BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Electrical power plant in Taylor County by Florida Municipal Power Agency, JEA, Reedy Creek Improvement District, and City of Tallahassee.	)))))	Docket No.060635EU

Direct Testimony of Dale Bryk

on behalf of

Intervenor, Natural Resources Defense Council
and
Intervenor, Rebecca J. Armstrong

November 2, 2006

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Bryk Exhibit ~~B~~ DB2: Biewald, B.; Woolf, T.; Roschelle, A.; Steinhurst, W. *Portfolio Management: How to Procure Electricity Resources To Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers.* Synapse Energy Economics prepared for the Regulatory Assistance Project and the Energy Foundation: Cambridge, MA, October 10, 2003, www.raponline.org/Pages/Feature.asp?select=15.

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Q: Please state your name, occupation, and business address.

A: My name is Dale Bryk, I am a Senior Attorney for the Natural Resources Defense Council's Air and Energy Program, and my business address is 40 West 20th Street, 11th fl., New York, NY 10011.

Q: Please summarize your education and experience.

A: Currently I direct NRDC's state climate policy work. My expertise is in the area of state energy and climate policy, including utility regulation, energy efficiency and renewable energy programs, greenhouse gas emission registries and regulation, emissions trading, green building and smart growth. I joined NRDC in 1997, prior to which I practiced corporate law at Davis Polk & Wardwell in New York. Since 2002, I have also taught the Environmental Protection Clinic at Yale Law School. I have a J.D. from Harvard Law School, a Masters Degree in international law and policy from the Fletcher School of Law and Diplomacy and a B.A from Colgate University.

Q: What is the purpose of your testimony today?

A: This testimony is submitted in support of NRDC's intervention to advocate for the best and least cost option for meeting Florida's power needs, and in particular to explain why the integrated resource planning process, and the meaningful consideration of demand-side management and other alternatives to coal-fired power generation are so vitally important in connection with the proposed 765 MW coal-fired Taylor Energy Center (TEC) that has been proposed by Jacksonville Electric Authority ("JEA"), Florida Municipal Power Agency ("FMPA"), City of Tallahassee (Tallahassee), and Reedy Creek Improvement District ("RCID"). It is absolutely necessary to meaningfully consider efficiency, conservation, and other alternatives to new coal-fired generating capacity, and it is vital also to fully consider in this context the likely risks associated with impending future regulation of carbon dioxide (CO_2). Only by thoroughly and meaningfully evaluating the full suite of available options can the PSC ensure that a particular project is the most cost-effective and least risky alternative available, and the best choice for Florida's energy consumers. Because of the short time frame for reviewing the record and developing testimony, my testimony provides only a summary overview of the relevant issues. Were more time available for examination and development of testimony I could address the relevant issues and facts of particular importance here in more detail.

Q: Why is integrated resource planning so important?

A: Most utility customers continue to receive service from hometown utilities, regardless of the status of retail competition in their state's electric industry, and these utilities have a solemn responsibility to engage in sensible electric-resource portfolio management. Such integrated resource planning (IRP) requires a fully integrated approach to identifying customer electric service needs and to selecting demand- and supply-side alternatives to meet those needs through a portfolio that minimizes total cost and environmental impacts, and has an acceptable level of risk.

Utility regulators bear a similar responsibility to enable effective portfolio management by aligning financial incentives with customer interests. In many cases, utility regulations are implemented so as to create a substantial financial *disincentive* for utilities to pursue cost-effective energy efficiency or other demand-side strategies. However, such disincentives can and should be eliminated.

Due to existing regulations governing utility cost recovery and default service procurement, most utilities invest exclusively in supply resources, and base their investment decisions exclusively on short-term contract price. They do not engage in long-term integrated resource planning and as a result, do not effectively manage risk for their customers. Regulators should require utilities to conduct such planning, which should include a comprehensive analysis of the costs, risks, and environmental impacts associated with all resource options – including both demand-side and supply-side resources. Achieving this goal in practice is difficult and requires particular expertise and the ability to balance sometimes competing objectives. When the IRP process fails, the results can be dramatic; consider for example the California energy crisis of 2001.[1] This experience demonstrates forcefully that utilities and other service providers must assemble a robust and diverse portfolio that includes demand- and supply-side resources. By including serious demand-side measure, as well as a variety of supply-side options that include significant renewable resources, utilities and utility regulators can protect against risks, including those related to fuel prices, future loads, fuel supply availability, and future environmental regulations.

Q: Why is the IRP process so complex?

A: The complexity of the IRP process grows in part from the multitude of different customers that a utility must serve, and the widely diverging uses to which these customers put the electricity that a utility supplies. While utilities customarily think of electricity merely as a commodity (to be provided at a specific rate per unit), in some ways – especially when considering demand-side options – it is necessary to consider how that electricity is being used in order to identify the best alternatives for resource management. Moreover, a long-term view is necessary because of the need for capital-intensive investments with sometimes long lead times, and because many new resources will continue operating for thirty to forty years or more – so utilities and regulators must consider the costs, benefits, and risks of investing in a particular resource over an extended time horizon.

Without comprehensive and inclusive long-term integrated planning, a utility or utility regulator is likely to "miss the forest for the trees." And such short-sighted decisionmaking can be especially disastrous where some factors relevant to good

[1] In 2002, the California Legislature enacted Assembly Bill 57, returning the utilities to the role of portfolio managers. See California Public Utilities Commission (CPUC) Decision 03-12-062, December 18, 2003. The California Public Utilities Commission has adopted several subsequent decisions providing guidelines for the utilities' portfolio management activities. See, e.g., CPUC Decision 04-12-048, December 16, 2004.

resource planning (including DSM options like efficiency and energy conservation, and potential pitfalls like the regulation of CO_2 as discussed in testimony by Daniel Lashof) are under valued, under utilized, or left out entirely of the equation. While each individual decision may seem best in isolation, it is essential to consider the *additive* effect of the decisions and the impact each will have on the overall portfolio, since cumulative impacts may create significant future problems, for utilities and consumers alike. In the end, the preferred resource plan is generally the one that has the lowest lifecycle cost (i.e., lowest anticipated long-term revenue requirement) and is most robust in the face of various risks, among other factors.

Q: Why is the IRP process important in this case?

A: While comprehensive analysis of costs, risks, and environmental impacts is an important part of overall IRP planning, it is also an important element of the decisionmaking process for individual power plant projects. Specifically, for each proposed project the PSC must meaningfully assess both demand-side and supply-side resources that could meet customers' needs, and should account for both known risks and for reasonably anticipated but unquantifiable risks.

In this case, the first step in evaluating the appropriateness of the TEC project must be to scrutinize the determination that demand will exist for new capacity in the relevant service areas, and analyze the costs, risks, and environmental impacts associated with the *full range* of potential resource options – including a thorough and detailed analysis of demand-side opportunities that could avoid the need for new generation capacity in the time frame contemplated for the project and at much lower cost. This analysis should also include consideration of distributed generation, renewable resources, thermal resources (such as natural gas-fired plants and integrated gasification combined cycle coal plants), transmission, and more.

In point of fact, energy efficiency is the most *cost-effective, reliable, and environmentally friendly* resource available. However, the record for this project includes, for the most part, only a superficial evaluation of such alternatives. Appropriately assessing the potential for energy efficiency resources requires a detailed analysis of the full range of end-uses (i.e. how various customers use energy), how much more efficient those end-uses could be, and what level of efficiency is achievable through voluntary programs that provide incentives and information to customers to improve their efficiency or through mandatory standards that set a minimum level of required efficiency.[2] Determining what portion of that energy efficiency potential is cost-effective then requires a detailed and realistic analysis of the total cost to society of procuring the energy savings.

As an example of how meaningful demand-side analysis can, in fact, provide for real opportunities, the city of Tallahassee has commissioned a study that demonstrates that it can meet a large portion of its medium-term additional capacity expectations through demand-side strategies. An additional portion of Tallahassee's energy needs can be addressed by developing biomass alternatives. In addition to raising serious questions about whether there is a demonstrated need for the additional capacity from this project in Tallahassee (given its expectation of 192 MW of power from DSM and biomass), this example shows that a meaningful evaluation of alternative strategies can be fruitful, and should be required of all participants in the TEC project. It is apparent from the record here that such alternatives have *not* been fully explored.

Similarly, assessing supply-side options requires a realistic and inclusive analysis of the costs, attributes, and risks associated with each resource. Every resource's fixed

[2] California's recent analysis of the potential for cost-effective energy efficiency provides a good example of this type of potential study. See Rufo, M.; Coito, F. *California's Secret Energy Surplus: The Potential for Energy Efficiency*. Xenergy Inc. for the Energy Foundation and the Hewlett Foundation, 2002, www.energyfoundation.org/energyseries.cfm.

and variable costs should be assessed either over the lifetime of the resource or over some fixed period, often thirty years. In order to allow all resources to compete on a level playing field, this analysis must incorporate accurate operating, cost, and risk assumptions for each resource. For fossil-fueled resources, including coal-fired power plants, forecasting fuel prices (with a sensitivity analysis) is a critical element of this cost assessment. Additionally, in the context of coal-based generation, the real likelihood of carbon regulation is an essential component of the overall analysis. As discussed in the testimony of Dan Lashof, CO_2 regulation appears to be a virtual certainty. Given the cost implications of CO_2 emission regulations, as discussed in Mr. Lashof's testimony, the advantages of DSM and other capacity alternatives to coal-based generation look even more promising – both in term of good resource planning in general and with respect to the interests of the particular customers on whose behalf the PSC must act in this case. If the full range of potential risk is not adequately understood, the PSC cannot make an informed judgment on behalf of the state's ratepayers.

Risks come in different types and may occur on different time scales, but it is essential that the utilities assess and mitigate *all* risks that could have a significant impact on customers. There are generally at least three different types of risks:

1. Risks that can be quantified and for which historical experience exists that can be relied upon in assessing the future risk (for example, load forecasts, fuel price fluctuations; etc.);

2. Risks that can be quantified but for which little or no historical experience can inform the assessment of the risk (for example, regulation of carbon emissions); and

3. Risks that cannot be easily quantified, but can be qualitatively assessed (for example, a change in FERC's market design, public acceptance of new resource siting, etc.).

The utilities have traditionally emphasized the first type of risk listed above in their analyses. However, the other two types of risks are no less significant or real. Even if they can't be quantified *based solely on historical experience*, they can often be quantified and incorporated in a meaningful way into the integrated resource analysis. The financial risk associated with future regulation of carbon emissions is a prime example of the type of risk listed in the second category above that the utilities have historically failed to assess or mitigate, and that has not been addressed here for the TEC. Indeed, the risk analyses in this case are incomplete for two reasons: (i) they fail to fully analyze all relevant risks, and (ii) while they assessed the *magnitude* of the risk due to some factors, they do not explore a full range of possible options to *mitigate* these risks.

Finally, as one component of the analysis underlying this decision, the applicants must realistically evaluate (in light of CO_2-related cost implications and other factors) the relative benefits of natural gas-fired power generation, and the benefits of advanced coal technologies like IGCC. With regard to natural gas, the fact that prices have been falling (NYMEX natural gas futures are down from about $14 dollars a year ago to about $7.50 now (see http://wtrg.com/daily/gasprice.html)) means that outdated assessments that do not adequately account for such cost adjustments need to be updated. Similarly, assessments of natural gas-related costs that do not account for the inherently lower CO_2 emissions of natural gas, should be updated to account for the likely costs associated with future CO_2 regulation. Additionally, the possibility of employing alternative advanced coal-combustion technologies (such as IGCC) that have tangible CO_2 benefits must be thoroughly evaluated in light of expected CO_2 regulation in order for the PSC to meet its obligations to energy consumers.

Q: Why are environmental impacts important?

A: Different resource decisions will have widely varying environmental impacts. Coal-based power generation, for example, by far has the most profound adverse health and environmental impacts. Coal plants emit air toxics, criteria air pollutants that cause smog, soot, and a wide range of adverse health conditions, as well as greenhouse gases that contribute to the threat of global warming and all of its associated ills. These impacts should be fully understood for each potential alternative resource, and should play a role in the PSC's balancing of different energy options. By analyzing the environmental profile of each type of resource, the utility and the PSC can assess the projected environmental impact of various options to help select an alternative that meets the objective of providing energy services in an environmentally responsible manner. This information is also necessary to assess the important element of financial risk exposure due to pollution emissions – one of the risk factors that directly relates to the cost-effectiveness and appropriateness of a particular energy resource option. For the TEC, the record does not appear to include a comprehensive assessment of comparative environmental impacts, and clearly does not incorporate a meaningful assessment the cost implications of potential environmental liability (including but not limited to the costs associated with future regulation of CO_2 emissions).

/s/ Dale Bryk
Dale Bryk
Senior Attorney
Natural Resources Defense Council

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Further Issues in Portfolio Management
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Appendix A. Portfolio Management Details

A.1 Further Issues in Portfolio Management

The Academic Literature on PM

As explained in Chapter 4, a diverse portfolio is less risky than any single investment, and the same is true for commitments for commodity supply—such as electricity. Diversification works because prices of different investments are not perfectly correlated; historically a decline in the value of one investment is often offset by a rise in the price of the other. In any individual investment, there are two sources of risk. First is unique risk, which can potentially be eliminated by diversification. Unique risk results from events that are specific to an individual investment situation. In the context of the stock market, unique factors are those that affect a particular company or sector, such as a mistake or a disaster affecting the company's production or a broader disaster affecting supply of a particular commodity essential to the sector. Second is market risk. Market risks are those that are due to macroeconomic factors that threaten all investments equally. With respect to the stock market, these risks include changes in interest rates, exchange rates, real gross national product, inflation, and so on, which affect the price of stock for all companies or all sectors in roughly the same manner.[48]

Equity portfolio managers, for example at large equity mutual funds, maintain diversity by investing in a wide range of different companies in different industries. In these funds, portfolio diversity is measured by the percentage of investment in any one company, and the percentage of investment in any one industry, both of which are reported in fund profiles. While there are sector-specific funds, these are universally recognized as more risky than broad-market funds that eliminate unique industry risks through diversification.

While diversification of holdings is import to lessen the effect of both unique and market risks, having a portfolio with a diverse range of investment durations is equally important. Bond portfolio managers generally spread risk over a series of different maturities, while maintaining an average portfolio maturity that is reasonable. In fixed-income financial markets, this is achieved by setting up a bond ladder, a series of bonds with a range of maturity dates. The advantage of this method is that the investor reduces the impact of volatile interest rates on the portfolio. If rates rise, the investor will soon have bonds maturing with which he/she can reinvest at the higher rates. Similarly, when rates decline, one can take comfort knowing that a good portion of the portfolio is locked-in at relatively high rates. These same concepts that apply to volatility in interest rates apply to commodity spot markets. If prices are falling, one will soon be able to begin

[48] Diversifying into different uncorrelated or counter-cyclical markets, in turn, can mitigate market risks. For example, allocating some investment to cash, bonds, or commodities can to some extent diversify equity market risk. See, for example, Culp, 2001.

taking advantage of that, while if they are rising, one is only gradually exposed to the full impact of that rise in price.

There is an entire class of mutual funds known as "balanced" funds. These are funds that invest in both equities and fixed-income instruments. Their equity investments are diversified across many industries, and their bond investments are diversified over many different maturities. Fund managers consider the risk of each asset and the overall portfolio. There are some managers that invest only in low-risk securities (i.e., companies with an expectation of stable earnings) while others are characterized by higher risk profiles, seeking to achieve higher returns.

The take-home message from the financial markets is that diversification reduces risk or volatility in prices. The unique part of the uncertainty in any individual investment is diversified away when that investment is grouped with others into a portfolio of different investment types and durations. Overall, diversification gives the investor more flexibility and protection from unknowns.

Portfolio Management: The Theory as Applied to Commodities

Just as diversification can protect investors from uncertainties in financial markets, diversified management approaches can protect companies and market participants from unknown changes in their industries. To decrease the impact of unique risk factors, a diversified portfolio for a utility might contain a mix of generation assets with uncorrelated prices and supplies. The well-managed portfolio will also draw from both demand- and supply-side resources and efficiency improvements, as well as a mix of short-term, medium-term, and long-term contracts to ensure price protection over time. In addition, if there is owned generation in the portfolio, risk protection will be further enhanced by applying the same portfolio management approaches to fuel acquisition, a technique long practiced in that part of the utility industry.

Varieties of Procurement Contracts and their Pros and Cons

Portfolio management in terms of commodities purchasing agreements between buyers and suppliers is at the forefront of current research at institutions such as MIT's Center for E-business. A well-managed contract portfolio is usually a combination of many traditional procurement contracts, such as long-term contracts, options and flexibility contracts, and usage of spot markets. Each of these elements has its own pluses and minuses, but in combination they can greatly reduce risk.

- Use of the spot market involves paying market price on the day that the commodity is needed. Spot market pricing can be quite volatile, and thus represents a risk for buyers. On the upside, buyers do not need to make any commitments, since spot market buying requires no advance agreements. Spot market reliance can be considered as protection against both falling demand and falling prices.
- Long-term or forward contracts are agreements between buyers and suppliers to trade a specific amount of a commodity at a pre-agreed upon price over time. No money actually exchanges hands until the commodity delivery date. The advantage to these contracts is that the buyer is no longer exposed to spot market volatility.

However, he/she risks signing an agreement when the spot market is high relative to future prices. All forward contract details are the responsibility of the individual buyer and seller. A strategy of purchasing forward contracts can be considered as a protection against drying up of supplies and rising prices.

- In an option contract, the buyer prepays a small fee up front in return for a commitment from the supplier to reserve a certain capacity on a good for future potential trade at a pre-negotiated price called the "strike price." In this case, total price is higher than the unit price (offered at *that time*) in a long-term contract, but one does not need to commit to buying a specific quantity. Typically, the buyer exercises the options only when spot prices exceed the agreed upon strike price of the option. If market prices are less than the strike price, the option fee has already been paid and may be thought of as the sunk cost of an insurance premium.
- A flexibility contract, on the other hand, exists when a fixed amount of supply is determined when the contract is signed, but the amount to be delivered and paid for can differ by no more than a given percentage determined upon signing the contract. Flexibility contracts are equivalent to a combination of a long-term contract plus an option contract. (Simchi-Leve 2002)

With regard to the different kinds of contract agreements, the buyer needs to find the optimal trade-off between price and flexibility. In other words, the buyers needs to find the appropriate mix of low price, yet low flexibility (long-term contracts,) reasonable price but better flexibility (option contracts) or unknown price and supply but no commitment (the spot market.) In addition, purchases should vary in duration, the way a bond portfolio might be laddered.

Derivative Instruments

So far, this subsection has focused on the actual contracts signed between buyers and sellers of commodity items. However, in addition to the work of managing a portfolio of contracts to support physical supply chain operations and logistics, many corporations have entire groups within their finance departments devoted to financially hedging or offsetting the pricing risk of key commodities through the use of derivatives. Financial derivatives have definite advantages over forward, fixed-price contracts. Most important, in many markets they are more liquid and have lower transaction costs.[49]

Derivative theory can be complex, but the core concepts are straightforward. In simplest terms, the worth of a derivative is based on the value of an underlying commodity or asset. One can think of derivatives as side bets on the value of the underlying asset. Like

[49] It is important to keep in mind that there are distinctive requirements that apply to accounting for derivatives under the tax code and under financial accounting standards. As has been evident to anyone following the business news in the past few years, these requirements can have critical impacts on the financial results of a corporation and must be carefully evaluated and understood to avoid difficulties. A few scandals aside, these requirements do not impair the beneficial aspects of derivative use, but rather ensure that investors, managers and regulators are properly informed. In fact, there are related requirements that apply to financial reporting of commodity contracts, as well. Expert professional advice in these areas is recommended prior to establishing a financial derivatives program.

insurance, use of such "hedges" reduces the effect of unknown events in return for a fee. The most common derivatives are futures contracts and swaps.

- *Futures contracts* are advance orders to buy or sell an asset. Like long-term, forward contracts, the price is fixed today, but the final payment does not occur until the delivery day. Unlike forward contracts, futures contracts are highly standardized and are traded in huge volumes on the futures exchanges. Those investing in futures contracts do not necessarily have any direct connection to or use for the commodity being traded. Instead, investors take part in the futures market in efforts to either profit from or protect their financial portfolio from the ups and downs in the price of one or more of the dozens of different commodities, securities, and currencies that are traded. If a buyer does not close out his/her position (sell the purchase contract to another buyer) before the delivery date specified by the futures contract, he/she must take physical delivery of the goods or sell them at the market price prevailing on the closing date.[50] However, futures contracts are rarely held to maturity, except, perhaps, by physical suppliers and consumers of commodities. They are readily traded, as profits and losses from these derivative instruments are realized daily. Generally, full service brokerage firms are used to handle investments in futures contracts. Specialist brokers, such as NatSource, trade electricity futures in some markets. Fees are paid to the futures commission merchant, the clearing corporation, the National Futures Association (NFA) and the futures exchange on which the contract trades. Taken together, these fees can range anywhere from $25 per contract for discount brokers who offer very little if any customer services, to over $95 per contract for full-service brokers. Additional services provided by full-service brokers consist of market commentaries, identification of trading opportunities, and trading tips or advice.
- A *swap* is a contract that guarantees a fixed price for a commodity over a predetermined period of time. At the end of each month, the prevailing market settlement price of the commodity is compared to the swap price. If the settlement price is greater than the swap price, the supplier pays the buyer the difference between the settlement price and the swap price. Similarly, if the settlement price is less than the swap price, the buyer pays the supplier the difference. Swaps were created in part to give price certainty at a cost that is lower than the cost of options. In swaps, no physical commodity is actually transferred between the buyer and seller. The contracts are entered into outside of any centralized trading facility or exchanges, making them over-the-counter (OTC) derivatives. Payment is sometimes direct, though often times through an intermediary bank or counter-party.

Financial companies are constantly coming up with new types of derivatives and variations on currently used instruments in order to suit a range of investor interests.

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[50] Conversely, if a seller does not cover the contract with a purchase from another seller by the closing date and cannot physically deliver, the seller must pay the market price prevailing on the closing date to make good on the promised sale. In most markets, the brokers or market makers perform these functions automatically and present bills to investors who are not physical suppliers or purchasers.

These include weather derivatives, and a form of swap known as a contract-for-difference.

Derivatives should be viewed as financial insurance instruments that protect the buyer from spikes (and the seller from dips) in commodity pricing. The intent of such hedging is to stabilize prices, not to lower them. In fact, risk adverse investors who seek protection from price volatility should be willing to pay an insurance premium. This premium might come in the form of transaction cost, or the difference in price between the bid and offer prices, known as the spread. In liquid markets, transaction costs (i.e., bid/offer spreads) are typically very small, and of little concern. In less-liquid markets, however, bid/offer spreads can be wide, and can have a more significant impact on the cost of transactions.

While derivatives do have their place in commodities risk management, they also have been the objects of scrutiny in a myriad of cases in the last 10 years. For example, in 1993, Orange County lost $1.7 Billion due to financial derivatives use. Meanwhile, Enron's 2001 bankruptcy, while not caused by derivative use, raised concerns about risk management and transparency of financial information. (EIA 2002)

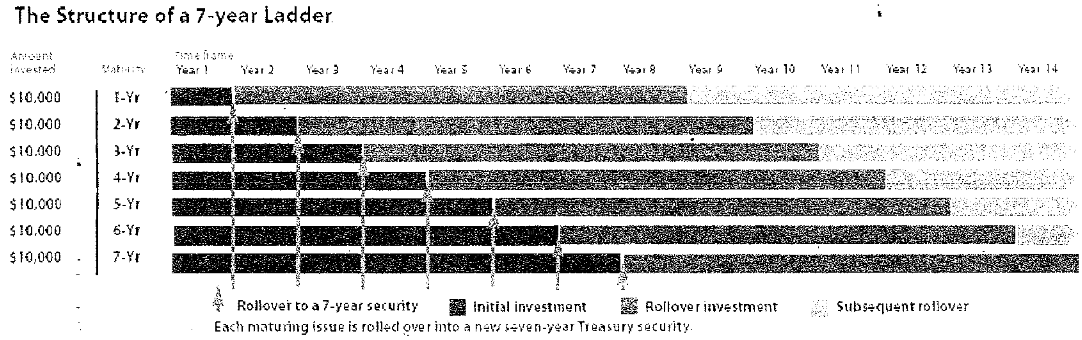
Price Averaging

Another well-accepted technique that can help manage the risk of a portfolio is called dollar-cost averaging. To dollar-cost average, a buyer will make several investments of equivalent dollar value in equally spaced time increments, regardless of price. For example, instead of agreeing to an annual commodities contract settlement of $50 million on Jan. 1, a buyer may instead agree to purchase $5 million worth of goods every 36.5 days. While some of the contract prices will be higher or lower, based on the spot price on the given day of settlement, the math for this technique guarantees that the buyer will acquire more goods when they are inexpensive and less when they are costly. This technique promises buyers that they do not have to worry about spot market prices on any given day. However, when using this method, instead of price fluctuations, buyers do experience fluctuations in volumes of goods purchased. As long as the buyer can bear these changes in volumes, dollar cost averaging is an excellent technique to manage price fluctuation risk.

Bond Laddering

Bond laddering is an investment strategy where the portfolio manager invests monies in bonds with a range of maturity dates. For the purposes of this example, we will choose a bond laddering range of 7 years, a beginning balance of $70,000 to be managed, and US treasuries as our financial instrument. Using this strategy, on day one, the portfolio manager divides up the monies into $10,000 portions and buys 7 Treasuries with durations of 1, 2, 3, 4, 5, 6, and 7 years respectively. As each bond matures, the portfolio manger reinvests the proceeds in Treasuries that will mature seven years from that date and, in effect, continues to build the ladder into perpetuity, as illustrated in Fig. A-1, below. (Engle 2002)

Figure A-1. Bond Laddering Example



There are several benefits from adopting this strategy. First, laddering reduces risks associated with market timing. Instead of trying to predict the best time at which one should lock in an interest rate, laddering provides both a range of current interest returns (capturing variation in the current term structure of interest rates) and, more importantly, a range of future investment opportunity time frames. Laddering also achieves immediate positive returns regardless of current economic conditions, unlike simply hiding the money under the mattress until economic conditions improve.

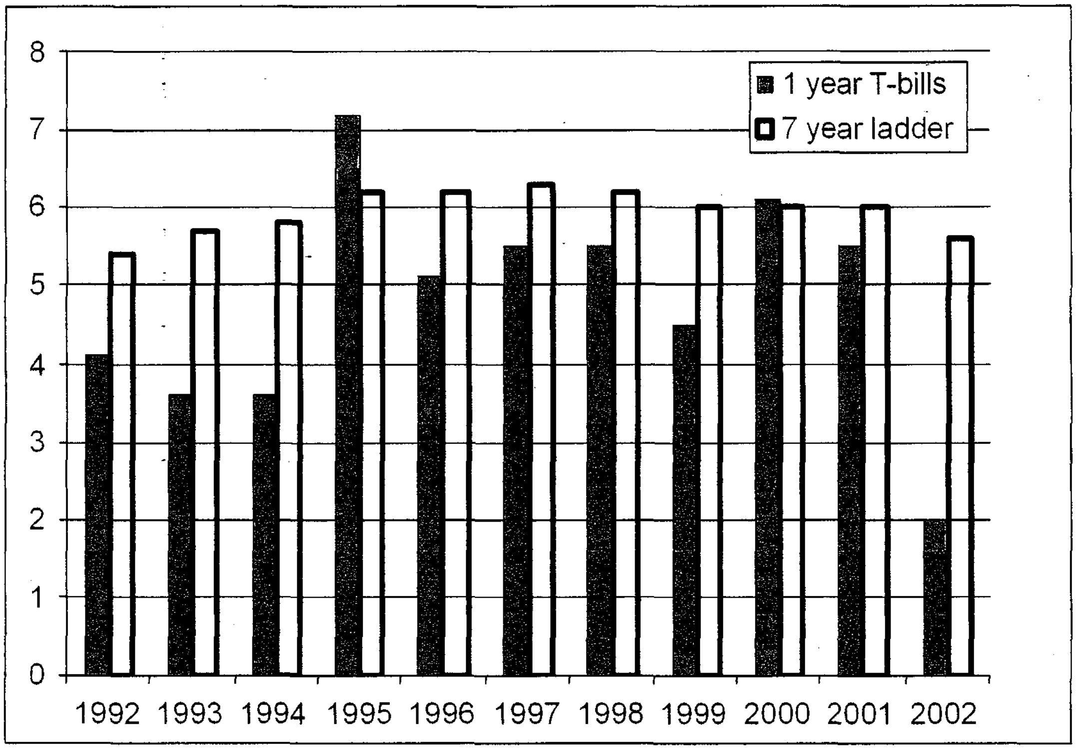
The second major benefit of a bond laddering strategy is that it provides some of the benefits of a longer-term investment, while retaining some of the benefits of a short-term investment strategy. In other words, in the laddering strategy, an investor commits funds neither to just the short-term nor just the long-term. Because a portion of the portfolio expires each year, laddering simulates a short-term liquidity risk approach. However, because funds are invested in a range of durations--averaging 3.5 years for the initial investments and increasing to 7 years over time--the returns on the portfolio are similar to those of longer-term investments, which typically yield higher returns, as described below, while avoiding the risk of locking all of the assets into a single long term investment at what may turn out to have been a time when the yield was lower than average.

Table A-1. Term Structure of US Treasury Yields September 25, 2003.

Maturity	Yield (%)
3 Month	0.83
6 Month	0.95
2 Year	1.62
3 Year	2.04
5 Year	3.01
10 Year	4.09
20 Year	5.00

In Table A-1, we see US treasury yields as of September 25, 2003. (Yahoo 2003) The data represents the available yields for bonds with various durations. Usually, the longer one commits monies to a particular investment fixed interest rate instrument, the greater the yield that is available. Thus, the fact the bond ladder returns rates of an average 3.5-7 year duration, while freeing up 1/7th of the portfolio yearly, is far better than simply investing in 1-year treasuries alone. This is illustrated in Fig. A-2. Here, we see that, over the10 year period from 1992-2002, 1-year treasuries returned 4.8% on average, while a 7-year ladder returned 5.9% annually on average over the same time period.

Figure A-2. Yearly Returns on the Bond Ladder Relative to Treasury Bills



So, investing in a laddered approach is superior to investing in 1-year treasuries, in terms of returns. However, one might ask, what would happen if one were to invest one's funds all at once into a 10-year treasury instead of annually into 1-year treasuries? According to our chart, 10-year treasuries currently yield 4.09%, which is lower than both the historical return on 1-year treasuries and on our ladder. Now, of course, 10-year yields in the past have oscillated, sometimes yielding higher than our laddered strategy and sometimes yielding lower returns. But again, the laddered approach eliminates both the risk that one will choose a "bad" time to lock in a rate for one's entire portfolio and the risk of having to reinvest all of that portfolio in a less than ideal economic environment upon maturity of the bond.

In short, a laddered investment strategy is both simple to set up and to manage. Through diversification, this strategy both reduces volatility of returns and drives up average returns.

Allocation of Risk between Buyers and Sellers

Turning to financial hedging instruments, derivatives allow buyers to transfer risk to others who could profit from taking the risk. Those taking the risk are called speculators.

Speculation is an activity where the parties take on more risk with the expectation of earning a profit. Speculators seek price volatility, while hedgers or buyers in our case are more interested in obtaining fixed prices. Speculators play a critical role in derivative markets, as they are willing to assume the risk that the hedger seeks to shed. Some speculators, like insurance companies or brokerage firms, have some advantages in bearing risk. First, due to experience, they may be good at estimating the probability of events and price risks. Second, they may be in a position to provide advice to buyers on how to reduce risk and thus lower their own risks. Third, they can pool risks by holding large, diversified portfolios of agreements, most of which may never seek payments.[51]

It is generally understood that there is a fine line between hedging to mitigate volatility and hedging for the purpose of pure speculation to earn profits. Imprudent speculation is undoubtedly an issue of concern for any industry's participants. It is up to regulators to better define this line.

> Futures contracts are held not only by market participants, but also by industry outsiders, including speculators. For example, as of July 1, 2003, large hedge funds, whose owners are non-participants in the oil market, were holding 51,546 contracts in long positions in the crude oil futures and options markets. Meanwhile, small speculators were holding a net long position of 19,207 contracts. As for oil companies, refiners and banks, 41,999 net short contracts were being held, split almost evenly between the futures and options markets. (Platts Global Alert 2003)

At this point, one might ask why a supplier would be willing to negotiate several types of contracts, instead of insisting on long-term contracts only; in a long-term contract, the buyer is obligated to purchase the commodity whether or not it is needed and therefore the buyer bears all of the risk. To begin with, it has actually been demonstrated that a portfolio of an option and a long-term contract is a win-win situation for both the buyer and the supplier instead of a zero-sum game. This is true simply due to the fact that suppliers usually face multiple buyers. Suppliers are actually better able to handle demand uncertainly when they pool the various risks of several buyers together, rather than dealing with demand uncertainty of a single buyer only. (Simchi-Leve 2002) Also, while it is true that long-term contracts provide the supplier with guaranteed revenue streams, they often result in smaller numbers of orders/buyers due to lack of flexibility. Thus, option contracts can be attractive for building buyer relationships and reducing risk. In addition, in option contracts, suppliers generally earn a higher margin, as they can charge more for an option than they can for a guaranteed agreement. Thus, a mix of contracts seems to be a win-win situation in reducing risks for both the buyer and the supplier.

The Build-Versus-Buy Decision

The previous discussion focused on the benefits of and tools for assembling a portfolio of various types of purchase contracts and derivatives to manage portfolio risk - primarily the portfolio risk faced by the buyer in a wholesale commodity market. But an entity,

[51] Risk pooling among default providers may be promising, but needs to be further developed as a concept for application in the electricity industry.

such as a default service utility, has a whole additional class of supply-side options--generating plant construction and ownership.[52] Under traditional rate regulation, ownership of generation was often the norm; primary reliance on purchases was mainly a strategy used by municipal and cooperative utilities, although many of them also owned plants or shares in plants.

Ownership of production facilities is, in some ways, analogous to buying the ultimate forward contract. Ownership brings with it complete insulation from spot price fluctuations and market power of suppliers. Unfortunately, plant ownership brings with it a large degree of unique risk, which must then be borne or mitigated. Some of these risks, well known from traditional regulation, are forced outages from equipment failures or other causes, labor actions, construction delays and overruns, fuel price and supply interruption risk, environmental risks, and natural disasters. Naturally, like any long contract, plant ownership as part of the portfolio meeting one's needs can create problems if demand drops significantly. Plant ownership may also prevent a utility from taking advantage of downward fluctuations in market prices. Ownership also requires large commitments of capital and management resources.

Important variables to consider in such a decision include the plants' fixed costs and capital requirements, fuel and other variable costs, emissions, and lead time, which vary considerably as seen in Table 7.1, above. If physical, or resource-based, contracts are being considered, the type and length of contracts, quantity determination, provisions for ancillary services, and selection among providers are all relevant. In either case, or if a combination of these approaches is contemplated, appropriate hedging strategies and management of trading and plant operation functions need careful consideration.

Both physical plant ownership and resource-based contracts bring with them advantages and disadvantages for PM. For example, long term rights to energy that is not tied to the prices or environmental risks of fossil fuels, resource-based contracts are potentially attractive. In many markets, long-term, fixed-price contracts are available *only* through resource-based contracts with owners of specific renewable plants or groups of plants. Indeed, many renewable energy projects must rely on such contracts if they are to be bankable at all. Such projects are also often highly modular, physically, allowing such resource-based generation assets to be laddered and diversified.

On the plus side, ownership enables the buyer to acquire specific types of resources with characteristics not available from the competitive market. For instance, a manufacturer may wish to build certain components to ensure they meet needed quality standards. As another example, there has been little development of renewable energy sources in many wholesale electricity markets, despite their environmental and long term risk benefits. If default service providers, their customers, or their regulators were to value such advantages, one way to obtain them, like any long term forward asset acquisition, would be to build and own the generating assets directly.

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[52] In addition, a utility can own the underlying fuel supply resource, by acquiring gas resources in the ground, coal-bearing property, or other "ownership" of fuel resources. This is not examined in this paper, but we note that this practice has been highly controversial in the past (captive coal), but also offers opportunities for reducing power cost volatility in a utility resource portfolio.

A plant owner also becomes a potential supplier in whatever wholesale markets exist for the product. Excess output can be marketed, perhaps at a profit. Some portion of the capacity can be used to sell options or other products to mitigate the mirror image risks that suppliers face.

A specific set of risks associated with forward contracts in a competitive wholesale marketplace has to do with the market power physical suppliers can exert. If the supplier owns the assets, the parties are considered nonintegrated. If the buyer owns the asset, the parties are integrated. The primary point here is that under non-integration, the supplier can use or threaten to use the asset in the market in a way that is not optimal for the buyer. For example, the supplier can simply withhold supply from the market. This concept is known as hold-up, as the supplier can hold-up or stop critical supplies from reaching the buyer until the market price has risen.

We normally expect competitive wholesale markets to provide suppliers with strong incentives to build value into their assets in order to improve their bargaining position with all parties. In a properly functioning market, the non-integrated supplier may invest great time and effort into improving efficiencies and offering best in class products and services. In contrast, under integration, there is no hold-up threat, because the buyer owns and hence controls the asset. In this setting, there is nothing to bargain about: the buyer owns the good and so simply takes it. The supplier loses control over the decision to sell to other buyers (and the decision to sell at all.) The supplier's only operational incentives come from the buyer, and thus, unless these incentives are heavily monitored and controlled, the supplier has no incentive to incorporate efficiencies or improve operations. Thus, while hold-up exists under non-integration, efficiencies, incentives, and operations may be better for both the buyer and supplier under non-integration than under the integrated scenario.

The preceding paragraphs encapsulate one policy argument for divestiture of power supply when competitive wholesale markets are created. The fact that those forces are not fully effective means that plant ownership may remain a useful option. Among the reasons these forces are not fully effective is a different perception by financial markets among the risk, and therefore the cost of capital, for merchant power plant owners compared with utilities serving retail customer loads. This differential is presently very significant. In addition, financial markets continue to assign a portion of the risk associated with long-term power costs to the purchasing utility, and this affects the buy versus build decision. These issues are significant, and will be discussed in Chapter 7.

In sum, because of its potential benefits to consumers, default service providers should evaluate plant construction and ownership as a possible component to their portfolio. However, ownership clearly adds additional and different risks that must also be managed appropriately. In many retail choice jurisdictions, the transition to competition has resulted in institutional constraints or strong disincentives for plant ownership.[53] Regulators (or legislators) may wish to evaluate and consider revising those systemic limitations.

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[53] This is not to say that vertical market power was not an issue that needed to be addressed at the time that divestitures were required.

A Buy vs. Build Example

It is informative to look at an example of the economics of the build versus buy decision for an electric utility. In the following analysis, we look at the cost of electricity from a natural gas combined-cycle plant under two different financing scenarios:

- A generating plant constructed and owned by a regulated utility.
- A generating plant constructed and owned by an independent power producer (merchant plant) with a long-term contract.

The analysis identifies the costs of capital for each situation based on the costs of raising equity versus debt financing under the different capital structures. We then estimated the levelized costs of electricity generation (in $/MWh), in order to compare the effects of the different financing scenarios. Results are shown in Table A-2. The documentation and assumptions for this analysis are provided below.

Table A-2. Levelized Price for Electricity Under Different Financing Scenarios

	Percent Debt Financing	Percent Equity Financing	Cost of Debt (%)	Cost of Equity (%)	Capital Recovery Period	Capital Recovery Factor	Levelized Price ($/kWh)
Regulated Utility	50%	50%	8	11	30 yrs	10.3%	44.5
Merchant Plant	80%	20%	12	16	20 yrs	13.6%	48.4

This analysis indicates that, all other things being equal, it is most economical for a regulated utility to build and operate its own generating facility. This is true because a regulated utility is, in general, the least risky of the three options and, thus, has lower costs of both equity and debt compared with a merchant plant.

The cost of power from the merchant plant is higher than the utility for two reasons. First, the merchant plant has a higher cost of debt and equity because they are a greater risk to their investors. Second, merchant plant owners typically need to recover their costs over a shorter time period than regulated utilities, because of the greater risks and because power contracts tend to cover shorted periods than the book life of the regulated power plant. This shorter capital recovery period is responsible for the largest portion of the difference between the regulated utility and the merchant plant. Of course, an electric utility would also need to consider all the costs and benefits of these different options, including the risks associated with owning a plant or entering into a long-term forward contract.

One benefit of plant ownership is that if the resource has value at the end of the original estimated project life, the utility "owns" it and the remaining life is available to serve consumers without having to pay a second time for the same resource. There are many power plants, primarily coal and hydro, that have long outlived their original estimated operating lifetimes and original financing assumptions. If the utility is purchasing a power contract, it receives protection in the event that a resource fails before the end of the contract, but gives up the potential for economical plant life extension unless this is provided for in the original contract. Some contracts do provide the utility with the right to purchase the resource for a specified price at the end of the contract, thus preserving this potential value.

Assumptions for Buy vs. Build Example

Financial Assumptions:

Most of the financial assumptions were based on those used by the US Energy Information Administration in preparing the Annual Energy Outlook (EIA 2003c)

- *Economic Life* – A capital recovery period of 30 years was assumed for the power plant owned by regulated utility. This is based on the typical depreciation schedule for a power plant owned and operated by electric utilities. An economic life of 20 years was assumed for a merchant plant. This is based on our estimate of the typical period that investors require to recover the capital costs of merchant plants. In practice, this economic life might be higher or lower, depending upon the financial circumstances of the power plant owner.
- *Financing Structure* – For the regulated utility, we assumed a 50% equity, 50% debt financing structure. This was based on a conversation with EIA, wherein we were told that the 2002 assumptions were 45% equity and 55% debt for new utility projects. Yet, there was strong belief that future financing values for 2003 and the foreseeable future would have less debt and thus we lowered the values to a 50/50 split. For the merchant plant with a contract, we assumed a 20% equity, 80% debt capital structure.
- *Debt Term and Cost* – We assumed the debt term to be a period of 30 years for the regulated utility, and 20 years for the merchant plant with a contract. For the regulated utility with a 50/50 debt/equity structure, we assumed debt costs to currently be in the range of 8%. For the merchant plant with higher debt financing, we assumed debt costs to currently be in the range of 12%.
- *Equity Cost* – Based on conversations with EIA, we assumed equity costs of 16% for the merchant plant. For the regulated utility, we assumed equity costs to currently be in the range of 11%.
- *Tax Depreciation* – We assumed an accelerated tax depreciation schedule over a 20 year tax life for both the regulated utility and the merchant plant.
- *Other taxes* – We assumed a federal tax rate of 34% based on EIA assumptions and an 8.8% average state tax rate.
- *Inflation rate* – We assumed inflation to currently be in the range of 2.5%.
- *Property Tax* - Property tax as a percent of the investment cost. This can vary substantially by location, but 2% ($20 per $1000 of valuation) is typical. The payment is considered to be constant in real dollars over the operating life of the plant.

Power Plant Cost and Operating Assumptions:

Unless otherwise noted, the power plant cost assumptions were based on those used by the US Energy Information Administration in preparing the Annual Energy Outlook (EIA 2003a) The assumptions below are for a conventional natural gas combined cycle unit. All costs are in 2001 dollars.

- *Capital Costs* – Overnight capital costs for a plant constructed in 2001, including contingencies: \$536/kW. All-in construction cost, including interest during a three-year construction period: \$620/kW.
- *Fixed O&M* – \$12.26/kW-yr.
- *Variable O&M* – \$2.0/MWh.
- *Heat Rate* – 7,000 Btu/kWh.
- *Fuel Price* – \$4/MMBtu. Assumed to represent the levelized fuel cost over the twenty-year study period, in real terms.
- *Capacity Factor* – 60%. Assumed to represent a mid-merit power plant in a competitive wholesale market.
- *Emission Allowance Costs* – none. Natural gas combined-cycle units emit very small amounts of SO_2. For simplicity, we assume that the unit is located in an area with no cap on NO_X allowances.

