs for the avoided costs, both capacity and energy, are discussed in Section III.B.2. Section III.B.2 also discusses the assumptions pertaining to the growth of customers in the model and its impact on the revenue requirement and base rates. The parameters for the different shareholder business models are discussed in Section III.A of the report.

2. Benefit-Cost Tests

The model performs three benefit-cost tests for the assumed energy efficiency program. These are:

- Total Resource Cost (TRC) Test
- Participant Test
- Ratepayer Impact Measure (RIM) Test

Each cost-effectiveness test is done on a separate worksheet. The Total Resource Cost Test is calculated in the “TRC Test” worksheet, the Participant Test is calculated in the “Participant Test” worksheet, and the Rate Impact Measure Test is calculated in the “RIM Test Potential” worksheet.

Each benefit-cost test worksheet contains three main sections. First, each worksheet contains a copy of the inputs, for easy reference. Second, it contains the components of the costs and the benefits, as defined by the particular test. Finally, the sheet contains the result of the benefit-cost test, as present values (using the After Tax Weighted Average Cost of Capital) and as ratios. The cost and benefit components of each test and the corresponding results are discussed in Section III.B.3 of the report.

Again, as portrayed above in Figure 28, ShareIM considers energy efficiency programs to be implemented for five years, and each year’s program creates energy savings for ten years from the time it is implemented. The model individually shows the results for the different annual programs and then cumulates the five programs to calculate the aggregate costs and benefits from the combined five-year program. The different tests are assessed at the aggregated five-year program level. Present values are of course additive, but there

[57] In the world with EE programs, we model rate cases as taking place, or not, to examine the issue of lost fixed cost recovery.

are situations, such as in California's shared savings incentive policy, where the individual year programs have a degree of independence.

Values for all three tests are calculated.

3. Recovery of Lost Fixed Revenues

The recovery of lost fixed revenues under the different incentive business models is calculated in the "Lost Fixed Revenue Factor Calc" worksheet. The recovery of these lost fixed revenues is made contingent on the user choosing the specific years in which rate cases are completed, as discussed below.

The basic construction of making the recovery of lost fixed revenues a function of the years in which rate cases are done is discussed in Section III.B.2 of the report. The choice of years in which rate cases are done can be determined by the user of the model in the section on "Year(s) of Rate Case to determine Lost Fixed Revenue Factor" in the "Inputs" worksheet. The user chooses a binary variable, which is set at the value of one for any year in which a rate case is done and zero otherwise, and is constructed for each year and each incentive model. The user of the model can choose a different set of rate case inputs for each business model. The rate case inputs chosen by the user in the "Inputs" worksheet will determine the calculation of the lost fixed revenues in the "Lost Fixed Revenue Factor Calc" worksheet.

In order to calculate the recovery of total lost fixed revenues based on the years in which rate cases are done, the following methodology is used. Starting with the last rate case done, lost fixed revenues that are recovered solely based on that rate case are calculated. Next, lost fixed revenues that are recovered from the second last rate case in addition to recovery from the last rate case are calculated. This is done for every rate case, proceeding from the last to the first rate case. These lost fixed revenues are then aggregated to determine the total lost fixed revenues that are recovered. This is done separately for each incentive model.

4. Shareholder Incentive Models

ShareIM considers four different shareholder incentive mechanisms. For each mechanism the costs, benefits, and net present value are calculated for the utility/shareholders, participants, and non-participants. For each model the resulting rate impacts are also calculated.

Prior to implementing any incentive mechanism, the model first considers a simplified case where the utility is allowed to break even, i.e., is made whole, but is awarded no incentives for implementing efficiency programs. This is done for purposes of illustration only and does not constitute a business model.

The following table describes the worksheets devoted to calculations pertaining to the different shareholder incentives. Note that the calculations for the utility/shareholders and the ratepayers are done on separate worksheets. For each business model, the worksheet that contains calculations pertaining to the utility/shareholders shows the cost and benefit components to the utility/shareholders and the recovery of costs under that model. Finally, the benefit-cost ratio and the net present value to the utility/shareholders are calculated. For each business model, the worksheet that contains calculations pertaining to the ratepayers shows the new rates under that model and the costs, benefits, and net impact on both program participants and non-participants.