Conclusion

Across many industries and over long periods of time, the optimal approach to portfolio management is generally found to be a balance of contracts of varying durations, price terms, and raw materials, and some small reliance on spot market, possibly supplemented with hedging instruments. In addition, long-term contracts or plant ownership can be "economically efficient" and make good sense in some situations.

A.2 Portfolio Management in Non-Electricity Industries

Companies in all industries are concerned about market risks. For product companies, these risks take the follow forms:

- Inventory risk due to uncertain demand by customers
- Rate change risks due to uncertain changes in international rate of exchanges
- Commodities risk due to uncertain cost of raw materials and resulting changes in the spot market

Companies are taking great strides to mitigate such risks, as over 60% of a typical producer's revenue is spent on raw material costs and services. For inventory risk, companies are favoring just-in-time manufacturing, wherein the company works closely with a supplier to ensure that inventories are kept at a minimum, but that there is constantly enough supply to match customer demand. For currency rate change risks, companies have begun to invest in financial swaps and derivatives, which allow companies to lower risk when selling/buying goods within international markets.

In the discussions below we focus on the third kind of risk, commodities risk, because this is the most important type of risk to electric utilities. We begin with a discussion here of how non-electricity companies attempt to mitigate these risks, and then describe recent efforts by electricity utilities.

Traditional Supplier Contracts

Traditionally, manufacturing companies have signed forward contracts with suppliers of critical commodities. The decision to use a traditional forward contract revolves around the current and expected future directions of market prices, the volatility of the market, and how soon a market direction change is expected. For both buyers and sellers, forward contracts guarantee the transaction of a known quantity and price of goods for a given time frame. From the buyer's perspective, the contract not only guarantees delivery of a critical good, at an agreed upon price, but also reduces the costs of procurement operations, as prices can be negotiated less frequently.

The typical length of a contract is dependent on the lifecycle of the industry or product. In the pork industry, type and quality of product might be considered constant and demand can be well forecasted. Hog cash contracts are typically renegotiated every 3-7 years. (Wellman 2003) Similarly, Gillette manufacturing, which has a long-term forecasted demand for steel for its razor blades, enters one-year contracts, typically with at least two suppliers worldwide. (Hollingworth 2003) Having multiple suppliers ensures competitive pricing from suppliers and mitigates the risk that one might not be able to meet demand. It also allows the staggering of contract start dates, such that the company is less affected by a price swing at the beginning of its buying cycle. At companies with faster life cycle products, such as Intel, contracts are negotiated anywhere from every quarter to every several years. For instance, with regard to CPU processors, with a lifetime of only a few years, multi-year contracts are typically avoided, as CPU obsolescence limits the contract horizon. (Neustadt 2003) Overall, studies show that the average commodity is re-priced roughly once a year.

[54] This does not seem to be common practice at either Gillette or at other consumer goods companies.

Commodity Procurement at Ford Motor Co.

While there are many advantages to long-term contracts, there are also disadvantages, particularly if they are not hedged or staggered and split among competing suppliers. In the early 1990's, most of Ford Motor Company's catalytic converters relied heavily on palladium metal. Global auto-industry demand for palladium had nearly quintupled between 1992 and 1996. Accordingly, prices slowly began to rise. However, because Russia had historically made its palladium available to American consumers, Ford figured the market would continue to remain roughly in balance despite the increases in demand. But, in 1997, Russia shocked the market by holding up palladium shipments to the US, resulting in a 3-fold increase in the price of palladium. Supply and demand oscillated for the next several years. Finally, in 2000, Ford's top managers approved a proposal to begin lining up long-term contracts and begin stockpiling palladium, despite the fact that prices were at record highs. Stockpiling was an unusual practice at Ford, and the Company did not have a process in place to use options to hedge the risk of changes to rare commodities prices. Yet, Ford went ahead and signed the long-term contracts for palladium shipments.

In the summer of 2001, there was yet another price shock in the palladium market. This time prices fell sharply to \$350/ounce, a 60% drop from their January \$1000/ounce highs. Yet, by this time, Ford had already engaged in the long-term contracts with suppliers and their inventory was immense. In 2002, the Company was forced to make a \$1 Billion write-off due to the difference between the market and book value of its palladium stockpiles.

Thus, while Ford had locked in a known price for palladium, the price fluctuation had resulted in overpayment and overstock of this rare commodity. Ford's mistake put the company in a very difficult situation in terms of answering to its investors' questions regarding the company's ability to manage commodity price risk. (White 2002)

Derivative Use in Other Industries

Aside from engaging in longer-term contracts and relational contracts, most leading chemical, agricultural, and consumer goods corporations use commodity swaps and commodity derivatives as tools to limit market risk. For instance, at Wonder Bread, market risk is discussed in the annual report:

> Commodities we use in the production of our products are subject to wide price fluctuations, depending upon factors such as weather, crop production, worldwide market supply and demand and government regulation. To reduce the risk associated with commodity price fluctuations, primarily for wheat, corn, sugar, soybean oil and certain fuels, we enter into forward purchase contracts and commodity futures and options in order to fix commodity prices for future periods. A sensitivity analysis was prepared and, based upon our commodity-related derivatives position as of June 1, 2002, an assumed 10% adverse change in commodity prices would not have a material effect on our fair values, future earnings or cash flows. (Wonder Bread Annual Report, 2002)

In other words, thanks to Wonder Bread financial managers, investors can be assured that a 10% swing in spot market prices for their raw material commodities will have an insignificant effect on the company's net income. Better yet, studies have shown that those companies that have begun to use financial hedging have seen an overall increase in their market value, whereas those that have abandoned hedging for some reason have shown a statistically significant decrease in market value. (Allayannis 2001)

A.3 Special Topic: Instruments for Use in the Transition Period Prior to Deregulation

The introduction of competitive markets is often accomplished by breaking up vertically integrated companies. For electricity, this means de-integration of large utilities that not only generate electricity, but also own transmission lines, and possess long-term power purchase agreements. Thus, industry restructuring means changes to the ownership and management of traditional industry infrastructure, which in turn affects spot market prices. Vesting contracts, as defined, are hedge contracts that are put in place prior to the divestiture of generation assets. Their main features are that they are regulated contracts that are not freely negotiated in the marketplace. Instead, vesting contracts are useful in the transition period from a regulated market to a more mature electricity market. These contracts allow the de-integrated industry segments to function without exposing them to abrupt changes in risk. They protect customers from spot market prices, promote the hedge contract market, and provide incentives for competitive entry. Companies can enter the deregulated environment with portfolios made up of only vesting contracts. As these contracts expire, parties can renegotiate and move to a mix of vesting and market-based contracts. Gradually, the buyers and suppliers will own a portfolio of market-based contracts and other assets.

Transition Using Vesting Contracts

In the mid-1990s, the Australian State of Victoria underwent electricity deregulation. Simultaneously, the government imposed vesting contracts that provided generators with a substantial part of their revenues at predictable prices for transitional periods of two to five years. One of the motives for deregulation in this region was the high cost of installed overcapacity in electricity generation, which was a consequence of large investments in coal stations by government-owned utilities as well as supply-side efficiency improvements. As a result, electricity prices in Australia fell by around 15 per cent in real terms over the decade to 1997-1998. Initially, the vesting contracts that had been put in place had much higher prices than pool prices, but this situation reversed in later years. In effect, the government-imposed vesting contracts shielded privatized generators from potentially severe financial losses, which could have developed from a short-term exacerbation of oversupply. (Kee 2001) Without the vesting contacts, privatized generators would have had no motivation to participate in the marketplace and there would have been a long-term shortage of generation. Following the initial period of oversupply and depressed prices, by 2001, these same markets suffered supply shortfalls and soaring spot market prices. The sudden rise in prices lead to closure of several major industrial facilities, primarily aluminum smelters. This type of "boom and bust" cycle of power development is not unlike similar cycles in other unregulated commodities such as oil and natural gas, or, for that matter, real estate development.

Conversely, failure to manage these transitions can be expensive. Rockland Electric has incurred significant risks due its failure to use short-term parting contracts effectively.

Transition without Vesting Contracts

In 1998, prior to deregulation in New York, Rockland Electric Company (RECO) entered into a short-term parting contract with the purchaser of its generating assets. Other New York utilities faced with the same market uncertainties took steps to manage/hedge short-term pricing risk. Most entered into longer-term transition power agreements (as parting contracts are called in New York) and other agreements that provided for significant amounts of supply for several years after generation divestiture, at prices that were at least partly fixed. New York State Electric and Gas (NYSEG), Central Hudson, and Niagara Mohawk all entered into parting contracts in 1998, 1999, and 2000 of at least two years in duration. Such contracts reduced their exposure to the spot market.

RECO and its customers, on the other hand, were completely exposed to short-term price volatility. As a result, RECO had unusually large costs for buying power in 2000. The company accrued excessive amounts of deferred balances, which are losses accumulated by utilities when the cost of purchasing electricity exceeds the capped rates they are allowed to charge customers. New Jersey's Electric Discount and Energy Competition Act (EDECA) requires that ratepayers reimburse utilities "on a full and timely basis all reasonable and prudently incurred" deferred balances.

However, there is currently a hearing to determine if balances in these accounts could have been avoided through longer contracts of 2-4 years. In fact, RECO could lose up to $20-30 million in this case, which it could have avoided by better managing electricity price risks. For example, a multi-year parting contract covering perhaps 50 percent of the Company's expected requirements would have been consistent with the Company's subsequent hedging approach, which called for hedging approximately 50% of its generation requirements. Unfortunately, by the time RECO had changed its procurement practices, prices had already risen, and the opportunity of a built-in hedge in the form of longer-term parting contracts had been lost.

A.4 Consideration of Contract Types

In Chapters 4 and 7 of this report, we reviewed the range of commodity contract structures and related financial hedging tools, both in the abstract and as applied to the electric industry. Here we will consider how those devices translate for use in electric default service portfolio management. This subsection begins with an overview of the types of market-based contracts that should be considered in assembling a portfolio.[55] We then provide a similar overview of financial hedging transactions and discuss how both types of transactions apply in PM. One special issue regarding reliance on contracts—contract disputes and enforceability—is also discussed briefly.

Long-term electricity contracts generally treat fuel price risk through one of three pricing mechanisms: (1) fixed prices, (2) indexed prices, or (3) "tolling" agreements.

[55] In addition to those discussed here, a very large number of contract types exist for what are usually called ancillary services. Ancillary services include, for example, generating reserves needed to ensure reliability and provision of units capable of being slowed down or speeded up to maintain proper 60 Hz power frequency. They are often traded as customized bilateral contracts (as is done in the class of resource-based contracts), and broker-mediated contracts. These types of services and contracts are beyond the scope of this report.

Forward Contracts

Forward contracts are the most traditional of the contractual instruments available for current PM. In a forward contract, the Buyer contracts with the Seller to take delivery of a specified amount of power at a certain location on the grid at specified times and prices. The power may or may not include ancillary services, such as capacity credit, or attributes, such as emissions tags or renewable energy credits.

Fixed-price electricity contracts typically establish a fixed and known price per MWh of delivered electricity. Alternatively, the price per MWh may vary according to a fixed schedule; the key point is that the price does not vary with market conditions. Such contracts clearly allocate fuel price risk to the Seller because the Seller is responsible for selling electricity at fixed prices while simultaneously dealing with a variable fuel price stream. The Buyer presumably pays a premium for fixed-price contracts because the Seller has to manage the fuel price risk to which it is exposed, which increases the Seller's costs. If the Seller does not adequately mitigate its exposure to fuel price risk it will be more likely to default on the contract, however, so the Buyer is left with some "residual" fuel price risk (i.e. contract default risk) with fixed-price non-renewable contracts. Conversely, the Buyer gives up certain opportunities to take advantage of favorable fuel price changes, and typically must take a specified (or minimum) amount of power whenever it is provided for in the contract, regardless of variations in the utility's load. This obligation to "take and pay," regardless of need for the power, is the reason that rating agencies impose a "debt-equivalent" penalty on the buyer when this type of contract is used.

Indexed-price contracts generally index the price of electricity to either inflation or to the cost of another commodity, for example, the cost of the fuel used to generate the electricity (Kahn 1992). When indexed-price electricity contracts are indexed to the price of the fuel used to generate the electricity, the fuel price risk is allocated to the Buyer because the Buyer receives a variable-priced product. Fuel price risk can be managed using financial hedging instruments. This type of contract causes a smaller "debt-equivalent" penalty for the Buyer, because the price paid is more likely to reflect the market value, meaning the utility can dispose of any surplus and recover most or all of the cost.

Demand and Energy contracts combine the features of the fixed-price and indexed-price contract forms. In this type of contract, the Buyer pays a fixed amount each month for the right to the take power (intended to represent the fixed costs incurred by the Seller), and then a charge per kilowatt-hour actually taken (representing the variable costs incurred by the seller.) The variable charge may be fixed or constrained, but is often indexed to a market price for fuel. This type of contract is more difficult to hedge, because the quantity of power to be taken cannot be known in advance by either the buyer or the seller.

Tolling contracts require the Buyer of the electricity to pay for the cost of the fuel used to generate the electricity (and sometimes other variable operating costs or uncontrollable costs), and the Buyer may also have the option of providing the fuel itself. Tolling agreements and fixed-price agreements conceptualize the service and product being provided by the Seller to the Buyer in fundamentally different ways. In fixed-price contracts, the Seller clearly sells the Buyer a product: electricity. In tolling agreements, on the other hand, the Seller is effectively providing the Buyer a service: the right to use the Seller's power plant to convert fuel to electricity. The Seller is paid not only for the use of its facility, but also for simply being available to generate (through a reservation, or "capacity" charge). In addition, the Buyer pays for the fuel used to generate the electricity. The risk of fuel price variability is therefore clearly allocated to the Buyer in tolling contracts. The Buyer can then choose to reduce its fuel price risk exposure through fixed-price physical fuel supply contracts, fuel storage, or financial hedging instruments.[56]

In general, long- and short-term forward contracts provide some of the security and stability utility-owned resources, and warrant consideration for inclusion as a significant portion of a default portfolio because these are traits that ratepayers are comfortable with and value.

Of course, over-buying forward contracts when prices and demand are uncertain can result in losses or rate pressure. Therefore, techniques such as laddering of contracts and diversification of technologies, fuels and suppliers should be pursued. Careful analysis of load forecasts and price projections should be used to establish a reasonable percentage of expected load to be met by long- or short-term forward contracts and which types should be included. Just as an investment portfolio should avoid too much investment in a single industry or single company, a power portfolio should avoid too much commitment to any specific fuel or generating unit.

Long-Term Resource-Based Forward Contracts and Renewable Generation

In contrast to fossil fuels, renewable resources typically have a less-variable (or even free) fuel cost stream, resulting in less fuel price risk for either party to an electricity contract. Hence, it is more common to have fixed-price contracts for renewable electricity than for natural gas-generated electricity.

Since the use of renewable resources decreases fuel price risk for both parties to a contract, all else equal, a fixed-price renewable electricity contract is a more complete hedge against fuel price risk for the Buyer than a fixed-price contract for natural gas-generated electricity. This is because the Buyer of a fixed-price gas-fired contract (if such a contract is available) may still bear some residual fuel price risk through potential contract default by the Seller if natural gas prices increase, as discussed above.[57] Experience shows that the risk of contract default or renegotiation in such cases can be significant for gas-fired contracts (EIA 2002), though the magnitude of this risk is difficult to assess with precision and therefore deserves additional analysis. (Bachrach, 2003)

[56] Arrangements for operating costs other than fuel may vary.

[57] Such counterparty risks exist in all markets, but in mature markets for standardized instruments, such as those discussed in Ch. 4, they are carefully minimized by trading rules of exchanges through practices such as daily settlement of value changes. See for example, CME 2003 and Culp 2001, p. 272.

Forward contracts are essentially the same instrument as the firm power contracts that have been traded bilaterally among utilities since the first interconnections between them. Those contracts now exist in a somewhat different environment. Since Order 888, they are no longer (usually) FERC-regulated cost based contracts or power pool mediated split the savings deals, but "market priced."[58] In many markets, brokers offer a kind of matchmaking service, posting ask and bid prices for standardized blocks of power for various time periods, e.g., monthly for two years and semi-annually for five years, but actual transactions take place between individual counterparties. Actual future contracts--fully standardized contracts traded anonymously on exchanges that provide regular clearing services--are now available on a number of commodity exchanges around the country.

[58] As discussed elsewhere in this report, this lack of wholesale price regulation does not mean that all such contracts are arm length transactions reflecting the economic valuation achieved in efficient free markets. Default service providers, who one way or another, continue to have effectively captive customers should be required to avoid any apparent or actual conflicts in trading, especially with affiliates.

Appendix B. Energy Efficiency Cost-Effectiveness Tests

B.1 Definition of Tests

The costs and benefits of energy efficiency are sometimes different from those of supply-side resources, and have different implications for different parties. As a result, five tests have been developed to consider efficiency costs and benefits from different perspectives. These tests are described below and summarized in Table B.1.[59]

- The Participant Test. The goal of this test is to determine the impact of efficiency on the customer that participates in the efficiency program. The costs include all the expenses incurred by the customer to purchase, install and operate an efficiency measure. The benefits include the reduction in the customer's electricity bills, as well as any financial incentive paid by the utility. This test tends to be the least restrictive of the other tests, because electric rates tend to be higher than avoided costs, and participating customers see the greatest benefit from the efficiency programs.

- The Energy System Test.[60] The goal of this test is to determine the impact of efficiency on the total cost of providing electricity (or gas, in the case of gas utilities). This test is most consistent with the way that supply-side resources are evaluated by vertically-integrated utilities. The costs include all expenditures by the utility (or program administrator) to design, plan, administer, monitor and evaluate efficiency programs. The benefits include all the avoided generation, transmission and distribution costs.

- The Total Resource Cost (TRC) Test. The goal of this test is to determine the total cash costs and benefits of the efficiency program, regardless of who pays and benefits from it. The costs include all the expenditures by the utility (or program administrator), plus all the costs incurred by the customer. The benefits include all the avoided utility costs, plus any other cost savings for the customer such as avoided water costs, avoided oil costs, reduced operations and maintenance costs to the customer, or non-energy benefits to low-income customers. For most efficiency measures, this test tends to be more restrictive than the Energy System Test, because customer contributions to energy efficiency measures are easier to identify than additional benefits not considered in the Energy System test.

- The Societal Cost Test. The goal of this test is to determine the total costs and benefits of efficiency to all of society, including more difficult to quantify benefits such as environmental benefits and economic development impacts. The costs and

[59] These tests are defined slightly differently by different Public Utilities Commissions. For the most comprehensive description and discussion of these tests, see CA PUC 2001 and LBL 1988.

[60] This has previously been referred to as the Utility Cost or the Program Administrator test.

benefits are the same as for the TRC Test, except that the benefits also include monetized values of environmental and economic development benefits. If environmental and economic development benefits are properly calculated, this test tends to be the least restrictive of them all, with the possible exception of the Participant Test.

- The Ratepayer Impact Measure (RIM) Test.[61] The goal of this test is to determine the impact on those customers that do not participate in the energy efficiency programs, by measuring the impact on electric rates. The costs include all the expenditures by the utility, plus the "lost revenues" to the utility as a result of having to recover fixed costs over fewer sales.[62] The benefits include the avoided utility costs. This test tends to be the most restrictive of all the efficiency tests, because the lost revenues have a large impact on the cost calculation.

Table B.1. Components of the Energy Efficiency Cost-Effectiveness Tests

	Participant Test	Energy System Test	TRC Test	Societal Test	RIM Test
Energy Efficiency Program Benefits:					
Financial Incentive to Customer	X	---	---	---	---
Customer Bill Savings	X	---	---	---	---
Avoided Generation Costs	---	X	X	X	X
Avoided Transmission and Distribution Costs	---	X	X	X	X
Resource Benefits (e.g. oil, gas, water)	---	---	X	X	---
Non-Resource Benefits (e.g. O&M savings)	---	---	X	X	---
Benefits to Low-Income Customers	---	---	X	X	---
Environmental Benefits	---	---	---	X	---
Economic Benefits	---	---	---	X	---
Energy Efficiency Program Costs:					
Program Administrator Costs	---	X	X	X	X
Participating Customer Costs	X	---	X	X	
Lost Revenues to the Utility	---	---			X

B.2 Shortcomings of the RIM Test

The RIM test should not be used as the primary tool for determining the cost-effectiveness of energy efficiency programs for the following reasons.

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61 This has previously been referred to as the Non-Participant test and the No-Losers test.

62 In some situations, efficiency program outlays and customer bill savings can result in secondary sales growth that can offset some of these "lost revenues." Such rate lowering effects of program driven secondary sales are usually counted in support of economic development discount rates and should be considered here as well.

- The RIM test will not result in the lowest cost to society.
- Rate impacts and lost revenues are not a true cost to society. Rate impacts and lost revenues represent a "transfer payment" between non-participants and participants. Consequently, they are not a new cost, and should not be applied as such in screening a new energy efficiency resource. Rate impacts and lost revenues may create equity issues between customers. However, these equity issues should not be addressed through the screening of efficiency programs, but through other means, as described below.
- Screening efficiency programs with the RIM test is inconsistent with the way that supply-side resources are screened. There are many instances where utilities invest in new power plants or transmission and distribution facilities in order to meet the needs of a subset of customers, (e.g., new residential divisions, an expanding industrial base, geographically-based upgrades). These supply-side resources are not evaluated on the basis of their equity effects, nor are the "non-participants" seen as cross-subsidizing the "participants." Energy efficiency resources should not be subject to different screening criteria than supply-side resources.
- Consumers, in the end, are more affected by the size of their electric bills (the product of rates and usage) than by the rates alone. The RIM test does not provide any information about what happens to electric bills as a result of program implementation
- A strict application of the RIM test can result in the rejection of large amounts of energy savings and large reductions in many customers' bills in order to avoid very small, *de minimus* impacts on non-participants' bills. From a public policy perspective, such a trade-off is illogical and inappropriate.

Even if the RIM test is not used to screen energy efficiency programs, there are two remaining rate effect issues that may be of concern to utilities and policy-makers: the potential importance of rate impacts of any size and concerns about equity between efficiency program participants and non-participants. These two issues are discussed in Chapter 6 of this report.

Appendix C. Distributed Generation Technology Characteristics

While any generating technology can be considered for distributed applications if it lends itself to small, dispersed installations, certain technologies have greater promise for DG.

- **Fuel cells** produce electricity and heat by combining fuel and oxygen in an electrochemical reaction and can operate on a variety of fuels including natural gas, propane, landfill gas, and hydrogen. Their direct conversion of chemical energy into heat and electrical energy offers quiet operation, low emissions, and high efficiencies. With present technologies, fuel cell electrical efficiencies range from 40% to 60%, and their combined electrical and heat efficiencies are over 80%, and provide highly reliable, premium quality power. Presently, the cost of fuel cells are relatively high at about $3,000 per kW, but are expected to become considerably lower under mass production.

- **Microturbines**, small gas turbines, with only one moving part, range in size from 30kW to several hundred kW and operate on a variety of fuels including gasoline, diesel, and natural gas. Microturbines are quiet, readily dispatchable, and well suited for commercial and industrial applications. First generation microturbines yield relatively low efficiencies of about 30%, but also have moderate capital costs of around $600/kW. It is anticipated that microturbines that are fueled by natural gas, without cogeneration, will produce electricity for 7 cents to 10 cents per kWh making them competitive with the combined cost of utility generation and distribution service in the near term.

- **Photovoltaic (PV)** devices convert directly sunlight into electricity and are modular, lightweight, contain no moving parts (unless tracking devices are used), release no emissions, need no water, and have low operation and maintenance requirements. Photovoltaic panels can be placed on rooftops giving this technology significant siting flexibility. However, small unit PV installations remain relatively costly at about $5,000/kW installed. (DOE 1997) PV installations require relatively large areas to produce significant amounts of power. The most common applications of PV technology to date have been to power small loads in remote, off-grid sites where utility line extension costs are prohibitive. As photovoltaics become more widely used, it is anticipated that resulting mass production will lead to significant price decreases. Some states have provided favorable tax rules for such investments. (IREC 2003)

- **Reciprocating engine/generator sets** run on a variety of fuels, come in sizes from 5kW to tens of MW with installed costs from $500/kW to $1,500/kW. These mass produced sets are supported by established sales and maintenance infrastructures, and are available as residential and commercial cogeneration packages. Drawbacks include relatively high emissions, noise, and maintenance requirements.

- **Wind Turbines** have been the subject of recent, ongoing technological advances have increased their efficiency and reliability while lowering their costs. Installed costs for wind turbines range from \$1000/kW to \$3000/kW. Adaptations to cold, icing environments has also made progress. While wind turbines have no fuel requirements and zero emissions, they typically produce power at only 30-40% of their rated capacity and can have site-dependent noise, wildlife habitat, and visual aesthetic concerns.

- **Storage Technologies**, the most common being the battery, store energy in chemical or mechanical form and like other storage devices can be used for peak shaving, spinning reserve, outage support, and voltage and transient stability. While not yet viable for storing large amounts of energy, batteries are currently used for uninterruptible power supplies, support for off-grid PV and wind systems, and emergency backup for lighting and controls. Other options include compressed air storage, pumped hydroelectric storage, and more exotic technologies such as flywheels and superconducting rings, both of which remain experimental.

In addition to the PM benefits cited above for ownership of physical generation, in general, distributed generation (DG) provides certain additional desirable features. DG development can, of course, defer or eliminate local and inter-regional T&D additions and upgrades with consequent capital and O&M savings and concomitant avoided investment risks. Additional T&D benefits of DG include reduced line losses, better voltage support, and improved power quality and reliability (with associated improvements to customer relationships). DG development can also deliver non-T&D benefits. These include new business opportunities in an emerging competitive market and reduced environmental impacts. This can bring improved public relations by "greening" the products of both the provider and the DG host customer. DGs greater modularity allows new capacity to follow load growth more closely and reduces the impact of outages. Finally, cogeneration placed on customers' premises promotes local economic development and other investments in the local community.

DG resources are most often installed at the distribution level and can be on either side of the meter. They are typically small, ranging from less than one kilowatt (kW) to only a few hundred kW, but much larger installations can be important in commercial and industrial settings.

On occasion, units of hundreds of kW up to 100 or more MW may be relevant where the capacity constraints being addressed are on the transmission or subtransmission level. Because transmission systems are designed for "n-1" reliability, maintaining service with one line out, there may be a number of conditions when a distributed resource will eliminate the need for a major transmission investment needed to secure a secondary transmission path that would seldom be needed.

On the supply side, gasoline and diesel fueled reciprocating engines have well-known cost and performance characteristics, while micro-turbines and fuel cells are more novel, but have potential advantages where air quality and power quality requirements are critical. Advancement in the efficiency, reliability, cost and maintainability of advanced technologies may be expected to continue and screening choices should be reviewed frequently.

In passing, it is worth noting that, the full range of DSM options also applies--both lost opportunity programs targeting new construction, renovation, and equipment replacement events and retrofit measures. Lost opportunity programs can be particularly cost-effective where T&D constraints are driven by rapid load growth. In areas with strongly seasonal peak loads, efficiency and load control measures that target the times feeder, substation, or regional loads peak should receive priority attention. Relevant DSM measures include: 1) efficient appliances, lighting, heating, and industrial processes; 2) utility or energy service provider control of specific customer loads; and 3) rate designs such as inverted rates, time-of-use rates, interruptible rates, and real-time pricing. Coordination of programs with ISO or RTO demand response offerings can improve cost effectiveness.

Interconnection of distributed generation has often presented technical and institutional barriers to development. Developers and participating customers need reasonable and predictable policies and interconnection rates and fees. Those requirements have only recently begun to be met in any widespread fashion. Regulators should act to ensure that these barriers are minimized. Recent adoption of a technical standard for generator interconnection by the IEEE should significantly improve the situation, as did an earlier standard for photovoltaic device interconnections.[63]

[63] For example, IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems, adopted June 12, 2003. See, http://www.eere.energy.gov/distributedpower/news/0603_ieee1547.html

Appendix D. Methods for Analyzing and Managing Risk

D.1. Risk Measurement Tools for Assessing Portfolios

When comparing electricity portfolios, we would like to be able to quantify and compare the risk of each portfolio. Similarly, when issuing an RFP for electricity supply, we would like to be able to specify a desired quantitative level of risk and to compare riskiness (to consumers) of bids.[64] There are ways to quantify many but not all of the risks that need to be evaluated. Even where there is an appropriate methodology, however, the availability of data may be limited. An introduction to this task was given in Section 9. Here, we review the primary quantitative methodologies for quantifying portfolio risk.

Risk measurement begins with a thorough assessment of the full spectrum of risks that affect each resource in the portfolio and that need to be addressed in planning. (Gleason 2000) This assessment should include a careful search for risks that are correlated with each other. Once risks have been identified, historical data and other sources should be used to quantify the magnitude and probabilities of those risks, as well as their correlation with each other. With that information in hand, there are several techniques for evaluating how those risks interact to form the risk profile of a portfolio.

When the relevant sources of variability are quantified for each portfolio component, the overall variability of the portfolio can be derived mathematically, at least for those quantified risks. The major complication to this task is that method for combining standard deviations of the components depends on how closely correlated are the fluctuations of the various components. This is quantified by the covariance of the component prices. For simple cases where there is historical data for the correlation of costs, such as for natural gas and oil, this effect can be computed directly. (Gropelli and Nikbakht 2000, p. 91) In other instances, simulation modeling may be needed. Finally, the techniques for estimating the effect of options and futures on the variability of portfolio costs are complex, but should be used where appropriate. (Trigeorgis 1996) Discussion of those techniques is beyond the scope of this report. Furthermore, there has been very little published research on application of these methods to electricity markets.

<u>Nominal Exposure Report</u>

A nominal exposure report is an analysis, for each broad type of portfolio component, of that component's dollar value and the amount of that dollar value that is exposed to loss.

[64] It is important to keep in mind that risk is a property of *both* an entire portfolio *and* the portfolio's component parts. That is to say, each resource in the portfolio will have its own level of volatility, counter-party risk, and so on, but the overall riskiness of the portfolio is *not* a linear sum of those risks. Depending on how closely correlated the various risks are, the overall portfolio may or may not be less volatile than the individual assets contained in it.

It is a snapshot of a particular risk exposure at a moment in time giving the amount of value that is *exposed* to loss, but does not represent the amount of loss that *could occur*. The latter amount is determined by other methods. (Culp, 2001)

Stress Testing

Stress testing a portfolio involves simulating different market conditions for their potential effects on the portfolio value. The basic question for a stress test is: how much loss might occur in the event of a crisis? In general, there are two methods used to answer this question. First, one can test the portfolio relative to historical shocks and see how the current portfolio might fare in a similar situation. The second approach is to brainstorm extreme scenarios and test their affect on the portfolio. The problem with these approaches is that history is unlikely to repeat itself exactly, and nobody can predict the future. Nonetheless, stress testing allows the portfolio manager to better understand how much loss might occur during a catastrophic event.

Mark-to-Market

Another approach to monitoring a managed portfolio is known as mark-to-market accounting. In this, periodically (as often as daily), one adjusts the value of the portfolio based on gains/losses in current market value of the assets relative to book value. The hope is that gains/losses are within the risk bounds of the portfolio owner. If they are not, one can try to rebalance the portfolio to better control risk. Mark-to-market is designed to show the full extent of a company's liabilities/risks over a period of time so that investors have no unwarranted surprises. While current market values are reported using this technique, actual realization of cash is unaffected. The same techniques applied to an electricity portfolio will provide evidence of whether consumers are exposed to unwarranted surprises in electricity costs.

Uncertainty Analysis Using Simulation

In practice, uncertainty analysis remains an evolving discipline for power supply portfolio planning. There is a paucity of applicable historical data for computing variances and covariances of prices and demands for both forward and option positions, and the multitude of physical supply- and demand-side alternatives is quite large compared to most financial markets. In addition, these alternatives, unlike those in most financial markets, have dimensions that go beyond price and price volatility.

Physical generation and DSM alternatives all have various unique risks that may or may not be well known, but they also have numerous qualitative costs and benefits not easily captured in costs, even societal costs. Some of these, such as cancellation rights, modularity benefits, and market power mitigation effects can, in principle, be evaluated as real options or assessed through dynamic programming. (Trigeorgis, 1996; Dixit and Pindyck, 1994)

In general, the current state of the art involves either scenario analysis, bounding case analysis, or simulation modeling using randomized inputs.[65] Uncertainty analysis allows one to determine which factors most affect a diversified portfolio. The manager can then focus on monitoring these factors and reducing the relative importance of them in the portfolio through diversification.

Decision Trees and Real Option Analysis

Decision tree analysis (DTA) is a traditional, systematic, and rational mathematical method for structuring and analyzing managerial decision problems in the face of uncertainty. It is most useful where there are a series of complex decision to be made at a sequence of points in time. (Trigeorgis 1996) At each point, options exist and, for each option, various uncertain outcomes can occur before the next decision point. The decisions available at each option point and the resulting possible outcomes from each then form a tree of contingencies. The decision points can be dates at which various portfolio additions could be chosen, and the uncertain outcomes would be the ensuing market conditions, for example. Once the relevant branches have been identified, each with its own sequence of decisions and outcomes for the uncertain variables, they can be evaluated one by one to determine the total cost of each of the available sequences of decisions given each of the possible outcomes on the uncertainties. This is a lot of arithmetic, but straightforward in principle. The various outcomes can be examined for insights into the possible results for each initial decision. Further, if probabilities can be assigned to each of the uncertainties, DTA becomes much more illuminating. Expected results for each initial decision can be computed that capture reasonably well the dynamics of decisions over time in the face of uncertainty. (Trigeorgis 1987, Houston P&L 1988, NEES, 1993)

Sensitivity and Scenario Analysis

People use models to gain insight into possible future outcomes. They then often take action based on the model's results. However, in order to take action, the decision maker should be fully confident that the model's results are robust – that small changes in the model's key variables will not yield extremely different outputs. It is also important to assess how well a candidate strategy can be expected to perform under different possible future trends.

Sensitivity analysis is performed in order to test the degree to which a model's results might vary as a result of both small and large changes in the value of each key variable used in the model. Originally, sensitivity analysis was created to deal simply with uncertainties in the input variables and model parameters. Over the course of time the ideas have been extended to incorporate model conceptual uncertainty, i.e. uncertainty in model structures, assumptions and specifications. Using sensitivity analysis, the portfolio

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[65] Both Monte Carlo or Latin Hypercube simulation model the effects on a portfolio of variations in a few key drivers. (Culp 2001, McKay 1979; Iman 1985) A computer simulation is run hundreds or thousands of times, varying each uncertain variable. One can then view the statistics of the simulated model and the resulting variability of particular outcomes.

manager is able to see how the optimal portfolio strategy is affected by changes in the values of key variables. The manager can then increase robustness/confidence by reformulating the model, such that the model's results remain firm under slightly changing conditions. Equally important, it is possible to evaluate, for each uncertain input factor, how much the forecasted results vary. This can provide insights for redesigning strategies and guidance for which input factors require the most careful monitoring.

Scenario analysis is similar to sensitivity analysis, but focuses on understanding how well a candidate strategy (or portfolio) can be expected to fare under significant excursions in the input variables. This is a model-driven form of stress testing and has long been used in IRP. In its longest standing form, scenario analysis begins by taking the forecaster's base case--the one that reflects the most likely versions of the future--and defining an uncertainty band around the most import input variables, often load forecast and fossil fuel prices. If especially relevant, a utility would sometimes also consider the best and worst potential availability factors for a large power plant, production rates for an especially large customer, or other unique factors important to its performance. Then, a few mutually compatible but extreme bundles of these input assumptions would be used as assumptions in the modeling instead of the base case. For example, a utility might consider how its portfolio would perform if its largest plant were out twice the normal hours/year and oil prices were at the high end of the spectrum, while load was at the low end of its likely band.

More recently, a new style of scenario planning has become common in the corporate world and is making some inroads in the electric industry. (Platts 2002) Intended to help planners in times of rapid change, scenario planning uses rigorous, disciplined analysis to develop narratives that describe what *may* happen in the form of intentionally divergent futures with sweepingly different social, political and economic natures. Quantitative models then use each of theses self-consistent but radically incompatible sets of input assumptions to test the robustness of various strategies. In a sense, this approach strives to hit the strategies with "bigger hammers" than traditional sensitivity studies to see what "breaks." By examining the results, strategies can be developed that may not be the best under any one future, but are survivable in all of them.

Summary

This section has reviewed a range of techniques for analyzing portfolio risk. The simplest to implement are the Nominal Exposure Report (which measure the amount of value that is exposed to risk, but not the magnitude of the loss that could occur) and Stress Testing (which estimates the impact of selected extreme outcomes in the market). These techniques can provide useful insight and do not require complex modeling and technical resources, but do not provide explicit, quantitative estimates of portfolio risk. Mark to Market is also straightforward to implement, but is a method for monitoring the ongoing value of a portfolio, not assessing its risk level; it is a management tool, not a planning or selection tool. Sensitivity Analysis (where portfolio performance is modeled under a variety of possible futures to identify and quantify potential weaknesses and strengths) is somewhat more demanding, in that some outcome modeling is needed, but begins to provide the information needed to reasonably compare portfolios for risk. If reasonable historical data or sound estimates of probabilities for different driving events, such as price excursions and outages, are available, Sensitivity Analysis can quantify the expected magnitude of risk. Proper application of this and the more complicated techniques covered in this section demand considerable experience and familiarity with the decision making context. Simulation Analysis and Decision Tree Analysis are two techniques that can be readily applied in simple cases, but become daunting when risks are numerous and complex. Their main advantage is that the can provide explicit, quantitative estimates of expected outcomes *and* the probability of better or work outcomes. Real Option Analysis is the most demanding method mathematically, but adds specific quantification of the value contributed by maintaining flexibility and reducing risks, a benefit not provided by other modes of analysis.

Each portfolio manager and regulators overseeing portfolio management should consider the resources available and select an appropriate level of investment in uncertainty analysis and portfolio risk assessment, given the planning and operating environment and the resources available. The most important tools for this work are an open minded approach to risk identification and careful analysis of which risks are correlated and which are not.

D.2 Efficiency Frontiers and Portfolio Optimization

Imagine you need to assemble a ten-year supply portfolio from a few dozen available supply alternative, all available in whatever quantities and lifetimes you wish. Each alternative has a known upfront cost and an annual capacity cost (either known or uncertain or mixture). You have forecasts of the future variable costs of power from each alternative, but for some alternatives this is quite uncertain. Some alternatives are also subject to unpredictable outages (which may occur at any time and may or may not be permanent). Some alternatives are also subject to regulatory or capital costs of uncertain amounts that may or may not be imposed, but could be significant and some guesses are available for what those costs might be *if* they occur. The actual amount of power needed for the next ten years can be forecast, but growth rates could range from zero to twice your forecast and can bounce around considerably from year to year, depending on weather and the economy (which also affect the variable cost of power, by the way). Certain hedging instruments are also available if you wish to use them, and it is expected that more such instruments will become available over time. How would you choose the "best" portfolio from among these alternatives?

This is the portfolio optimization problem. Even with the simplifications used above, it is clearly challenging. Yet it is essentially the same problem that most manufacturers face. Determining how much to invest in each asset in such a portfolio in order to minimize risk while minimizing expected cost can, in principle, be formulated and solved mathematically.[66] We will make a short diversion to look at the analogous similar problem of managing an investment portfolio where the goal is to maximize return on

[66] This would generally be a nonlinear optimization model, likely a dynamic, multi-period one

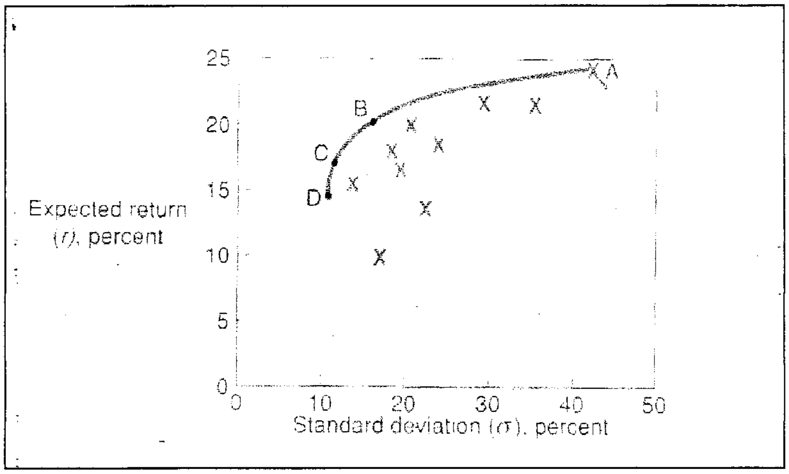
investment while minimizing risk.[67] In that field of study, a model, known as the efficiency frontier model, is helpful for guidance.

Now, let's imaging that a number of adequate candidate portfolios have been put together. Using the forecasts mentioned above and their error bounds or uncertainties, each candidate portfolio can be given an expected return and a measure of how uncertain or variable that return is (the standard deviation of the portfolio's return). Let's plot each candidate portfolio as a point on a graph where the vertical axis is the expected return and the horizontal axis is the variability of that return. (Figure D.1 shows an example.) What will usually be seen is that for each degree of variability (risk) shown as a location on the horizontal axis, there will be some portfolio that has the best (highest) return. (Some of these are marked A, B, C, and D in the figure.) A line connecting these "best of breed" portfolios is called the *efficiency frontier*. One will always prefer portfolios along that line. These are efficient portfolios because they offer maximum expected return, at each given risk level.

Although the process of computing the efficiency frontier is theoretically straightforward given a particular set of resource options and given levels of uncertainty in prices and demands, there are difficulties to using the efficient frontier in practice. Namely, the efficient frontier is computed based on future expected returns and future standard deviations and covariances among portfolio assets. Unfortunately, it is difficult to predict what these future values will be. One has to be careful that the optimization model that is supposed to minimize the risk of the portfolio will not turn out to be minimizing noise only. As a practical matter, planners typically resort to one or more of the uncertainty analysis methods described below, but it is worthwhile to remember that what we are trying to do is find that efficiency frontier and select a point along it that best suits our valuation of risk. It is also important to remember that we should always be on the lookout for new alternatives that could result in lowering the risk of a portfolio (moving it to the left on this graph) or its cost (moving it down).

[67] In the IRP or default service provider PM contexts, it may be best to think of the objective function (the measure of a portfolio's success) as being the life cycle societal cost or life cycle total resource cost of the portfolio and seek to minimize that value, but this subsection will cast the argument in terms of maximizing return. While there is usually a starting point portfolio and a variety of outlays (purchase commitments, construction investments, hedging expenditures, and so on) that might improve the life-cycle cost, the cost of which may be compared to the resulting savings to derive a "return" to be maximized, this may overcomplicate the analysis.

Figure D-1. Example of an Efficiency Frontier



Efficient portfolios: each cross represents the expected return and risk of individual investments. The shaded area shows the possible combinations of expected return and risks from investing in a mixed portfolio. One will always prefer portfolios along the upper, heavy line. A, B, C, D represent efficient portfolios because they offer maximum expected return, at a given risk level. Describe special considerations in integrating supply and demand-side options.

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Exhibit DB 2
pgs

Synapse
Energy Economics, Inc.

Portfolio Management:

How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers

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Executive Summary

A Brief Description of Portfolio Management

Portfolio management offers electric utilities and their regulators a process for making the most of the rapid changes and developments in today's electricity markets. A utility or default service provider that actively participates in electricity markets, and that carefully chooses among the wide variety of different electricity products and resources, will be able to provide better services to its customers over both the short- and long-term future.

Portfolio management begins with the primary objectives of a utility or default service provider in obtaining electricity resources for customers. Providing reliable electricity services at just and reasonable rates will continue to be a primary goal of electric utilities. Other objectives include mitigating risk; maintaining customer equity; improving the efficiency of the generation, transmission and distribution system; improving the efficiency of customer end-use consumption, and reduction of environmental impacts. Portfolio management provides a process for utilities to determine and implement the mix of electricity resources that will achieve these objectives to the greatest extent possible.

Portfolio management requires several key steps on the part of electric utilities or default service providers. Portfolio managers must first prepare load forecasts that represent the best assessment of customer demands for generation, transmission and distribution services for the long-term future. They must then assess all the opportunities available for meeting customer demand through cost-effective energy efficiency resources. The next step includes assessing the wide variety of generation-related opportunities, including building power plants; purchasing from the wholesale spot market; purchasing short-term and long-term forward contracts; purchasing derivatives to hedge against risk; developing distributed generation options; building or purchasing renewable resources; and expanding transmission and distribution facilities. The next, and most challenging, step in portfolio management is to develop the optimal mix of these resources that will best achieve various objectives identified by the utility and promoted by the regulators.

With the current lack of retail competition, default service providers have little pressure or incentive to pass the benefits of their long term portfolios on to retail customers. State policymakers need to create the necessary conditions for the full benefits of successful portfolio management to flow to retail electric customers It may also be that some default service providers only *passively* participate in the competitive electric market, by purchasing all of their generation from relatively short-term options. In so doing, they are missing many opportunities, and they are leaving their customers vulnerable to higher costs and greater risks. In order to benefit from competitive electricity markets, default service providers must participate more *actively* in procuring resources for their customers.

Portfolio management is also important for those utilities that remain vertically integrated. It provides a means for these utilities to meet the traditional objectives of providing reliable, low-cost electricity services by taking advantage of the new and emerging opportunities available from the competitive wholesale electricity markets.

The Benefits of Portfolio Management

In jurisdictions where retail competition has been introduced, the vast majority of customers continue to be served by the default service provider. This trend is likely to continue well into the foreseeable future, as a result of the many barriers that limit customers' ability to switch to alternative generation companies. Portfolio management provides a means for these customers to enjoy some of the benefits offered by the competitive wholesale markets, through the efforts of the portfolio manager who essentially acts as their "broker."

If done well, portfolio management will result in lower electricity costs, lower electricity bills, and more stable electricity prices. If, instead, default service providers are allowed to simply pass the costs of short-term generation contracts to customer, customers will be subject to higher electricity prices, greater volatility in prices, and greater risks of future cost increases.

Portfolio management will also improve the operations and the competitiveness of the wholesale electric markets. By representing large volumes of customers, and by increasing the demand for a more diverse range of competitive options (e.g., a variety of forward contracts), portfolio management will result in a more robust wholesale market, and will limit the ability of a few key generation companies to manipulate the market through the predominance of short-term contracts and spot market purchases. In sum, portfolio management is not only consistent with competitive markets; it is, in fact, necessary to ensure that competitive wholesale markets are robust.

Regulators will also benefit from portfolio management, as it provides them with an opportunity to ensure all customers continue to be provided with the best possible electric services available. Portfolio management is also one of the few policy tools available that allows regulators to simultaneously promote competitive wholesale electricity markets and protect consumers from some of the risks of competitive markets.

Portfolio management also offers other advantages to customers, regulators and utilities. It can reduce the risk of price volatility and of future price increases through the promotion of diverse resource types. It can help improve reliability by promoting smaller, modular resources, and by slowing down load growth. It can also promote the more efficient use of electricity resources, improvements in the utilization of transmission and distribution facilities, and increased use of renewable and distributed generation resources.

Demand Forecasts: Must Assess the Impacts of Customer Choice

Load forecasts play an essential role in portfolio management, as they provide the foundation for making decisions about the need for new electric resources. Load forecasting techniques are by now well-established in the electric utility industry. However, electricity industry restructuring and portfolio management raise several new issues for utilities and regulators to consider.

- Regulators should require utilities to provide descriptions and documentation of their load forecasts as part of their portfolio management obligations.
- Utilities in states with retail electricity competition should be required to prepare and present separate load forecasts for transmission and distribution (T&D) services and for default generation services.
- The forecast of demand for default service must include a comprehensive assessment of the competitive electricity market over the short-, medium- and long-term future, in order to assess the extent to which customers are likely to switch providers.
- The forecast of default service demand must include a detailed estimate of future default service customer retention rates, by customer class.
- In competitive markets, the forecasts of demand for default service should include a broader range of sensitivities than typically used by a vertically-integrated utility.

Finally, as the roles for providing default and competitive generation services become spread across more than one entity (competitive generators, distribution utility, other default service providers, etc.), it will be important for regulators to clarify who has responsibility for making comprehensive load forecasts.

Energy Efficiency: Still a Cost-Effective Resource Option

Throughout the US there is a large potential for energy efficiency measures that reduce customer demand but cost significantly less than generating, transmitting and distributing electricity. Energy efficiency programs offer enormous opportunities for lowering system-wide electricity costs and reducing customers' electricity bills. They also offer other important benefits in terms of reducing risk, improving reliability, mitigating peak demands, mitigating environmental impacts, and promoting economic development.

Despite widespread scaling back of utility energy efficiency programs during the 1990s, the primary rationale for implementing energy efficiency programs – to reduce electricity costs and lower customer bills – is just as relevant in today's electricity industry as it has been in the past. Consequently, energy efficiency is an important resource to include in portfolio management, because it can (a) lower electricity costs and customers' bill, and (b) reduce the amount of generation needed to be obtained from the market.

Some states have established a system benefits charge (SBC). A fixed charge is collected from all distribution customers to provide stable base funding for energy efficiency activities and to address some of the concerns created by restructuring. However, SBCs in place today fall far short of capturing the full potential for cost-effective energy efficiency to meet the future needs of the system and consumers. Consequently, portfolio management should be used to identify and implement additional energy efficiency beyond that which is implemented through SBCs.

The methodologies and tools for assessing and selecting cost-effective energy efficiency resources are by now well-established. In general, efficiency programs should be implemented if their total life-cycle costs are lower than those of comparable generation, transmission and distribution facilities. The Rate Impact Measure test, representing a narrow and short term perspective, should not be used as the primary criterion for screening energy efficiency resources. Instead, rate impact concerns should be addressed through proper program design and budgeting.

Generation Resources: A Variety of Opportunities

Portfolio management requires that utilities and default service providers take advantage of all the electricity generation, and generation-related, opportunities that are available in today's electricity markets, including:

- *Building and operating a new power plant*. Within this category there are many technology and fuel types to consider, each with important planning considerations such as capital costs, financing requirements, fuel costs, construction lead time, compliance with environmental regulations, siting and permitting, and more.
- *Purchases from the wholesale spot market*. These offer the advantage of no long-term commitment and flexible response to customer demand, but the disadvantage of being highly volatile and subject to market risk.
- *Short-, medium-, and long-term contracts for power*. Forward contracts avoid exposure to spot market volatility and can reduce costs, but mean that buyers cannot take advantage of falling market prices if they occur and incur the risk that the counter-party may default, or that demand may fall.
- *Option contracts and flexibility contracts.* These contracts provide greater certainty than forward contracts but may result in additional transaction and pricing costs.
- *Financial derivatives such as futures contracts and swaps*. These provide the buyers with financial hedge against future price spikes. The goal of derivatives is to stabilize prices, but not necessarily lower them.
- *Distributed generation facilities*. These are small, modular generation technologies that can be installed in particular locations on the power grid where generation is especially valuable, including a customer's premises.

In addition, there are a variety of ways that the actual purchasing of these resources can be implemented in order to get the best deal for customers. For example, "dollar cost averaging" is a technique whereby purchases of a commodity are made in small increments at frequent durations (e.g., 12 monthly purchases instead of a single yearly purchase), in order to mitigate the effects of price fluctuations and spikes.

It is important for utilities and portfolio managers to consider many factors in comparing these different generation-related opportunities. For example, physical hedges (such as building or buying renewable resources to hedge against gas price risk) are likely to be more reliable and safer than financial hedges (such as gas fixed price gas contracts or gas price futures), because the latter are only available for relatively short time periods and are subject to default, bankruptcies and forced renegotiation from the seller.

Transmission and Distribution: Integrate Into the Resource Plan

Portfolio management also requires that utilities and default service providers consider transmission and distribution opportunities and costs in developing the resource portfolio. Decisions regarding the maintenance or enhancement of T&D facilities will have important consequences for the development of generation and efficiency resources, and vice versa.

Portfolio managers should consider not only the generation resources that are available with the existing transmission system, but also those that could be tapped via new or upgraded transmission. Similarly, evaluation of generation resources should reflect the costs, engineering and permitting requirements and impacts of transmission required to bring the power to consumers.

Conversely, portfolio managers should also consider whether costly T&D upgrades and enhancements can be deferred or avoided through strategic placement of power plants, energy efficiency investments or distributed generation technologies. The interplay between T&D investments and alternative resource options will have important implications for the T&D portions of customers' bills as well as the generation portion.

Determining the Optimal Resource Portfolio: Putting It All Together

The most important aspect of portfolio management is in determining the optimal combination of resources to meet customers' needs. At this point in the portfolio management process, all of the analyses described above are pulled together to identify the preferred resource portfolio.

Portfolio managers should clarify their objectives, and use these as selection criteria for making decisions between competing resource options. The primary objectives should include: (a) maintain low cost of electricity; (b) provide safe and reliable electricity service; (c) maintain stable electricity prices over the short- and long-term; (d) mitigate risk, both in terms of price volatility and price increases; (e) utilize resources efficiently, at the customer end-use, and at generation, transmission and distribution facilities; (f) mitigate environmental impacts of electricity services; and (g) maintain a flexible portfolio, able to respond to market and industry changes.

Resource portfolios should be prepared to cover the long-term planning horizon (e.g., 20 years), in order to capture the full range of opportunities, benefits and costs associated with resource decisions. Determining the optimal resource portfolio requires several steps:

- Determine a set of generation options that would best be able to meet the expected customer demand. This should be based on a comprehensive assessment of conventional power plants, renewable resources, spot market purchases, and short-, medium, and long-term power contracts.
- Assess opportunities for transmission and distribution upgrades and enhancements to improve the mix of generation options. Similarly, assess opportunities for different mixes of generation options to reduce T&D costs or improve T&D

opportunities. Distributed generation options should be factored into this assessment.

- Determine the set of energy efficiency programs that would reduce demand and reduce the costs of the generation, transmission and distribution options selected so far. The potential for "demand response" to reduce costs during peak periods is also considered at this point. All efficiency measures and programs that can reduce the total cost of electricity should be integrated into the resource plan.
- Conduct risk analyses to assess the extent to which the resource portfolio is subject to short-term and long-term risks. This includes anticipating key potential deviations from the assumptions and forecasts used, and assessing the sensitivity of the resource portfolio to potential uncertainties.
- Determine the set of financial hedging instruments that would help mitigate the key risks that might remain in the resource portfolio. The optimal resource portfolio should strike the appropriate balance between reducing costs and reducing risks.

The portfolio manager may need to iterate a portfolio through these steps several times in order to fully assess the inter-related effects of the different resource types. Another approach is to develop several alternative resource plans, and assess how each of them meets the planning objectives and criteria. Smaller default service providers, with less expertise and resources, may simplify some of these steps, but each step is important in the portfolio management process.

Default service providers in jurisdictions where retail competition is allowed will have greater uncertainty regarding customer demand for generation services and thus should analyze several different scenarios for customer demand. An optimal resource portfolio should be determined for each of the different demand scenarios, and each portfolio should be flexible enough to respond to changing demand over time.

Maintaining an Optimal Portfolio Over Time: Vigilance and Flexibility

Once an optimal resource plan has been determined, the portfolio manager must implement the plan flexibly and judiciously over time. Ongoing evaluation and updating will not only help realize the full potential of PM and risk management, but will also allow portfolio managers to respond to unexpected developments in wholesale electricity markets and the industry in general.

To ensure that the portfolio strategy is successfully implemented, an action plan should be prepared that covers (a) acquisition and disposal of portfolio elements; (b) monitoring of market conditions, environmental trends, and electric loads; (c) monitoring of portfolio performance; and (d) evaluation of potential new acquisitions or hedging instruments. Counterparty credit and settlement risk require constant attention. Both supply and demand side initiatives should be evaluated on a regular basis.

Regulatory and Policy Issues: Clear Guidance and Incentives

Legislators, regulators and other stakeholders will have to play a key role in portfolio management in order for it to be successful. First and foremost, legislators and regulators must make it clear that all utilities and default service providers must actively and aggressively pursue all opportunities to reduce costs, mitigate risks and achieve other key public policy goals.

Regulators should require utilities to submit periodic (e.g., every two years) portfolio management plans and progress reports that describe in detail the assumptions used, the opportunities assessed, and the decisions made in developing their resource portfolios. Regulators should carefully review these plans and either approve them or reject them with recommendations for modifications necessary for approval.

Finally, regulators should establish regulatory and ratemaking policies that provide utilities with the appropriate financial incentives to prepare and implement proper resource portfolios. This includes incentives to (a) design and implement cost-effective efficiency programs; (b) develop cost-effective distributed generation options; (c) identify and implement the optimal mix of power plants and purchase contracts; (d) implement risk management techniques, and (e) implement, update and modify the resource plan over time in order to respond to changing market and industry conditions.

1. Introduction

Overview of Portfolio Management

Providing good retail electric service in today's electricity industry is challenging due to volatile wholesale market prices, fuel supply risks, market power considerations, uncertainty about environmental impacts and regulations, and bankruptcy filings by major players. In situations with retail electricity restructuring, there are additional challenges associated with the possibility of customer switching.

Portfolio management (PM), both as a theory and a practical reality, has been successfully applied in a wide range of industries to procure resources and manage risks. Portfolio management as applied to the electricity industry is based on the simple notion that a utility or default service provider that actively participates in electricity markets, and that carefully chooses among the wide variety of different electricity products and resources, will be able to provide better services to their customers over both the short- and long-term future.

Portfolio management requires several key steps on the part of electric utilities or default service providers:

- Portfolio management begins with the regulators, utilities and other stakeholders identifying the primary objectives that should use in obtaining electricity resources to meet customers' needs.
- Portfolio managers must prepare load forecasts that represent the best assessment of customer demands for generation, transmission and distribution services for the long-term future.
- They must then assess all the opportunities available for meeting customer demand through cost-effective energy efficiency resources.
- The next step includes assessing the wide variety of generation-related opportunities, including building power plants; purchasing from the wholesale spot market; purchasing short-term and long-term forward contracts; purchasing derivatives to hedge against risk; developing distributed generation options; building or purchasing renewable resources; and expanding transmission and distribution facilities.
- The next step in portfolio management is to develop the optimal mix of these resources that will best achieve the various objectives. A sound portfolio management approach will seek to adopt a variety of resource types to lower costs, reduce risk, and achieve other key objectives.
- Finally, utilities and default service providers must constantly upgrade and modify their resource portfolios and acquisition plans in order to respond to industry changes over time.

Outline of this Report

This report provides regulators, utilities, or other parties that have a stake in the provision of electric generation with theoretical and practical concepts and methods for managing the procurement of electricity resources through portfolio management. We hope that this report will be used as a reference document to assist with the understanding and application of portfolio management techniques. The list below provides a general guide for the various topics covered.

The need for portfolio management. Chapter 2 provides the rationale for implementing portfolio management, either in jurisdictions with retail competition or in those without. It also defines the term "default service provider," and discusses the volatile nature of prices in today's wholesale electricity markets.

The benefits of portfolio management. Chapter 3 presents some of the key benefits of portfolio management, including the regulatory benefits, the ability to mitigate risks, the ability to promote more efficient and robust wholesale electric markets, and the ability to improve system reliability.

Portfolio management concepts. Chapter 4 presents some of the key portfolio management concepts that can be applied in any industry, along with examples of how these general concepts can be applied in the electricity industry. It also provides a brief discussion of some of the portfolio management practices that are being applied in the electricity industry today, both in states with and without retail competition.

Forecasting electricity demand. Chapter 5 discusses the role of demand forecasting in portfolio management, and explains how default service providers must develop forecasts of the demand for generation services despite the uncertainty introduced by retail competition.

Options for managing electricity demand. Chapter 6 discusses the benefits of energy efficiency, and the role energy efficiency must play in portfolio management. It explains how portfolio managers should consider energy efficiency resources above those required through system benefits charges, and how the rate impacts of energy efficiency programs should be addressed.

Generation options. Chapter 7 presents an overview of the many types of generation options available today, including different technology types, different ownership/purchase arrangements, and distributed generation options. It also discusses different types of power contracts, financial hedging instruments, and how to balance long-term versus short-term options.

Transmission and distribution options. Chapter 8 discusses the role that transmission and distribution facilities should play in portfolio management, and the relationship between T&D, generation and efficiency resources.

Determining the optimal resource portfolio. Chapter 9 describes some of the concepts used to select among the many resource options in order to meet the primary objectives of portfolio management, and lists several techniques for analyzing risk exposure.

Maintaining an optimal resource portfolio. Chapter 10 explains why and how a portfolio manager should upgrade and modify their resource portfolios and acquisition plans in order to respond to industry changes over time

Regulatory and policy issues. Chapter 11 presents some of the regulatory and policy issues that will need to be addressed in order to support the implementation of portfolio management. The objective of this Chapter is to only raise the key regulatory issues; it does not provide a detailed description of the policies necessary to make portfolio management happen. Such policies should be the subject of further research.

2. The Need for Portfolio Management in Today's Electricity Markets

Nationally, electricity markets are undergoing extraordinarily rapid change. For the first time, states need to develop ways to protect retail electric customers from price fluctuations found in competitive markets.

States that have introduced retail electricity competition have typically established "default service providers" to ensure that all customers have uninterrupted, reliable access to electricity generation services. Many legislators and regulators originally expected that over time most customers would switch to competitive generation providers, and that the default services would only be needed either as a transitional mechanism, or as a means of serving only a small number of customers. As such, less attention was paid to the requirements for providing default services, and the policies associated with default service providers.

What Is a Default Service Provider?

Jurisdictions that allow retail competition have typically established a "default service provider" who delivers *generation service* (as distinct from *transmission and distribution services*) for any customer who, for whatever reason, does not have a competitive retail provider. The default service is sometimes referred to as "standard offer," and the default service provider is sometimes referred to as the "provider of last resort."

In many states, the default service provider is the remaining distribution utility. Sometimes it is a competitively-selected entity functioning in a manner similar to competitive generation companies. In jurisdictions without retail choice, or in which not all customer groups have retail choice, the incumbent vertically-integrated electric utility typically continues to provide monopoly *generation service*, along with transmission and distribution services.

This report uses the term *default services* to mean generation service provided to customers who do not have access to retail choice for any reason, including lack of retail competition. A *default service provider* is whatever entity provides that default service.[1]

However, in most states that have established retail competition the vast majority of customers continue to be served by the default service provider. (Alexander 2002) This is due to many reasons, including limited generation options, lack of customer information, lack of customer interest, uncertainties associated with restructured electricity markets, and transaction costs associated with switching.

It is quite likely that the majority of customers, especially residential, and small commercial and industrial customers, will continue to require default services well into

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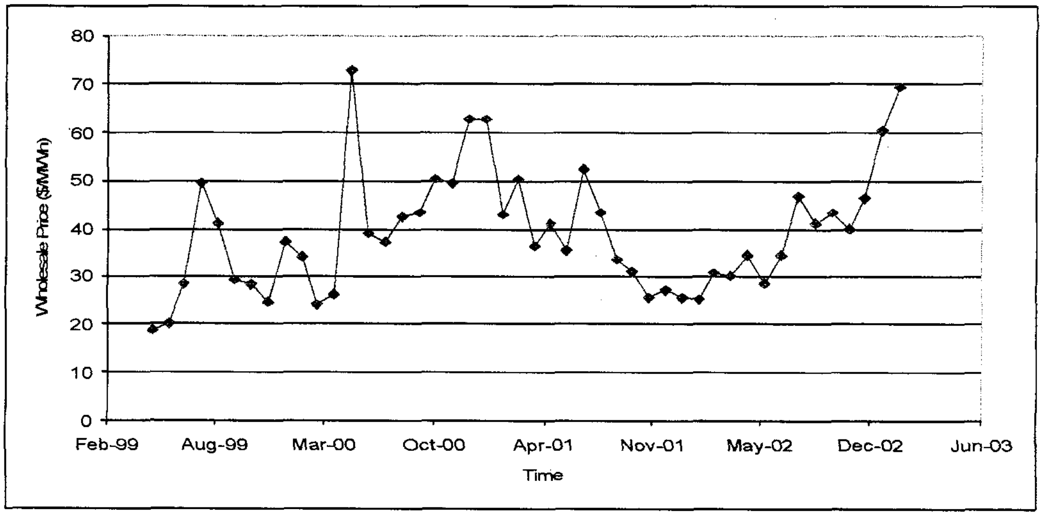
[1] Some jurisdictions that established retail choice offered a *transitional default service* for a limited time or with limited eligibility. This report does not explicitly discuss such transitional default services. However, regulators should consider whether and how to apply PM principles to transitional default services, where they exist.

the foreseeable future. Legislators and regulators can play an essential role in ensuring that these customers are provided with reliable, low-cost electricity services at stable prices in the near-term and over the long run. (Harrington, et al. 2002) Portfolio management offers the tools and techniques to achieve this important goal.

For example, recent procurement practices, particularly in areas with retail choice, overemphasize relatively short-term contracts. Many default service providers simply establish new generation contracts for short-term power every six or twelve months. This exposes customers (or providers, depending on how each jurisdiction allocates market risk) to costs based on whatever happens to be the state of the market on a particular date each year or half-year, with the forward cost of power very strongly influenced by the level of spot market prices at the time.

Figure 2.1. Wholesale Electricity Prices in New England



For example, the wholesale electricity prices in New England have fluctuated dramatically in recent years, as indicated in Figure 2.1. If a default service provider were to purchase all of its generation through a short-term contract at the time of one of the peak wholesale prices, then its customers would end up paying considerably more for electricity than necessary.

In recent years, those states relying upon short-term wholesale market prices for default services (e.g., Massachusetts, New York, Texas) have experienced higher costs and greater price volatility than other states with default services. (Alexander 2002) Portfolio management offers a way to mitigate against higher costs and price volatility.

Portfolio management practices can also benefit providers and customers in jurisdictions that have not introduced retail choice. Portfolio management can be used by vertically-integrated utilities to protect themselves (without undue transfer of risk to consumers) from uncertainties in wholesale markets, transmission congestion costs, environmental compliance costs, credit risks, fuel price risk, and ancillary service costs. Thus, in all states, restructured or not, portfolio management is a way to deal with the evolving developments, uncertainties, and volatilities in the electricity industry.

This report concerns itself with portfolio management issues and techniques from the perspective of a single electric utility or, at most, a single state. That is, we address here the question of why regulators should ensure that sound portfolio management practices prevail in the acquisition of electricity resources for both monopoly service customers and default service customers under retail choice. The same benefits and techniques are applicable at other geographic resolutions. Entire power pools, Independent System Operators, and Regional Transmission Organizations can and should consider how to take advantage of portfolio management or, perhaps more importantly, how to facilitate the harvesting of portfolio management benefits by their load serving entities. At the other end of the scale, cities and sub-state regions are beginning to recognize the importance of electric energy availability, price risks, and environmental risks to their interests. This has lead to concerted energy planning efforts by cities and other government entities not ordinarily concerned with utility regulation. (BED 2003; SF 2002) While this report does not specifically address either of those ends of the geographic spectrum, many of the concepts and principals should translate effectively.

3. Benefits of Portfolio Management

3.1 Portfolio Management Offers Regulatory Benefits

Regulators will benefit from portfolio management, as it provides them with an opportunity to ensure all customers continue to be provided with the best possible electric services available. In states that allow retail competition, portfolio management is one of the few regulatory tools available to protect customers from some of the risks of competitive markets, and to ensure that customers are provided just and reasonable rates.

Portfolio management also offers a way to shift the electric utilities' focus from short-term, market-driven prices to long-term customer costs and customer bills. This shift allows regulators to maintain (or reintroduce) key public policy goals into the critical function of power procurement for the large majority of electricity customers. Portfolio management offers regulators a mechanism to promote energy efficiency, build markets for renewable generation, encourage fuel and technology diversity, and achieve environmental objectives.

3.2 Portfolio Management Can Reduce Many Types of Risks

Under traditional rate regulation, retail ratepayers saw a cost of power (generation service, exclusive of T&D and G&A) determined in large part by the embedded capital cost of owned power plants and by purchased power contracts with fixed or largely fixed prices. Some fraction of the cost of power from those resources was driven by fuel prices. Those fuel prices were, in turn, set by volatile markets, but most utilities engaged in some form of hedging for fuel purchasing and any fuel cost savings from hedged purchases (or inherently low cost fuels like coal) largely flowed through to customers. Any modest excess or shortfall of power was dealt with in trades between rate-regulated utilities, often under "split the savings" arrangements that benefited the rate payers of both the selling and buying utilities.

More recently, many wholesale power markets have moved to a structure in which *all* power generated in a given hour is offered into a bid-based spot market in which the clearing price set by the *most expensive* source, typically natural gas-fired power. This has introduced immense volatility into spot prices. Simultaneously, some jurisdictions required default providers to divest themselves of plant ownership and long term hedging contracts, thereby exacerbating utilities' reliance upon spot markets and short-term contracts. While the vertical market power concerns that led to such constraints may have been important, the result was often catastrophic for the provider or the consumer. (Harrington, et al., 2002; Alexander 2003)

Fortunately, PM practices can help to reduce risk exposure and reclaim some of the cost efficiencies that were discarded with the adoption of a "merchant generation and spot market" approach to electricity. Some of the key risks facing the electricity industry are briefly discussed below.

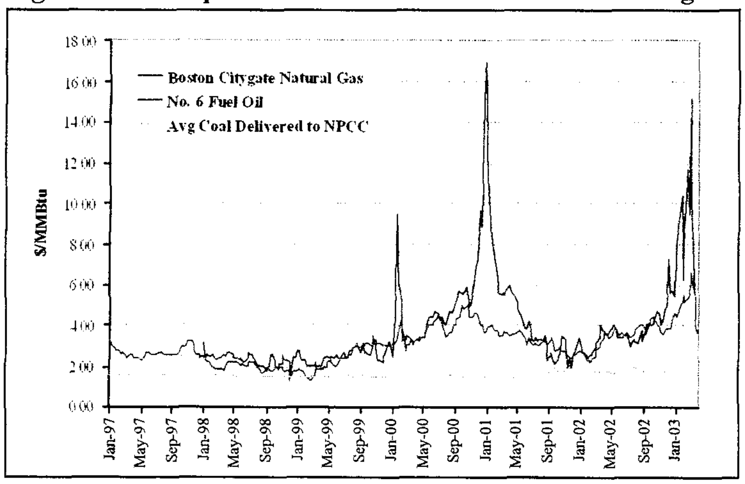
Risks Due to Gas Prices and Supply

> "Average U.S. peak electricity prices are expected to rise 48 percent in 2003 from the previous year, mostly the result of a surge in natural gas prices... We do not forecast a return to normal supply- demand balance... before 2008." (UBS 2003)

Increasingly, many regions of the U.S. are relying on natural gas to generate electricity. As a result, wholesale electricity prices are directly linked to natural gas prices, which have been highly volatile in recent years relative to other fuels. While the resource base for natural gas remains large, increased production will require massive investments and time. For instance, in Atlantic Canada, major new supply is unlikely to materialize before the end of 2008. It is anticipated that such investments will be linked to higher commodity prices, increased price volatility, and larger trading volumes. Thus, it seems gas price volatility and, hence, electricity price volatility are here to stay until new gas supplies are commercialized in future years. (Levitan & Associates, Inc. 2003)

In the New England region, gas as a fuel source for electricity has been increasing markedly. In 1999, gas-fired generation represented 16% of all electricity in the region. In 2003, this number increased to 41%. It is expected that use of natural gas to generate electricity will total 49% in New England by 2010. Other than the state of Texas, New England is the most gas-dependent region in North America for power generation. Interestingly, gas-fired units set over 50% of all electricity prices in New England. As indicated in Figure 3.1 natural gas prices have been highly volatile in recent years, and are have been much more volatile than other fuels such as coal or fuel oil.

Figure 3.1. Comparative Fuel Costs Delivered to New England.



Source: ISO New England, 2003

Risks Due to Future Environmental Regulations

Compliance with federal and state environmental regulations can be costly. And there is considerable uncertainty about the type and extent of environmental regulations that may be imposed in the near- to long-term future. While it is difficult for utilities and default service providers to predict the full impact of future environmental regulations, planning for such uncertainties and hedging against those risks is feasible and vital.

Quantifying Regulatory Risk

PacifiCorp has estimated that the cost of meeting present, pending and future SO2, NOx, and Hg regulations will be substantial, with related after-tax O&M, A&G and capital expenditures through 2025 ranging between $500 million to $1.7 billion (NPV). The lower figure represents an SO2 scrubber and low NOx burners scenario. The higher amount represents full controls (SO2 scrubbers, Selective Catalytic Reduction controls for NOx, and bag houses with activated carbon injection for mercury). (PacifiCorp 2003)

Utilities already must comply with sulfur dioxide (SO2) and nitrous oxides (NOx) emission requirements; most utilities recognize that CO2 regulation in some form is highly likely. Several proposals to amend the Clean Air Act to limit air pollution emissions from the electric power industry are being discussed at the national level, the most important being:

- President Bush's Clear Skies Act/Global Climate Change Initiatives.[2]
- The Clean Air Planning Act of 2002 introduced by Senators Carper and Lincoln.[3]
- The Clean Power Act introduced by Senator Jeffords.[4]

To protect themselves against the risk of such future regulations, utilities can diversify by investing in generating assets with a mix of emissions profiles. For example, utility companies might acquire or build wind farms or convert from coal to gas-fired plants, rounding out their portfolio to include more environmental- and regulation-friendly assets. Portfolio management offers regulators, utilities and default service providers the tools necessary to develop a diverse set of electricity resources.

Similarly, energy efficiency and demand-side management programs also provide significant hedging value against environmental risks. Demand-side hedging programs are by no means unique to the electric industry. Liability insurers not only hedge their payout risks by re-insuring those risks, but engage in both customer specific education and technical assistance and generic programs (such as establishing the Underwriters'

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2 The Clear Skies Act would require reductions for SO2, NOx, and mercury (Hg) in two phases (2008 and 2019) with tradable allowances. The proposal addresses the different air quality issues across the county and would set emission caps to account for these differences. The Global Climate Change Initiative is a voluntary greenhouse gas (GHG) reduction program. It focuses on improving the carbon efficiency of the economy, reducing current emissions of 183 metric tons per million dollars of GDP to 151 metric tons per million dollars of GDP by 2012. The program encourages generators of CO2, including power plants, to reduce emissions.

3 The Clean Air Planning Act would regulate SO2, NOx, Hg, and CO2 emissions from the electric generating sector: (1) the SO2 mandate would reduce emissions over three phases to 2.25 million tons in 2015; (2) the 2-phase NOx program culminates with a 2012 cap of 1.7 million tons; (3) the mercury cap would be in two phases, 2008 and 2012; and (4) the two-phase CO2 program would cap emissions at 2005 levels in 2008 and 2001 levels in 2012.

4 The Jeffords bill would require power plants to reduce SO2 and NOx emissions by 75 percent, mercury emissions by 90 percent, and carbon dioxide to 1990 levels, all by 2008.

Laboratory) to reduce those payouts. Airlines and cellular communications companies engage in peak shaving rate designs, as do many restaurants (in the guise of early bird discounts).

Hedging Environmental Regulatory Risk

Cinergy Corporation provides electrical power to about two million customers in Ohio, Indiana, and Kentucky. Ninety percent of the electricity it produces comes from its coal-powered plants, which release as much as 70 million tons of CO_2 annually. Cinergy's CEO has publicly stated his belief that energy companies should reduce emissions or at least avoid increases. Cinergy has spent $1 billion to convert a coal-fired plant to natural gas, which emits about one-third the carbon dioxide per MWh generated, and to buy two gas-fired plants. It has also experimented with windmills and fuel cells. Cinergy has recently announced a commitment to reduce its carbon dioxide emissions by 5 percent by 2010 (Boyer 2003). By managing its carbon emissions Cinergy is hedging against future environmental regulation risk. (Cortese 2003)

3.3 Portfolio Management Promotes More Efficient Markets

Wholesale markets for electricity have fallen short of the ideal of perfectly competitive and efficient markets. Severe market power problems have occurred and may continue to occur in various markets.[5]

Portfolio management can reduce retail customers' exposure to wholesale market power, and even reduce the extent to which market power is a problem in those wholesale markets. For example, PM encourages default service providers to mix short- and long-term wholesale power contracts to manage commodity supply and price risk. This action also limits the extent to which large players in the spot market can profitably exercise market power through strategic withholding, fostering more stable competitive markets for both the short-term and the long-term. "The use of portfolio management may be the greatest leverage state regulators have to influence the actual operations of wholesale markets." (Harrington, et al., 2002, 7 ff.; Cavanagh 2001)

Furthermore, not all types of fuels and technologies are equally able to enter the markets. Renewable technologies are often more capital intensive than fossil fuel technologies and also face information and capital access barriers that prevent them obtaining financing if their only potential for revenue comes from competing in spot markets or selling under short term contracts. PM can properly value the hedging benefits of such technologies and of energy efficiency, increasing the competitiveness and efficiency of wholesale power markets.

5 For the nature of such threats and their importance, see, Trebing 1998. For the reality of the problems, one need only consult the electric industry trade press anytime in the past five years. Perhaps the ultimate form of market power faced in assembling a default service portfolio is the situation where an affiliate of the default service provider is able to capture the role of seller to that provider. Here, long-term contracts and even plant ownership or resource-based contracts are no solution. Comparisons to short-term or spot pricing may be helpful in monitoring or mitigating such power, but only strong codes of conduct and affiliate transaction rules, coupled with clear PM guidance and expectations can hope to adequately protect consumers in such a situation. (Burns, et al., 1999, p. 19)

3.4 Portfolio Management Can Improve System Reliability

PM can not only reduce price volatility and mitigate market power, but also offers significant reliability benefits. Reliability benefits should be a factor in valuing portfolio alternatives. Smaller units, varied technology types and fuels, and other factors can reduce the exposure to system outages and the cost of avoiding those outages.

Diversification among Smaller Resources

Sound application of PM should lead to diversification of electricity resources, suppliers, and contract types and terms. Diversification can take the form of varied fuels, technologies and a mix of generation, transmission and demand-side resources. On average, each particular resource will be a relatively smaller proportion of the resource mix than if diversification were not pursued. Relying on a large number of small resources is inherently more reliable than a portfolio made up of one or a few resources subject to unique risks.[6]

The cost of providing adequate system reserves in a control region is affected by the choice and size of the generating resources in that region. Reserves and operating requirements for both loss of load and system stability contingencies (for example, installed capacity margins and spinning reserves, respectively) are often driven by the largest single potential outage that could occur on the system, typically a large power plant or transmission line tripping out. Therefore, a portfolio of smaller, more dispersed resources, both supply- and demand-side, has the potential to reduce the cost of reliability for all market participants.

Readily dispatchable demand-side resources such as interruptible cooling loads can reduce the amount of reserves needed, while saving the fuel cost of keeping a spinning reserve unit operating in an unloaded mode. The availability of demand-response can also lead to more efficient system dispatch and provision of operating reserves, with associated benefits in the form of reduced system fuel costs and air emissions (Keith, et al., 2003).

Diversification among Technology and Fuel Types

Different types of fuels are subject to different supply risks. While coal is a domestic and abundant fuel, it has in the past been subject to regional disruption in labor disputes. Natural gas is both inherently volatile in price and dependent on a small number of pipelines for delivery, the failure of which can cause supply shortfalls and additional price volatility. (RAP 2002) A system that relies on stored fuel supplies (either storage of fossil fuel near the unit, or stockpile of coal or biomass) or have short transportation

[6] Diversification does require the expenditure of management resources and may, in some situations, entail some additional costs over what might be perceived as the least-cost single resource. For example, small generators tend to have higher capital costs per kW than larger units of the same technology (up to a point, but not indefinitely). While not without their own concerns, ownership or contracts for shares of a number of large generating stations can deliver diversification benefits while also tapping into economies of scale.

routes are less subject to fuel disruption. This variation can be properly valued with portfolio management techniques.[7]

Certain types of technologies can be subject to industry-wide reliability issues. For example, after the TMI nuclear accident, most nuclear power plants in the country were shut down for extended periods for safety upgrades.

Shortening outage recovery times is another important reliability issue. System restart after a wide-spread outage can be a complicated and time-consuming process. Reliance on very large, central station generating plants can further complicate that process. One reason it took so long for the August, 2003, outage in the Eastern US and Canada to be restored appears to be the fact that a large number of large nuclear and fossil-fired plants tripped off-line at the start of the outage. First, nuclear power plants may have been required to shut down because they require back-up off-site power for critical safety systems. Second, the size, complexity, and impact on the electric grid of large central power stations, both nuclear and fossil-fired, makes bringing them back on-line very challenging technically. Smaller units, and those with more minute-to-minute flexibility in output, are much easier to manage during a system restart. Finally, because the potential damage to a large (or "nuclear"?) unit from a trip is significant, operators may be more cautious bringing them back on line than they would be for other types of resources and wait for assurance that there will not be secondary trips.

Wind power is an interesting case in connection with reliability. It is, of course, intermittent, but does add to system reliability, particularly when pooled across a control region with diverse wind regimes. Simulations applying traditional measurement techniques to wind (30% availability) show that they add as much to system reliability as their capacity factor multiplied by their capacity (i.e., 100 MW of wind, with a 30% capacity factor makes the same contribution to system reliability as 33 MW of combustion turbine with a 10% forced outage rate). (Lazar 1993; Bernow, et al., 1994)

Some resources are peak-oriented, and add more to reliability than would necessarily be assumed from typical measures like "availability" or "forced outage" rates. An example would be solar PV, which might have a 35% annual capacity factor, but is most available on hot sunny days when loads are highest in most regions, providing significant hedging against peak price fluctuations. (Awerbuch, 2000)

7 Diversity across fuel types reduces both supply disruption and price volatility risk. However, it is important not to mistakenly identify substitutable fuels as independent in this regard in resources or markets where different fuels are readily substitutable (e.g., No. 2 fuel oil and natural gas can often be burned in the same generator).

Fixed Price Renewables and Market Peak Prices

Market clearing price savings and volatility reductions can be especially great when fixed-price renewables are added on peak. Photovoltaics will generate the most electricity during midday in the summer season; just when electric load and price is highest for most regions. The importance of peak load shaving is well known, but the value of photovoltaics in reducing load in frequently overlooked. A recent study analyzed the market price of electricity in the PJM region in order to determine the value of generic load reduction. (Marcus and Ruszovan 2002) The estimated value of PV load reduction during the on-peak hours during that summer season was over 27 cents/kWh in the PJM (4.8 times the market price calculated from the regression) and roughly 8.1 cents/kWh during summer mid-peak hours. PV's summer on-peak load reduction value may very well be equal to or exceed the levelized cost of electricity from the panel. This effect is thought to be especially pronounced in unhedged markets.

4. Portfolio Management: Concepts and Practice

4.1 The Basic Idea

This Chapter reviews the key concepts and tools for portfolio management in any industry, and offers a few examples of how it can be applied to electricity industry. Appendix A gives a more extended presentation, along with a discussion of instruments used in non-electric industries.

A basic tenet of financial management is the idea that a diverse portfolio is less risky than any single investment. The same is true for commitments for commodity supply, such as electricity. Because prices of different investments are not perfectly correlated, a decline in the value of one investment is often offset by a rise in the price of the other. When we apply this notion to power supply and efficiency alternatives, we can take advantage of similar variations. Each technology and resource options has its own cost structure and economic drivers. Gas generation has moderate capital costs, but significant fuel costs driven by natural gas prices. Wind energy has high capital costs, but is insensitive to fuel prices. By combining them in appropriate proportions, we can get a mix with a lower, more stable cost than by relying on either alone. (Awerbuch 2000)

Any individual investment or generation alternative has two main sources of risk. The first is *unique risk*, which results from events that are specific to an individual investment or resource. For common stocks, unique factors are those that affect a particular company or sector, such as a mistake or a disaster affecting the company's production or a broader disaster affecting supply of a particular commodity essential to the sector. For generation resources, unique risks include a failure at a specific plant and unexpected regulatory costs affecting a technology.

The other type of risk is *systematic risk*, such as risks due to macroeconomic factors that threaten all investments or power supplies equally. (Culp 2001, 26) With respect to the stock market, these risks include changes in interest rates, exchange rates, real gross national product, inflation, and so on, which affect the price of stock for all companies or all sectors in roughly the same manner. For generation assets, oil and gas shortages or price spikes are examples; recessions or booms that change the demand-supply balance are also types of systematic or market risks.

Equity portfolio managers maintain diversity by investing in a wide range of different companies in different industries. While there are sector-specific funds, these are recognized as riskier than broad-market funds that eliminate unique industry risks through diversification. The manager of an electric resource portfolio would diversify by relying on a variety of different power plants using different fuels and technologies, by using firm power contracts of varying durations and starting dates, and by acquiring a mix of supply- and demand-side resources.

The "take-home message" from the financial markets is that diversification reduces risk or volatility in prices. The unique part of the uncertainty in any individual investment is diversified away when that investment is grouped with others into a portfolio of different investment types and durations. Overall, diversification gives the portfolio manager more flexibility and protection from unknowns. A well-managed portfolio will draw from both demand- and supply-side resources, as well as a mix of short-term, medium-term, and long-term contracts to ensure price protection over time. In addition, if there is owned generation in the portfolio, risk protection will be further enhanced by applying the same portfolio management approaches to fuel acquisition, a technique long practiced in that part of the utility industry.

Whose Ox Will Get Fed? How to Deliver the Benefits of PM to Consumers

Consider the case of the international petroleum company, Exxon. As a portfolio manager, Exxon owns a mix of long-term supplies (owned oil wells) and forward contracts. They sell their product in what is essentially a short-term market. (That is not to say that a firm like Exxon does not engage in forward sales or put options, but that at its *retail* end, its *small end use customers*, especially for gasoline, are buying virtually 100% on the spot market at the gas pump.) It is Exxon that reaps the benefit of its PM efforts, not consumers. In the electricity industry it is essential to find ways to bring the benefits of portfolio management to electric customers.

It is important to remember that risks relate to various time frames. There is the day-to-day and month-to-month volatility of spot market prices for fuels and electricity and their impact on cash flows for utilities and prices for consumers. There are challenges in addressing very long term risks like the viability of a new technology or the future of world oil markets. In the medium term, say three to five years, there are numerous risks affecting specific markets, generating facilities, state and regional economies, and the like. Many of the purely financial techniques discussed in the this report are particularly suited to managing the shorter term risks. Others, such as laddering of contracts, can help manage and reduce uncertainty in the mid-term. To address long term uncertainties, such as major market shifts or new environmental regulations, we need to pay attention to physically resources in the portfolio, as well as the physical resources underlying long term contracts and markets as a whole, and apply tools like diversification and demand side resources to cope with them.

Finally, we must be careful not let the focus on risk management be a distraction from the need to minimize total cost of energy service to consumers and society. Portfolio management should be viewed as an enhancement to sound resource planning, not a replacement for it.