Table 6

Worksheet Name	Contents of Worksheet
RIM Test Distributed	Calculations of costs, benefits, and net present value to the utility/shareholders when the utility is made whole but is not awarded any incentives Calculation of factors that would impact rates under this scenario
Part, Non-Part Tests Utility BE	Calculations of costs, benefits, and net present value to participants and non-participants when the utility is made whole but is not awarded any incentives Calculation of resulting rates under this scenario
VPP Utility Shareholder Test	Calculations of costs, benefits, and net present value to the utility/shareholders under the Virtual Power Plant business model Calculation of factors that would impact rates under this model
VPP Part & NP Test	Calculations of costs, benefits, and net present value to participants and non-participants under the Virtual Power Plant business model Calculation of resulting rates under this model
SS Utility Shareholder Test	Calculations of costs, benefits, and net present value to the utility/shareholders under the Shared Savings business model Calculation of factors that would impact rates under this model
SS Part & NonP Tests	Calculations of costs, benefits, and net present value to participants and non-participants under the Shared Savings business model Calculation of resulting rates under this model
Bonus RoE Util-Shareholder	Calculations of costs, benefits, and net present value to the utility/shareholders under the Bonus ROE business model Calculation of factors that would impact rates under this model
Bonus RoE Part & NonP	Calculations of costs, benefits, and net present value to participants and non-participants under the Bonus ROE business model Calculation of resulting rates under this model
NO Bonus RoE Util-Shareholder	The purpose of this worksheet is to assess the impact on rates in the Capitalization model when no bonus is awarded on the capitalized energy efficiency asset
ESCO Util-Shareholder	Calculations of costs, benefits, and net present value to the utility/shareholders under the ESCO business model Calculation of factors that would impact rates under this model
ESCO Part & NonP	Calculations of costs, benefits, and net present value to participants and non-participants under the ESCO business model Calculation of resulting rates under this model
ESCO	Calculations of costs, benefits, and net present value to the ESCO under the ESCO business model

The following are the main inputs for the different business models and these are contained in the “Inputs” worksheet and can be changed by the user of the model.

Virtual Power Plant Model:

- The predetermined Share (percentage from 0 percent to 100 percent) of the total gross stream of avoided capacity and energy costs, which is awarded to the utility as incentive. One hundred percent, minus the Predetermined Share, is the direct benefit to the ratepayers, as well as not having to pay for the direct costs of the programs that the utility incurs. The participants would also pay for whatever part of the total installed costs they, as voluntary participants, agree to pay.

Shared Savings Model:

- The predetermined share of the total resource net benefit awarded to the utility/shareholders, which is composed of gross capacity and energy benefits, minus the total installed cost of the EE measures.
- The percentage of the determined shareholder incentives awarded for each year's program, to be collected in rates totally in the succeeding year. The rest of the shareholder incentive earned accrues in the seventh year of the program. This loosely follows California Public Utilities Commission policy, which allows for measurement and evaluation studies to be conducted for past and future EE programs. There is a "second bite at the apple" for consumer advocates to review and possibly dispute the savings amount, timing, and various other issues. This percentage can be chosen independently for each of the five years of conducting the EE programs.

Bonus ROE Model:

- The premium return on the equity portion of the energy efficiency regulatory asset.
- The period of amortization of the regulatory asset.

Regulated ESCo Model:

- The predetermined share of customers' bill savings collected by the ESCo through the contract, until all utility EE costs are paid off leaving.
- The predetermined share of bill savings collected by the ESCo after all costs are paid off, which is the future "true profit."

For each of the business models the total revenue requirement is calculated based on the rates determined the energy efficiency world in the "Graph Rev Reqmt" worksheet. It also graphs the revenue requirements.

5. Graphs

A series of worksheets contain graphs that summarize the results of the model. Results comparing the net present values and the rates in the different business models are depicted graphically. The worksheets containing the various graphs are described in the following table.

Table 7

Worksheet Name	Contents of Worksheet
Graphs Before Incentives	Graphs showing the factors that affect the reference rates and the resultant rate in the scenario where the utility is made whole, and the NPV to the program participants and non-participants
Graphs After Incentives	Graphs comparing the NPV to the utility/shareholders, participants and non-participants under different business models
Graph Rates Compare	Graphs comparing rates and annual changes in rates under different business models
Graph Rates Compare VPP	Graphs comparing rates and annual changes in rates under the Virtual Power Plant model
Graph Rates Compare SS	Graphs comparing rates and annual changes in rates under the Shared Savings model
Graph Rates Compare Bonus RoE	Graphs comparing rates and annual changes in rates under the Bonus ROE model
Graph Rates Compare ESCO	Graphs comparing rates and annual changes in rates under the ESCO model

Finally, the "Addl Report Graphs" worksheet contains the components of the net resource benefits of the energy efficiency program under each business model. These graphs are discussed in detail in Section III.C.3 of the report.