Varieties of Procurement Contracts: Pros and Cons

Portfolio management in commodity purchasing is at the forefront of current research at institutions such as MIT's Center for E-business. A well-managed commodity portfolio is usually a combination of many traditional procurement contracts, such as long-term contracts, options and flexibility contracts, and usage of spot markets. Each of these contract types, listed below, has its own pluses and minuses, but in combination they can greatly reduce risk.

- *Spot purchases* involve paying market price on the day that the commodity is needed. Spot market pricing can be quite volatile, but requires no commitments. Spot market reliance protects against both falling demand and falling prices, but exposes the portfolio to risks from rising demand or prices.
- *Forward contracts* are agreements between buyers and suppliers to trade a specific amount of a commodity at a pre-agreed upon price at a given time or times.[8] Payment is on the delivery date. Forward contracts avoid exposure to spot market volatility, but accept the risk that market prices may fall, that the counter-party may default, and that demand may fall.
- In an *option contract*, the buyer prepays a (relatively) small *option fee* up front in return for a commitment from the supplier to reserve a certain quantity of the good for the buyer at a pre-negotiated price called the "strike price." The cost of the option may increase the total price compared to the price (offered at *that time*) of a long-term contract, but one does not need to commit to buying a specific quantity. Typically, the option is *exercised* only when the spot price (on the date of need) exceeds the strike price of the option.
- A *flexibility contract* is like a forward contract, but the amount to be delivered and paid for can differ based on a formula, but by no more than a given percentage determined upon signing the contract. Flexibility contracts are equivalent to a combination of a long-term contract plus an option contract. (Simchi-Leve 2002)

Buyers need to find the optimal trade-off between price and flexibility by an appropriate mix of low price, low flexibility (long-term contracts,) reasonable price but better flexibility (option contracts) or unknown price and supply but no commitment (the spot market.) Varying durations as well as contract types can help.

Commodity Hedging for Manufacturing

Hewlett Packard is perhaps one of the best examples of a company that has gone with the new portfolio contract approach for hedging commodities risk for plastics and other materials. Specifically, in an effort to maximize expected profit while minimizing product cost risks, Hewlett Packard invests in 50% long contracts, 35% option contracts, and leaves 15% of its commodities purchasing needs open to the spot market. (Billington 2002)

Financial Derivatives

So far, we have focused on *physical contracts* (for actual physical delivery of a commodity) between buyers and sellers. Financial derivatives are another kind of

[8] The term or time period of a forward contract can be of whatever length the parties choose and often begins sometime in the future. For example, power contract can be for one month, one year or for the life of a generator and may start immediately on signature, the next month, or one or more years into the future. Forward contracts for less than one year are often called "short-term" contracts, but they are still referred to as "long," as opposed to "spot" purchases.

contract that can have definite advantages as part of a portfolio. Most important, in many markets they are more liquid and have lower transaction costs than physical contracts.[9]

In simplest terms, derivatives may be thought of as side bets on the value of the underlying asset. Like insurance, use of such "hedges" reduces the effect of unknown events in return for a fee. The most common derivatives are futures contracts and swaps.

- *Futures contracts* are advance orders to buy or sell an asset. Like forward physical contracts, the price is fixed at the time of execution, and payment occurs on the delivery day. Unlike forward contracts, futures contracts are highly standardized and traded in huge volumes on futures exchanges, often by speculators as well as physical buyers and sellers. They are readily traded, as profits and losses from these derivative instruments are realized daily under exchange rules.
- A *swap* is a contract that guarantees a fixed price for a commodity over a predetermined period. At the end of each month, the prevailing market settlement price of the commodity is compared to the swap price. If the settlement price is greater than the swap price, the supplier pays the buyer the difference between the settlement price and the swap price. Similarly, if the settlement price is less than the swap price, the buyer pays the supplier the difference. Swaps give price certainty at a cost that is lower than the cost of options, with no physical commodity actually transferred between the buyer and seller.

New types of derivatives and variations on currently used instruments are constantly offered in order to suit a range of investor interests. These include weather derivatives, and a form of swap known as a contract-for-difference.

Derivatives should be viewed as financial insurance instruments that protect the buyer from spikes (and the seller from dips) in commodity pricing. The intent is to stabilize prices, not to lower them.

While derivatives do have their place in commodities risk management, they also have been the objects of scrutiny in a high profile disputes. For example, in 1993, Orange County lost $1.7 billion due to improper use of financial derivatives. Meanwhile, Enron's 2001 bankruptcy, while not caused by derivative use, raised concerns about risk management and transparency of financial information. (EIA 2002)

Price Averaging

Another well-accepted technique is dollar cost averaging. To dollar-cost average, a buyer will divide necessary purchases into equal dollar amounts at equally spaced time increments, regardless of price. For example, instead of buying a single forward contract

9 It is important to keep in mind that there are distinctive requirements that apply to accounting for derivatives under the tax code and under financial accounting standards. These requirements critically impact the financial results of a corporation and must be carefully evaluated and understood to avoid serious legal difficulties. A few scandals aside, these requirements do not impair the beneficial aspects of derivative use, but rather ensure investors, managers and regulators are properly informed. In fact, there are related requirements that apply to financial reporting of commodity contracts, as well. Expert professional advice in these areas is recommended prior to establishing a financial derivatives program.

on Jan. 1 for $50 million of product (to be delivered in monthly increments), a buyer may instead purchase $5 million worth of goods every 36.5 days. While some of the contract prices will be higher or lower, based on the market price on the given day of settlement, the math for this technique guarantees that the buyer will acquire more goods when they are inexpensive and less when they are costly. However, instead of price fluctuations, buyers experience fluctuations in volume of goods purchased. As long as the buyer can bear these changes in volumes, dollar cost averaging is an excellent technique to manage price fluctuation risk.

Laddering

A portfolio made up of only forward contracts can still be diversified to reduce risk. Like a board of directors whose terms are staggered so that a certain fraction expire each year to ensure turnover yet benefit from continuity of management, a portfolio of power supply contracts can be structured so that a modest fraction of the portfolio turns over each year. This laddered approach eliminates both the risk that one will choose a "bad" time to lock in a price for one's entire portfolio and the risk of having to go to market for all of that portfolio in a less than ideal economic environment when a single contract expires. This technique is similar to laddering of bond portfolios for investors; a detailed example of that method is shown in Appendix A.1.

Allocation of Risk between Buyers and Sellers

Derivatives allow buyers to transfer risk to others who could profit from taking the risk. Those taking the risk are called speculators. Speculators play a critical role in derivative markets, as they are willing to assume the risk that the hedger seeks to shed. Some speculators, like insurance companies or brokerage firms, have some advantages in bearing risk. First, due to experience, they may be good at estimating the probability of events and price risks. Second, they may be in a position to provide advice to buyers on how to reduce risk and thus lower their own risks. Third, they can pool risks by holding large, diversified portfolios of agreements, most of which may never seek payments.[10]

There is a fine line between hedging to mitigate volatility and hedging for the purpose of pure speculation to earn profits. Imprudent speculation is undoubtedly an issue of concern for any industry's participants. It is up to regulators to define this line. Like most regulatory issues, this will likely develop and evolve gradually over time and with experience in specific cases. Some of the portfolio management hedging techniques have had limited and, usually, ad hoc or specialized uses in electric utility planning and regulatory oversight to date, and default service introduces new complications to portfolio management. For these reasons, research is needed to identify the portfolio management tools most suitable for use under various regulatory regimes and to adapt them to the needs of utilities, default service providers and their customers and regulators.

[10] Risk pooling among default providers may be promising, but needs to be further developed as a concept for application in the electricity industry.

Drawing the Line on Speculation

One example of speculation by a regulated utility is the experience of Nevada Power Company during the Western Market crisis in the spring of 2001. late in 2000, Nevada Power established a procurement strategy with a purchasing target and began buying large amounts of "6x16" blocks of power under forward contracts to meet that target for a time period including the summer of 2001. In February 2001, with forward contracts filling the target, Nevada Power purchased an additional 275 MW of 6x16 power for the third quarter at a price of $419/MWh. In April 2001, at the peak of the market, Nevada Power paid $513/Mwh for another 125 MW of 6x16 power for the third quarter. These two purchases had a total cost of $262 million–but after the Western market prices collapsed in the Spring of 2001 this power turned out to have a market value of only $38 million. The Company had procured this power in excess of its needs and was speculating on further increases in market price and the potential for revenues from sales of surplus power. (Biewald 2002) The net loss of more than $200 million was found by the regulators to have been imprudent. (Nevada PUC 2002) Even with the disallowances of these and other costs in Docket 01-11029 and subsequent cases, Nevada consumers have experienced "the highest [rate] increase in the nation over the part 12 years." (Associated Press 2003)

4.2 Portfolio Management in the Electricity Industry Today

Electricity spot market prices demonstrate extreme volatility compared to other commodities, as seen in Table 4.1 below. This volatility is caused by shifts in supply and demand, volatility in fuel prices, and transmission constraints. Some of these shifts are predictable like diurnal usage patterns. However, demand for electricity is also heavily affected by unpredictable and uncontrollable factors like weather and the economy.

Additional, complicating factors include demand surges during summer heat waves, inability to store large quantities of power, the existence of few substitutes, relatively inelastic demand, and market entry barriers, notably capital costs high relative to the marginal production cost.

As a result, it is even more important to apply portfolio management techniques in the electricity industry than in other industries. It is interesting to note that the volatility in electricity spot prices is dramatically greater than in stock and bond markets, where portfolio management techniques are universally-accepted, well-established practices.

Table 4.1. Spot Market Price Volatility for Selected Commodities

Commodity	Average Annual Volatility (Percent)[11]	Market	Period
Electricity			
California-Oregon Border	309.9	Spot-Peak	1996-2001
Cinergy	435.7	Spot-Peak	1996-2001
Palo Verde	304.5	Spot-Peak	1996-2001
PJM	389.1	Spot-Peak	1996-2001
Natural Gas and Petroleum			
Light Sweet Crude Oil, LLS	38.3	Spot	1989-2001
Motor Gasoline, NYH	39.1	Spot	1989-2001
Heating Oil, NYH	38.5	Spot	1989-2001
Natural Gas	78.0	Spot	1992-2001
Financial			
Federal Funds Rate	85.7	Spot	1989-2001
Stock Index, S&P 500	15.1	Spot	1989-2001
Treasury Bonds, 30 Year	12.6	Spot	1989-2001
Metals			
Copper, LME Grade A	32.3	Spot	January 1989-August 2001
Gold Bar, Handy & Harman, NY	12.0	Spot	1989-2001
Silver Bar, Handy & Harman, NY	20.2	Spot	January 1989-August 2001
Platinum, Producers	22.6	Spot	January 1989-August 2001
Agriculture			
Coffee, BH OM Arabic	37.3	Spot	January 1989-August 2001
Sugar, World Spot	99.0	Spot	January 1989-August 2001
Corn, N. Illinois River	37.7	Spot	1994-2001
Soybeans, N. Illinois River	23.8	Spot	1994-2001
Cotton, East TX & OK	76.2	Spot	January 1989-August 2001
FCOJ, Florida Citrus Mutual	20.3	Spot	Sept 1998-December 2001
Meat			
Cattle, Amarillo	13.3	Spot	January 1989-August 2001
Pork Bellies	71.8	Spot	January 1989-August 1999

Source: EIA 2002.

What states are doing

States with Retail Competition

Twenty-four states and the District of Columbia allow competitive retail sale of electricity. (EIA 2003b) Both suppliers and buyers are experimenting with processes and systems to protect themselves and their investors from volatility in electricity prices within a competitive marketplace.

Each affected state has its own legislative or regulatory mandates regarding restructuring. One consideration in those deliberations is whether and how to provide for default service. The concept for default service under retail choice is to ensure that if a customer does not choose a specific energy provider or loses that provider, the customer will automatically receive electricity from the default service provider. In some retail choice states, default service is provided under contracts issued by regulators to competitive providers who bid for the job. In other states, former incumbents are mandated to provide default service. The durations of such contracts or mandates vary between states. Contract variables include length, price of the contract, and fuel (renewable vs. coal.). Compensation and cost recovery arrangements also vary. Broadly, three processes are used to acquire energy for default service in a retail choice context:

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[11] The average of the annual historical price volatility.

- Competitive bid for retail service by generators
- Cost-based rates based on utility generation costs and purchase commitments, and
- Wholesale spot market prices directly passed on to buyers.

For example, in Rhode Island, default service is competitively bid in 6 months increments, while in Maine, contracts are bid annually. Other states, such as Massachusetts, do not have a competitive bidding process for default service. Instead, the utilities can directly pass wholesale spot market prices on to consumers.

Some states, including New York, have demonstrated that multi-year contracts provide investment incentives. Consolidated Edison is offering a 10-year purchase contract in order to attract generation investment into the New York City region (Oppenheim 2003) In this case, longer-term contracts for default service are being used as portfolio management tools that protect market participants against service instabilities.

Table 4.2. Default Term in Various States.

State	Default Term
Connecticut	4 years, ending Dec. 2003
Maine	3 years, ending Dec. 2004
Maryland	2-8 years, ending between 2002 and 2008
New Jersey	34 months 1/3 of supply ending June 2006, 10 months for 2/3 supply

Source: Besser 2003; Alexander 2002.

Montana delayed complete retail access for all consumers to July 2004, because the region does not have a competitive power supply market in place. In March 2003, Montana adopted *Rules Pertaining to Default Electricity Supply Procurement Guidelines.* These rules set forth a process and policies that must be followed by "default supply utilities (DSU)." A DSU must "plan and manage its resource portfolio in order to provide adequate, reliable and efficient annual and long-term default electricity supply services at the lowest total cost." [Rule V (38.5.8209)] A DSU may, but is not required, to offer a green or renewable energy product. The DSU is obligated to acquire its portfolio based on long-term needs and risk analysis. The term "long term" is not specified, but is defined as the longer of the term of any existing contract in the DSUs portfolio, the longest term of any contract under consideration for acquisition, or 10 years. The guidelines also make clear that DSM resources must be considered. Competitive bidding is not required, but to the extent that the DSU does not rely on competitive solicitations, it must justify its approach. The resource acquisition rules for DSM programs reflect the prior least cost planning rules that remain in effect in Montana for vertically integrated utilities. There is a prohibition on using a non-participant test (see "RIM Test" in Appendix B), targets to achieve a steady and sustainable use of demand side resources, and "cream skimming" in DSM programs is prohibited. (Alexander 2003) In addition, in Montana, default service must be provided for a lengthy transition period that does not end until July 1, 2027, thus ensuring a long planning and acquisition horizon.

States without Retail Competition

The electric industry remains vertically integrated in many states, and some have adopted portfolio management practices. Many states have Integrated Resource Planning (IRP) requirements which server to protect providers and consumers from spot market price volatility (among *many* other purposes). IRPs are used to evaluate alternative generation and end-use efficiency investments in terms of their financial, environmental, and social attributes, as well as reliability impacts. The overall impact of IRP programs has been to increase utility investment in energy efficiency and environmentally desirable generation technologies like cogeneration, wind, small hydro, biomass, and solar. (Jaccard 2002)

For example, Georgia's 1991 IRP requirements call for utilities to file a plan at least every three years that includes a 20-year projection of energy requirements and considers the economics of all options available to meet these requirements, including supply-side resources, demand-side resources, purchased power, and cogeneration. Long-term plans for the type of facility needed, the size, and the required commercial operation date are determined and approved by the GPSC. Before construction of a facility has begun or a purchased power agreement is finalized, the GPSC must first certify the need for the facility, contract or conservation program, and determine that it is the appropriate type facility based on economic analysis. Once certified, the utility is guaranteed recovery of the actual incurred costs. The IRP Act is intended to provide the GPSC a means to ensure that a reliable supply of low cost energy will be available long-term.

Table 4.3. IRP Programs for Selected States Without Retail Choice

State	Initiation of IRP (year)	Frequency of Filing
Georgia	1991	Must file every 3 years
Oregon	1989	Must file every 2-3 years
British Columbia		Currently not required
Utah	1992	Must file every 2 years
Idaho		Must file every 2 years
Vermont	1991	Must file every 3 years, but waived for several years; new IRPs due for all retail electric utilities during 2003-4
Washington		In concept every 24 months, but frequency has varied.

Source: (NPPC 2003)

Other states, such as Washington and Oregon, do not include a pre-approval element to their IRP, instead relying on traditional after-the-fact prudence review. This practice is being considered in IRP rulemakings, in light of arguments from the financial community that pre-approval by the regulatory body is viewed as a valuable risk-mitigating measure.

Use of Longer-Term Contracts by Electric Utilities

Because electricity prices have been regulated for most of the last century, price risk management is relatively new for this market. However, some companies have been working toward a portfolio management approach. For example, in 2002, PacifiCorp relied on short-term and spot market electricity purchased for no more than 20.5% of total energy requirements. (PacifiCorp 2003)

In other settings, regulatory policy requires many utilities, such as natural gas companies, to purchase a mix of contract durations in order to control price volatility. Actions to stabilize gas prices have been ordered or authorized in Arkansas, Kentucky, Georgia, Colorado, Iowa, Oklahoma, Kansas, Missouri, Mississippi, and California. While most recent regulatory attention has focused on gas volatility, the same principles apply to peaks in electricity prices. (Oppenheim 2003)

Long Term Gas Supply Contracts: Failure to Hedge

Electricity companies continue to look to other energy industries for reasons to engage in longer-term contracts. One example occurred not too long ago, wherein the Nevada Public Utilities Commission found that Southwest Gas Corporation failed to use strategies to reduce price risk in 1996-1997. The Commission found that Southwest could and should have been in tune with price risk techniques. Southwest failed to research the use of fixed price contracts in its gas supply portfolio and failed to investigate advantages of financial hedging mechanisms that could have protected customers from significant price increases over the 1996-1997 winter season. As a result, the Commission disallowed $4.7 million of gas costs. (Costello 2001)

Derivative Use in Electricity Markets

Industry participants have agreed that the use of derivatives could help to limit market risk in a deregulated electricity industry, not only for the individual utility, but for the market as a whole. For instance, overall market volatility has actually declined significantly with use of derivatives in the commodity markets for cotton, wheat, onions, and pork bellies. (EIA 2002) Derivative instruments are most efficient and successful in commodity markets with large numbers of informed buyers and sellers and in those markets where there is timely, public, and accurate information on prices and quantities traded. And thus, the prospect for an active electricity derivatives market is directly linked to industry restructuring; until electricity spot markets work well, the successful use of electricity derivatives will be limited. (EIA 2002)

Hedging however can still be effective in the meantime. One means to do this is through creative derivatives that do not rely solely on the underlying spot price of electricity. For example, weather hedges have been used by some utilities to build climate adjustments built into their fuel supply contracts. (EIA 2002) In addition, power plant owners can purchase or trade SO_2 and NO_X allowances, as established by the Clean Air Act, to manage their permit price risk. Similarly, companies can buy insurance against certain improbable events. One example is the use of multiple trigger derivatives. For instance, a power plant might be paid money if it experiences a forced outage during a period when the spot price also exceeds an agreed upon spot price.

There is also evidence that hedging through use of derivatives has great potential for mitigating risk. Gas futures, for example, are now highly standardized, even though the New York Mercantile Exchange (NYMEX) first offered them only in April 1990. After a slow start, natural gas market participants now make extensive use of the futures market. Futures markets now allow marketers to offer a range of pricing options to their customers. In addition, some gas utilities have recently begun hedging as a tool to offer their customers gas at fixed prices. Gas futures are now much more liquid and, therefore, more easily traded than forward, fixed-price gas contracts. In addition, gas derivatives generally have lower transaction costs than forward contracts due to their liquidity. All of this suggests a good eventual outlook for the electricity markets, which are currently only thinly traded beyond a few years. (Costello 2001)

Hedging by Pacificorp

PacifiCorp uses a procurement and hedging strategy to ensure a low cost, safe, and reliable supply of power. This includes investment in cost-effective demand-side management programs, construction of peaking units, and purchases of weather derivatives, forward power contracts, and other portfolio optimization opportunities. The company's summer season procurement strategy uses both financial and physical hedging instruments beyond standard on-peak products. The standard on-peak product available from the over the counter market is a block purchase that requires taking the power for 16 hours a day, 6 days a week. If PacifiCorp were to purchase enough such blocks to meets its absolute one-hour peak, it would be excessively long in all the other on-peak hours. If it does not, it would be subject to excessive price swings in what the company calls "superpeak" hours. To minimize risk and save money for both the customers and PacifiCorp, the firm uses daily call options, 15-year leases with early termination rights on physical plants (a resource-based contract), and weather derivatives. (PacifiCorp 2003)

5. Forecasting Electricity Demand

5.1 The Importance of Load Forecasts

Load forecasts play an essential role in electricity portfolio management, as they provide the foundation for making decisions about the need for generation, transmission, and distribution facilities. Load forecasts also play a critical role in assessing the potential for energy efficiency resources, because they can reveal the amount and type of electric end-uses and their associated efficiency opportunities. Furthermore, electricity forecasts, and associated forecasting scenarios, provide regulators and utility planners with information necessary to anticipate how future events might affect customer demand. This information is important for analyzing risk and developing a flexible, adaptable resource plan. (NARUC 1988)

Regulators should require utilities to prepare and submit detailed, properly documented load forecasts as part of their portfolio management obligations. It is important that regulators have access to reliable, accurate and well-documented load forecasts for their oversight and review of utility resource plans. As described in more detail below, good load forecasts are necessary for the regulatory review of plans to meet both T&D services and generation services, regardless of whether a utility is vertically integrated or distribution only.

In this report, we will use "demand" in the economic sense of consumer requirements, and when we refer to electricity "load" forecasts, we are referring to forecasts of both electric energy demand (in MWh) and electric peak load (in MW). Where not explicitly stated otherwise, the following discussion will presume that forecasts of energy and peak load will be prepared for the relevant time periods, whether years, seasons, days of the week, or times of the day. It is important for utilities to forecast both types of demand, because the size of energy and peak demands will have different implications for the types of supply-side and demand-side resources that could be used to meet that demand.

5.2 Standard Forecasting Techniques

Econometric forecasting models have been used by electric utilities for many years to forecast electricity demand. These models correlate electricity demand with relevant economic and demographic indicators, such as electricity prices, population growth, gross state product, and heating and cooling degree days.[12] While econometric forecasting techniques and models are well-established in the electric industry (as well as other industries), they suffer from a lack of detail and an inability to address changes in

[12] Time series projections (statistical projection methods that correlate the forecasted loads only or primarily with time, past values of the load, or both) may sometimes be adequate for short-term projections, but do not capture structural or feedback effects and should usually not be relied on for long-term projections.

end-use technologies or changes in the relationships between electricity demand and the factors with which it is assumed to be correlated. (NARUC 1988) For those utilities in regions with retail choice it is even more important to be able to some of these changes.

End-use forecasting models have been used by electric utilities since the 1980's and 90's, to address some of the limitations of econometric forecasting models. End-use models use a "bottom-up" approach, which analyzes each contribution to electricity demand, such as lighting measures, appliances, space-heating equipment, refrigeration equipment, motors, etc. The model forecasts the number and type of all the end-uses in a utility's service territory, and multiplies those by estimates of electricity consumed per end-use, to derive the total load forecast.

The advantage of end-use forecasting is that it allows the user to analyze changes in electric end-use technologies and customer usage patterns, which is necessary for a comprehensive assessment of energy efficiency and load control resources and for integrating the forecasting effort with the demand-side management planning. The disadvantage of this approach is that simpler versions do not capture the effect of economic and demographic changes that are likely to affect electricity demand. (NARUC 1988)

This limitation can be addressed by using forecasting models that combine both econometric and end-use techniques. These combined models provide utilities with the best capability for portfolio management, and provide regulators with the greatest opportunity to review and oversee portfolio management practices.

There are many uncertainties involved in forecasting future electricity demands. Electricity prices, macro-economic effects, evolution of changing technologies and the rates at which they penetrate the relevant markets, weather, the costs of competing fuels such as natural gas, and other factors can have a substantial effect on customer electricity usage.

Utilities should address these uncertainties in at least two ways. First, they should explicitly identify the assumptions that they have made regarding the key factors that might affect electricity demand in the future, so that regulators can assess for themselves the uncertainties embodied in these assumptions. Second, utilities should conduct sensitivity analyses, where alternative assumptions are made regarding these key factors, to indicate how the load forecast might change under a different future. These sensitivity analyses can also be grouped into future scenarios (e.g., low load growth, expected load growth, and high load growth), to indicate the likely range of electricity demand under very different future conditions. Additional methods, such as Monte Carlo simulations varying multiple factors simultaneously, may be warranted.

5.3 Considerations in a Restructured Electric Industry

Load forecasting techniques are by now well-established in the electric utility industry. However, electricity industry restructuring and portfolio management in that setting raise several new issues for utilities and regulators to consider.

First, it is important that regulators explicitly require utilities to provide detailed descriptions and documentation of their load forecasts as part of their portfolio management obligations. Load forecasts play such an important role in demand-side management, distributed resource planning, and portfolio management in general that regulators must be able to review them periodically in order to ensure that the objectives of portfolio management will be achieved.

Second, distribution-only utilities in states with retail electricity competition should be required to prepare and present separate load forecasts for T&D services and for default generation services. As customers choose to purchase generation services from competitive suppliers, the demand for T&D services will differ from the demand for default generation services. A thorough, reliable forecast of T&D demands will be necessary for demand-side management planning and distributed resource planning, as well as other utility planning needs. And a thorough, reliable forecast of generation demands will be necessary for proper management of the default service generation asset portfolio.

Third, the forecast of demand for default service must include a comprehensive assessment of the competitive electricity market over the short-, medium- and long-term future. The potential for customer switching to competitive generators represents a new and challenging load forecasting uncertainty that must be assessed thoroughly. Utilities and portfolio managers should not simply assume that all default service customers will switch to the competitive market within the short-term future, thereby unburdening them of the obligation to manage the default service portfolio or, conversely, that those customers will remain on default service indefinitely.

The forecast of default service demand must include a detailed estimate of future default service customer retention rates. This estimate should be based on an up-to-date analysis of the competitive electricity market in the state and region of interest, including, by customer class, assessments of:

a) the extent to which customers have switched to (or back from) alternative generators in the past;

b) likely changes in prices in the wholesale electricity markets;

c) the extent to which the retail electricity market will become more competitive in the future;

d) how competitive generation services will compare with the default service offers;

e) the types of customers likely to switch to competitive generation service, as well as the load shapes associated with those customer types, including any differences between those types of customers (or their load shapes) and those that are expected to remain on default service; and

f) the customers that might return to default services after switching to competitive generation service.

Default customer retention will clearly be affected by default service prices, so the utility should integrate this analysis with the development of the preferred generation portfolio.

Fourth, in competitive markets, the forecast of demand for default service should include a broader range of sensitivities than typically used by a vertically-integrated utility or for the T&D demand for a distribution-only utility. Default service demand in a competitive market is inherently more uncertain than the demand for T&D or generation services where customers do not have retail choice. This uncertainty does not eliminate the need of each utility to make a forecast, rather, calls for even more creativity and analysis in recognizing, assessing and accounting for that uncertainty.[13]

Fifth, forecasts should account for the relationships between regulatory policy and utility forecasts. If regulators impose no restrictions on customers moving from competitive to default service, large sophisticated customers will move back and forth with high frequency – whenever one or the other offers a temporary price advantage. This was experienced in extreme terms in the early years of competitive gas transportation service, with industrial customers switching on a daily basis. If, on the other hand, significant exit fees, re-entry fees, vintaging, or other sanctions are imposed on migratory customers, the utility's default service load will be more stable.

One important step towards providing this increased attention to planning in the face of uncertainty is to include sensitivities in the default services demand forecast that reflect the full range of likely customer retention rates. Another important step is to develop a portfolio of demand-side and supply-side resources that is dynamic and flexible enough to respond in relatively short time periods to deviations from the expected demand for default generation services. Methodologies for achieving this latter step are described in the following chapters.

Finally, as the roles for providing default and competitive generation services become spread across more than one entity (competitive generators, distribution utility, other default providers, etc.), it will be important for regulators to clarify who has responsibility for making comprehensive load forecasts. For regulatory, planning and reliability purposes, it will be necessary to have a consistent set of forecasts covering all electricity services, regardless of who eventually provides the service. The distribution utility is the obvious candidate for making such forecasts, but some states may prefer other options. Either way, whoever prepares the forecast will need to be compensated for its forecasting efforts, and there should be procedures in place to protect competitively sensitive information.

[13] This concept is similar to that of forecasting fossil fuels prices. It is widely understood that the forecasts of fossil fuels (especially natural gas) are inherently uncertain, and are rarely accurate. It is also widely understood that planners need to prepare the best forecast of fossil fuel prices possible, and to account for uncertainty through other aspects of the planning process.

6. Evaluating Options for Managing Electricity Demand

6.1 The Many Benefits of Energy Efficiency

Throughout the United States there is a vast potential to improve the efficiency with which electricity is used. All types of electricity customers have numerous opportunities to replace aging electric equipment with newer, more efficient models, or to buy a high-efficiency product when purchasing a new piece of electric equipment.[14] There is a long and ever-growing list of new technologies to reduce electricity consumption, including compact florescent lighting; efficient refrigerators; efficient heating, ventilation and air conditioning equipment; efficient motors; water heater improvements and insulation; weather-stripping of houses and businesses; and more. (Interlaboratory Working Group 2000) There are also many design and behavioral modifications that allow citizens and businesses to manage their energy use more efficiently.

Since the 1980s many electric and gas utilities have used energy efficiency programs to manage customer demand.[15] In integrated resource planning (IRP), energy efficiency programs have been viewed and used as "resources" to meet customer demand, in much the same way that power plants represent resources available to the utility.

Many efficiency measures cost significantly less than generating, transmitting and distributing electricity. Thus, energy efficiency programs offer a huge potential for lowering system-wide electricity costs and reducing customers' electricity bills. A fundamental principle of IRP is that utilities should identify, assess and implement all the demand-side resources that cost less than supply-side resources.

In addition to lowering electricity costs and customers' bills, energy efficiency offers a variety of benefits to utilities, their customers, and society in general.

- Energy efficiency can help reduce the risks associated with fossil fuels and their inherently unstable price and supply characteristics and avoid the costs of unanticipated increases in future fuel prices.
- Energy efficiency can reduce the risks associated with environmental impacts. By reducing a utility's environmental impacts, energy efficiency programs can help utilities and their ratepayers avoid the hard to predict costs of complying with potential future environmental regulations, such as CO2 regulation.

[14] Energy efficiency as used in this report is defined as technologies, measures, activities and programs designed to reduce the amount of energy needed to provide a given electricity service (e.g., lighting, heating, refrigeration, motor power). In other words, the level of electricity service to customers is maintained or improved, while the amount of energy required is reduced.

[15] Most of these programs have focused on measures to influence customer usage behavior and customer adoption of energy efficiency measures. There are also many important opportunities to influence the market of energy efficiency technologies through building codes and equipment efficiency standards.

- Energy efficiency can improve the overall reliability of the electricity system. First, efficiency programs can have a substantial impact on peak demand, during those times when reliability is most at risk. (Nadel 2000) Second, by slowing the rate of growth of electricity peak and energy demands, energy efficiency can provide utilities and generation companies more time and flexibility to respond to changing market conditions, while moderating the "boom-and-bust" effect of competitive market forces on generation supply. (Cowart 2001)
- Since efficiency programs have a substantial impact on peak demand, they help reduce the stress on local transmission and distribution systems, potentially deferring expensive T&D upgrades or mitigating local transmission congestion problems. (This issue is addressed in more detail in the Chapter 7.)
- Energy efficiency can result in significant benefits to the environment. Every kWh saved through efficiency results in less electricity generation, and thus less pollution.[16] Energy efficiency can delay or avoid the need for new power plants or transmission lines, thereby reducing all of the environmental impacts associated with power plant or transmission line siting.
- Energy efficiency can also promote local economic development and job creation by increasing the disposable income of citizens and making businesses and industries more competitive, compared to importation of power plant equipment, fuel, or purchased power from outside the utility service territory.
- Energy efficiency can help a utility, state and region increase its energy independence, by reducing the amount of fuels (coal, gas, oil, nuclear) and electricity that are imported from other regions or even from other countries.

6.2 The Role of Ratepayer-Funded Energy Efficiency in the Past

Integrated Resource Planning and Electricity Industry Restructuring

Electric utilities began implementing energy efficiency programs since the early 1980s.[17] In the late 1980s and early 1990s there was a significant increase in utility investments in energy efficiency programs, partly as a result of increased support from regulators through IRP and related policies. In many states, energy efficiency programs were seen by regulators and utilities alike as an essential component of a vertically-integrated utility's portfolio of resources.

With the introduction (or the prospect of) of electricity restructuring during the 1990s, the energy efficiency programs offered by utilities began to contract dramatically. In 1993

[16] Unlike other pollution control measures – such as scrubbers or selective catalytic reduction– energy efficiency measures can reduce air emissions with a *net reduction* in costs. Thus, energy efficiency programs should be considered as one of the top priorities when investigating options for reducing air emissions from power plants.

[17] In some cases, utilities offered weatherization and other early programs in the late 1970s in response to oil price shocks.

electric utility investments in energy efficiency peaked at roughly $1.6 billion nation-wide; by 1997 they had dropped to roughly $900 million, a decline of about 44 percent and a sharp turnaround in the previous growth. (York and Kushler 2002)

This decline in energy efficiency investments was driven by many factors. Regulators relaxed or ignored IRP and demand-side management (DSM) policies in the light of retail competition policies which advocated for more reliance upon market forces and less regulatory oversight. Utilities were concerned that successful energy efficiency programs would limit their ability to recover stranded costs, or that they would be unable to recover their energy efficiency investments from a shrinking customer base.

Some regulatory policies introduced at the time of restructuring, such as performance-based ratemaking, can, unless properly designed, make it more difficult for utilities to recover their energy efficiency costs. (Kushler 1999) In addition, the separation of generation providers from T&D utilities created an apparent split in the incentives for implementing energy efficiency: should efficiency be provided by a T&D utility, and if so, should the avoided cost of generation be used to justify the efficiency investments?

Administratively-Determined Energy Efficiency

In response to these concerns, some states that introduced electricity competition have also introduced a new policy – the system benefits charge (SBC) – to ensure that efficiency would continue to provide benefits to electricity customers. Often established through legislation, the SBC is a fixed charge collected from all distribution customers, regardless of generation service provider, to fund DSM programs (and in some cases other activities that offer public benefits). In this way, the electric utility is guaranteed to recover its energy efficiency costs, regardless of competing regulatory polices and regardless of the extent to which customers switch to alternative electricity suppliers.

SBC policies explicitly acknowledge that there is still an important role for energy efficiency activities in a restructured electricity market and that the market barriers that discourage optimal levels of investment in efficiency still exist. They also acknowledge that distribution utilities are in the best position to collect funds for energy efficiency programs, and in many cases to implement or manage implementation of those programs. They are also based on the notion that, while the benefits of energy efficiency such as price risk reduction, avoided generation costs, and avoided T&D costs might accrue to different market actors, there is a role for regulation to play in making sure that those benefits are somehow obtained through the remaining regulated utility.

SBC policies have been primarily responsible for a turnaround in the decline in energy efficiency investments in recent years. Since 1998 US electric utility expenditures on energy efficiency have increased slightly, to about $1.1 billion in 2000. (York 2002)

For the purposes of this report, we refer to energy efficiency activity supported by a system benefits charge as "administratively-determined." This is because the amount of energy efficiency funding is often set through legislative negotiations, and is not based on an assessment of the full potential of energy efficiency to meet customer demand. This type of energy efficiency activity is different from that based on IRP practices, where the efficiency is considered a resource that should be compared directly with supply-side resources. We refer to this latter type of efficiency activity as "resource-driven."

While the actual programs implemented through administratively-determined energy efficiency might be similar or identical to those implemented through resource-driven energy efficiency, the amount of funding and the overall mandate may be very different. The amount of efficiency funding available through system benefits charges tends to be well below the amount of funding that would be necessary to acquire the full cost-effective energy efficiency resource. In many states, the amount of energy efficiency funding from the SBC is significantly lower than the amount that had previously been available when efficiency programs were based on an IRP process.

Efficiency Funding Levels under SBC and IRP

As one example, in Massachusetts electric utilities spent roughly 3.8% of total electric revenues on energy efficiency programs in 1994, when the funding was based on an IRP process. Since 1997 the efficiency program funding has been based on a legislatively-determined SBC, and the energy efficiency funding currently represents roughly 2.4% of total electric revenues. (MA DTE 2003) The Massachusetts SBC is currently set at $2.5/MWh, and is the third-highest SBC in the country. (ACEEE 2003)

Non-Utility Energy Efficiency Program Administrators

Recently, several states have begun looking for alternative entities to administer energy efficiency programs. This change has partly been driven by restructuring activities and some of the concerns listed above regarding the role of distribution-only utilities in providing energy efficiency services.

Some states (ME, IL, OH, WI and NY) shifted the responsibility for energy efficiency administration to state government. Oregon has established an independent, non-profit agency, the Energy Trust of Oregon, Inc., to administer the energy efficiency programs there. Vermont established a new function, the Vermont Energy Efficiency Utility, to act as an regulated energy efficiency utility independent of the electric utilities in the state and bid out that function competitively. (Harrington 2003)

Other states (CT and MA) explicitly decided to leave the energy efficiency responsibilities with the distribution-only utilities. Massachusetts also allowed towns and cities to establish municipal aggregators to provide generation service to all customers in their boundaries, and to replace the local distribution utility as the provider of energy efficiency programs. To date only one municipal aggregator, the Cape Light Compact covering all of Cape Cod and Martha's Vineyard, has taken advantage of this option.

6.3 The Role of Energy Efficiency in Portfolio Management

The primary rationale for implementing energy efficiency programs – to reduce electricity costs and lower customer bills – is just as relevant in today's electricity industry as it has been in the past. It is just as relevant in a restructured electricity industry with retail competition as it is in state or region with fully-regulated, vertically-integrated utilities.

Furthermore, some of the other benefits of energy efficiency are even more valuable in today's electricity industry than in the past. Recent spikes in the price of natural gas and the prices of some wholesale electric markets illustrate the risk-reduction benefits of energy efficiency. Maintaining electric reliability during peak hours can be more challenging and expensive in a restructured wholesale electricity market. Concerns over the environmental impacts of the electricity industry have increased over time, and the likelihood of future carbon regulations increases with each passing year. Energy efficiency is also more valuable in a competitive wholesale market, as it can make the demand side of the market more responsive to the effects of the supply side (e.g., price spikes, volatility, market power abuse).

Portfolio management (PM) provides a methodology and a regulatory forum to obtain the many benefits of energy efficiency, regardless of the industry structure. PM explicitly recognizes that both vertically-integrated and distribution-only utilities have an essential role to play in managing the electricity resources used to serve electric customers. The management of these resources will be most efficient, and provide the greatest benefits to customers and society, if it includes *all* cost-effective resources on both the demand-side and the supply-side.

Even in a restructured electric industry, distribution-only utilities are well-positioned to support the implementation of energy efficiency programs, for several reasons:

- First, the distribution utility retains a business relationship with each customer connected to the grid. No other energy supplier has an equally universal relationship with retail consumers.
- Second, energy efficiency can contribute to meeting the utility's T&D service obligations at least cost and with reduced risk.
- Third, to the extent that a distribution-only utility provides default service, it can use energy efficiency as means of reducing the cost and risk of that service.
- Fourth, even if a distribution-only utility provides little or no default service, it is still well-positioned to support energy efficiency activities by (a) assessing the full potential for cost-effective energy efficiency, (b) raising the funds needed to support the efficiency through an SBC, and (c) implementing programs if no other agency is designated to do so.
- Finally, and very importantly, distribution utilities have an obligation to implement cost-effective energy efficiency resources in order to comply with their mandate to provide low-cost, reliable, and safe power to their customers.

6.4 Methodologies for Assessing Energy Efficiency Potential

Avoided Costs of Electricity Generation, Distribution, and Transmission

The methodologies for assessing the potential for energy efficiency under portfolio management are essentially the same as those that have been used in the past in the context of IRP. To summarize, portfolio managers should compare the costs and benefits (including risk reduction) of energy efficiency resources with those of supply-side resources, and select the combination of the two that results in the lowest costs and the greatest benefits to the utility and its customers.

Ideally, portfolio managers should iterate between the analysis of energy efficiency potential and the analysis of supply-side potential, to create a truly integrated plan, because the decisions made regarding the amount and type of energy efficiency resources will affect the costs and impacts of the supply-side resources, and vice-versa. In practice, however, it is common to shorten the analysis by estimating the "avoided costs" of generating, transmitting, and distributing electricity, and comparing these to the costs of implementing the energy efficiency. Those energy efficiency measures and programs that cost less than the supply-side avoided costs are considered to be "cost-effective," and should be implemented as part of the utility's resource plan.

It is important to note that even where retail competition is allowed, the avoided costs used to evaluate energy efficiency programs should include the costs of generation as well as transmission and distribution. This is necessary to enable portfolio managers to identify and implement energy efficiency resources that help lower the costs of providing default service. It also remains important in those instances when distribution-only utilities are no longer providing default service. In such instances, the distribution-only utility would be acting as an agent for identifying the full potential for energy efficiency, and for collecting the funding for that energy efficiency, in order to ensure that the benefits of energy efficiency will accrue to the entire electric system and its customers. As described above, distribution utilities are in the best position to play this role in a fully restructured electricity industry.

Furthermore, for many peak-oriented end-uses, such as air conditioning, the value of avoided transmission and distribution costs may equal or exceed the value of the energy savings. In addition, efficiency savings reduce losses, which contribute to both energy savings and to peak demand savings. A lower load means a lower reserve capacity requirement, and this value must also be taken into account. Finally, avoided environmental costs should be computed, and should clearly be incorporated in the societal cost test discussed below.

Different Perspectives on Energy Efficiency Costs and Benefits

There are several additional considerations in deciding which energy efficiency measures and programs should be considered cost-effective. The costs and benefits of energy efficiency differ from those of supply-side resources, and have different implications for different parties. As a result, five tests have been developed to consider efficiency costs and benefits from different perspectives. These tests are described in Appendix B.

In theory, all of these tests should be considered in the evaluation of energy efficiency resources. (CA PUC 2001) Some programs will require trading-off one perspective versus another (e.g., some programs might not pass the Rate Impact Measure (RIM) test but offer substantial benefits according to the other tests). The portfolio manager has the responsibility to carefully consider what tradeoffs should be made in order to determine the optimal selection of efficiency resources. It is important to keep in mind that none of these tests directly quantify the value energy efficiency measures have with respect to reducing portfolio risk or mitigating market power, prices and price volatility.

In practice, regulators tend to adopt one of these tests as the primary guideline for screening energy efficiency programs. The remaining tests can then be used, if needed, to provide additional information about programs that might be marginally cost-effective.

In recent years, most regulators have adopted the Total Resource Cost (TRC) test as the primary methodology for defining energy efficiency cost-effectiveness. The TRC test reflects the total direct costs and benefits to society, and therefore provides a more comprehensive picture than the other tests.[18] In other words, applying the TRC test will result in the minimum direct total cost to society, and is thus considered "economically efficient," at least if external costs are neglected. (Krause 1988) The Societal Cost test is rarely used because of the technical and political difficulties of estimating the monetary values of environmental externalities. The Rate Impact Measure test is rarely, if ever, used to screen energy efficiency programs for reasons discussed in the following section.

Accounting For Potential Rate Impacts

Energy efficiency programs can sometimes lead to small increases in electric rates. These increases are not due to the costs of the efficiency programs themselves (e.g., the SBC), because over time these costs are offset by the efficiency savings. Rather, the rate increase is due to the fact that a utility's energy sales will decline as a result of the efficiency savings, and electric rates may not sufficient to recover the existing fixed costs on the system. Paradoxically, electric rates may need to be increased even though the total cost of providing electricity has been reduced, and electric bills, on average, have declined. The RIM test identifies the extent any potential increase in electric rates.[19]

Portfolio managers should consider both rate and bill impacts of DSM programs. Rate impacts have always been a concern for utilities, regulators, and electricity customers. Rate impacts may be even more important in those states with retail competition as they may encourage customers to switch from the default service provider to alternative generation companies. However, the RIM test should not be used as the primary tool for determining the cost-effectiveness of energy efficiency programs. The reasons are discussed in Appendix B, but chief among them is that using the RIM test will not result in the lowest cost to society.

Even if the RIM test is not used to screen energy efficiency programs, there are two remaining rate effect issues that may be of concern to utilities and policy-makers. The first issue is that rate impacts of sufficient size can be considered a problem – despite the fact that they are a consequence of creating a lower-cost electricity system. This issue should be addressed by evaluating the package of energy efficiency programs as a whole,

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[18] With the exception of the Societal Cost test.

[19] It is important to note that any such "lost revenues" do not impact rates until the utility's rates are adjusted to account for the difference in sales, typically during the utility's next rate case. Between rate adjustments, lost revenues reduce the utility's profits, but do not increase customers' rates. If revenues have been decoupled from sales, the impact may occur sooner, depending on the mechanism.

including those programs that might increase rates and those that might decrease rates, and quantifying the potential rate impacts over time. These rate impacts should then be compared to the expected reductions in total electricity costs, so that the portfolio manager and regulators can evaluate the trade-off that might have to be made between lower costs and higher rates. Experience with energy efficiency programs in the past has demonstrated that significant reductions in costs can be achieved with very small increases in electricity rates.

Also, it is important to consider long-term rate impacts and long-term reductions in electricity costs. Often the rate impacts occur only in the short-term, while cost savings can last over many more years.

The second issue is the equity effects between efficiency program participants and non-participants. While this should not be a driving factor in selecting electricity resources, it is nonetheless good public policy to mitigate equity effects between customers. There several ways that the equity impacts of energy efficiency programs can be mitigated, or eliminated, through efficiency program design and implementation, including:

- Efficiency programs should be designed to provide opportunities to all customer classes and subclasses, and to address as many electric end-uses and technologies as possible within cost-effectiveness guidelines
- Efficiency programs should be designed to minimize the costs incurred by the electric utility (or program administrator). To the extent that customer contributions can be secured without adversely affecting the level of program participation, rate impacts can be lessened.
- Efficiency programs should be designed to maximize the long-term avoided costs savings for the electricity system.
- Efficiency programs that result in lower rates should be combined with those that might increase rates, to lower the overall rate impact.
- Budgets for efficiency programs targeted to a specific customer class (i.e., low-income, residential, commercial, industrial) may be based on the amount of revenues that each class contributes to the efficiency funds if equity impacts are determined to be severe.

6.5 The Relationship between Portfolio Management and SBCs

System Benefit Charges Do Not Address the Full Potential for Efficiency

The introduction of a system benefits charge to finance energy efficiency does not eliminate the need for portfolio managers to assess the full potential for energy efficiency to reduce electricity costs. Because SBC's tend to be set through legislation (i.e., administratively-determined), they are not typically based on a comprehensive assessment of the potential for cost-effective energy efficiency resources to displace supply-side resources. As a result, all of the system benefits charges in place today fall far short of capturing the full potential for energy efficiency to reduce electricity costs.

In fact, system benefits charges were never intended by their proponents to address all cost-effective energy efficiency opportunities, or to be the only means by which utilities or others could implement energy efficiency programs. They were intended to provide a minimum amount of support at a time when electric utilities were drastically cutting back on efficiency efforts due to concerns about restructuring. (NRDC 2003)

So, there is clearly room for additional energy efficiency activities beyond those supported by a system benefits charge. What is relevant to this report is the risk reduction and PM benefits that such programs can provide. Those benefits were reviewed above and will be discussed further in Chapters 8 and 9. Here, we will consider trends in how those programs might institutionalized. As described above, vertically-integrated utilities and distribution-only utilities are both well-positioned to identify this potential, and are obligated to identify and promote this potential as part of their mandate to provide low-cost, reliable, and safe power to their customers.

Energy Efficiency and Portfolio Management in California's Recovery

Legislators, regulators and utilities in California have recently taken steps to promote energy efficiency resources as part of the portfolio management process, and to implement energy efficiency programs that go well beyond those funded by the state's SBC:

- In September 2002, Gov. Davis signed legislation requiring utilities to periodically develop "resource procurement plans" for Commission review. The plans must demonstrate that the utilities will "create or maintain a diversified procurement portfolio consisting of both short-term and long-term electricity and electricity related and *demand reduction* products (emphasis added). (CA Legislature 2002, page 87)
- In October 2002, the California Public Utilities Commission issued an order requiring distribution utilities to resume procurement of resources to meet customer electricity demands. The order requires distribution utilities to "consider investment in all cost-effective energy efficiency, regardless of the limitations of funding through the public goods charge mechanism." (CA PUC 2002, page 27) The public goods charge is California's SBC, and is currently set at $1.3/MWh.
- In April 2003, the distribution utilities filed 20-year resource procurement plans that contain energy efficiency programs at roughly twice the size of those that can be supported through the state's SBC. (NRDC 2003)
- In May 2003, an Energy Action Plan was adopted by California's key energy agencies: the Public Utilities Commission, the California Energy Commission, and the Consumer Power and Conservation Financing Authority. The Action Plan cites energy efficiency as the top priority and notes that "the agencies want to optimize all strategies for increasing conservation and energy efficiency…" (CA Energy Action Plan 2003, p. 4)

Funding for Additional Energy Efficiency Activities

When a utility identifies cost-effective energy efficiency opportunities beyond those which can be funded through a SBC, it will be important to provide reliable and stable funding for those additional efficiency activities. Utilities will need to be assured timely recovery for any additional efficiency costs, and that changes in the electricity market (e.g., customers switching to alternative generators or new restructuring regulations) will not create a financial barrier to their energy efficiency activities.[20]

Stable, reliable, and fair cost recovery policies have always been important in promoting utility energy efficiency activities, and are especially important with the uncertainties created by restructuring. Regulators should explicitly develop energy efficiency cost recovery policies to support this important component of portfolio management.[21]

One option is for regulators to allow for energy efficiency cost recovery within the utility's rates, in addition to the cost recovered through the SBC. The SBC would be considered a constant "floor" for the amount of efficiency, and the additional costs could vary over time depending upon the outcome of the portfolio management process.

Another option is to use the portfolio management process to establish the size of the system benefits charge. When a utility completes a new resource plan and identifies the potential for cost-effective energy efficiency activities, the SBC could be modified by the regulator to provide the utility sufficient funding to cover the costs of those activities. In other words, SBC's could be resource-driven and not administratively determined.[22]

Regardless of the mechanism used to recover the additional energy efficiency costs, it is essential that they be recovered through rates applied to all distribution customers. This ensures that utilities will recover their costs regardless of the extent to which customers switch to alternative generation suppliers.

Coordination of Portfolio Management with Independent Energy Efficiency Administrators

In those states where energy efficiency programs are administered by entities other than the regulated utilities or the portfolio managers, it is important that the portfolio management process be coordinated with those independent efficiency program administrators, in several ways:

- Efficiency program administrators should play a central role in contributing to the efficiency analysis of the portfolio manager. The program administrator should provide information and guidance "from the field" on the technical and economic potential for energy efficiency.

[20] As with all of their resource procurement activities, utilities should always be required to design and implement energy efficiency programs efficiently and prudently in order to recover their expenses.

[21] Many efficiency programs provide for cost savings on the utility's side of the meter. Examples include more efficient transformers, new substation equipment, and higher voltage distribution systems. These also cost money, but unlike efficiency measures installed on the customer's side of the meter, they do not reduce utility revenues because metered energy consumption is not affected. The cost of these types of measures should be funded by the distribution utilities without reliance on the funds generated by an SBC.

[22] Many SBC's are set by legislation, and it may be politically difficult to modify that legislation on a periodic basis. However, if legislation established the general requirements for an SBC, but enabled the regulatory commission to set the size of the SBC periodically through the portfolio management process. Another option is for the regulatory commission to establish an additional charge to be applied to all distribution customers to recover any additional efficiency costs above those covered by the SBC.

- The results of the portfolio manager's efficiency analysis should be shared with the efficiency program administrator for use in modifying programs and planning new programs to comply with the findings of the portfolio management process.
- If the SBC funding for the efficiency program administrator cannot cover all the efficiency activities identified by the portfolio manager, then the SBC funding should be modified to equal those costs, as described in the preceding section.
- The savings that efficiency provides to T&D must be added to the generation savings in evaluating potential, in order to be able to target programs where they provide the maximum benefit. The independent efficiency administrator should have full information from the distribution utilities and regional transmission system owner/operator(s) of the locational benefits of efficiency.

In sum, while the portfolio manager would have the primary responsibility for assessing the potential for energy efficiency programs, and the administrator would have the primary responsibility for implementing those programs, the two agencies should work together so that both goals are pursued in parallel.

A recent study compared the advantages and disadvantages of alternative entities for administering energy efficiency programs. (Harrington 2003) The authors concluded that the success of energy efficiency programs depends less on upon the administrator, and more upon the "clear and consistent commitment" of regulators and policy makers. They identify the following factors that are important when considering the issue of who should administer energy efficiency programs: "responsiveness to PUC direction, regulatory performance incentives that are properly constructed and implemented, staff competency, sustainability of the institution and its budget sources, and link to system planning decisions." (Harrington 2003)

These conclusions support the need for portfolio management to reflect energy efficiency activities – regardless of who administers the programs. Portfolio management should provide clear direction from regulators, policy and cost recovery support from regulators, consistency and sustainability for the administration and funding of efficiency, and a clear link to electricity system planning process and decisions

7. Evaluating Generation Options

7.1 Preliminaries

This chapter examines how generation assets fit into developing a portfolio for default service.[23] In the broadest sense, little has changed during the turmoil of the past 10 years: providers must choose between buying power or building generators and must determine the appropriate amount and types of generation assets for its needs. In another sense, everything has changed, and change shows no sign of abating. New or improved generation technologies dominate markets – markets that did not exist ten years ago. Bilateral power contracts continue to be important, but against a backdrop of shifting standards for rate-making and transmission access. Load serving entities are often required to obtain new and different power products and a wide range of ancillary services. New power products are traded in new markets, including mercantile exchanges and derivatives markets. Transactions with traders and brokers, rather than traditional utilities or independent power producers, are commonplace. In sum, the same old job still needs doing, but in a different technical, financial and regulatory environment, even for utilities operating under traditional regulation.

Portfolio development in retail choice states must take into account how the jurisdiction dealt with pre-existing ownership of generation assets. In some cases, divestiture was total, and the default service provider starts with a clean slate. In others, this provider owns plants or forward contracts covering some or all (or more than all) of the default service requirement. If such legacy assets are owned by corporate affiliates, the availability and pricing of such power can be especially problematic. Regulators should see that policies are in place to ensure default service providers deal effectively and in a least-cost manner with legacy generation assets, imposing appropriate codes of conduct and rules for affiliate transactions where needed.

7.2 Physical Generation Types

Table 7.1 lists the key planning and risk management attributes of generation technologies. Many other variables, such as remaining useful life, licensing risks, vulnerability of fuel delivery and electric transmission routes, maintainability, availability and physical reliability are also important, but should be evaluated for each plant.

Each technology has its own profile of costs and risks. Plant types with high fixed costs or long lead times can become a burden if demand fails to materialize and may not be suitable for peaking requirements. Types with high variable costs can be vulnerable to fuel price fluctuations, but often fit well in moderate quantities as peaking resources.

[23] As mentioned above, we use the term "default service" to encompass both the provider of last resort in a retail choice environment and the monopoly utility in a traditional fully regulated setting, and use "generation assets" to mean the entire range of physical and financial options for acquiring power.

Development of a physical generating asset mix traditionally focused on two issues: adequacy (i.e., reliability) and total cost. Within the constraint of needing to meet peak loads and total energy requirements at the required level of reliability, the mix should be optimized for cost using sound dispatch modeling and taking transmission costs and constraints into account.

For any generation asset, modularity and other types of flexibility can significantly reduce risk and, on average, result in a less costly mix. Wind farms, fuel cells and photovoltaic generators, and certain types of fossil fueled turbine plants can be installed in modular increments, allowing the pace of development to be accelerated, slowed or halted, as circumstances dictate. This creates significant real savings through the option value such flexibility gives the portfolio manager. (Trigeorgis 1993)

A portfolio that includes smaller and more dispersed units can provide certain reliability benefits. Each generating technology has different scale properties that affect such decisions. In the past, nuclear and some coal unit designs have pushed past the 1000 MW mark, but advanced designs may target sizes one-fifth to one-half that. Combustion turbine units enjoy very significant economies and efficiencies of scale, with units in the hundreds of MW dominating utility construction, while microturbines are typically available in the tens of kW, as are fuel cells. Hydro unit costs and efficiencies are completely site specific. Optimally efficient wind turbines (and wind farms) for utility scale installations are getting larger. Solar PV efficiency is not strongly size dependent.

In summary, generation planning typically begins with finding a least-cost portfolio of just generation assets adequate to meet the forecasted demand at the required reliability level. This will usually be a mix that includes some long term forward contracts and some resource based assets, either owned plant or contracts for specific physical resources. (This "buy vs. build" issue is discussed below and in Appendix A.)

Given ongoing restructuring trends and uncertainties in the default service market and wholesale power markets, many default service providers are reluctant to consider ownership of power plants or contracts for specific plants; some are even forbidden to do so by law. But all the same advantages and disadvantages apply in the realm of bilateral, resource-based contracts for power. Even if only market-based contracts are considered and resource-based contracts rejected, the relevant markets depend on these same physical generation technologies and market pricing and availability are subject, ultimately, to the same pressures. The challenge for regulators (or legislators) is to fashion institutional structures that drive resource planning that properly takes into account the full range of options under suitable decision rules.

Table 7.1. Key Variable for Generating Plants Technologies

Type of Plant	Up-Front Capital Costs	Variable Costs	Emissions	Construction Lead Time
Hydro	High to Very High	Very Low	Nil aside from some impacts of new flooding, but significant non-air environmental impacts	Long, except for possible re-powering of previously operated sites
Coal-fired	Moderate to High	Low if rail transportation is good; generally stable	Very High with special concerns for some fuel types; Ash disposal and cooling water issues may be important	Moderate to Long
Gas-fired	Moderate	Moderate but Volatile	Nil SO_2, Low NO_x with proper control, CO_2 lowest of fossil fuels with combined cycle units	Low if pipeline capacity is available
Oil-fired	Moderate	Moderate but Volatile	High except Moderate for distillate fuel	Moderate
Cogeneration	Site and fuel specific	Fuel specific but net fuel cost can be low if displacing other fuel used for heating or cooling	Fuel and technology specific, but can be Low or Very Low if on-site fuel use is displaced	Site and fuel specific
Geothermal	Moderate to High, and site specific	Low to Moderate depending technology and site	Nil air emissions but some ground water disposal challenges can be serious	Site specific, often long
Wind	High	Very Low	None but can have significant aesthetic and land use impacts	Site specific but can be Long; . depends on state of prior wind resource surveys
Fuel Cells	High to Very High	Fuel dependent	Nil for hydrogen, Very Low for natural gas, Low for other fuels	Short for currently available size units
Solar	Very High	Nil	Nil	Very Short
Pumped Storage	High, and site specific	Depends on cost spread of on and off peak power in applicable market	Same as emissions from off peak power used (plus losses of about 1/3)	Very Long
Nuclear	Very High	Low to Moderate	Air emissions Nil, cooling water requirements can be large, Radiological emissions and waste production High	Very Long but potential approval of standardized new designs may reduce lead time

7.3 Buy Versus Build Decisions

Electricity providers have available to them a unique strategic option: to build and operate generation facilities instead of or alongside outsourcing power supply. Some default service providers may be uniquely positioned to take advantage of generating plant construction and ownership. Under traditional rate regulation, ownership of generation was often the norm; primary reliance on purchases was mainly a strategy used by municipal and cooperative utilities, although many of them also owned plants or shares in plants.

In theory, and absent an overbuild situation, resource-based contracts will bear a price that includes a competitive equity return for the power developer. If market power is present, margins can be much higher. A default service provider might be able to provide lower cost capital for plant development. This is usually true under traditional rate-of-return regulation. For a default service provide in a retail choice setting, this may or may not still be the case. Even if it is not, default service providers should still consider and seek to quantify the risk mitigation benefits of a portfolio containing owned plants. In some cases, plant ownership or resource-based contracts may be the only means to avoid complete dependence on market-based contracts and vulnerability to price swings, market manipulation, and fuel availability. Variables that should be considered in such a decision are discussed in Appendix A.1.

On the plus side, ownership can deliver specific types of resources with characteristics not available from the competitive market. For instance, there has been little development of renewable energy sources in most wholesale electricity markets, despite their environmental and long term risk benefits. If default service providers, their customers, or their regulators were to value such advantages, one way to obtain them, like any long term forward asset acquisition, would be to build and own the generating assets directly. Other advantages include escape from market power of suppliers and a chance to sell options or other products to mitigate the mirror image risks that suppliers face, as well as the possibly substantial value of the plant at the end of its financing life, which is often much shorter than the engineering life.

One special benefit of plant ownership is that if the resource has value at the end of the original estimated project life, the utility "owns" it and the remaining life is available to serve consumers without having to pay a second time for the same resource. This value can be considerable, as we have seen many nuclear and fossil plants repowered or refurbished to run much longer than their original financing lives.

In sum, because of its potential benefits to consumers, default service providers should evaluate plant construction and ownership as a possible component to their portfolio. However, ownership clearly adds additional and different risks that must also be managed appropriately. In many retail choice jurisdictions, the transition to competition has resulted in institutional constraints or strong disincentives for plant ownership.[24] Regulators (or legislators) may wish to revisit those limitations.

[24] This is not to say that vertical market power was not an issue that needed to be addressed at the time that divestitures were required.

A Buy vs. Build Example

The fixed (capital related) costs of power from a natural gas combined-cycle plant can vary considerably depending on the ownership type. We consider two possibilities of a plant constructed and owned by (1) a regulated utility or, (2) an independent power producer (merchant plant) who has a long-term contract for the sale of the plant's output. The results are shown in Table 7.2. Detailed assumptions are shown in Appendix A.1.

All other things being equal, we find it is most economical for the regulated utility to build and operate its own generating facility, because it is, in general, the least financially risky of the two options. A regulated utility has lower costs of both equity and debt, because they pose less risk to their investors. A regulated utility can also recover its capital costs over a longer period (typically 30 years) than an independent power producer, because the utility is subject to less risk of recovering these costs.

Table 7.2. Levelized Price for Electricity Under Different Financing Scenarios

	Percent Debt Financing	Percent Equity Financing	Cost of Debt (%)	Cost of Equity (%)	Capital Recovery Period	Capital Recovery Factor	Levelized Price ($/kWh)
Regulated Utility	50%	50%	8	11	30 yrs	10.3%	44.5
Merchant Plant	80%	20%	12	16	20 yrs	13.6%	48.4

7.4 Forward Contracts

In Chapter 4, we reviewed commodity contracts and related financial hedges. Here we will consider how those devices can be used in electric default service portfolio management. Details on these and other contract types are given in Appendix A.4.

Forward contracts are the most traditional of the contractual instruments available for electric PM. They provide for delivery of a specified amount of power at a certain location on the grid at specified times and prices. Such contracts, especially long-term ones, generally handle fuel price through one of three pricing mechanisms:

- *Fixed-price contracts* establish a set price per MWh of delivered electricity or a fixed schedule for those prices. Either way, the price does not vary with market conditions, and the Buyer presumably pays a premium to compensate the Seller for accepting exposure to fuel price risk.
- *Indexed-price contracts* adjust the price of electricity according to either inflation or the cost of another commodity, such as natural gas or oil. (Kahn 1992) These contracts allocate fuel price risk to the Buyer. Forward contracts oblige the Buyer to "take and pay," regardless of need for the power, so bond rating agencies impose a "debt-equivalent" penalty on the buyer when forward contracts are used. The

penalty is smaller with indexed-price contracts than with other types of forward contracts.[25]

- *Demand and energy contracts* combine the features of the fixed-price and indexed-price contract forms. The Buyer pays a fixed amount for the right to take power and a fixed or indexed charge per kWh taken.
- *Tolling contracts* require the Buyer of the electricity to pay for the cost of the fuel used to generate the electricity (and sometimes other variable operating costs or uncontrollable costs), and the Buyer may also have the option of providing the fuel itself. Tolling agreements and fixed-price agreements conceptualize the service and product being provided by the Seller to the Buyer in fundamentally different ways. In fixed-price contracts, the Seller clearly sells the Buyer a product: electricity. In tolling agreements, the Seller is effectively providing the Buyer a service: the right to use the Seller's power plant to convert fuel to electricity.

Forward contracts are essentially the same instrument as the firm power contracts that have been traded bilaterally among utilities since the first interconnections between them, but those contracts now exist in a somewhat different environment. Since Order 888, they are no longer (usually) FERC-regulated cost based contracts or power pool mediated split-the-savings deals, but "market priced."[26] In many markets, brokers offer a kind of matchmaking service, posting ask and bid prices for standardized blocks of power for various time periods, e.g., monthly for two years and semi-annually for five years, but actual transactions still take place between individual counter-parties. Real future contracts--fully standardized contracts traded anonymously on exchanges that provide regular clearing services--are now available on a number of commodity exchanges around the country for some interchanges.

In general, both long- and short-term forward contracts provide some of the security and stability of utility-owned resources, and warrant consideration for inclusion as a significant part of a default portfolio because these are traits ratepayers value.

Of course, buying forward contracts entails some price risk for the fixed cost portion and also from uncertain demand. Therefore, laddering contracts and diversification of technologies, fuels and suppliers should be pursued.[27] Careful analysis of load forecasts and price projections should be used to establish a reasonable amount and type of long- or short-term forward contracts that should be included. Just as an investment portfolio

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[25] Bond debt penalty refers to an adjustment made to the bond rating of a utility based on how much reliance it has on take or pay forward contracts. Rating agencies assign a portion of the fixed cost obligation of the contracts as debt in computing the capital structure of the purchasing utilities in determining the bond rating. (EIA 1994) To the extent that such a penalty is applied, it can eventually result in higher interest costs for the utility and impact distribution rates via the revenue requirement.

[26] As discussed above, the absence of wholesale price regulation does not mean that such contracts are always arm length transactions reflecting efficient free markets. Default service providers, who one way or another, continue to have effectively captive customers should be required to avoid apparent or actual conflicts in trading, especially with affiliates.

[27] Appendix A.1 provides a detailed example of how laddering reduces risk when investing in bonds. The risk mitigation effect can be obtained by laddering power supply contracts.

should avoid too much investment in a single industry or single company, a power portfolio should avoid too much commitment to any specific fuel or generating unit.

In contrast to fossil fuels, renewable resources typically have a less-variable (or even free) fuel cost stream, resulting in less fuel price risk for either party to an electricity contract. Hence, it is more common to have fixed-price contracts for renewable electricity than for natural gas-generated electricity. Since the use of renewable resources decreases fuel price risk for both parties to a contract, all else equal, a fixed-price renewable electricity contract is a more complete hedge against fuel price risk for the Buyer than a fixed-price contract for natural gas-generated electricity.

One Disadvantage of Contracts: Contract Disputes and Nonperformance

Physical ownership of generation plant has one particular advantage over both resource- and market-based contracting: performance is in the hands of the interested party—the owner!

A contract dispute is currently taking place in Connecticut. There, market participants are divided on whether federal energy regulators should allow a unit of NRG Energy Inc. to terminate a power-supply contract with Connecticut Light & Power Co. (CLPC). In this case, agreements between the two parties were negotiated before New England divided its power market into eight zones and began determining separate power prices for each zone based on local availability of generation and transmission. NRG gave CLPC only five days notice intent to terminate power-supply agreements, stating that the CLPC had violated the agreement by withholding $20 million in payments related to transmission line congestion in New England. The Federal Energy Regulatory Committee (FERC) had directed NRG to continue upholding the contract for the time being so the commission could make its own decision on the matter. (McNamara 2003)

This type of dispute is an example of why rating agencies assign a risk-penalty to utilities relying on long-term contracts. If the seller becomes insolvent, or the resource becomes uneconomic, the utility is left with either a defaulting provider, or a high-cost resource. If the regulator allows the costs to be passed through to captive customers, it can be recovered, but if customers are not captive, or if the demand does not exist, it can create a difficult situation for the buyer.

7.5 Spot Markets and Trading: Balancing Long and Short Positions

It is common wisdom that the transaction costs of forward contracts and hedging instruments and the risk premia demanded by those who sell them result in extra cost, over the long term, compared to the spot market. After all, the argument goes, markets are efficient at finding the lowest available clearing price and no one really has a crystal ball clear enough to "beat the market."

So, why not go "100%" short and depend on the spot market for all power? The wisdom of doing so depends on two assumptions that may be interesting theoretical ideals, but certainly do not play a large part in the world-view of successful corporations that trade year in and year out in commodity markets. The first set of assumptions is that markets are perfect: that there is a very large number of buyers and sellers, none of whom have any market power, that there are no information or transaction barriers for purchasers or sellers to enter the market, and that capital is fungible and can immediately be deployed into or out of power generating plants. It is well known that these are not traits of today's wholesale power markets. (Harrington, et al. 2002)

Second, there is an implicit assumption that every buyer and seller has infinitely deep pockets and can wait forever for the "long term" savings of spot market reliance to materialize. In fact, though, even the largest corporations have limits to the losses they can absorb due to market fluctuations and "surprises," so some forms of forward contracting and hedging are an essential part of PM.[28]

On the other hand, going "100% long" is betting the business that one's hunches (or the instantaneous state of the market) are going to be correct. This is especially true if one is contemplating committing to a single forward position all at once for all or most of one's needs, as has been the practice in some default service bidding jurisdictions. Some spot market buying and selling is essential, if only because loads cannot be perfectly predicted hour by hour, and contracts are not available in infinitely divisible sizes. A reasonable portfolio will (aside from hedging instruments to be discussed below) contain a mix of forward positions with maturities of varying lengths and short positions.[29]

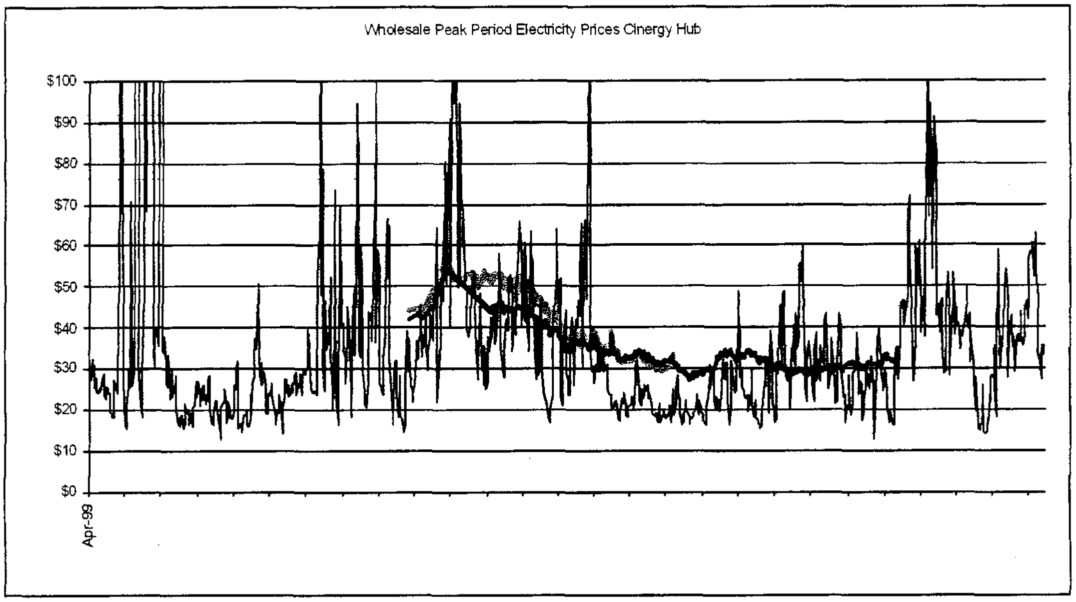
Multi-year contracts reduce the volatility of electric prices compared to short-term or annual contracts. Six-month contracts have proved to be only slightly less volatile and costly than spot market pricing. (MAACAP 2001) Fig. 7.1 shows daily clearing prices for peak-period energy at the Cinergy hub for April 15, 2000, through August, 2003. Also shown are the prices for the one-year forward contracts for peak period power in 2002 and 2003, as priced by the market during 2001 (for both future years) and 2002 (for 2003 forwards only).

Note, for example, that during 2002 forward contract prices for 2003 delivery were much less volatile than either the 2002 or 2003 spot prices, while during 2001, one-year forward contract prices for delivery in 2002 were less volatile than spot prices during both 2001 and 2002. In this particular period of history, forward contracts bought during the first three quarters of 2001 for delivery during 2002 had an average price greater than the spot price that ultimately prevailed during 2002, while the reverse was true for 2003 futures purchased during 2002. The crucial point, however, is that the one-year forward contracts were less volatile than spot purchases would have been. Combined with laddering, these contracts would have greatly moderated price volatility without the need to "outguess" the market. (It is worth noting that a similar strategy followed during 2000, had forward contracts been available then, would have produced comparable risk reductions during the volatility and price spikes of late 2000 and early 2001.)

[28] Serious spot market trading can also require significant investment in staffing and systems. A small amount of spot trading happens automatically under most regional clearing market rules and may be sufficient to handle a small buyer's needs without requiring a large "back room" trading operation.

[29] A short position is an unmet requirement to be met from the spot market as needed, or from advantageous contracts that may become available over time.

Figure 7.1. Wholesale Peak Period Electricity Prices: Cinergy Hub



Not only can portfolio managers reduce their exposure the price volatility present in the market, but trading of longer term contracts in a given market reduces suppliers' incentive and ability to manipulate prices. If suppliers know that most or all of a buyer's needs are going to be negotiated on a single day or in a single round of acquisitions, they have an incentive and, perhaps, the ability to artificially increase prices on that day through strategic bidding or withholding. Most default service plans are presently negotiated every 6 months to 1 year. Laddering and multi-period contracts may be able to decrease price volatility and market power.

7.6 Risk Management and Hedging

Chapter 4 reviewed the financial hedging instruments that have been developed for various risk management situations. Risk management is, perhaps, the most rapidly evolving aspect of finance today. Virtually every financial institution, including those concerned with commodity trading, are being forced to attend to global risk management due to deregulation, narrowing margins, and increased mobility of capital. (Gleason 2000) The fundamental concepts of global risk management--measuring, controlling and accurately pricing the financial risks they are taking--also apply to portfolio management in an electric industry now subject to many of those same pressures.

There are not as many choices for managing electric resource portfolios as there are in financial markets that benefit from some twenty-five years of maturation. Useful tools for hedging electric supply price risk do exist, however and deserve attention in properly managed portfolios. In any event, just trading forward positions or spot purchases is unlikely to adequately protect either default service customers or the provider's stockholders.

A mix of long- and short-term forward contracts, spot purchases, and, where suitable, resource-based assets can improve PM, reduce risk and volatility for providers and ratepayers, while advancing long-term environmental and renewable energy goals. For example, a default service provider with little retail rate flexibility but operating in a market dominated by gas prices and weather driven price spikes could investigate hedges relying on natural gas or weather derivatives, two derivative industries that are reasonably mature. The Chicago Mercantile Exchange has initiated trading of weather futures and options on a monthly or seasonal basis for each of ten U.S. cities. Natural gas futures and options have been traded on a number of exchanges for some time.

The commodity hedges, derivatives, and swaps discussed so far address the subset of global risk called market risk, i.e., the risk that long positions taken could lose value over time or that the cost of covering short positions could increase over time. Addressing market risk is a substantial challenge in itself, but additional risks can be managed through hedging. A provider whose power is purchased across a national border, e.g., from Canada or Mexico, or is produced from a fuel that is purchased overseas might face currency exchange risk.[30] The robust trade in foreign exchange derivative can be used to control such risks. Some resource-based or system power contracts are indexed to one or another measure of inflation or the cost of money; hedges against such risks are also available.

While the availability and track record of hedging instruments in the electric sector is not extensive, they do exist; cost savings and risk reduction can be achieved through their use. For example, PJM hub futures and options trade on the New York Mercantile Exchange, and Commonwealth Edison and TVA hub products at the Chicago Board of Trade. Reliance on electricity futures and, to the extent they exist, derivatives should be undertaken cautiously until their performance is understood and reliable. The use of derivatives and other hedging mechanisms are subject to special tax and accounting rules and their use requires expertise in these areas.

All affected parties – default service providers, regulators, and advocates – should begin making an effort to learn about risk management and financial derivatives and to prepare for using them as they become available and sound. Default service providers should also engage in sound risk analysis and risk management and act, where appropriate, to encourage the development of viable "markets" for hedging instruments, the more standardized the better. Regulators should encourage and expect such behavior on the part of utilities and default service providers on behalf of consumers who do not have the ability to manage their own portfolios, especially since the retail choice providers have not offered ordinary consumers products with a range of price stability, as was once anticipated. (Harrington, et al., 2002, p. 6)

[30] See, Gleason, 2000, p. 65 ff. Many such "import" situations are under contracts or in markets denominated in U.S. dollars, so this may be a relatively uncommon occurrence, but there have been proposals in the past from generating plants that would have had dedicated, but imported fuel sources, such as Nova Scotia coal or Venezuelan crude.

7.7 Limitations of Hedging Strategies

Earlier in this Chapter, we considered the question of whether it is reasonable to rely 100% on spot purchases or, conversely, to go "100% long" with forward purchases. Our conclusion was that neither course is appropriate for a utility or a default service provider, especially given the current state of wholesale electricity markets and markets for electricity hedging instruments. Some commentators on the industry are suggesting that it is not necessarily for utilities or default service providers to include ownership of renewable generation, physical contracts for renewable generation or energy efficiency in their portfolios, because the same levels of risk mitigation are available through proper use of hedging instruments. This section will examine that notion. While we strongly recommend evaluation and use of financial and other hedging instruments as part of PM, we conclude that the argument for relying solely on those instruments to achieve the consumer goals for PM is misdirected.

First, there are limits to how much risk is diversifiable through adding more and different assets to the portfolio or through hedging. Non-diversifiable risks are those systematic risks that affect all asset prices (in some way). For example, changes in aggregate consumption growth in the economy tend to drive all asset prices in the same direction. (Groppelli and Nikbakht 2000, 90) It is also important to distinguish between financial and business risks. The former are risks that can be quantified and hedged; the latter are those that cannot. (Culp 2001, 26-9, 202) A holistic view of business strategy and tactics needs to be developed for utilities and default service providers taking this into account.

System reliability can be ensured only by genuine physical resources. There are certain power system realities that cannot be avoided or dealt with on paper. Each ISO or control region mandates that physical resources underlie each claimed capability. In most cases, the control authorities physically audit those resources and require them to demonstrate their real generating or transmission capability periodically.

Risk considerations are important in procuring electricity, and it is useful to think of hedging (at least) two types of risk: (a) short term risks (volatility in prices on a daily, monthly, or even annual basis) and (b) long term risks (risks associated with uncertainty about the basic levels of "average" prices over periods longer than a year). For long-term risks, the potential for fossil fuel prices or market supply and demand balances to evolve differently than expected is quite large. (See, for example, Keith, et al., 2003.)

For the short-term risks, forward contracts and various financial instruments can be used to good effect. As mentioned above, hedging instruments bring with them a certain level of counter-party risk—often small for market traded hedges--that should be evaluated and taken into account. However, it is reasonable to expect currently available products will be supplemented with additional products over time, providing a range of tools for portfolio managers to use in developing a balanced and appropriately hedged portfolio that substantially mitigates short-term price risks. On the other hand, without new physical resources that are independent of the fossil fuel price risk that dominates wholesale electricity markets, these hedges may become unreliable as too many paper hedges chase too few physical hedges. Furthermore, fixed price renewables have been found to have the capacity to greatly reduce prices and price volatility when delivered at peak hours, such as photovoltaics often are. (Marcus and Ruszovan 2000)

For the long-term risks, forward contracts and financial instruments are even less able to do the job on their own without an underlying non-fossil physical resource corresponding to the hedge.[31] Fixed-price gas contracts are only available out about five years and are expensive and thinly traded more than two or three years into the future. Fixed price electricity contracts are available for some hubs on a commodity basis, but for only a few years into the future. Bilateral contracts for gas and electricity can be negotiated at fixed or indexed prices for longer periods, but if not "backed" by an underlying fixed price resource, there is a significant risk of default if market prices rise high enough. Thus ownership of renewable generating facilities or physically based contracts with sellers who own such facilities is an essential part of a resource portfolio that seeks to effectively hedge long term risks.

So, hedging long-term risks with purely financial instruments or forward contracts is limited by the (relatively) modest time horizons offered, by immature or thinly traded markets for some of those instruments, and by serious counterparty risks due to the sheer size of the dollar amounts that would need to be hedged. Beyond those issues, there are fundamental limits to how far the economy as a whole can go in offering futures and fixed-price contracts when the underlying technologies have costs that fluctuate significantly. When every firm in the market is seeking to hedge against the same risk, after a certain point, only technologies immune to fuel price risk, such as renewables and efficiency, can underlie hedges for multi-billion dollar risks. Defaults, bankruptcies, and forced renegotiations or abrogation of contracts have all happened and can happen again when firms run out of funds to make good on commitments. Further, hedges are not free, impose risks of their own, and are usually not perfect hedges for the specific risks default service providers face. (Awerbuch 2000)

7.8 Distributed Generation: An Emerging Option

Distributed generation refers to the use of modular electrical generation and storage technologies, and specifically targeted DSM programs strategically sited and operated to supplement central station generation plants and the T&D grid. On the "supply side" of the concept, relevant technologies include small-scale internal combustion engine-generator sets, small gas turbine generators and microturbines, energy storage systems, photovoltaics, wind generation, and fuel cells.[32] The potential benefits include avoiding

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[31] It might be suggested that nuclear and coal generation can supply fill this gap as well or better than renewables. We doubt it; those resources are correlated with and subject to many of the same risks as gas or oil generation. Coal prices are not independent of oil and gas prices and are subject to the same regulatory and environmental risks, as well as their own major technology risks.

[32] Wind generation offers many of the same benefits–modularity, ability to provide dispersed voltage support, fossil fuel and air emissions risk reduction, power closer to remote loads, etc. However, since DUP often driven by potential benefits for solving local T&D peak loading and capacity constraint problems, non-dispatchable technologies (or, at least, those that are not constant), wind as a distributed generation technology requires special consideration.

or deferring T&D upgrades; improving power quality; lower T&D losses; and, given the shorter lead times and the modularity of the technologies involved, reduced risk of costly generation and T&D over-capacity by more closely matching electrical supply to demand. (Vt. DPS 2003) Distributed generation benefits are discussed further in Chapter 8. Distributed generation technology characteristics relevant to PM are summarized in Appendix C.

Default service providers, if institutional and regulatory structures are supportive, can acquire significant environmental and economic development benefits for society while reducing portfolio cost and managing portfolio risk by carefully selected, planned, and implemented DG use. However, few electric utilities have fully embraced DUP due to a number of significant barriers, including the dispersion of benefits, incompatible regulatory structures, and the changes and distractions accompanying industry restructuring. Appropriate new regulatory policies, mentioned briefly in Chapter 11, will be needed to enable acquisition of those benefits.

8. Evaluating Transmission and Distribution Options

8.1 Transmission and Distribution in Portfolio Management

Traditional integrated resource planning (IRP) calls for utility planning to meet forecasted power needs through the combination of adequate, safe, and reliable generation, transmission, distribution, and demand-side resources that has the lowest life-cycle cost including the costs of environmental impacts. Transmission and distribution resources in such a plan serve both reliability and power requirements. Some generation resources may require the addition of transmission capacity so power can be delivered to load centers or exported. Alternatively, access to wholesale power markets may require additions to transmission capacity. If the selected portfolio seeks to meet growing power needs through central station generation or market purchases, distribution upgrades may also be needed. Conversely, to the extent that a portfolio will meet needs through distributed generation or demand-side management, less investment will be needed in T&D. In any portfolio, some T&D investment is likely to be required over time to replace plant that is deteriorated or to meet reliability requirements.

T&D resource needs may be thought of as driven by one or more of three forces: (1) engineering reliability requirements, (2) a need to deliver power to or from generators and markets, or (3) economic opportunities deriving from geographic differentials in power costs. Often, a T&D option will advance more than one of these categories. T&D investments should be evaluated in comparison with distributed resource alternatives (described below) as well as generation options of all types.

T&D construction sometimes faces significant permitting and siting challenges. Other factors in T&D upgrades include high fixed costs, lumpiness, land use and aesthetic impacts, electrical losses incurred, and a need for technically sophisticated engineering analysis and design, especially at higher voltages or if DC transmission is involved. T&D upgrades usually have low annual operating costs (if constructed by the user) or relatively high annual usage charges (if acquired from another entity). T&D additions or upgrades can either raise or lower line losses or create engineering problems for existing systems, depending on the system. To address these complexities, high-voltage transmission additions or upgrades located in or connecting to a power pool, ISO or RTO will usually require detailed engineering studies and pre-approval before interconnection.

Portfolio managers should consider not only the generation resources that are available with the existing transmission system, but also those that could be tapped via new or upgraded transmission. Conversely, evaluation of generation resources should reflect the costs, engineering and permitting requirements and impacts of transmission required to bring the power to consumers. The line loss and reliability side benefits of transmission investments may be significant, and option value may be added through access to additional markets or varieties of generators. Some of these costs and benefits also apply to distribution investments.

In the case of vertically integrated utilities, T&D resources and distributed resource alternatives should be considered at all levels of the grid from local distribution feeders through subtransmission to bulk transmission properly coordinated with ISO's or other regional entities, as needed.[33] Where there has been disaggregation, but default service is still provided by the distribution-owning utility, the situation is more complex, but the goal should be the same. Some T&D upgrade options and most or all distributed resource alternatives will be within the scope of planning and action of the default service provider.[34] Coordination with ISO's or other regional entities can provide distribution only utilities a forum for exploring bulk transmission resources as a part of portfolio management.

Finally, if default service is delivered by a non-utility entity under bidding or other arrangements, it may be difficult to position the default service provider to evaluate or plan either T&D investments or distributed resource planning and acquisition. If those activities are to be undertaken successfully, they may need to be a function of facility-based utilities or regulators with implementation of non-generation alternatives placed appropriately. In all three of these service environments, regulators should carefully design rates, incentives, planning requirements and related activities to provide clearly assigned responsibilities and expectations regarding the identification, planning and delivery of T&D and distributed resource alternatives as part of default service PM.

8.2 Distributed Utility Planning Concepts

Distributed utility planning (DUP) is a generalization of IRP as it was developed over the past fifteen years or so. IRPs twin notions of minimizing life cycle societal costs and an even playing field for all supply-side and demand-side resources made no particular distinction, at least in principle, between T&D options and other available resources. (NARUC 1988) As DSM programs matured and proved themselves, it became clear that DSM could cost-effectively defer or eliminate the need for T&D upgrades in certain situations, especially where there upgrade was being driven by a projected capacity constraint and reasonable lead time was available. Sometimes, a partial T&D upgrade and a DSM program can be combined to meet resource needs for many years.