6. *Financial Impact*

The financial aspect of the Energy Efficiency model constructs a simplified income statement and statement of cash flow. Given energy rate and consumption parameters, as well as a host of other user defined constraints from the first part of the model, a user can determine the effect an implementation of any of the four Energy Efficiency models might have. The input sheet contains several parameters that are unique to the financial statements, and manipulation of these inputs affects the financials. Inputs that are unique to modeling the income statement and the statement of cash flow are "Shares outstanding" (the number of shares in the hypothetical entity), "Equity" (the dollar book value of equity), and a choice of "Grow Equity by Revenue Growth" or "Capacity." This last switch allows the user to choose whether the company's equity grows with the revenue generated or with capacity. Other parameters are shared with the parts of the model discussed above. All production and fuel costs as well as the rate are taken from the calculations performed in other parts of the model; specifically, *Model* Part & NonP. Thus, the financial performance is largely driven by the modeled rate impact and cost structure. Unless explicitly stated, the Bonus ROE, Shared Savings, and ESCo models are calculated under the assumption that lost fixed revenue is recovered while the VPP model is calculated under the assumption that lost fixed revenue is not recovered.

In each of the dark green tabs denoting the financial model "EE Bonus ROE," "EE Bonus ROE Fixed Recover," "EE Shared Savings," "EE Shared Savings Fixed Recover," "EE ESCo," "EE ESCo Fixec Rec," "EE VPP," and "EE VPP Fixed Recover" appear. The base case income statement is presented at the top of the sheet. Below the base case, a theoretical Energy Efficiency (EE) income statement is presented with and without incentives (models without incentives always being presented on the right hand side). Further down the sheet, a base case statement of cash flows is demonstrated as well as the theoretical EE cash flows with and without incentives. A graphical version of the financial results presented in each of these green tabs can be viewed in the succeeding blue tabs.

In order to build each of the income statements, a top-down approach was implemented beginning at revenues, followed by progressively working "down" by calculating operating costs, taxes, etc. Thus, revenue is calculated as the "regular" unit rate multiplied by the number of energy units that are consumed each year. Additional revenue such as the return on investment for the "Bonus ROE" model was calculated using the before-tax weighted average cost of capital multiplied by the equity portion of the unamortized regulatory assets. An additional incentive "adder" was then calculated by multiplying an assumed "adder" rate by the unamortized regulatory asset. Incentives for the Shared Savings, ESCo and Virtual Power Plant models are calculated based on parameters from the Input sheet. The corresponding rates can be found in the Compiled Cost and Compiled Cost Decoup tabs. Fixed Costs are calculated as the quantity of the number of units consumed multiplied by the average fixed cost, less the total return on equity. Fuel expenses are equivalent to the fixed cost rate times units consumed. Income tax is calculated as a percentage of this operating margin, subtracted from the margin and a net income is reached. Given shares outstanding we can then calculate an earnings per share (EPS) number and compare to the status quo world without EE programs. Cash flows are determined similarly by subtracting operating costs from revenue, then subtracting out program costs and taxes. Note that taxes have been recalculated as opposed to pulled from the income statement. It should also be noted that in both the statement of cash flows and income statement it is assumed firm equity grows at a proportional rate to either capacity or revenues, depending on the user preference. Shares outstanding grow by this same proportion.

The following graphs are included:

Tab	Description
Net Income Bus as Usual	Net Income over time without EE
Net Income Fixed Incent	Net Income in the Shared Savings, Bonus ROE, ESCo, and VPP model assuming all but the VPP model recover lost fixed revenue
Net Income Bonus	Net Income in the Bonus ROE model depicted against the base case without EE
Net Income Shared Savings	Net Income in the Shared Savings model depicted against the base case without EE
Net Income VPP	Net Income in the VPP model depicted against the base case without EE
Net Income ESCo	Net Income in the ESCo model depicted against the base case without EE
NI CF Bonus ESCo	Net Income and Cash Flow in the ESCo model
NI CF Bonus ROE	Net Income and Cash Flow in the Bonus ROE model

The Brattle Group

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