In the second half of the 1990's, as wholesale electric market competition became a reality and many jurisdictions disaggregated vertically integrated utilities, it became

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33 As discussed above in Chapter 7 for generation assets, some service territories are dealing with transition issues for pre-existing ownership of transmission assets, ranging from total divestiture to continued ownership of legacy assets. These situations are further complicated by the fluid state of transmission ownership, operation and pricing as FERC and the regions grapple with emerging ISOs, ITCs, and RTOs. Additional complexities are introduced where such legacy assets are owned by corporate affiliates, although FERC Orders 888, 888-a and 2000 provide for some separation, at least regarding system operation. Regulators should ensure default service providers deal effectively and in a least cost manner with any legacy transmission assets, imposing appropriate codes of conduct and rules for affiliate transactions where needed.

34 Larger DG options or those interconnecting at high voltages may require coordination with or approvals from transmission owners, ISO's or other regional entities responsible for interconnection standards.

apparent that opportunities for savings in integrated planning of distributed alternatives to both T&D upgrades and generation needed special attention to avoid a loss of focus and momentum. At the same time, advances in small-scale generation technologies, such as micro-turbines and sold-state interconnect devices, and improvements in the cost and efficiency of renewable generators brought the option of small, dispersed generation to the fore. As a result of this tension, a renewed focus on such concepts arose under the rubric of distributed utility planning or "DUP."[35]

DUP is best viewed as an ongoing, cyclical planning process including the following steps.

1. Identification of areas with existing or projected T&D supply problems.
2. Definition of the region in which load reductions would be reasonably to help defer or avoiding the T&D reinforcement or reducing its cost.
3. Identification of deferrable costs and the load reductions that would be needed to defer those costs for various periods of time.
4. Determination of the benefits of DSM load reductions in the form of revenue requirement, societal costs and risk reduction.
5. Development of targeted DSM and DG programs to relieve congestion.
6. Estimation of non-T&D side benefits from DSM and DG load reductions.
7. Selection among the available options based on minimizing net societal costs.
8. Implementation planning.

While T&D reliability standards and institutional arrangements for planning and implementing improvements differ, DUP is equally applicable at all voltage levels. It is directly applicable to T&D capacity constraints and, to some extent, to reliability issues not driven by capacity constraints. However, DUP is also relevant to portfolio management for default service by virtue of the risk management benefits and option value it can deliver. To realize these benefits in the context of default service provision, it is necessary for regulators or state governments to provide an institutional structure that bridges any gaps in the integration of resource planning created by the institutional structure chosen for delivery of default service. The critical points are (1) to put DUP in place as a fully-functioning activity of facility-owning utilities and (2) to create a mechanism to include in DUP decision-making the benefits and costs available to default service portfolio management from distributed resource alternatives.

8.3 Distributed Utility Planning Policy Issues

DUP faces regulatory and institutional barriers. Among these are the fact that benefits are dispersed and incompatible regulatory structures at both state and ISO levels.[36] In

[35] See, for example, David Moskowitz et al. 2000.

[36] The following paragraphs rely heavily on work by the Vt. Department of Public Service, *op. cit.*

deploying a distributed resource installation, there is often a kind of inverse commons effect: some of the benefit will accrue to the owner of that installation, but the remainder will flow to others, including retail customers, upstream transmission entities, and the public.

> "Consider, for example, the hypothetical installation of a fuel cell at the site of an electronics manufacturer located on a constrained distribution feeder. Benefits to the manufacturer from this installation include premium quality power, enhanced reliability, and process heat. Benefits to the distribution utility serving this manufacturer are voltage support and the deferral of feeder upgrades. The general public benefits from reduced air emissions and avoided postage stamp T&D rate increases. The default service provider (which may be the distribution utility or may be a third party) involved benefits from increased interaction with its customer and lower supply risk. From a societal perspective, the sum of all of these benefits, depending on the situation, could exceed the incremental cost of the fuel cell over the cost of conventional options. At the same time, no single set of benefits is large enough to entice any one entity to ultimately own and install the unit. Hence, a market failure results." (VT DPS 2003)

Regulatory policies such as performance based rates, emission credit trading systems, tax incentives, streamlined permitting or subsidies could help overcome these barriers. Where applicable, regulatory directives, incentives, and cost-recovery mechanisms may be useful. The presence of retail choice and accompanying divestiture mandates require special provisions if artificial barriers to distributed generation development by distribution utilities, whether or not they provide default service, are to be surmounted.

9. Determining the Optimal Resource Portfolio

Establish Objectives for Determining the Optimal Resource Portfolio

In order to make decisions and trade-offs between the many different types of electricity resources available, it is necessary to establish clearly-defined objectives. These objectives should be developed through an inclusive public process involving the many stakeholders in the electricity industry, in order to ensure that the objectives reflect the needs of affected parties and the lessons learned from recent experiences in the electricity industry. Regulators must ensure that portfolio managers apply these objectives appropriately in developing their resource portfolios.

Some of the key objectives of portfolio management are the following:

- Provide safe and reliable electricity services, at the distribution, transmission, and generation levels for all customer groups.
- Minimize electricity bills, for all customer types.
- Charge stable electricity rates over the short- and long-term.
- Reduce the risks associated with electricity services and prices, including the risks associated with price volatility, uncertainty, financial risks, and the risks due to future environmental regulations and reliability.
- Implement a diverse and balanced set of electricity resources, including (as appropriate to the situation) various fuel types, technology types, contract terms, and financial hedging instruments.
- Improve the efficiency of the electricity system, with regard to customer end-use efficiency and the efficiency of the generation, transmission and distribution systems.
- Maintain equity across customers.
- Ensure that all customers can benefit from positive developments in the wholesale electricity markets.
- Mitigate the environmental impacts of electricity resources.

Consider All Resource Options

Sound portfolio design begins with load forecasting and a review of the planning environment in terms of strengths and weaknesses of existing resources, economic and technological trends, and strategic threats and opportunities. Next, a portfolio – temporarily limited to physical generation assets and forward contracts, plus any required T&D additions or upgrades – should then be assembled that provides an adequate, safe, reliable, and environmentally sound power supply at the lowest life-cycle present value cost.[37]

All reasonable resource options should be considered. Supply options that should be considered include conventional generation plants, renewable or evolving technology generating plants, resource- and market-based contracts, life extension and repowering, and T&D investments that make additional supply sources accessible or reduce line losses or capacity requirements.[38] All resources must be evaluated even handedly, counting costs for capital, operating, fuel, maintenance, ancillary services, environmental compliance, permitting and decommissioning.[39]

The next step is to examine alternatives to generation: methods for controlling and moderating demand, such as energy efficiency savings, DUP options (both DSM and DG), transmission upgrades or additions, load control and load response programs. This step must begin with a thorough knowledge of the purposes to which each customer class puts electric consumption, the efficiency levels of those end uses, and the costs and savings of the full range of measures and programs available to modify that demand.

The cost-effectiveness of these alternatives is then evaluated. One means is to screen them by comparing efficiency measure costs to the generation and T&D costs (both capital and operating) avoided by them (including reductions in T&D losses and reserve requirements). Special attention should be paid to measures that save power at times when loads are highest. Cost-effective DSM and DG measures incorporated into the portfolio to the extent they can cost-effectively displace or defer supply-only options. (NARUC 1988)

Address Risk

Many jurisdictions and utilities conducted integrated resource planning in a least-cost analytical mode, with risk management treated as a supplementary exercise, and the required reliability level treated as a given. Given today's sweeping and ongoing market changes, it is prudent to place greater emphasis on treatment of uncertainty and risk issues in portfolio management.

Risk management alternatives can be evaluated in terms of the degree of volatility removed, their implementation cost, and/or their susceptibility to regulatory scrutiny. Specific types of risks facing the electricity market include:

- Fuel price risk.

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[37] Each jurisdiction must consider what definition of cost it finds most appropriate. The various options for this definition were discussed in Section 7 of this report.

[38] Generation capacity requirements are sometimes driven not by the need to serve energy or peak load, but by reliability concerns. In effect, capacity is sometimes required to protect against T&D or generating outages. In many situations, T&D improvements or smaller, more modular generating plants can reduce the need for generating capacity.

[39] A system dispatch model should be used that treats plant outages probabilistic loss of load computations, not by simple derating. This is essential not only for accuracy, but so that the reliability benefits of intermittent resources may be captured correctly. (Lazar 1993)

- Fuel availability risk.
- Uncertain ability to balances supply and demand of electricity.
- Transmission congestion costs.
- Environmental compliance costs.
- Environmental operating restrictions.
- Ancillary service costs.
- Credit risk.
- Uncertain availability of resources – including demand side management and distributed generation.
- Electricity market structure uncertainty.

From a generator's point of view, high volatility and risk are important in terms of stable revenue streams and in terms of determining the worthiness of new investments; investors have a hard time determining whether current prices indicate long-term values or transient events. From a residential or industrial consumer's perspective, electricity price risks can have a direct effect on consumer wealth, as well as on the ability of consumers to budget their expenses and make financial plans.

There are several means of addressing risk in the development on the optimal portfolio. The first means is in the selection of supply-side and demand-side resources themselves. If the least-cost portfolio is overly sensitive to uncertainties in load, market prices for fuels or wholesale power, or environmental risks, then modifications are needed to the portfolio to protect against these uncertainties. In general, portfolio optimization using energy efficiency and renewable resources will be able to deliver reduced risk at the same cost as the initial portfolio, or lower cost with the same risk, or a combination of the two. (Awerbuch 2000) Also, if a portfolio results in inappropriate costs for some classes of customers or places them at higher risk than others, further changes may be needed.[40]

The second means of addressing risk in the development of the optimal portfolio is through the use of financial hedging methods that can further reduce cost and risk. Portfolio managers should examine how the more complex financial and power transactions can augment a traditional least-cost portfolio of generation, T&D, and DSM assets to further mitigate risk and reduce cost. It is important to note that, without a sound resource plan that accounts for risk through the choice of supply-side and demand-side resources, hedging will simply increase the cost (hedging is not free) and reduce the variability of a portfolio that is more expensive and riskier to rate payers and society than it needs to be. (Bolinger, et al. 2003)

Finally, portfolio managers need to analyze the risks associated with candidate portfolios, using techniques that explicitly capture the variability and uncertainties associated with long-term resource planning. There are a variety of techniques that seek to quantify the uncertainties associated with a given portfolio, so that alternative portfolios may be

[40] For example, the base case may include a major expansion for a very large commercial or industrial customer that requires significant new power supply and T&D commitments if it is to be met at the lowest expected. However, if that expansion is uncertain, smaller rate payers are placed at risk, and alternative measures that reduce the size of the new commitments needed, or have shorter lead times so they can be deployed if and when the additional load develops, may be more appropriate.

compared on both cost and uncertainty. Some of these methods also help to identify the components of a portfolio or the environmental variables that contribute most to that uncertainty. This can be helpful in designing improved portfolios. The choice of risk management techniques include several types of stress testing or scenario testing, mark-to market, computer simulations, decision tree analysis, and real option analysis. These techniques are described further in Appendix D. The rest of this subsection reviews the overall approach to measuring and comparing portfolio risks.

When comparing electricity portfolios, we would like to be able to quantify and compare the risk of each portfolio. Similarly, when issuing an RFP for electricity supply, we would like to be able to specify a desired quantitative level of risk and to compare riskiness (to consumers) of bids.[41] To illustrate this process, we will consider two types of risk: price volatility and counter-party risk.

Price volatility can be assessed quantitatively for each resource and the portfolio as a whole in terms of the standard deviation of the price. For fixed price contracts, this is zero. For many renewables, the variable cost is zero, but the total cost depends on the kWh output. If the output's variability is known, the price variability can be computed.

Counter-party risk is more challenging to quantify. Doing so requires an assessment of the sources of such risk, the probabilities of those risks materializing, and the price impact if they do. For example, in the case of a contract for the output of a specific power plant, one counter-party risk is always vendor bankruptcy. In bankruptcy, the vendor can reject the contract.[42] Assessing the probability of bankruptcy for a particular vendor is difficult, but may be informed by the vendor's bond rating and leverage as shown in its audited financial statements, if available, as well as the nature of the resources physical or otherwise, on which the vendor relies.[43] Finally, using these probabilities and an estimate of replacement power cost, the increment of variability that counter-party risk will contribute to the overall variability of the contract can be estimated.

Not all risks can be quantified reliably, if only because historical data are lacking or future performance cannot be relied on to replicate history. In such cases, qualitative assessments, such as management audits, may need to be relied on. In other cases, such

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[41] It is important to keep in mind that risk is a property of *both* an entire portfolio *and* the portfolio's component parts. That is to say, each resource in the portfolio will have its own level of volatility, counter-party risk, and so on, but the overall riskiness of the portfolio is *not* a linear sum of those risks. Consider a portfolio with two components, both owned by the utility so there is no counter-party risk: a 400 MW gas combined cycle power plant and a 400 MW oil-fired steam plant, with any shortfall in output to be made up at a market price dominated by gas-fired generation at the margin. The two generating plants each have certain risk of forced outages, price volatility, and regulatory risks due to possible new emissions standards. Since the two plants are physically separate, the portfolio has lower *average* forced outage risk than either plant separately. Since they are different technologies, the same is true of environmental risks; for example the gas unit would likely be affected less by new SO_2 restrictions than the oil unit. Depending on how closely correlated gas and oil prices are, the cost of the overall portfolio may or may not be less volatile than the cost of the individual plants.

[42] Other possibilities, such as a renegotiation of the contract, can be analyzed in a similar manner.

[43] Relatively recent credit scoring methodologies used in the finance industry may be of use here. See for example, Gleason 2000, p. 167 ff.

as analyzing risks of additional environmental regulation, estimates of the likely costs of compliance with new regulations can be applied.

Portfolio managers should begin by emphasizing orderly risk identification and data collection. Historical data on resource availability and price volatility of key cost inputs should be available for most resources. We recommend starting with careful estimation of portfolio price variability, as described above, taking into account at least these factors, plus careful qualitative evaluation of other risks. Such an assessment should include careful analysis of the degree to which the risks affecting the cost and performance of the underlying physical resources are congruent with the guarantees made by vendors, if any. Some portfolio managers and regulators may wish to add quantification of probabilities and price consequences of the most salient counter-party and regulatory risks affecting the most important portfolio components.

Service providers or regulators issuing RFPs for power to supply monopoly or default service customers should require provision of the necessary data (under seal if necessary) for such analysis. Experience does not permit drafting at this time of RFPs that establish a specified level of risk to be delivered, and the lack of experience in doing so would likely discourage bidders from participating in a solicitation that did so. In competitive solicitations, regulators should instead specify that selection will be based on both price and some defined measure of risk, such as that given above, with some weighting.

10. Maintaining an Optimal Resource Portfolio over Time

10.1 On-going Portfolio Management

Once an optimal resource plan has been determined, the utility needs to implement the plan flexibly and judiciously. Ongoing evaluation and updating not only help realize the potential of PM and risk management, but assist in coping with and responding to the unexpected.

One reason flexible portfolio options are beneficial is because they create an ability for the portfolio manager to make adjustments over time as uncertain future developments solidify and new opportunities or uncertainties arise. To reap those benefits, the portfolio manager must continuously monitor the environmental factors that could impact cost effectiveness and risk, investigate and evaluate new resources and opportunities to add value to the portfolio or reduce risk, assess the actual performance of portfolio components against their expected performance and, generally, act diligently to maintain the integrity of the portfolio and adjust to ongoing developments. (Culp 2001, 485 ff.)

To ensure that the portfolio strategy is successfully implemented, an action plan should be prepared that covers acquisition and disposal of portfolio elements; monitoring of market conditions, environmental trends, electric loads and end uses; checks portfolio performance; and seeks out and evaluates potential acquisitions or hedging instruments. Counterparty credit and settlement risk require constant attention.[44] Both supply and demand side initiatives should be evaluated on a regular basis. The action plan should provide for scheduled reviews and updates of goals, assumptions and strategies.[45]

For any portfolio, especially one containing medium- or long-term forward contracts or hedges, it is important to routinely assess risk exposure as part of performance monitoring. The market risks of most interest to portfolio managers are wholesale power prices, fuel prices, and electricity demand. Credit risks (counterparty settlement risk, primarily), operational risk (owned plant performance, for example), legal risk (contract disputes), regulatory risk (FERC market rule changes), and event risk (war, natural

[44] In many forward contract markets for power and gas today, *sellers* or market rules require costly credit guarantees from *buyers*, even fully regulated utilities. Conversely, default service providers and utilities must follow the financial health of major counterparties carefully. The NRG contract dispute, described in Section 7.4 above, is just one example of how serious this issue can be.

[45] Despite these cautions about maintaining a dynamic, continuously evaluated and adjusted portfolio, it is also important to provide a reasonably stable budgetary and institutional environment for long term projects. In particular, DSM and DG programs require lengthy implementation periods to bear fruit, and an unstable operational environment will doom them to failure. Many renewable energy projects are so capital intensive that long term commitments are necessary so they can attract appropriate financing. Modular design and careful, ongoing process evaluation offer opportunities for dynamic PM, while still providing the kind of stable environment these resources need to mature.

disaster, political events) may also be important. Tools for exposure assessment are discussed in Appendix D.

10.2 Procurement of Resources

In addition to action planning and plan updating, a default service provider will need, at some level, to engage in plan implementation: actually buying and selling power and hedging instruments and acquiring DSM and DG resources, as called for in those plans. It is beyond the scope of this paper to explore fully the management of each of these functions, but we will indicate the key elements necessary for successful procurement of each category.

At the outset, it is worth pointing out one longstanding concern with the management and staffing of non-traditional generation assets. Proper *integration* of each function (and staff carrying it out) with a coordinated enterprise-wide effort requires solid commitment from and ongoing follow through by top management. It is also hard, but necessary, to ensure *parity* of these functions within the firm. Generation and T&D ownership are the traditional roles of utilities, and supply planning units are often led by engineers who are more technically oriented and less customer oriented than those involved in DSM or DG work. Trading of contracts and hedges may be done by personnel or even located in units that come from an accounting or finance background. Some functions may be outsourced. Each of these situations flows from natural historical developments and, indeed, responds to very real job requirements. But it is up to top management to ensure that decisions *between* these alternatives are based on sound communication and rational priorities. (NARUC 1988, 16; Gleason 2000, 221 ff.)

Perhaps the best understood of these procurement functions is the construction and operation of conventional power plants. Even here, it is important examine the way in which these decisions flow from and react to PM decisions. Construction planning should maximize flexibility so that work can be slowed, canceled or accelerated and, if possible, so that capacity can be increased or decreased. Those decisions also need to be managed to maximize value and minimize risk. (Trigeorgis 1996)[46] Operations of combustion generators will also entail a variety of cost minimization and risk management tasks not least of which is application of the entire repertoire of PM techniques to fuel supply and arrangements for the sale of any temporary or seasonal excess power.

Developing or purchasing physical generation or resource-based contracts for renewable energy adds new challenges to the implementation requirements for traditional power plants. Most relevant renewable technologies are evolving rather than mature, while utilities, regulators, local residents, and other stakeholders are less familiar with the issues and benefits.

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[46] Ownership structures can impact this issue. On the one hand, a partial ownership (or contract rights) to several power plants under construction provides some risk protection compared to sole ownership of a single unit. On the other hand, lead or sole owners have much more ability to manage projects to suit their needs. Each project needs to be considered from both perspectives.

As mentioned above, procurement and management of long- and short-term forward contracts may require the creation of what is essentially a commodities trading operation, which can require substantial investment and lead time to develop and prove itself. Hedging operations are even more complex. The learning curve for both can be quite steep and mistakes costly. (See Gleason 2000, generally, for examples.) One alternative is outsourcing of procurement. As indicated in the box below, Green Mountain Power has used this approach. The appearance of "structured products," where an investment bank or other commodity risk taker provides all or part of a commodity portfolio could be considered, although the cost premium can be quite high.

Outsourcing Supply Portfolio Management

Green Mountain Power Corporation (GMP) sells electricity and energy services and products to about one-fourth of Vermont's retail electricity customers. GMP also sells electric power at wholesale in New England and sells operations services to other utilities in Vermont. The company has a risk management program that has an objective of stabilizing cash flow and earnings by minimizing power supply risks due to such things as risk of fossil fuel and spot market electricity price increases.

Specifically, the company initiated a contract to outsource its power procurement responsibilities to Morgan Stanley Capital Group, Inc. ("MS"). As of February 1999, MS began purchasing the majority of the Company's power supply resources at indexed prices (for fossil fuel-fired plants) or at specified prices (for contracted sources), while selling to GMP at a fixed rate to serve pre-established load requirements. More specifically, on a daily basis, and at MS's discretion, GMP sells power to MS from either its own power resources or those available to it. MS then sells to GMP sufficient power to serve pre-established load requirements, all at a predefined price. MS is also responsible for scheduling supply resources. This contract, along with other power supply commitments, allows the Company to fix the cost of much of its power supply requirements, subject to power resource availability and other risks. The MS contract is effective through 2006. It saved the Company an estimated $4 to $5 million during 2000 alone. (Dutton 2002)

To date under this contract, the Company's retail rates have remained below the average of all major electric utilities in New England. (Green Mountain Power 2003) For the remaining life of the contract, the volume of transactions under the contract will be modified. GMP will take back contracts representing the majority of its committed supply, namely contracts with HQ and Entergy; these contracts have very stable pricing, so the risk reduction from handing these contracts to MS to manage is not worth the cost. There will continue to be some volume of power, based on fossil-fired units and estimated at $6 million per year, handled under the contract. (Sedano 2003)

More importantly, hedging and commodities trading are outside the experience of many electric utilities and their regulators. Where they are familiar activities, it is usually in the context of either purchasing generator fuel or for retail gas utilities. Certainly, well-defined rules need to be developed for such activities to protect consumers from ill considered speculation.

Procurement and ongoing management of DSM resources is less novel, but still requires careful oversight. Program planners and managers must have access to expertise about cutting edge technologies in a wide variety of end uses from residential lighting to building shells and HVAC controls, types of engineering not usually in the skill set of traditional utilities. Energy efficiency is only one aspect of a building or manufacturing process, and will often need to be marketed as a set of coordinated benefits to the end user. (Sedano 1998).

DSM action plans should provide adequate resources, including knowledgeable staff, for program design and marketing, either directly or through contractors, for such functions as direct customer marketing, interface with trade allies, public education on energy efficiency programs, and branding. As part of its program management responsibility, the utility should collect, manage and analyze tracking data on participating customers, trade allies, and general program operation and regularly report to management, regulators and the public, make ongoing adjustments to program operation based on tracking and monitoring. (VT DPS 1997, 84 ff.)

Finally, it is worth mentioning that ongoing information gathering should be an integral part of any PM implementation plan. Pilot programs, R&D tracking, and competitive intelligence gathering and analysis are a few of kinds of information gathering that will assist in keeping a PM strategy alive and functioning.

10.3 Flexible Application of PM

The most effective approach to PM is likely to vary with the regulatory and competitive situation of each jurisdiction. After the restructuring wave of the 1990s, the regulatory landscape is much more varied than it formerly had been. Not only are some states restructured and some not, but those that have restructured addressed default service and transitional arrangements differently. However, there are three main categories into which states fall:

1. Retail competition with competitive acquisition of default service;
2. Retail competition with default service by the (disaggregated) distribution company; and
3. Fully regulated retail service by vertically integrated companies.

Though the goals are the same, PM is a somewhat different process for states in each category. (Harrington, et al., 2002, 19 ff.) In the broadest terms, states in categories 2 and 3 need only import into their existing oversight expectations for utilities to use PM for the benefit of ratepayers. In some states, the certain restrictions were imposed on the utility's default service activities that may interfere with sound PM; such restrictions may need to be modified. California's prohibition of forward contracts is the classic example. In category 1, the regulator supervising the competition could, in principle, develop bidding specifications and performance criteria that would require sound PM and flow the benefits to ratepayers.

In each of these categories, however, there remains to be developed practical ways and means for regulators to implement these goals. For example, a regulator would benefit from a rule or formula that would compute the proper target degree of uncertainty or variance in expected retail price for default service. Unfortunately, such rules are unlikely to be available and would likely need to be adapted for each state's situation and available alternatives. Best practices should be developed for default service PM, but even they would need to be revised over time as new hedging products become available and PM understanding progresses.

One challenge facing regulators who seek to promote sound PM will be the complexity of the data and methodological issues that would have to be addressed in a rule making or litigated case to establish PM requirements and standards. Similar difficulties were faced and overcome in the initiation of IRP requirements in the early 1990s. In addition, some commissions found that the periodic dockets for review and approval of IRPs were challenging. This risk needs to be addressed, but should not deter regulators from pursuing PM requirements and oversight. Rather, experience developed over the past decade in collaborative rulemaking and collaborative settlement processes for litigated cases should give some confidence that these complex matters can be addressed reasonably and expediently for the benefit of consumers. In addition, commissions may avail themselves of the extensive case management tools developed in anti-trust and mass tort litigation which go under the rubric of complex case management. (See, for example, Fed. R. Civ. P. 16(c)(12) and Federal Judicial Center 1995.)

11. Regulatory and Policy Issues

It has become clear from the experience with electricity industry restructuring to date that default service providers must play an active role in managing generation services to retail customers. Default service providers will be serving the vast majority of electricity customers well into the foreseeable future, and they continue to have an obligation to provide reliable electricity services at just and reasonable rates to these customers. For utilities not subject to restructuring, these roles have not been changed, but the tools available to improve the quality of their electricity services have evolved.

It has also become clear that all electric utilities – vertically-integrated and distribution-only – must take greater care in managing resource portfolios. The recent developments in the competitive wholesale electricity markets create greater opportunities but also greater pitfalls. A passive or inactive utility is more likely to suffer from the pitfalls than benefit from the new opportunities.

It is also clear that regulatory guidance and oversight will be critical to achieve the goals of portfolio management, and to ensure that all utilities have clear direction regarding their roles as portfolio managers. Many utilities in states with restructured electricity industries have been acting as though they have a lesser obligation to manage resource portfolios than in the past, in part as a result of the explicit or implicit policies and directives from regulatory commissions. This trend must be reversed in order to ensure that electricity customers are well served, that the market provides benefits to all customers, and that neither consumers nor utility shareholders are exposed to the kind of radical volatility that affected California in 2000-2001.

On a practical note, in any regulatory setting, decision makers will need to address factors that go beyond the data and theory of portfolio management. Political realities, regional priorities and preferences, land use impacts of various resource options, availability of utility and commission resources and skill sets, institutional constraints and histories, and authorizing legislation, all impact not only how portfolio management should be done, but whether and when it can be implemented in regulation. Furthermore, the technical analysis and managerial decision making necessary to plan and implement portfolio management requires not only theoretical knowledge, but also a thorough grasp of the context in which the plan will be carried out, including jurisdictional priorities and preferences. Experience and knowledge matter in making these decisions. Initial conditions, too, will have a strong influence on proper portfolio management due to the long-lived nature of the resources that underlie existing portfolios and the markets in which new resource can be acquired. Oversight and management of portfolio management planning and implementation will be critical to control the risks that arise from those decisions, themselves.

While a complete discussion of the policies necessary to support portfolio management is beyond the scope if this report, we list a few key areas that require attention from legislators, regulators and other stakeholders in the industry.

- *Clarify the objectives.* In states that have allowed retail competition, regulators need to explicitly require utilities or non-utility default service providers to be more active with portfolio management and to adopt portfolio management techniques. In states that have not allowed retail competition, regulators still need to clarify utilities' responsibilities regarding portfolio management in light of the uncertainties associated with regulatory and market changes in recent years.

- *Provide periodic regulatory review.* Successful portfolio management will require regulatory guidance and oversight on an on-going basis. This requires that regulators periodically review and assess the decisions and the actions of portfolio managers, whether the jurisdiction operates with pre-approval, ex post review or both.[47] The traditional IRP process is a good basis and venue for this type of review. Experience in several states, most notably Nevada, shows that ex-post review can produce very painful results for utilities.

- *Provide guidance on risk management.* There is a need for legislators and utility regulators to provide guidance on expectations about the risk management responsibilities of default service providers, whether integrated utilities, distribution companies, or other types of default service providers. Guidance on the level of risk appropriate for default service portfolios would be valuable to inform the development of appropriate mixes of types of resources and the duration of commitment to those resources. At a minimum default service providers should be required to address their strategies and performance in portfolio plans, integrated resource plans, bids, or other processes. Since this is a novel task for regulators and the utility industry, further research on methods for establishing and achieving risk management goals should be pursued.

- *Allow stakeholder input to the process.* One of the more challenging aspects of portfolio management is in balancing the many different criteria for selecting the optimal resource portfolio. This balancing act often involves trade-offs that affect different stakeholders differently. In order to ensure proper balancing of the different interests, it is important to allow the various stakeholders to provide input into the portfolio management process. Adequate participant funding is another essential element to ensure stakeholder participation.

- *Provide utilities with appropriate financial incentives.* Utilities cannot be expected to adopt portfolio management processes or implement resource portfolios that result in negative financial consequences for the company. Regulators must ensure that ratemaking and restructuring policies will promote sound portfolio management practices and discourage inaction or improper management practices. Regulators should ensure that existing policies – such as performance-based ratemaking mechanisms – support and do not hinder portfolio management practices.

[47] Even under pre-approval regimes, implementation must still be monitored, if only to identify changes in policy that are needed.

- *Provide appropriate incentives for energy efficiency activities*. Electric utilities face significant financial barriers to implementing energy efficiency programs. Under traditional ratemaking approaches, efficiency savings result in lost sales, which can result in lost profits between rate cases. If legislators and regulators designate electric utilities as the primary entity to plan for and implement energy efficiency programs, then it is essential that ratemaking policies be designed to overcome this financial barrier. The most effective approach is to decouple the utility's profits from its sales using a revenue cap approach to setting electricity rates. (Synapse 1997) Removing utility financial incentives for energy efficiency program is essential regardless of whether the utility is vertically-integrated or distribution-only. Because of this financial barrier faced by electric utilities, legislators and regulators should consider alternative entities for implementing energy efficiency programs.

- *Address barriers to distributed generation*. Electric utilities also face barriers to the development of distributed generation. As with energy efficiency, distributed generation on customers' premises can result in reduced T&D sales and thus reduced utility profits. In addition, many distribution utilities are prohibited from owning any form of generation, due to concerns about vertical market power. Regulators should identify policies to help overcome these barriers in order to allow distributed generation to play a meaningful role in portfolio management.

- *Provide appropriate cost recovery*. Some resource portfolios might not result in the absolute lowest-cost plan in the short-term, once other factors are considered. For example, hedging options may require higher up-front costs, but be desirable because of their risk benefits. Similarly, renewable resources might cost more than some fossil-fueled resources, but be desirable because of their diversity, risk and environmental benefits. For example, coal-fired generation may appear cheaper in the short-run, but exposes the utility and its consumers to carbon dioxide mitigation costs in the future. Regulators need to provide utilities with some level of comfort that such additional expenses fall within the concept of portfolio management and can be recovered from ratepayers.

- *Pre-approval of resources and cost recovery*. The issue of cost recovery raises the question of whether regulators should "pre-approve" resource portfolios, and provide utilities with some certainty that they will be allowed to recover the costs associated with the resources therein. Pre-approval of resources with some assurance of cost recovery should be used with great caution, and only if certain critical conditions are met. It is essential that pre-approval only be applied to resource portfolios that were developed with proper portfolio management techniques, with meaningful and substantial input from key stakeholders, and with proper oversight from the regulators.

- *Pre-approval and resource implementation*. There is an important difference between pre-approval of a portfolio management plan, and pre-approval of the costs of specific resources acquired under that plan. Utilities must do more than plan well in order to be allowed to recover the costs of their resources. They should also be required to demonstrate on an ex post basis that they have prudently and efficiently implemented the approved resource portfolio, and that they have properly responded to changing conditions since the plan was first developed.

- *Address market sensitive issues*. Regulators need to be aware that some of the information used in developing and assessing resource portfolios would be considered "market sensitive" by competitive actors in the electricity markets. As such, this information will need to be kept confidential to avoid market distortions or abuses. On the other hand, this issue should not be used to limit the information utilized and assessed in the portfolio management process. An efficient marketplace depends on a continuous flow of information, so that all buyers and sellers have access to the same data. Procedures can be established to ensure that market sensitive information is not provided except as part of a general system of disclosure equally applicable to all market stakeholders.
- *Facilitate the regulatory process*. Portfolio management involves many complex and challenging analyses and decisions, and regulators need to find a balance between (a) regulatory and stakeholder input and review, and (b) a feasible, timely process for developing, reviewing and approving resource portfolios. As described in Section 10.3, experience developed over the past decade in collaborative rulemaking and collaborative settlement processes for litigated cases should give some confidence that these complex matters can be addressed reasonably and expediently for the benefit of customers. In addition, commissions may avail themselves of the extensive case management tools developed in anti-trust and mass tort litigation which go under the rubric of complex case management. (See, for example, Fed. R. Civ. P. 16(c)(12) and Federal Judicial Center 1995.)

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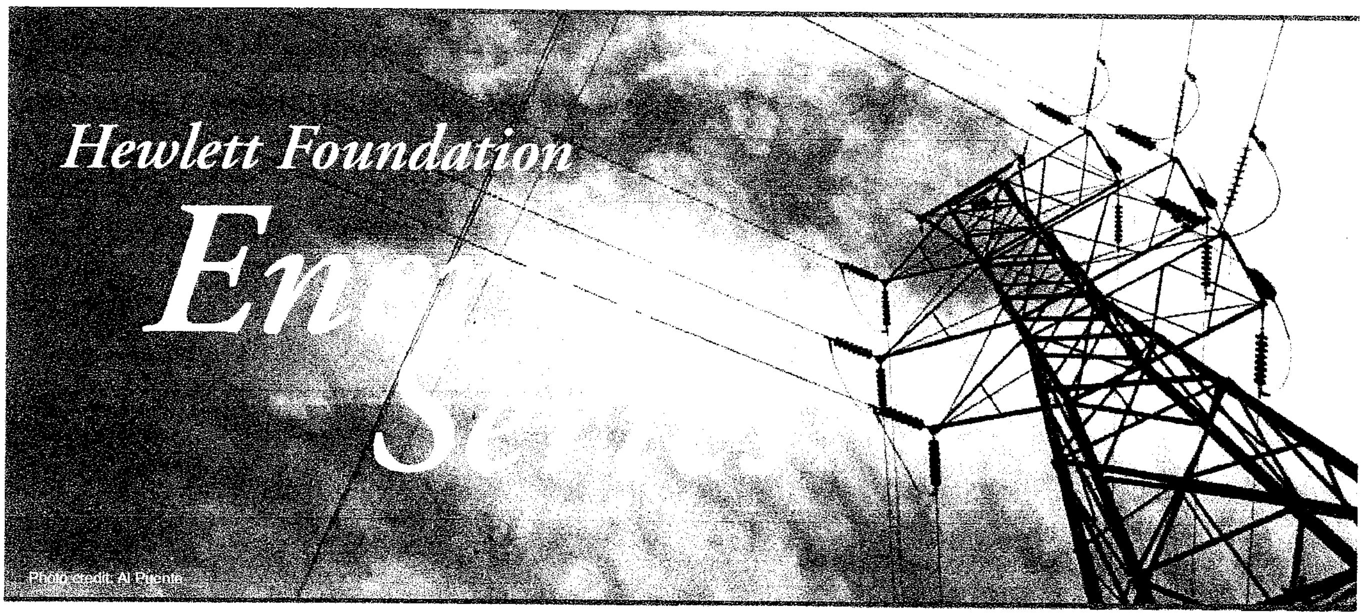
Portfolio Management

Protecting Customers in an Electric Market That Isn't Working Very Well



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TOWARD A SUSTAINABLE ENERGY FUTURE

Portfolio Management:

Protecting Customers in an Electric Market That Isn't Working Very Well

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The Regulatory Assistance Project
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The Regulatory Assistance Project (RAP) is a non–profit organization, formed in 1992, that provides workshops and education assistance to state public utility regulators on electric utility regulation. RAP is committed to fostering a restructuring of the electric industry in a manner that creates economic efficiency, protects environmental quality, assures system reliability and applies the benefits of increased competition fairly to all customers.

EXECUTIVE SUMMARY

After ten years of restructuring activity, virtually every residential and commercial customer, more than two thirds of total load, remains a captive customer of one variety or another. Worse, the future has been truncated into short-term markets where even four years can be an expensive eternity. This paper discusses the need for a return to long-term portfolio management with a stronger regulatory responsibility for long-term public benefits.

Ideally, fully competitive markets with all customers making choices that reflect their own values would allow an optimal selection of resources. That's what markets are supposed to do. This vision for competitive electricity markets rests upon three essential conditions:

1. clear information and an opportunity to choose from a broad array of resources;

2. the actual exercise of choice; and

3. customer and supplier choices not skewed by significant market barriers and failures.

None of these three conditions is present in current retail electricity markets in the United States. Customers have little information, almost no choice, and standard offer service plans deter new market entrants by undercutting market prices.

Portfolio management is needed as an antidote to market power. Market power is most easily exercised in short-term markets where bidding strategies and capacity withholding can be profitable to suppliers. Portfolio management can reduce the risk of market power by relying more on long- and medium- term contracts and other proven risk management tools and less on spot markets. The long-term market is much less susceptible to these practices. The long-term market also benefits from the price–reducing effects of new entrants, new technologies, and other efficiency gains. Thus, in addition to reducing consumers' exposure to unwanted price volatility, another key role of portfolio management is to reduce consumers' exposure to market power–ridden, short-term markets. *The use of portfolio management may be the greatest leverage state regulators have to influence the actual operations of wholesale markets.*

Thinking about how to apply portfolio management to improve the service offered to retail customers requires understanding the differences among states in how retail service is now provided. Efforts to restructure the electricity industry have created wide variations among states as to how retail service is provided to low-use customers. About half of the states have continued to regulate retail service for small-use customers on a cost-of-service basis while the other half have made various attempts to introduce competitive markets for small-use retail electricity service. The need for portfolio management exists in all states but the scope of portfolio management, the allocation of responsibility among different entities, and the regulatory approach are likely to differ significantly.

Creating a balanced and robust portfolio requires a process that includes:

• Collecting reliable data on electricity end-use demand patterns;

• Collecting reliable data on and evaluating technical alternatives for demand-side alternatives, capable of improving their the energy-efficiency or load profiles associated with particular end-uses;

• Calculating the costs and electric-load impacts of the demand-side alternatives;

• Comparing their costs with the economic costs and environmental impacts of conventional and alternative electricity supply options;

• Defining and projecting future energy-service (end-use) demand scenarios;

• Testing the sensitivities of potential plans to anticipated risks such as changes in fuel costs, load or weather patterns, and testing the plan in a variety of scenarios;

• Designing an integrated supply and demand-side plan that is robust (meaning performs well under most or all scenarios), has an acceptable level of risk, satisfies the least-cost criteria in terms of economic costs and environmental impacts;

• Reforming regulatory incentives, such as by decoupling revenues from sales, so as to make the "least cost" portfolio the most profitable course of action;

• Implementing a rate design consistent with the price patterns and demand assumptions used in building the portfolio; and, most important of all,

• Implementing the least-cost strategy.

Energy efficiency and renewables are some of the best the tools available to reduce consumer costs, prices, and risks. But by itself, adoption of portfolio management does nothing to assure that these resources will be of interest to the portfolio manager. Experience shows that even under the best conditions portfolio managers under-invest in these resources. This is the main reason most states that have elected to try retail competition have adopted System Benefit Charges and Renewable Portfolio Standards to assure that at least minimum amounts of these resources are delivered. It will remain a critical responsibility of regulators and lawmakers to keep energy efficiency and renewables a part of portfolio management.

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I. INTRODUCTION

After ten years of restructuring activity (dated from the enactment of the federal Energy Policy Act of 1992), virtually every residential and low-use commercial customer remains a captive customer of one variety or another. In some states customers are captives of short-term energy markets. In other states they are captives of negotiated rate freezes that are about to end, exposing them to risks that were not fully appreciated a few years ago. In the remaining states where the pretext of retail competition does not exist, customers are captive to vertically-integrated utilities that focus more on their own uncertain future than on the long-term interests of their customers. This paper discusses how portfolio management can be applied in each of these situations, improving the cost and quality of electric service without impinging on the effort to build competitive retail markets in those states committed to that goal.

Electric restructuring has been a massive undertaking. After a decade of effort, we can begin to identify outcomes, some intended, some unintended, and some just plain undesirable. On the positive side, wholesale markets are slowly taking shape. It appears that competitive wholesale markets, though obviously harder to design and implement than first thought, are feasible but it will be some time before they are fully functioning and fully competitive.[1]

On the other hand, retail markets are functioning only for a small number of the largest customers. For the vast majority of residential and commercial customers, about 60% of total load, retail markets have not yet come into existence. The sole viable version of retail competition to emerge for low-use customers appears to be the aggregate bidding of the retail franchise, such as municipal aggregation in Ohio and bidding–out of default service[2] in Maine and New Jersey. These are essentially the bidding out of the entire retail franchise. The retail market may never work for most low-use customers on anything but a conditional "franchise" basis. The non-traditional customers may in fact be a "natural monopoly".

The most serious problem caused by the slow development of competitive wholesale markets and the non-existence of retail markets is that all but the largest customers have been stripped of the multiple benefits of portfolio management.[3] What is portfolio management? It is the long run management of a diverse set of demand and supply–side resources selected to minimize risks and long run costs, taking environmental costs into account. The essential characteristic of portfolio management is resource diversity. Not mindless diversity, but diversity carefully selected and managed to reduce risk, particularly the risk of price volatility, a salient feature of the wholesale markets. The lack of portfolio management exists to some extent in all states, but it is particularly acute in states that have moved to retail competition where customers are increasingly being forced into short-term energy markets.

State Regulators Affect Wholesale Markets When They Set Retail Rate

Setting retail rates is the most powerful point of leverage state regulators have over how wholesale markets function and what products the markets offer. With upwards of 95% of all load served on default rates, and likely to remain that way in the foreseeable future, the "demand" characteristics of the default rates becomes the primary force in defining the range of products offered at wholesale. If customers are to be served with a relatively stably priced, diverse portfolio of resources, it will be because state regulators require it. What we have learned in the recent few years is that if state regulators sit back, the market on its own, offers short-term products of only a few years duration, ignores most renewable resources, and does not produce the price stability and predictability desired by most customers.

II. The Problem

A. The Failure of Portfolio Management

Where customer choice exists, it was created in the hope that competitive retailers would provide a wide range of products and services. One expected product was long-term price stability for customers wishing to avoid the price volatility of hourly, daily, monthly, or even yearly markets. Why have such products failed to materialize? There are probably many explanations. The primary one is poorly designed default service pricing which left default service priced below any feasible retail cost. As a result, there are very few retail competitors serving small customers and most suppliers who first entered the market have since left. With very few competitors, it is unlikely that the hoped for innovative services and long-term stable-priced products will develop.[4]

It is not that the market lacks long-term portfolio management: large wholesalers, retailers, and traders may be very sophisticated portfolio managers. The problem is that the price stability benefits of their long-term portfolio management efforts are not accessible to low-use retail consumers. This problem may be inherent in the nature of energy markets, or it may simply earmark a flawed competitive market where no pressure exits to cause these benefits to be passed on to customers. A central issue for regulators is how to structure default service to encourage good portfolio management AND ensure the resulting benefits are delivered to customers.

Here are some of the specific problems arising out of the failure of portfolio management:

1. Wholesale providers are offering short-term products and managing for their own risk, not consumer's least cost;

2. Retail sellers do not offer a broad array of all possible resources (demand–side and renewable resources have largely been left out of the market due to lopsided market rules) leaving customers no real opportunity to put together a stable, diverse personal portfolio;

3. Retail customers are forced into short-term markets which make the markets even more volatile (or, exacerbates volatility);

4. Year-to-year price volatility, especially upward jumps in price of short-term markets is likely to be unacceptable to the vast majority of customers;

5. Short-term markets are especially susceptible to market power problems, which, in turn cause short-term market prices that are even higher and more volatile;

6. The reliance on short-term markets has led to a greater use of lower capital cost, higher operating cost facilities, which invariably have been fossil-fuel units, those most associated with environmental harm;

7. A sole focus on gas–faired combustion turbine, which can lead to a diversity problem in some places (like CA); and,

8. The lack of long-term financial arrangements may prevent the construction of new plants by all but the incumbent vertically integrated utilities, narrowing participation in the wholesale markets.

B. Loss of Integration, Diversity, and Price Stability

Under accepted regulatory theory in the pre-restructured world, each vertically integrated utility had the responsibility to acquire all generation, transmission, and distribution resources needed to serve its jurisdictional customers. Utilities were expected to provide service using the most efficient portfolio of resources, over time. That meant making acceptable trade-off choices among all available resources, including: short- and long-term demand– and supply–side resources; transmission and distribution; as well as alternatives such as distributed resources.

System planning analysis required careful comparisons among the costs and functions of disparate resources (such as between a peak power generator and a transmission system upgrade or between an energy efficiency program and a generator), and the testing of possible resource portfolios against one another using various planning scenarios which took account of uncertainties (such as unexpected weather patterns or fuel price changes). The analysis considered total life cycle costs, patterns of costs over time, environmental impacts, and rate designs. The method of analysis for comparing such diverse resources was termed integrated resource planning (IRP).[5]

Diversity and price stability was delivered because utility planning, construction, and contracting decisions were incremental in nature. Each year, or so, a relatively small amount of resources were added to a much larger base of supply. The effect on consumer prices due to periodically tight market conditions or high fuel costs was moderated by both the size and mix of embedded resources.

Although the development of competitive wholesale power markets was long overdue, the advent of restructuring activity at both the state and federal levels caused integrated resource analysis and portfolio management to take an unfortunate turn for the worse. When competitive generation markets demonstrated that the book value of many utilities was far in excess of their market value, utilities became understandably nervous that they would not be able to recover their embedded costs and stopped acquiring resources for the long-term. Further, as retail choice entered the scheme, generation functions were unbundled or divested from regulated transmission and distribution functions. In several states customers were given increased opportunities for choice, but the only choices offered were, with very few exceptions, relatively short-term market-prices. Customers lost the benefits of integrating diversified investment in generation, transmission, distribution, energy efficiency, and load management. Finally, in almost all states, utility-sponsored energy efficiency programs were cut back dramatically.[6]

Instead of a single entity making resource acquisition decisions, decisions in several states are now made piecemeal with no structural or market support for identifying the value to be gained or lost as between, say, additional transmission investment as compared to a generation purchase as compared to a demand–side management program. There is no entity that is positioned to benefit from efforts to identify, compare, and determine the most efficient quantities of each resource.

Ideally, fully competitive markets with all customers fully participating, making choices that reflect their own values would allow the optimal selection of resources— that's what markets are supposed to do. This vision for competitive electricity markets rests upon three essential conditions Customers must have:

1. clear information and an opportunity to choose from a broad array of resources;

2. the actual exercise of choice; and

3. customer and supplier choices not skewed by significant market barriers and failures.

None of these three conditions is present in current retail electricity markets in the United States. Customers have little information, almost no choice, and standard offer service plans deter new market entrants by undercutting market prices.

Losing the single entity that was in a position to evaluate alternatives and make tradeoffs would not be so bad, if replaced with market-based mechanisms that revealed the value of different options to market participants and customers. But, this has not happened. Generation markets fail to accommodate a demand response; transmission investments continue to be made on a planned, socialized cost basis; no market participant is making trade–offs between supply– and demand–side options; and, distribution companies in many states are trying to balance responsibilities between requirements for what may be very short-term generation needs versus longer-term distribution system operations. Value is being lost. In point of fact, for most Americans, restructuring has taken away the actual benefits of integration but not yet replaced them with the potential benefits of competition.

C. The Risks of Price Volatility

Electricity markets in California, Illinois, the Northeast and mid-Atlantic regions, Australia, and Canada have all shown how volatile electricity prices can be. Although volatility is highest from hour-to-hour, even the day-to-day, month-to-month, and year-to-year volatility is more than most customers are probably prepared to accept.

Even in well-functioning electricity markets year-to-year price swings will likely be in the range of 2 to 3 cents per kWh. The annual average price can easily increase by more than 3 cents per kWh if natural gas prices are high and reserve margins are narrow, compared to when natural gas prices are low and ample generating capacity exists.

Academic economists would likely offer two responses. The first is that competitive generation and retail competition are needed to send more efficient price signals. Because electricity costs at the margin are highly volatile, prices should be volatile too. This gives buyers the right price signals to use electricity when costs are low and to avoid electricity use when prices are high. In theory, over time, such responses will enhance the efficiency of energy use. And second, with effective competition and retail choice, customers who dislike volatility can choose suppliers and products with fixed prices or moderate price swings, much like consumer choices between fixed and variable rate mortgages. We believe this perspective misses three critical limitations of existing electricity markets:

1. Almost no competitive markets have competitive service providers for any customers other than the large industrial users. Current default service policies in most markets mean there are almost

no competitive retail suppliers and few of the existing competitive retail suppliers offer long-term options to consumers. Moreover, the creation of default service as a hoped-for "transitional" service has had the effect of undermining the providers' ability to commit to long-term resources to fulfill standard offer supply commitments. Thus, default service plans—ironically, created to provide stability and continuity for low-use customers—have essentially guaranteed that we will never know what a real market would have provided.

2. Existing wholesale electricity markets are characterized by the lack of demand response and the presence of market power, both of which make prices higher and more volatile. Markets can be structured to promote more or less volatility, and current electricity markets are greatly biased to the high volatility end of the spectrum.[7]

3. Default service customers don't see hourly, daily, or weekly price signals due to the lack of necessary metering and rate design offerings. With retail access, even fewer customers will likely see real-time prices because, given the choice, most small customers choose flat rather than real-time prices (like in telecom, long distance service). Also, with retail access, suppliers that serve small consumers usually do not see the price signals either, because they are billed for electricity purchases based on average load profiles rather than the real-time use of their customers. This means suppliers have no reason to respond to volatile prices either (that is, there is no immediate and direct financial benefit to them for doing so). Further, where resource changes take place on a time horizon longer than that of the short-term market, there is a fundamental mismatch between prices and the addition of needed new capacity. That is, short-term price spikes are not likely to result in the near-term provision of new generation supply.

All of these factors combine to make today's electricity markets more volatile than they need to be, and policy makers in many jurisdictions have implemented retail access and standard offer polices that result in almost all low-use customers being in excessively volatile, short-term (one year or less) markets.

In theory, long-term price stability simply requires a customer to sign a long-term contract for power. In reality, however, most retailers do not offer long-term contracts and low-use customers do not sign them. There are many possible explanations for why there are no long-term electricity products. It is probably for the same set of complex reasons that there are no long-term contracts for other commodities ranging from gasoline to pork bellies. Knowing the reasons why these products are lacking is less important than simply observing that they are lacking and then taking steps to manage the risks that their absence imposes on consumers.

D. Market Power is Accentuated in Short-term Power Markets, and Unchecked Market Power Worsens the Inherent Volatility of Electricity Markets

The evidence is rapidly mounting that market power is a more serious problem than originally thought. Studies by the California ISO's Market Monitoring Committee following the enormous price run up of late 2000 and early 2001 found that market power in the California market accounted for about $7 billion in excess charges.[5] If this estimate is even close, market power already cost California consumers far more than any estimate of the efficiency gains to be squeezed out of competitive markets. The cost of market power problems in California threatened to quickly exceed the total stranded cost that California utilities accumulated over the 20 years prior to restructuring.

At least as frightening as the degree of unchecked market power (where all generators regardless of intent benefit by "piling on") is the slow pace at which the regulatory, legislative, and judicial process seems to be able to solve the market problems, once they are identified. Whether we will ever be able to reduce market power to acceptable levels is a debatable and important question. But, in the meantime, portfolio management provides a way to reduce consumer exposure to it.

Portfolio management can reduce the risk of market power by relying more on long- and medium- term contracts and other proven risk management tools and less on spot markets. Market power is most easily exercised in short-term markets where bidding strategies and capacity withholding can be profitable to suppliers. The long-term market is much less susceptible to these practices. The long-term market also benefits from the price–reducing effects of new entrants, new technologies, and other efficiency gains. Thus, in addition to reducing consumers' exposure to unwanted price volatility, another key role of portfolio management is to reduce consumers' exposure to market power–ridden, short-term markets.

The critical question for every regulator and policymaker right now is whether it is prudent to put the vast majority of small customers into the short-term market for all of their electricity needs. Most certainly, in a fully regulated monopoly market structure, if a utility put 100% of its load into the short-term market, it would have been found to have acted imprudently and been penalized accordingly. But, whether the answer is, "No, we don't want to be 100% in the short-term market because prices will be unacceptably volatile." Or, "Yes, because price volatility adds economic efficiency to the grid and will be tolerated by consumers." We at least need a temporary portfolio manager until effective means of reducing market power have been put into place. In either case, portfolio management is an essential function of the electric system under current conditions. It may be a necessary function for a very long time. The challenge, of course, is deciding specifically what should be incorporated into the portfolio management function and who should do it.

E. Comparing the Prudence of Long and Short-term Purchasing Strategies

One method to highlight the prudence of a provider's purchasing strategy is to consider the extremes of its options. At one end of the spectrum is a portfolio that is 100% in the spot or short-term market ("Spot Market Case"). At the other end, is a portfolio that is 100% long-term with fixed prices ("Long-Term Case"). By "fixed" price, we mean pre-determined price, even if that number changes over time under a contract schedule. What are the strengths and weaknesses of these two strategies?

The term "prudence" is derived from the legal concept known as the "prudent man theory." That is, what would a prudent decision-maker do, based on the information they ought to know at the time when they are making a decision? In this context, prudence is closely aligned with accepted risk management or portfolio theory. The prudent manager will apply accepted risk management principles when assembling a resource portfolio. Accepted risk management theory is premised on the notion of diversification. It, therefore, seems to preclude both the Spot Market Case and the Long-Term Case, unless special circumstances would be identified for electric markets that would exempt them from the tenets of the theory. Without proof of such special circumstances, the theory holds that the least risky portfolio is one that provides the greatest diversification.

1. Spot Market Case

The principal strength of the Spot Market Case is its flexibility. As operating cost characteristics shift over time, a purchaser can modify their supply portfolio to capture the most efficient basket of resources. In a "pure" spot market case, the purchaser essentially allows the spot market to accomplish this directly and they merely "take" the spot market price as it is presented. The purchaser achieves the "optimum" or cheapest portfolio of supply, given the choices available at that point in time.

The weakness of this case, in addition to the obvious exposure to price volatility, is the absence of any entitlement to resources with any certain price or operating characteristics. The entire supply portfolio turns over every hour. In this case, the purchaser is not just a price-taker, but a supply-taker as well, with no firm resource commitments available to them.

Regulated utilities have generally been penalized for over reliance on short-term markets. For example, this approach to supply portfolio management was rejected for a natural gas utility by the New Mexico Public Utilities Commission (Case No. 2752, May 1, 1997). That decision was heavily influenced by the rate shock associated with a doubling of gas prices over a two-month period and the associated flow-through of those costs to customers—especially its impact on low-income and small commercial customers. Although the utility argued that a 100% spot market portfolio was the least cost option over the long -run, the Commission rejected that position because of its associated risk of price volatility. While the Commission declined to find the utility's past purchasing practice imprudent, partly in response to the Company's assertions that (1) the issue had never been raised and (2) there was no clear mechanism for recovery of hedging expenses, it made clear that a pure spot market portfolio was not an acceptable or prudent strategy going forward. California's recent experience only serves to reinforce that conclusion, although the particulars of California's restructuring framework caused utilities, rather than customers, to bear the risk (with the exception of San Diego Gas & Electric).

Even if one could achieve lower long-run costs through reliance on the spot market (an as-yet unproven assertion), the potential adverse impact on customers of large price swings over short time horizons can be devastating. This is especially true for low-income and small commercial customers or their proxies, the load serving entities. When these very real social costs experienced by these and other customers are included in the analysis, reason dictates a move away from intensive reliance on spot market supplies. In short, such a strategy is inconsistent with sound risk management and should, therefore, be considered imprudent.

2. Long-term Case

While one might expect symmetry at the other extreme, it is not necessarily so. The principal advantage of having a long-term fixed price portfolio is, obviously, price stability and an assurance of a supply with known, and presumably desirable, pre–commitment price or operating characteristics. A not too obvious correlation to this is that, under ordinary circumstances, the purchaser is unlikely to enter into long-term contracts with extremely high, fixed prices; although, as discussed below, California, with its extraordinary circumstances, achieved the opposite result.

The principal weakness of a long-term fixed price portfolio is the risk associated with being "wrong" as compared to cheaper alternatives that come and go in the interim (the extreme of which is the spot market). This weakness is partly a function of the extent to which long-term fixed price supplies are acquired all at once or are staggered ("laddered") over time. Once again California offers a lesson in the extreme. In response to the disastrous impact of being essentially 100% in the spot market, long-term fixed price contracts were signed for virtually all of California's power needs going forward. Whenever long-term contracts are negotiated, the prices will inevitably be influenced by then–existing spot market prices and near–term expectations about those prices. Unfortunately, California's contracts were negotiated at a point in time when supplies were tight or uncertain and spot prices were high (or were presumed to continue to be high over the near–term horizon). And, power companies appeared to be exercising market power and manipulating the market.

However, subsequent to the negotiation of those contracts, a variety of changed circumstances have lowered both spot market prices and expectations about them in the near term. As a result, purchaser's remorse has set in and an effort is now underway to renegotiate the contracts because they appear to be high cost, *as compared to today's spot market expectations.*

Does this mean that the Long-Term Case is as imprudent as the Spot Market Case? Perhaps, but the adverse impacts of the Long-Term Case may not be as severe as those of the Spot Market Case. Much of the purchaser's remorse phenomenon can be mitigated where long-term purchase contracts are laddered over time, like dollar cost averaging in a mutual fund, causing only a limited portion of the supply price to be impacted by then-existing spot market price expectations. Nonetheless, the extreme Long-Term Case, which also generally runs afoul of accepted risk management theory, is probably not a prudent strategy either.

In short, the "prudent" portfolio manager will seek a balance between the two extremes, allowing for sufficient opportunity to capture short-term benefits, while maintaining a stable base of diverse supply. In evaluating a supply portfolio, it is important to credit long-term components with some value for avoided price shocks, even if their cost *in retrospect* appears higher than the spot market. Indeed, retrospective comparisons of the choices made by a portfolio manager run afoul of the principles embedded in the prudence standard and therefore should be avoided by the regulator. The comparison should be to the alternatives at the time when the choices were made.

The Failure to Pass Portfolio Benefits to Customers

The gasoline and heating oil markets are other examples of the failure to pass portfolio benefits to customers. In the gasoline market, Exxon, Texaco, and Shell are all portfolio managers. Each has assembled a portfolio of oil wells they own, supply contracts of various types and durations, financial hedges of all sorts, and, in varying degrees, spot market purchases. Meanwhile, retail gasoline consumers are all essentially in the spot market. Consumers may have some timing flexibility if they fill their tanks weekly. Farmers with on-farm fuel tanks may be in a slightly longer duration market. In the case of fuel oil or propane for home heating, many suppliers offer price stability for a year. But there are no longer-term products offered to or bought by consumers. In these markets, all consumers are essentially in the short-term market.

If the world price of gasoline and heating oil goes up by 20%, the retail price of gasoline and heating will go up by 20%, or something close to it, within a day or two. The average cost to Exxon, Texaco, and Shell does not go up 20%, because spot purchases are only one part of their portfolios. When the price of gasoline goes up by 20%, oil companies make a lot of money. The firm that had the best-managed portfolio makes the most money. Electricity markets are now like oil markets. But, even if a retail supplier is an excellent portfolio manager, neither the price stability nor the low average cost achieved through their diversity of supplies will necessarily flow through to their customers.

III. It is Time to Return to Portfolio Management

The concept and practice of portfolio management is not new to this industry. Portfolio management means assembling a mix of long-, medium-, and short-term resources, resource types, and financial instruments with the aim of most efficiently balancing long run cost and risk. The goals of portfolio management are the same goals as in decades of utility regulation and are currently being sought by introducing the greater use of competitive markets in this sector. The goals are to obtain: the least costly mix of resources; high system reliability; stable, affordable prices; minimized negative impact on the environment; markets untainted by market power; and, of increasing concern, system security. This is of course what major suppliers in the electricity market do today on an ongoing basis to protect their aggregate positions in the volatile electricity market. What has been lost is that these "portfolio" benefits are no longer passed on to customers.

Using portfolio management to achieve these economic, social, and environmental benefits does not require abandoning or slowing the shift to more competitive **wholesale** markets, but policy makers do need to be more aware of the looming gap between consumers' reasonable expectations and the gritty realities of emerging electricity markets, both retail and wholesale. Without retail competition, the utility, default service provider, or other licensed monopoly retail electricity provider is the portfolio manager. The manager can dampen the wholesale market price volatility by limiting the amount of resources drawn from the short-term market at any one time. A robust portfolio would consist of a diverse mix of power plants, contracts, spot energy purchases, and other risk-reducing measures such as investments in energy efficiency and renewable resources, as well as demand management and load response programs. This sort of robust portfolio does not need to be sacrificed to emerging markets. The trick is to recapture the positive elements of IRP that have been lost, without adversely affecting market development.

A. Revisiting Integration

Not all of today's regulators will be familiar with the strategic integrated portfolio concept known as Integrated Resource Planning, or IRP. IRP for the electric utility industry evolved in the 1980s. It broadened the scope of system expansion planning from traditional supply-side resources (that is, wires and power plants) to a more complete economic analysis that integrated all available resources and technologies. This included resources available on the demand-side, such as investments in programs to acquire energy efficiency and load management resources. In practice, IRP promotes the development of electricity supplies and energy-efficiency improvements, including managing the growth of demand (DSM options), to provide energy services at minimum total cost, including environmental and social costs. Ideally, IRP investigates the broadest reasonable range of options to meet demand for electric service, including technologies for energy efficiency and load control on the demand-side, as well as decentralized and non-utility generating sources. By selecting technologies and programs to minimize the total cost of electric service, and incorporating analysis of environmental and social costs, IRP makes it possible to plan electric supply and demand-side options that will meet electricity demands most efficiently without wasting economic or environmental resources.

Creating a balanced and robust portfolio requires a process that includes:

- Collecting reliable data on electricity end-use demand patterns;
- Collecting reliable data on and evaluating technical alternatives for demand-side alternatives, capable of improving their the energy-efficiency or load profiles associated with particular end-uses;
- Calculating the costs and electric-load impacts of the demand-side alternatives;
- Comparing their costs with the economic costs and environmental impacts of conventional and alternative electricity supply options;
- Defining and projecting future energy-service (end-use) demand scenarios;
- Testing the sensitivities of potential plans to anticipated risks such as changes in fuel costs, load or weather patterns, and testing the plan in a variety of scenarios;
- Designing an integrated supply and demand–side plan that is robust (meaning performs well under most or all scenarios), has an acceptable level of risk, satisfies the least-cost criteria in terms of economic costs and environmental impacts;
- Reforming regulatory incentives, such as by decoupling revenues from sales, so as to make the "least cost" portfolio the most profitable course of action[9];
- Implementing a rate design consistent with the price patterns and demand assumptions used in building the portfolio; and, most important of all,
- Implementing the least-cost strategy.

The IRP planning horizon generally spans 10 to 20 years, or as long as can be reasonably forecast, with a specific action plan developed for the upcoming two to three years. Total electricity demand is disaggregated by sector, end-use, and technology, with as much resolution as possible given available data. Technologies for improving energy end-use efficiency or influencing load shapes are identified. The technical and economic performance of these alternatives are estimated, compared, and ranked according to cost-effectiveness. Based on these results, DSM programs and other energy–efficiency strategies are analyzed in terms of their total costs and rates of market penetration over time.[10]

Production–cost analysis of the performance of existing and new electric supply alternatives is used to rank these alternatives according to marginal cost values. The results are compared to the marginal costs of demand–side options, including environmental costs to the extent possible. The two sets of options (supply- and demand–side) are then compared and combined to produce the integrated least-cost electricity plan. The integrated electricity plan is subjected to further financial evaluation and sensitivity analysis before the final plan is completed. The incorporation of these issues may re-order the ranking of the integrated plan somewhat, or exclude certain resources from the plan. This step fine-tunes the IRP results to account for specific issues and options inherent in the local or national setting.

B. Key Portfolio Management Considerations

Deciding what resources are needed requires taking into account a long list of variables.

- *Demand*—What is the likely level of demand for service over the relevant time period? What kind of end uses will drive that demand? How variable is the forecast? What factors are responsible for the variability? What ranges are those factors likely to take?

- *Resources*—What are the available resource choices? What are the trade-off choices that can be made among resources? What is the range and variability of fuel prices, market prices, construction costs, investment and financing costs likely to be incurred to provide the required service?

- *Reliability*—Will the resources operate when they are needed and what are the costs of replacement power or damages if they don't?

- *Environmental*—Will the resources incur environmental damage that isn't internalized to the price? Who will pay these costs and when?

- *Market power*—Are prices subject to manipulation by market participants?

- *Security*—Are there external threats to the selected resources? What are those threats? Can they be ameliorated? If any of the threats materializes, what additional costs might be incurred as a result? What additional costs might be incurred to protect against those threats?

Under traditional regulation, customers bore virtually all the risks and benefits of power supply decisions. Utilities bore the risk of making imprudent decisions. Utilities and regulators managed risks through the IRP process, certificate of need reviews, and post hoc prudence reviews. One of the goals of moving to a fully competitive retail market was to change this risk allocation. It was hoped that in a competitive market, customers would have a wider range of choices and would bear only the risks they chose. However, as we have seen to date, essentially no competitive market for services to low-use customers has developed.[11]

C. How Much Risk for Small Customers?

A critical issue for portfolio management is deciding what level of risk small (non-industrial) customers should be asked to assume. This decision requires judgment informed by the tradeoff between risk and price. Identifying and assessing the risks of different portfolios is the heart of IRP. IRP helps portfolio managers decide what mix of energy resources and financial arrangements best strikes a balance between price level, price risk, price volatility, total energy costs, environmental and other non-price effects, and financial risk. Key questions and issues include:

- How much exposure should there be to any one fuel, or conversely, what is the desirable level of fuel diversity? This question is particularly pertinent in light of the massive increase on reliance on natural gas and the diminishment of energy efficiency resource procurement in the last five years or more.

- How are purchase arrangements structured? If most energy comes from contractual arrangements, how long are the contracts and are they staggered in both time and size ("laddered") so as to minimize exposure to price volatility?

- How much reliance is there on spot markets, which may be unacceptably volatile?

- How much reliance is there on renewable resources like wind and solar, with no or fixed fuel costs, as a hedge against high fuel price volatility?

- How much reliance has been placed on financial contracts as compared to physical power contracts and physical power assets?

- Are the contract terms at odds with underlying market realities? For example, a contract that relies on a fixed or banded gas price may simply be breached if gas prices take an unexpected leap or fall. A fixed price gas contract may not be honored when gas prices rise dramatically.

- Have environmental costs been internalized or otherwise accounted for?

- What is the total cost of supplying energy services to customers under the proposed portfolio, and have cost-effective demand-side resources been tapped to lower total costs to customers?

- Can these resources be delivered to market reliably, or will they impose new contingencies or transmission constraints that raise the risk of outages or the cost of meeting reliability standards?

D. Portfolio Management and Energy Efficiency and Renewable Energy

Energy efficiency and renewables are some of the best the tools available to reduce consumer costs, prices, and risks. But by itself, adoption of portfolio management does nothing to assure that these resources will be of interest to the portfolio manager. Experience shows that even under the best conditions portfolio managers under-invest in these resources. This is the main reason most states that have elected to try retail competition have adopted System Benefit Charges and Renewable Portfolio Standards to assure that at least minimum amounts of these resources are delivered. It will remain a critical responsibility of regulators and lawmakers to keep energy efficiency and renewables a part of portfolio management.

1. Energy Efficiency

Cost-effective energy efficiency (energy efficiency that saves a kWh for less than the marginal cost of producing and delivering a kWh) always reduces customer bills, but it may or may not reduce prices. Making cost-effective energy efficiency a part of its portfolio hinges on two related factors—the incentives faced by the portfolio manager and how the wholesale market is structured.

The incentives faced by the portfolio manager will be determined by the regulatory rules, if the portfolio manager is regulated, or by the contract terms, if the portfolio manager is a competitive supplier. In either case, careful attention to how the portfolio manager makes money is the key to understanding its interest in energy efficiency. For example, if portfolio managers are insulated from the risk of high spot market prices and are allowed to earn a margin on all sales, they will have no reason to invest in energy efficiency, even where efficiency would lower the cost of the portfolio to customers.

Efficiency Response in California

California provided a stark example of how well the right incentives can work. In California, the portfolio manager's (the distribution utilities) prices were fixed when their wholesale supply costs increased to levels well above the default service price. Instead of making money on increased sales, the California utilities suddenly found themselves losing large amounts of money on every kWh they sold. They responded with a newfound and enthusiastic embrace of energy efficiency. Electricity demand was lowered 6.7 % overall, and an average of 10% for the summer peak hours. The Legislature authorized an additional $859 million for load reduction programs in 2001 and 2002.* Redoubled energy efficiency investment was a major reason the crisis ended faster than predicted. Several of the energy efficiency incentives were not an integral part of the original market design; they were the temporary and unplanned result of unusual circumstances. It remains to be seen how thoroughly California will incorporate these recent energy efficiency lessons in future reforms.

*The Summer 2001 Conservation Report, The California Energy Commission, February 2002

The structure of the market may also influence whether the portfolio manager has an incentive to invest in energy efficiency. In particular, if the value of demand response is fully incorporated in wholesale markets, the portfolio manager will have a much stronger incentive to pursue load management and some limited types of energy efficiency.

2. Renewables

As for renewables, their virtue is their freedom from fossil fuel cost volatility and escalation as well as their insulation from new environmental costs arising from air pollution or climate change mitigation requirements.

Portfolio managers can reduce price and other risks through physical or financial hedges. But, despite oft-repeated assertions about the "sanctity of contracts," all hedges do not have the same level of security, either to producers or to consumers. What types of hedges are best from the consumers' perspective? Coal or nuclear power claim to offer stable long run prices but surely when the risk of additional environmental and security costs are included in the calculation they lose serious attraction as hedges. Nor does nuclear power have a particularly strong reliability history. For many years 60% capacity factors were common.

The most difficult situation is one in which a fundamental cost such as the price of natural gas skyrockets and carries market clearing prices along with it. If market prices greatly exceed the expectations of participants, there is a risk that suppliers, including portfolio managers, will default on their obligations. There are already numerous examples. The bankruptcy of Enron and the subsequently rejected contracts show how the strength of the counter-party in a financial risk management deal can be illusory. Retail suppliers in California and Pennsylvania have ceased service and returned customers to the default provider. For example, an early default service provider in Maine (chosen through a competitive bidding process) had its wholesale providers default when market prices increased thereby causing the Maine PUC to agree to raise the fixed price the retailer had originally agreed to. The lesson is that if market prices increase, suppliers who agreed to deliver fixed prices will be quick to seek relief of one sort or another, including breach of contract. Buyers may also pursue contract rejection or reformation, as demonstrated by recent contract renegotiations and extensive litigation in California. The essential point is that financial promises to deliver fixed prices may be meaningless if market conditions change too much.

Hedges in the form of contracts with renewable generators can provide a higher level of security.[12] Indeed, one of the best hedges is one with a physical asset that has underlying cost characteristics matching the hedged contract prices. A fixed priced contract for the output of a gas–fired power plant provides the appearance of price stability, but there is a risk of non-performance if gas prices increase, while buyers may seek price reformation if gas prices drop significantly. The same contract with a wind facility can provide more security as it lacks the risk of a variable fuel cost. Of course, renewable resources do have some fuel risk: the wind may not blow, the sun may be clouded over and, droughts may occur but the risks are probably small compared to the price volatility of fossil fuels, and they can be hedged by making many small renewable investments rather than a few large ones.

E. Scope of Portfolio Management For Three Types Of States

Thinking about how to apply portfolio management to improve the service offered to retail customers requires understanding the differences among states in how retail service is now provided. Efforts to restructure the electricity industry have created wide variations among states as to how retail service is provided to low–use customers. About half of the states have continued to regulate retail service for small–use customers on a cost–of–service basis while the other half have made various attempts to introduce competitive markets for small–use retail electricity service. Of the half trying to develop retail competition, some use the distribution utility as the default provider and other put default service to bid. The need for portfolio management exists in all three types of states but the scope of portfolio management, the allocation of responsibility among different entities, and the regulatory approach are likely to differ significantly. We will divide the various arrangements into three categories.

Competitive Acquisition of Default Service (Category 1)

A few states that have moved to retail competition are committed to establishing standard offer service on a competitive basis. Maine is the best example, having had three cycles of competitive bidding for standard offer service. The first two cycles resulted in viable bids of only one year in duration but the third cycle has resulted in contracts three years in length. Other New England States (Massachusetts and Rhode Island) have solicited competitive bids for default service but did not receive any acceptable responses. New Jersey has recently awarded bids for standard offer service. Pennsylvania has solicited bids for a small portion of standard offer service but no viable bids were received.

Utility Provides Default Service (Category 2)
The larger group of states that have adopted retail competition have arrangements that rely upon the distribution utility to supply default services. These are states where the distribution company, often pursuant to the original negotiated restructuring arrangements, provides standard offer service. Massachusetts, Rhode Island, Connecticut, New York, Maryland, Delaware, and Montana are examples of this arrangement. Pennsylvania largely remains in this category. California was a version of Category 2. Service was provided by the distribution utility under a fixed rate agreement but the utilities were able to recover only the short-term market price for these customers, which seemed to work until the market price soared well above the amounts recoverable under the rate agreements. In most of these states the current rate arrangement will lapse at the end of the restructuring transition period. It is not at all clear what arrangements will be made for standard offer service in these states following the expiration of the rate arrangements. Texas has required default service customers be transferred to a utility's affiliate and served at a rate set by the PUC.

Vertically Integrate, Fully Regulated (Category 3)
This group contains the largest number of states; they are the states that have not adopted retail completion. They include all states not mentioned in the previous two categories.[13] Among the states that continue to use traditional cost-of-service regulation, many fail to integrate a full range of demand-side programs into the system, thus losing the cost reduction benefits of a more balanced portfolio. Moreover, concerns about future industry structures and whether competition will grow or decline are preventing states from addressing this problem.

Where electric service is still provided by vertically integrated firms, it remains the utility's obligation to provide "just and reasonable rates" to all customers. This obligation is typically met through integrated resource planning (IRP), with varying levels of regulatory oversight and approval. IRP is the process by which utilities and policymakers manage the portfolio of assets—generation, poles, wires, etc.— needed to meet demand. It provides an analytical framework for assessing the various risks a utility and its customers face—business, financial, market, environmental, political—and for evaluating the full range of options to manage those risks.

1. Competitive Acquisition (Category 1)

General
We begin by describing what portfolio management is in the context of a state with retail competition and where default service is provided on a competitive basis. We begin here because the role of the portfolio manager is the most limited and the most clearly separated from other functions that are needed to achieve effective portfolio management but that are performed by other entities.

In Category 1 states, the portfolio manager is not the distribution utility. The portfolio manager is a competitive service provider assembling resources to supply the only the default customer block. Although it is theoretically possible to impose wide ranging portfolio management obligations on the default service provider doing so will be inconsistent with its obvious incentives and its narrow mission.

The portfolio manger only fulfills part of the complete set of integration functions. The portfolio manager can be expected to develop a portfolio that is consistent with its interests and the obligations it has agreed to accept. Thus, for example, if the RFP asks for a fixed amount of energy each year for 10 years, there will be no need to prepare a long-term demand forecast but it will need to assemble resources that allow it to meet long-term fixed price obligations without undue financial risk. On the other hand, if the RFP asks for a bid to serve the default service customers in a specific geographic area, demand forecasting will be important. And, if the RFP asks the portfolio manager to supply default service for just two years and indexes the default service price to natural gas prices, the portfolio manager will assemble a low-risk portfolio depending mostly on short-term gas-fired resources.

In no case will the portfolio manager have any reason to consider the full range of transmission, distribution or distributed resource options. The portfolio manager will only consider demand-side options to the extent that the value of these resources is exposed in the design of the wholesale market.

Because the portfolio manager in these states will have a limited planning role, establishing the overall integrated energy plan will remain an important role for state government. IRP (without regard, for the moment, to the particular administrative process by which it is devised and reviewed) would be used to identify the terms and conditions that the portfolio manager will be competing to meet.

The limited role of a default service provider is underscored by considering three key factors in portfolio management: duration, financial risk, and price volatility. These key factors in portfolio management need to be in any RFP for competitive default service. None of which would be expected to be a matter for the portfolio manager to determine in its own planning function. This means a state agency; perhaps the state agency responsible for planning, however, would use IRP to make these basic decisions that would be reflected in an RFP.

Duration

The duration of the default service obligation is critical. Moving customer prices away from excessive exposure to short-term markets will require greater use of long-term commitments. Without long-term default service commitments, customers will be exposed to short-term markets even if the supplier has secured long-term stable priced resources.

Financial Risk

Recent experience in the power market underscores the need be concerned about the level of financial risk of the portfolio manager. The RFP should specify limits on the portfolio manager's financial risk arising from reliance on spot market purchases and reliance on financial (rather than physical) contracts. This may also impose fuel diversity and renewable requirements.

Price Volatility

Markets in California and elsewhere have demonstrated just how volatile electricity prices can be. Planners and policymakers need to decide the maximum yearly or monthly exposure to price volatility.

Energy Efficiency

The responsibility for acquisition of energy efficiency for Category 1 states is best assigned to an entity other than the portfolio manager. The portfolio manager's incentives will likely be to increase sales with the possible exception for the load management that is valued by the market in demand response. The funding responsibility for energy efficiency and renewable resources, such as through familiar system benefit charges (SBC) would not be imposed solely on the portfolio manager but would be implemented in ways that affect all load serving entities.

Other Responsibilities

Government policy makers, legislative, executive, or administrative, must undertake other relevant actions that are clearly not the responsibility of the portfolio manager, but will influence the cost, price, and resource mix selected by the portfolio manager. These other critical government roles include:

1) Market Design
Assuring well-designed wholesale markets that address market power, demand response, and fair treatment of intermittent renewable resources.

2) Transmission
Pricing and planning transmission to permit the portfolio manager to consider costs and cost saving.

3) Energy Efficiency and Renewables
Designating the minimum amount of energy efficiency and renewable resources to be included in the state's electricity mix and establishing that green resource options are offered as part of default service.

4) Distribution Planning
Integrated planning of the distribution system including: design of retail rates such as the use of distributed resource credits designed to encourage customer use of distributed resources in high cost areas.

5) Align Regulatory Incentives
Consistent regulatory incentives that remove the sales throughout incentives.

2. Distribution Utility (Category 2)

General

Category 2 states are those that have moved to retail competition but have imposed the obligation of default service on the existing distribution company. In some of these states, such as New Hampshire, the distribution company still owns generation or has long-term power supply contracts and uses these resources on a cost-of-service basis to provide a significant portion of its default service needs. In other states, such as Massachusetts, the utility owns little or no generation but is required to act as a purchasing agent for default service customers and it has made some long-term supply arrangements.

The wide range of Category 2 states means some details of portfolio management will differ from state to state. However, the common element of these Category 2 states makes portfolio management different from portfolio management in Category 1 states, is that default service is provided by the distribution utility. This means the portfolio manager has the ability to incorporate distribution system planning, including the cost–effective applications of distributed resources, as a seamless part its portfolio management function.[14]

Other Responsibilities

In other respects, basic decisions such as default service customers' exposure to financial risk and price volatility must rest with a government agency. Otherwise the distribution utility can be expected to develop a portfolio that best meets its interests, which are different than the interest of default service customers.

More Lessons from California: Crisis Response is Messy and Inefficient

A key lesson from California is the need to have an overall strategy or road map regarding needed resources and the way in which they will be integrated. The lack of such a plan has contributed to the costly "clean up" of its 2001 market meltdown. There, in the weeks following the astonishing run–up of generation prices in late 2000 and early 2001, major efforts were launched by state agencies to both contract for new resources and, simultaneously, to stimulate major demand reductions. The lack of integration between these two resource "selections" has led to very high priced—and unneeded—capacity. California was, of course, in a desperate situation but clearly a little advance IRP planning would have gone a long way to ameliorate the crisis and to hold costs down.

3. Vertically Integrated (Category 3)

General

Category 3 states are those that have not moved to retail competition. In these states, portfolio management is similar to IRP and includes all activities with the exception of wholesale market rules. The fact that the portfolio manager is an integrated utility makes some oversight and planning functions much easier. For example, even under traditional regulation, the integrated utility has an incentive to consider load management and some types of distributed resources to address problems in high cost distribution areas.

The primary challenge in these states is for integrated utilities to become adept at making the most effective use of wholesale markets when adding resources, including learning how to maximize the wholesale market value of system demand reduction.

Other Responsibilities

Here again, basic decisions such as default service customers' exposure to financial risk and price volatility must rest with a government agency. Otherwise the utility can be expected to develop a portfolio that best meets its interests, which are different than the interest of default service customers

F. Administrative Options

What sort of process should be used to prepare the portfolio plan? Administratively, there are many options ranging from:

1. A full adjudicatory process where all assumptions, methods, and analysis are subject to public filing, discovery, sworn testimony, cross examination, and full rights of appeal. Many states used this process to implement IRP and some still do. The process works better (in terms of efficiency and timeliness rather than outcome) in some states than others. The number of parties, the perceived stakes of the proceeding, the personalities of the participants, and the way practice before the commission has evolved all contribute to any assessment of how well this process works.

2. Legislative or rulemaking style proceedings with opportunities for alternative filings and public comments are another approach that have been used successfully. This may take the form of a state energy office charged with the planning responsibility. A recent example is the recently formed California Consumer Power and Conservation Financing Authority charged with the responsibility to:

- "furnish the citizens of California with reliable, affordable electrical power;
- ensure sufficient power reserves;
- assure stability and rationality in California's electricity market;
- encourage energy efficiency and conservation as well as the use of renewable energy resources; and
- protect the public health, welfare and safety."[15]

The Authority conducted its planning and assembled a written "investment plan" which it circulated for public comment. The final plan was submitted to the legislature on February 15, 2002.

Another good example to these two approaches can be seen in portfolio decisions relating to renewable resources. Again, we use California as an example but a very similar story could be told for many other states:

During the 1980's and early 1990's, the CPUC was deeply engaged in carrying out its approach to IRP, known locally as the Biennial Resource Plan Update (BRPU). Every two years, the CPUC held a lengthy adjudicatory process designed to identify the best mix of new resource additions. There were many parties, most of whom were active in trial type hearings involving every assumption, model, and input used. The outcome was a commission decision specifying what the state's utilities were to buy or build.

By all accounts, the process was exhaustive and exhausting. The quality of the data and analysis was as good as that produced in any state and probably better than most. In the end, commission decisions were based on the data, the analysis, judgment, and the application of state policy as reflected in state laws. The results were not bad but the process was excruciating.[16]

In contrast, during and since restructuring California has used a very different process to make fundamentally similar decisions relating to investment in renewables. The California legislature has enacted laws requiring significant investment in renewables. The record upon which these decisions were made is not as easily described or documented as the record in the BRPU proceedings. Yet it appears that the conclusions reached by California lawmakers were based of extensive analysis performed by stakeholders and government agencies. There was ample opportunity for public input.

Whatever administrative approach is used, there must be substantial opportunity for public and stakeholder input must be provided. Portfolio management is a service provided to small customers that for a variety of reasons do not choose their own service directly. Default service customers are essentially captive customers and their interests are being served by the conditions imposed on the provider of default service. No level of analysis can eliminate the judgment that must go into the selection of a reasonable portfolio. If judgment cannot be eliminated, and default service customers are at risk for the resulting portfolio, it is essential that public and stakeholder interests, particularly stakeholders that represent the interests of default service customers, inform the portfolio requirements.

The right option for any one state is best determined by that state, based upon its own history and its restructuring status and goals. For example, a Category 1 state may decide it only needs to establish several fundamental criteria, such as how much year to year volatility it is willing to accept for default service how much financial exposure in terms of reliance of financial contracts it is willing to accept. Then it may design a "laddered" system of procurement that solicits 10-year bids each year for 10% or so of it total needs for default service. The criteria will drive bidders to limit the amount of financial versus physical contracts and the amount of exposure to fuel price risk, such as natural gas.

The planning function will determine the level of funding for energy efficiency and any minimum level of investment in renewables. These requirements may be imposed on the portfolio manager directly or may be carried out separately.

For this type of situation legislative approaches may be adequate, provided a responsible state agency has the resources and responsibility to put forward a reasoned plan for comment and amendment.

Oregon's Electric Energy Restructuring

Oregon has created a unique approach to electricity restructuring, allowing all business customers to choose their provider, but also creating a portfolio of PUC regulated choices for small business and residential customers.

Legislation (Senate Bill 1149 (requiring electric industry restructuring Oregon's largest investor– owned utilities went into effect on March 1, 2002.

The restructuring was designed to give customers more options while at the same time encouraging the development of a competitive energy market.

Senate Bill 1149 included a number of key provisions:

- All large business consumers will be allowed to continue to purchase power from their current utility under a regulated cost-of-service rate or purchase energy directly from an Electricity Service Supplier (ESS). Purchasing power from an ESS is known as "Direct Access." Large customers choosing Direct Access will receive credits for the value of existing generation resources;
- Residential and small business consumers will choose cost–of–service rate or portfolio rate options. Small non-residential consumers may also opt for Direct Access;
- A 3% public purpose charge will be collected from retail customers to fund and encourage energy conservation and development of renewable energy;
- A Low–income bill assistance fee, administered by the Oregon Housing and Community Services Agency, will continue to be collected by PGE and PacifiCorp.

The law established general framework, but it left much of the implementation up to the Oregon Public Utility Commission through its rulemaking and rate setting processes. The following is an outline of how the basic elements of SB 1149 will be implemented.

- The utility isn't required to sell and assets which generate electricity
- Utilities can negotiate long–term contracts to protect the consumer from the volatile spot market
- No consumer is forced into the energy market
- All consumers have the choice of receiving a regulated cost–of–service offer from the utility
- All nonresidential consumers will have the ability to purchase electricity either from a provider know as an Electricity Service Supplier (ESS) or their existing utility
- Both large and small nonresidential consumers who buy power from an ESS will have the opportunity to return to a utility offer
- Each utility will provide default emergency rates in case an ESS halts service to a non–residential customer
- Your bill will be redesigned to reflect the various costs that factor into your total bill
- All consumers will receive information so that they may compare the fuel mix and emissions of the electricity supply options that are offered to them

Residential and small nonresidential consumers will receive a portfolio of energy options. Small non–residential is defined as those who use less than 30kW demand monthly. The portfolio includes:

- A traditional basic rate
- A Time–of–Day Supply Service
- A Fixed Renewable Service that includes new renewable resources
- A "Renewable Usage" Service
- A "Habitat Restoration" Service
- Seasonal Flux (PacifiCorp only)

Small business customers can also opt for Direct Access.

A 12–member portfolio advisory committee crafted the options and recommended them to the Commission for approval. The committee included utility representatives, local governments, residential consumer and small nonresidential groups, public/regional interest groups, and staff of the Oregon Public Utility Commission and Oregon Office of Energy.

Public Purpose Fee and Low Income Bill Assistance

The law established an annual expenditure by the utilities of 3% of their revenues to fund "Public Purposes", including energy efficiency, development of new renewable energy and low–income weatherization. Rates will increase on March 2, 2002 to fund these activities but by less than 3% because money utilities currently spend for these purposes will be removed from rates at the same time. Future expenditures the utility otherwise would have made for these purposes will be included in the 3% fee instead of rates. The public purpose fee will appear as a separate item on your bill.

The law requires 80% of the funds designated for conservation to be spent in the territory of the utility from which they were collected.

The first 10% goes to Education Service Districts for energy audits and subsequent energy efficiency measures.

The remaining funds go into four public purpose accounts:

- 56.7% Conservation
- 17.2% Renewable Energy
- 11.7% Low-income Weatherization
- 4.5% Low–income Housing

The conservation and renewable energy funds are administered through a new nonprofit entity, the Energy Trust of Oregon.

The law also established a $10 million a year low–income bill assistance fund to be spent in the territory of the utility that collects it. The current amount is 35 cents a month for residential consumers and .035 cents/kWh for nonresidential consumers. The Oregon House and Community Service Agency distributes the money through community action agencies.

Source: Oregon Public Utility Commission website: www.puc.state.or.us

G. Putting It All Together: Options for Portfolio Management

The best approach to portfolio management turns on a combination of specific state experience, the how the state has already decided to restructure the electric utility, and the provision of default service. But regardless of these variables, there are a few characteristics of portfolio management that are essential and should therefore be shared by any reasonable approach.

The essentials are as follows:

1. High Quality Data and Analysis is Key.

The quality of the data and analysis used to specify the requirements of the portfolio needs to be high. Identifying a reasonable portfolio is not a simple task. The risks, costs, and performance of all options need to be well understood. Careful forecasts of the energy service needs, with sensitivities, to be met by the portfolio manager must be prepared. The mix of supply and demand–side resources that strike the right balance between cost, risk, and environmental performance must be identified. Portfolio management is also a dynamic process.

2. Portfolio Management is Dynamic.

The portfolio is not selected in one year and then left static for long periods of time. Every year or two resources are added and resources are lost due to retirements or contract terminations. Demand patterns shift in unforeseen ways. Technology changes and new options become available. Perceptions of risk change such as those that accompany geopolitical shifts, environmental requirements change and a host of other possible factors. This means the analysis underlying the portfolio must be reassessed and the portfolio adjusted.

3. Consider All Supply and Demand–side Options.

All demand and supply options need to be considered even if a particular option, or set of options, is not directly available to the portfolio manager. For example, the portfolio manager may have the responsibility to consider demand–side options, the value of which can be realized in the wholesale market. There may be other demand–side options that are not within the direct purview of the portfolio manager, but which make economic sense to pursue in some other fashion. Long–term efficiency improvements or market transformation programs funded though System Benefit Charges and energy efficiency standards are the best examples.

4. The Wholesale Market Structure Needs to be Well Developed.

Besides having all the usual efficient market characteristics, the key principle should be to reveal the value of all options to all participants and to provide a mechanism for acquiring those options. The best example is demand response. Demand response has substantial value, yet we have too much experience showing how easy it is to design markets that ignore demand response entirely. If the wholesale market has been designed to fully incorporate demand response, the portfolio manager will be able to identify the market value of demand response and include strategic investments in demand–side reductions and distributed resources in its business plan.

Who Performs the Portfolio Management Function?

As the discussion above suggests, the questions of who the portfolio manager is (competitive providers, the distribution utility or a state agency) and whether the portfolio manager is regulated or competitive are interesting, but not critical. The paramount consideration is what portfolio management functions the default service provider can perform and what portfolio management functions ultimately rest with government. The answers to these questions turn on an assessment of the interests, risks, and incentives faced by the default service provider and the interests of default service customers.

IV. What are the Risks of Portfolio Management to Consumers and Regulators?

Thus far the discussion has focused on the benefits of portfolio management. It is also important to describe the risks portfolio management imposes on customers and regulators and some of the policies needed to address these risks.

A. Portfolio Management Prices and Short-term Market Prices

Portfolio management reduces price volatility risk but does not guarantee the lowest possible prices to customers at all times. In the same way that the return on a mutual fund will not always exceed the return on the "market", not even the best electricity portfolio management can guarantee prices that will at all times be less than the price in the short-term market (or less than the prices of other managed portfolios).[17] Indeed, this is the fundamental essence of portfolio management—the averaging out of price volatility over time. Sometimes the portfolio manager's price will be below the market price, and sometimes it will be above. The greater the volatility of the spot market, the greater is the potential value of portfolio management. The fact that low, short-term prices will occur, and at times may persist for a year or more, presents great political—risk to a portfolio management approach.

Recall that most of the support for restructuring in the mid-90s was fueled by the fact that utilities' portfolio prices (a blend of competitive and regulated prices) were above prevailing, short-term market prices (in markets where utilities were fully recovering their fixed costs through customer rates). How will consumers, regulators, and legislators react if long-term portfolio management is adopted and market prices again fall below the portfolio manager's prices? The portfolio of resources recently assembled by the Department of Water Resources on behalf of California consumers in the 2001 market crises in that state were soon found to be more costly than the prices the market produced under the federal price caps imposed in the wake of the crises. These contracts, which totaled over $42 billion, have been alleged by the California Attorney General to exceed fair market prices by at least $7 billion due, in part, to market manipulation. The California PUC has ruled that those excess costs will have to be passed on to customers. There are no easy answers, but from a policy perspective there are two choices. Customers either will be entirely exposed to the price volatility and market power risks inherent in short-term markets, or they will be served from a portfolio of long-, medium-, and short-term supplies. Neither option will make customers happy all of the time. A good process for portfolio management, a process that is transparent and sustains public confidence, will improve the odds of sound outcomes over time.

B. Entry and Exit Policies

If retail access is permitted to coexist with portfolio management, conditions must be placed on consumers' rights to shift between the managed portfolio and competitive retail suppliers. Rigorous application of this principle is essential to avoiding the build–up of potential future stranded costs. Such conditions must be sufficient to reasonably mitigate the risks assumed by the portfolio manager through long– and medium–term commitments. Otherwise, at times when the short–term price is below the portfolio price, customers will leave the portfolio, and the manager may be saddled with stranded costs. The reverse can also occur when market prices rise, as recently seen in both California and Pennsylvania.

How can these problems be addressed? Different options may be pursued depending on a state's desire to encourage competitive entry. For example, open enrollment periods could be allowed whenever the portfolio manager's contractual commitments are less than its customers' load or when its average price is less than or equal to the prevailing market price. Or, open enrollments could be scheduled periodically, such as when the portfolio manger is preparing to contract for additional resources. *Moreover, it is not necessary to offer all portfolio customers the same price.* Those who choose a retail provider and then wish to return to the portfolio may be obliged to pay a portfolio price that reflects current, not historic, conditions, like a homeowner refinancing a mortgage.

V. RAP's Suggested Approach to Portfolio Management

A. Overview

With the background of the essential elements of portfolio management and the range of administrative options, we turn to a suggested portfolio management approach. We describe our suggested approach in the context of one of the most difficult situation, a state that has moved to retail competition, and that is prepared to have at least a portion of default service provided by competitive suppliers. When discussing PBR, we also assume that the state is prepared to allow the distribution utility to provide a portion of default service.

B. Planning

Use a comprehensive, credible, and open planning function to determine a few basic criteria that will be incorporated in a competitive solicitation for default service. These basic criteria could be developed and proposed by a responsible state agency having the necessary resources and responsibility to put forward a reasoned plan. Legislative procedures allowing for comment and amendment may be adequate. The process should consider the following:

Short–term Needs

What immediate needs exist to cover today's load?

Long–term Needs

The needed resource additions for which commitments must be made in the next one to three years, plus the forecasted demand for the next 10 to 15 years.

Least–cost balance of supply and demand–side resources

This includes an assessment of the level of cost–effective funding for energy efficiency and any minimum level of investment in renewables recognizing that these requirements may be imposed on the portfolio manager directly or may be carried our separately.

Price volatility

How much year–to–year price volatility is acceptable and achievable for default service?

Financial risk

How much financial risk (reliance of financial contracts) it is willing to accept.

Procurement Plan

Consistent with these criteria, design a schedule for procurement. For example, the manager may solicit 10 to 15 year bids each year for 10% or so of the total forecasted needs for default service. Keep in mind that renewable resources, because they are almost all capital expense, do better when compared to resources over a period of 15 years or more.

Align Incentives

Design a PBR approach to default service that allocates risks reasonably and provides rewards and punishments for superior or inferior service. Removing the throughput incentive for the distribution utility as well as for the PM (if it is an entity separate from the distribution company) are essential parts of such a PBR.

C. Discussion of Suggested Approach

The Planning Process

There is no avoiding the fact that some overarching level of planning will be needed. When the lights go out, when prices spike to intolerable levels, or when markets fail to deliver what they were expected (as they may despite all best efforts), the public and their elected officials will ask how and why it happened. Explaining that "it was the market" and no one had the responsibility to keep a watchful eye on the system will not suffice. Planning provides a road map to remedy when things go unexpectedly haywire. Making "emergency" decisions in a vacuum often leads to further trouble.

The scope of utility planning may be more limited than it was in the past but its importance has not been diminished. Thus, utility planning does not mean that a detailed plan with specific detailed contracts or energy efficiency programs is imposed on different participants. But it does mean that an entity is responsible to assemble all of the important pieces in one comprehensive and comprehensible plan.

Planning will require looking at the wholesale generation market and staying aware of who is building what and where. Planning means assessing how the expansion of the generation market is affecting the transmission system. It also means forecasting consumer demand for energy services, assessing how these demands could be met in the most cost–effective manner, and comparing the results to what the market is delivering. Planning needs to be informed by the market and planning needs to inform market designers of needed reforms and refinements.

Utility planning has never been, nor will it ever be, a simple process. The tools and practice of IRP are well known and well documented. What is needed now is to assign the planning responsibility to a responsible and capable government agency and then use the planning process to inform and coordinate the various participants in the restructured markets.

Restructuring which began in the mid–90s did not eliminate the need for use of IRP but it did result in different parts of IRP being parceled out to different entities. The result was the loss of anyone having the big picture clearly before them. Essentially, planning is needed at two levels:

- **Strategic Oversight**
  A continuing process of strategic oversight, conducted by a government or quasi–government entity, with responsibility to look ahead at *the entire market and grid* (including wholesale, balance of grid, generation, and demand resources, etc.) and assess where things are going. A lot of what is covered in such an assessment will not be under the direct control of the government or a regulated utility it's in the hands of many actors, including market actors. But particular government policies will be indicated by such an assessment, and can be based upon it. This is what many state energy plans have traditionally done. However, with the emergence of regional wholesale markets, regional planning such as for transmission must also be a part of this overall assessment. If done by government, this is the plan that would broadly set how the minimum level of renewable resources and energy efficiency will

be included in the provision of retail electric service, such as the RPS and SBC investments required in several states today as part of their restructuring laws.

• **Investment Plan**
Second is an investment plan for default service, designed and implemented by the portfolio manager. The default service provider, if it is to have a long–term franchise, will by necessity be in the active power management business and thus will need to do its own continuous planning, taking into account its obligation to meet the specific resources requirements which may have been created by government.

The Criteria

One reason planning is a government function is that it requires substantial exercise of judgment in matters that are affected with the public interest. For example, one purpose of planning is to assess the likely extent of price volatility of different portfolios. This part is more or less a numerical and statistical exercise. Also needed, however, is an assessment of how much price volatility is acceptable to default service customers. This is not a simple arithmetic exercise easily delegated to a private party.

Our preferred approach is to use the planning process to identify important criteria that can reasonably be incorporated in conditions imposed on competitively procured default service. This combines the strength of a comprehensive and publicly accountable the planning process with the strength, innovation, and efficiency of the competitive market. In some cases all or part of the default service may be provided by the distribution utility. The most important criteria are as follows:

• **Resource Needs**
Assessing the resource needs is the most basic outcome of the planning process. This requires a year–by–year forecast of the energy service needs of consumers generally, and default service customers in particular, and the demand– and supply–side resources available to meet the need. Given the nature of competitive wholesale markets, reliable information on new resources may be limited to the next few years but the forecasts should nevertheless be long–term (at least 10 years or, better, as far as can be reasonably foreseen).

These long–term planning processes both inform, and are informed by, the wholesale market. Planners see the types and locations of investments that are being made, the types of risk management tools being used, the evolution of markets and market rules to deal with new types of resources, and the types of needs and expectations customers express. Investors, customers, and others see the aggregated size and location of demand and supply, which help make future investment, purchase, and location decisions.

• **Price Volatility**
One of the main considerations for portfolio management for default service customers is the acceptable level of price volatility.

For the most part, low–use customers do not have advanced metering capabilities and, even if they did, they would not choose to take service under the real–time prices that such metering makes possible. Portfolio management for these customers seeks to provide them with competitively and stable priced default service while exposing the portfolio manager to enough market risk to provide efficiency incentives without exposing them to so much financial risk as to risk default.

Competitive markets can deliver as much or as little price volatility as one is willing to accept. There is of course a cost involved, but the cost, or even whether the cost is positive or negative, is difficult to intuit. For example, consider a proposed ten–year contract from two resources, one based on natural gas and the other based on a mix of wind and hydro. Assume, as is the case in most markets, that spot energy prices are driven by the cost of natural gas. Assume further that based on current conditions and forecasts the 10–year levelized cost (as distinguished from price) of both resources is 5 cents per kWh.

Now, suppose an RFP for default service specifies the desire for a ten–year fixed price contract. The wind/hydro resource costs are essentially fixed so, absent market power, bids for fixed price service will be about 5 cents. In contrast, to meet the bid, the gas based supplier will have to either bear some fuel price risk, or buy some other form of insurance, to cover the risk that gas costs will be above current forecasts. As a consequence, its bid will have to be above 5 cents.

Next, consider the exact opposite situation and the RFP for default service specifies a 10–year contract with separate capacity and energy prices and the energy portion indexed to natural gas. This RFP matches the cost structure of the gas resource so, absent market power, its bid will be about 5 cents. Now it is the wind/hydro resources that face a problem. The wind/hydro resource faces the risk that gas prices will drop and the default service price will fall below its cost. To cover this possibility it will either bear some fuel price risk, or buy some other form of insurance, to cover the risk that gas costs will fall below current forecasts. As a consequence, its bid will have to be above 5 cents.

Thus, how much does price stability cost? Perhaps nothing; it depends on the underling cost level and cost structure of the resource.

How much price volatility is acceptable is a judgment call. Scenario planning is an effective tool for identifying and quantifying the likely and possible range of hourly, daily, monthly, and annual price volatility that would occur in spot energy markets absent market power. Because default service customers will not be on real–time meters, monthly and annual price volatility is of greatest importance. In general, the "planned" price volatility for default service should be reasonably low and should definitely not be tied to natural gas prices.

Reducing default service price volatility through portfolio management should be combined with good, cost–based rate design. The use of time differentiated rates, seasonal rates, inclined block rates to reflect long–run marginal costs should be applied to default service rate design just as they are or should be to fully regulated rates.

Likewise, insulating default service customers from highly volatile spot markets does not mean that the default service provider should be insulated from day to day market prices. A limited level of exposure of the default service provider to the spot market combined with wholesale market rules that give the default service provider an incentive to manage its customers load are desirable features.

Default service customers will be insulated from short–term market volatility but they are not insulated from long–term competitive prices. Default service is a regulatory creation in response to the fact that competitive retail markets have not developed to the point that competitive retail providers are giving customers choices between fixed and variable prices. Regulators are essentially creating a buying agent for default service customers specifying the terms that default service providers compete to meet.

More importantly, although default service customers see a stable price, the default service providers do not. If a provider agreed to a 5 cent fixed price and spot prices go to 20 cents, the default service provider will have a powerful incentive to either reduce its own cost or to free up electricity for sale to the spot market. In either case, the default service provider has an incentive to reduce its customer's use of electricity. How it acts on this incentive may be even more effective than the politically naïve option of increasing default service prices to 20 cents.

Financial Risk

Financial risk of the portfolio manager should also be specified. As described earlier the nation has already seen several instances where entities in the position of a portfolio manager have essentially defaulted on their commitments. Thus, consider the example described above where a state's regulators decide that price volatility should be limited and 10–year fixed price contracts are sought. Consider three scenarios:

1. the winning bidder owns gas–fired resources;

2. the winning bidder neither owns nor even has long–term contracts with any resources. The winner intends to rely entirely on spot markets and is betting that spot markets prices will remain stable or will decline; or

3. the winning bidder has no resources or physical contracts but has signed hedging contracts with a party of limited financial capability.

What happens if gas prices double? Spot prices will likely double, raising the risk that the winner will default on the default service contract, leaving default service customers with little or no protection and no option but to buy from the now inflated spot market.

Consider what happens if gas prices double but the winning bidder fit one or more of the following situations:

1. the winner owned renewable or other resources whose costs were unrelated to changes in gas prices (this might include gas generators who have secured gas supplies on a long–term, fixed or moderated–cost basis;)

2. the winner held physical contracts with renewable or other resources whose costs were unrelated to gas prices; or

3. the winner had purchased one or another form of insurance from an entity with ample financial resources.

In any of these situations, default service customers are much more likely to be protected. (Of course in our legal system any party is free to break a contract. The difference is that if the supplier in any of these latter situations breaks the contract, there are underlying financial assets to pay damages.)

• Energy Efficiency and Renewable Resources
To some extent, the steps we have described will result in some levels of energy efficiency and renewables being delivered by the market. Well–designed wholesale markets will include demand response, demand bidding and other related features that will allow some levels of energy efficiency to compete. Most of the demand response measures, however, are better suited to load management than long–term energy efficiency.

Efficient wholesale markets will also eliminate discriminatory barriers to renewable resources, especially intermittent resources. Wholesale market improvements will help distributed resources to some extent, but substantial barriers remain in the retail and distribution utility areas.

Reasonable limits on price volatility and financial exposure will also encourage portfolio managers to invest in renewable resources. Some may suggest that coal or even nuclear power offers the same sort of price stability but both of these sources carry a high level of environmental risk (and for nuclear, security risk) that is not shared by renewable resources.

But, remaining shortcomings of wholesale and retail markets, combined with well known market failures with regard to energy efficiency mean that investment in these resources will fall far below the levels identified as being cost–effective and achievable in the planning process. The failure to accommodate the intermittent nature of renewables in transmission pricing and ancillary market policies is another type of barrier to which public policy must respond. This is why policies such as SBCs and RPSs have been adopted and proven effective in so many places.

Thus, we suggest that the planning process be designed to identify the achievable energy efficiency and renewable resources over and above what is expected to be delivered by portfolio managers. This incremental amount of these resources should be built into the market generally, not just imposed on default service providers.

• Procurement Schedule
The procurement schedule addresses two related issues. How much should be bought at any one time, and how long should the procurement last? Where default service is being provided competitively now, the tendency has been to buy it all at one time and to commit to relatively short periods of time (one month to 3 years). Portfolio management would yield a different result, one that leans much more toward small periodic purchases for longer periods of time with some, but limited, exposure to spot markets.

The planning process will examine the need for resources over the long–term, but not all the resources need should be procured immediately and not all of the resources should end at the same time. Diversity of contract types and duration is the best way to limit risk.

As any investor knows, there is no simple formula to give the perfect amount of diversity. So the bad news is judgment is required. The good news is when it comes to default service, almost any judgment is better than the ad hoc system in effect in most states today.

While perhaps far from perfect, we suggest phasing into a procurement schedule that makes roughly 10–year commitments each year for 10% of the needs of default service customers would provide a reasonable level of protection.[18] Thus, if default service load requires 10,000 MW of supply and demand (and assuming now growth to make the arithmetic easy) each year one would sign 1,000 MW of 10–year contracts.

We suggest that individual default service customers will not be assigned to a particular portfolio manager. Instead, the group of portfolio managers (as many as ten, each of whom has about 10% of the default service load) will in the aggregate provide default service. Customer service issues, (signing up customers, bill payment, disconnection, etc) will be delivered by a common entity or the distribution utility.

Consider the following implications of such a series of 10–year laddered contracts:

1. If retail competition becomes a real option, this means 10% of customers could leave default service without stranding any resources. (This is a faster transition to retail competition than has actually been seen in any state.)

2. If market conditions change, exposure of default service customers is limited to the combined effect of price volatility provisions of the non–expiring contracts and the addition of a new 10–year contract.

3. If one of ten contract arrangements defaults, risk is limited.

4. Some amount of default service needs, probably not more than 10% may be in the spot market at any given time.

• Performance Based Regulation

1. Basic Principles

Finally, a few words about the incentives faced by the portfolio manager. The regulatory approach taken to portfolio management will result in the portfolio manager facing certain incentives. It is important to understand in any particular instance what those incentives will be and to assure that they are consistent with customer service goals and with sound public policy.

The portfolio manager should face a reasonable set of incentives. For example:

• If the portfolio manager's sole responsibility is to buy on the wholesale market and pass the costs through to customers, it faces virtually no risk and is subject to no meaningful standard of conduct. This means it has very little incentive to manage the portfolio in a way that controls either price levels or price volatility.

• If the portfolio manager has a fixed price obligation with an open–ended quantity obligation, it has an incentive to manage costs and increase sales whenever spot prices are in excess of its fixed price.

• If the portfolio manager has both a fixed price obligation and a fixed quantity obligation, it has no throughput incentive.

• If the portfolio manager has an obligation to serve a significant population (either as a monopoly utility or as a default service provider) for a significant period, it should be able to count on a predictable, though not static, population to reduce the need for excessive risk management costs.

The incentives faced by the portfolio manager will be determined by two primary factors: Who is the portfolio manager, and what is the structure of the contract for default service? We begin by considering the situation where the portfolio manager is a competitive supplier and then the situation where it is the distribution utility.

Broadly speaking the portfolio manager will have two internal incentives: minimize risk and maximize profits. With respect to risk, the conditions we suggest imposing on any portfolio manager addresses most issues so we focus on actions that maximize profits.

Of the many ways the portfolio manager could increase profits there are two that regulators need to worry about and should take steps to protect against. These are cutting costs by reducing service quality and increasing revenues by increasing sales or throughput.

To the extent there are any customer service obligations it is best to include specific measurable service quality standards and related rewards or penalties in the procurement contract. If as we suggest, customer service is provided centrally, the issue is not too serious.

The incentive to increase sales or throughput is a problem for two reasons. First, is the well–known and documented effect on energy efficiency. If the contract is structured so increased sales predictably lead to increased profit, the portfolio manager will have an incentive to discourage increased energy efficiency, no matter how cost–effective for the individual consumers or for society.

Second, many states probably consider default service a temporary stopover on the way to full retail competition. If this is the case, a throughput incentive means the portfolio manager will resist any expansion of competitive retail services.

2. Competitive Providers
Eliminating the throughput incentive for competitive providers can be accomplished in several ways. The simplest is to structure each of the laddered contracts to specify a given amount of energy. In this way increased sales have no effect on any particular portfolio manager. The increase (or decrease) is made up through spot purchases.

A second alternative is to structure the contract like a two–part tariff. A fixed payment for the bulk of the contract quantity sales and a variable payment set at spot prices of any excess. In this way, increased revenues from increased sales come with increased costs. If most of the contract volume is on a fixed price, the default service provider will still have an incentive to help manage customer loads during periods of high spot prices.

3. Distribution Utility
If the portfolio manager is a distribution utility we have two issues to address. The first is the throughput issue, which now even more serious because it exists for both default service as well as distribution services. The second issue relates to the portfolio management function of the distribution utility.

If the distribution utility is simply assigned the portfolio management responsibility without having to compete for the job, how do we know that the distribution utility is doing a good job? What benchmarks or performance standards are used to ensure that it does? A distribution utility that is not required to compete for the default service franchise is a monopoly service provider that must be closely supervised. A performance-based regulation plan may be the best means of providing that supervision. How do we construct such a PBR?

In most respects these are not new issues. Most of the issues raised by PBR alternatives to traditional cost of service apply with equal force here. What is new is (1) the focus is on one aspect of utility service, portfolio management for default service customers; and (2) experience with competitively provided default service provides one new possible benchmark.

There is a long and not very successful history of efforts to develop reasonable benchmarks against which to measure a utility' performance. Efforts to find an acceptable benchmark consisting of groups of similar utilities has always failed for one reason or another.

The situation we now face, however, presents a new opportunity. Consider the following for a case in which the distribution utility owns no generation:

- The planning process and the setting of criteria imposed on competitive default service providers takes place as described above.
- An RFP for default service is issued for a portion of the current period's default service needs.
- The terms offered by the winning bidder establishes the performance benchmark for the distribution utility.
- The distribution utility can either (a) agree to perform on the same or better terms than the winning bidder for the remaining default service needs or (b) decline to match those terms, in which case the remaining portions of the standard offer service block are also bid out and provided competitively.
- Next year the process repeats itself for the next 1/10 of the load, which would be coming free from expiring contracts.

The ability to use the market to provide a benchmark for the same product, at the same time, for the same duration, with the same terms and conditions eliminates most of the major historical technical and historical difficulties associated with regulatory attempts to construct performance benchmarks for electric utilities. The important questions to be addressed are whether the wholesale market is competitive and whether the portion of the default service put out to bid is large enough to provide a reasonable market test.

VI. Conclusion

The vast majority of ordinary customers (non–industrial) will likely be served through the default provider for a long time. Leaving default service tied to the spot market creates unreasonably and imprudently volatile prices as well as greatly contributes to the markets' volatility. Default customers should be served through a diverse set of resources managed over the long–term so as to reduce risk and price volatility. The greater use of long–term contracts will help to stabilize the markets and will work to reduce market power that has been fueling the instability. The loss of diversity and long–term price management has been the largest negative outcome from electric market restructuring to date. There are number of ways in which portfolio management can be designed and implemented to match the philosophies and experience of individual states. We recommend that state regulators and policy makers give the question of portfolio management immediate high priority.

ENDNOTES

[1] While wholesale competition is "feasible," we do not mean to suggest that there is anything inevitable about it. It has been difficult to establish the essential elements of workably competitive wholesale markets, and maintaining effective wholesale competition will be equally challenging over time. The pattern of consolidation among energy providers both in the U.S. and abroad is but one response of market participants seeking to dampen the effects of robust competition; other techniques for amassing market power are evolving as well.

[2] We use the words "default service" or "default" to mean the service retail customers receive if they do not select a provider. States use various terms to describe this service, (e.g., standard offer, or provider of last resort). All are included here under the general term "default". A good overview of the problems default service has run up against in several states can be found at: Alexander, Barbara, *Default Service For Retail Competition: Can Residential and Low Income Customers be Protected when the Experiment Goes Away?, 2002.*

[3] R. Cavanagh, 2001, Revisiting "the Genius of the Marketplace": Cures for the Western Electricity and Natural Gas Crisis, *The Electricity Journal*, 14 (5) June.

[4] Indeed, one of the few clear lessons from retail competition, is that the marketing and transaction costs for serving small customers are in the range of 1 cent per kWh. This added cost may well exceed the potential efficiency gains from increased competition. In part, the high cost of providing competitive retail service has convinced most states, in essence, to give up on real competition for low–use customers.

[5] Integrated Resource Planning (IRP) and electric restructuring are historically connected. The implementation of IRP processes in the late 1980's and early 1990's, together with the requirement to purchase QF power from independent generators, revealed the competitive potential of the wholesale electric market. In the states which required their utilities to put identified resource needs out to bid, often as part of the IRP process, the utilities were deluged with responsive bids from independent producers and other sellers in high multiples of the amounts sought in bid solicitations. For example, it was a common occurrence for a utility to receive 4,000 MW of power projects bid in response to a RFP looking for 200 MW of power—often at prices below the utility's embedded cost of power. These results demonstrated to customers and regulators alike that the wholesale electric power procurement market could be competitive: It was no longer necessary to consider wholesale power procurement as a required component of a vertically integrated, regulated monopoly utility industry structure. IRP did the country the favor of identifying the generation market as potentially competitive and led directly to the path of industry restructuring. Thus, at the time the CA PUC issued its initial policy blueprint for establishing a fully competitive electric sector for that state (the Yellow Book) in 1994, marking the opening of an intensive period of state electric industry restructuring activity, about 36 states were requiring their utilities to use IRP to secure the resources to serve their retail electricity customers (NARUC Compilation of Utility Regulatory Policy 1994-1995). Perhaps even more importantly, experience with utility IRP demonstrated the existence of a large, low-cost resource base on the customer side of utility meters, as well as the

viability of demand-side management techniques to acquire them. It is critical that these lessons not be lost as the nation strives to design techniques for portfolio management either in vertically integrated franchises, or in states that have incorporated some measure of competition.

The 1992 Energy Policy Act (EPACT) clearly reflects these parallel (and not entirely harmonious) paths of planned and competitive approaches to electric system efficiency. That Act required each state to consider implementing IRP (most states already had IRP policies in effect but federal law often lags state realities). It established the authority of FERC to order use of the interstate transmission network to wheel power between unrelated buyers and sellers and created a new class of exempt wholesale generators, who were granted open access to the transmission system. Essentially the vision in EPACT was that of state-directed IRP with utilities shopping among all available resources when expanding system capacity and the federal opening of the transmission system to all sellers of generation services to greatly enlarge the pool of available resource options. The wildcard, of course, was retail competition (retail wheeling was the catchphrase in 1992).

[6] Despite a generally solid record of success of utility-sponsored DSM programs between the mid-1980s and 1993, the programs suffered sharp reductions in the face of restructuring. Prior to restructuring, U.S. electric utilities reported plans to increase DSM expenditures from $2.74 billion in 1993 to $3.5 billion in 1999. (Nadel, Kushler, *The Electricity Journal*, October 2000) Instead, what actually happened was that 1999 DSM expenditures were cut by almost half, to $1.4 billion, (EIA, *Electric Power Summary Statistics, 2000*) and expenditures focused on energy efficiency, aside from load management, declined by about two-thirds. Some states, such as New Jersey, increased efficiency expenditures during the 1990's, while others, particularly in the Northwest, saw steep declines. The cutbacks may be abating somewhat as both California and New York have taken serious steps to revive utility investment in energy efficiency (Nadel, Kubo, Geller, *State Scorecard on Utility Energy Efficiency Programs, ACEEE 2000*).

[7] Argentina provides an example of a vigorously competitive generation market that has been designed to minimize market power and price volatility. The key design feature is that generators' bids are made for a three–month period, rather than hourly or daily. Experience there has shown that this practice virtually eliminated the gaming of bids and stabilized prices.

[8] Hildebrant, Eric, July 9, 2001, *Analysis of Payment in Excess of Competitive Market Levels in California's Wholesale Energy Market*, May 2000-2001.

[9] S. Carter, 2002, Breaking the Consumption Habit: Ratemaking for Efficient Resource Decision, *The Electricity Journal,* 14(10) December.

[10] Hirst, *A Good Integrated Resource Plan: Guidelines for Electric Utilities and Regulators*, Oak Ridge National Laboratory, 1992. Also, Harrington, et. al. *Integrated Resource Planning for State Utility Regulators*, RAP 1994.

[11] Large industrial customers, unlike the commercial and residential classes, usually have choices regarding whether they want to increase or decrease production in response to energy price. They are acutely aware of their marginal costs of production and are prepared to respond to price changes. Low-use customers and most particularly low income, low-use customers tend to think of electricity use in terms of total monthly cost rather than marginal prices.

[12] See, Bolinger and Wiser, Quantifying the Value That Wind Power Provides as a Hedge Against Volatile Natural Gas Prices, presented at Wind Power 2002, Portland, Oregon.

[13] Oregon is an unusual version of Category 3. Retail competition was not extended to residential customers under Oregon's restructuring law but, two of the three types of service options required to be offered to the residential class, the two "clean" options, were successfully put out to competitive bid. See text box page 23-24.

[14] Many Category 2 states may already have at least some portion of default service provided by long–term resources. So, unlike Category 1 states, the shift to long-term commitments will be relatively easy to make.

[15] CA Public Utilities Code Section 3300, Chapter 10, effective 13 August 2001.

[16] The California BRPU process was undermined by a strange set of FERC rulings that failed to grasp the very different values, including risk reduction, offered by different resources. It is unclear what those FERC decisions might mean today where regional wholesale markets are far more developed and incumbent IOU's more experienced and possibly more accepting of the competitive acquisition of new resources. See, Moskovitz and Bradford, Paved with Good Intentions: Reflection on FERC's Decisions Reversing State Power Procurement Processes, *The Electricity Journal*, August/September 1995.

[17] However, the more the short-term market suffers from market power, the more often the portfolio manager's price will look attractive.

[18] To phase in to this type of procurement plan from a starting point that has no long-term contracts may require a two or three year period where contracts of 1 to 10 years are signed.

California's Secret Energy Surplus

The Potential for Energy Efficiency

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TOWARD A SUSTAINABLE ENERGY FUTURE

California's Secret Energy Surplus:

The Potential For Energy Efficiency

FINAL REPORT

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Principal Investigators:

Michael Rufo and Fred Coito; Oakland, California

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This report may be downloaded from the Energy Foundation web site at http://www.ef.org.

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ES. EXECUTIVE SUMMARY

This study estimates potential energy and peak demand savings from energy-efficiency measures in California. In contrast to energy conservation, which often involves short-term behavioral changes, energy-efficiency opportunities are typically physical, long-lasting changes to buildings and equipment that result in decreased energy use while maintaining constant levels of energy service. It was recently estimated that roughly 70 percent of California's peak demand reduction in the summer of 2001 is attributable to short-term conservation behavior rather than long-lasting efficiency improvements (Goldman et al. 2002). Our study shows that significant additional and long-lasting *energy-efficiency* potential exists.

ES.1 Study Scope

As a result of California's conscious efforts to fund and promote energy efficiency through programs and state standards since the mid-1970s,[1] the state was already the most efficient in the country in terms of per capita electricity use prior to the recent energy crisis. Since then, the state has faced supply shortages, rate increases, price volatility, and future price and supply uncertainty—all of which have combined to warrant comprehensive analysis of energy-efficiency potential. This study focuses on assessing electric energy-efficiency potential in all sectors in California. The study assesses technical, economic, and achievable potential savings over the mid-term, which we define as the next 10 years, and is restricted to energy-efficiency measures and practices that are presently commercially available. This study leverages recent work conducted by the major investor-owned utilities in California and the California Energy Commission. These studies provided an extensive foundation for estimates of potential in existing commercial and residential buildings. The current effort would not be possible without these recent underlying studies. To expand coverage to all sectors and vintages in the state for the 10-year forecast period, significant additional work was conducted to estimate potentials for the industrial sector and for new buildings constructed between now and 2011.

ES.2 Key Findings

If all measures analyzed in this study were implemented where technically feasible, we estimate that overall technical peak demand savings would be close to 15,000 megawatts (MW). If all measures that are economic were implemented, potential peak demand savings would amount to roughly 10,000 MW. Because achieving efficiency savings requires programmatic support, we estimate savings under several future investment scenarios. As shown in Figure E-1, net program peak savings potential ranges from roughly 1,800 MW under current funding (Business-as-Usual) to 3,500 MW if funding is doubled (Advanced Efficiency), to 5,900 MW if funding is

[1] It is estimated that California's efficiency standards and programs have saved roughly 10,000 MW (the equivalent of 20 large power plants) over the past 25 years (California State and Consumer Services Agency 2002).

quadrupled (Maximum Efficiency). In Figure E-2, we show how achieving the energy-efficiency savings identified in this study would affect forecasted peak demand in the state. Without energy-efficiency programs, projected peak demand in the state is expected increase from around 53,000 MW today to rough 63,000 MW by 2011. With implementation of all cost-effective program potential, we estimate that growth in peak demand could be cut in half.

Figure ES-1

Potential Efficiency-Based Reductions under Increasing Program Funding

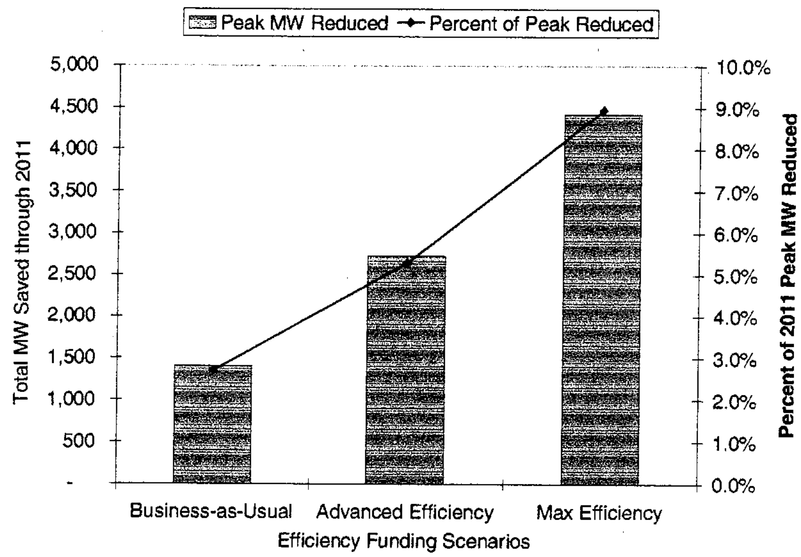
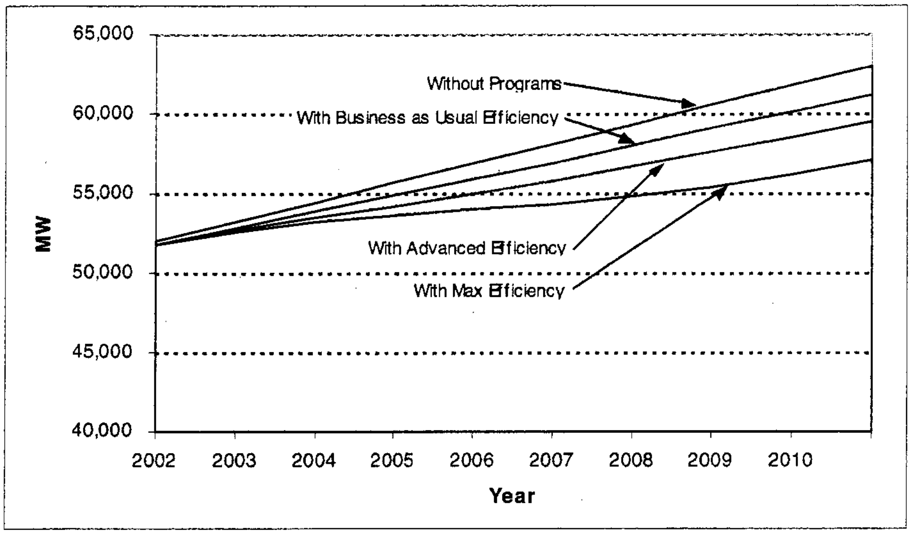


Figure ES-2

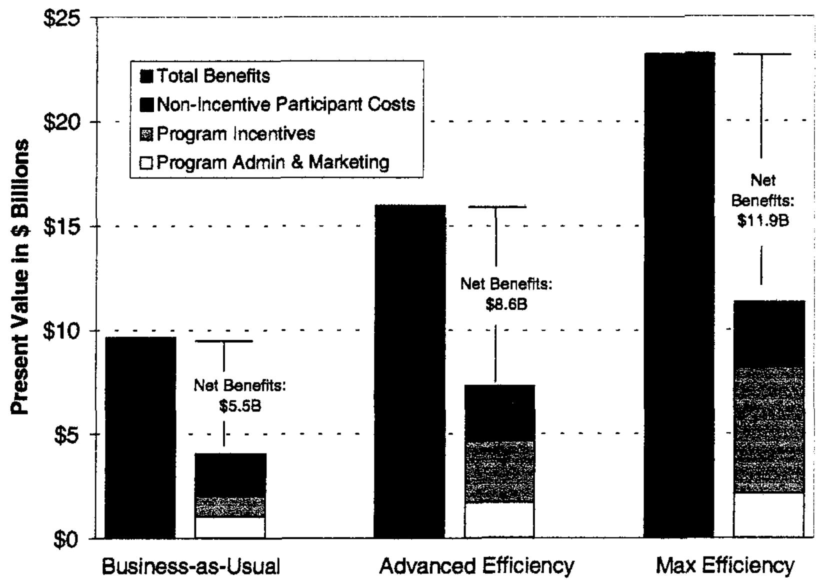
California Peak Demand Forecast and Efficiency Potentials



We estimate that more than $2 billion would be spent on programs to promote efficiency in California over the next 10 years if current efficiency program spending levels continue—an investment projected to yield roughly $5.5 billion in savings. Further, the study shows that increasing funds for these programs would not only reduce consumption, but would also capture billions of dollars in additional savings. As shown in Figure E-3, by doubling the amount spent on such programs, the state could save over $15 billion on electricity costs, at a net savings of $8.6 billion. If all of the 10-year achievable potential were captured, savings would exceed $20 billion, with net benefits of $11.9 billion. Efficiency potential is also analyzed in this study under several alternative forecasts of future energy supply costs. Efficiency potential is shown to be robust across a wide range of plausible future energy supply costs.

Figure ES-3

Benefits and Costs of Electric Energy-Efficiency Savings—2002 to 2011*



*Value of benefits and costs over life of measures, nominal discount rate = 8 percent, inflation rate = 3 percent.

The results of this study demonstrate that energy-efficiency resources can play a significantly expanded role in California's electricity resource mix over the next decade. While it is extremely important to have determined that more cost-effective, electric efficiency savings can be achieved, this study does not seek to answer the larger resource-planning question of how much energy efficiency ought to be purchased as part of a well-diversified overall portfolio of electric resources for the state. To determine the optimal mix of electric resources over the next 10 years, a new analytical framework will be needed. Although developing such a framework is not a part of the current study, we see it as the next logical step in a process that is critical to putting California's mix of future electric resources back on track. Under one such approach, *portfolio management*, the long-run management of a diverse set of demand and supply-side resources is selected to minimize risks (including price volatility) and long-run costs, taking environmental costs into account.

1. INTRODUCTION

In the 1980s and early 1990s, a number of studies estimating energy-efficiency potential in California were conducted periodically. These studies were abandoned, however, with the advent of electric restructuring in the state. Recently, a number of factors—supply shortages, rate increases, price volatility, future price and supply uncertainty—have combined to warrant a detailed analysis of energy-efficiency potential.

This study estimates potential electricity and peak demand savings from energy-efficiency measures in California, the world's fifth biggest economy. In contrast to energy conservation, which often involves short-term behavioral changes, energy-efficiency opportunities are typically physical, long-lasting changes to buildings and equipment that result in decreased energy use while maintaining constant levels of energy service. Examples of energy efficiency include:

- Compact fluorescent lighting systems that deliver equivalent light using 70 percent less electricity than incandescent light bulbs

- New variable-speed drive chillers that deliver cooling to buildings using 40 percent less energy than typical systems in today's buildings

- Energy management control systems that eliminate energy waste and optimize building operation

- Identification and repair of leaks in industrial compressed air systems that otherwise result in wasteful increases in product costs.

These types of improvements, and hundreds of others, reduce electricity consumption without affecting the end-use services (e.g., light, heat, "coolth," drivepower, and the like) that consumers and businesses require for comfort, productivity, and leisure.

This report provides both detailed and aggregated estimates of the costs and savings potential of energy-efficiency measures in California. In addition, forecasts are developed of savings and costs associated with different levels of program funding over a 10-year period. Program savings and cost-effectiveness estimates are also evaluated under several possible future scenarios that take into account uncertainty in electricity rates and wholesale energy costs.

We leverage recent work conducted by the authors for the major investor-owned utilities in California and the California Energy Commission.[1] These studies provided an extensive foundation

[1] These studies addressed energy-efficiency potential in the commercial and residential sectors for existing buildings. See, for example, *California Statewide Commercial Sector Energy Efficiency Potential Study*, prepared by XENERGY Inc. for Pacific Gas & Electric Company, funded with California Public Goods Charge Energy Efficiency Funds, July, 2002; and *California Statewide Industrial Market Characterization*, prepared by XENERGY Inc. for Pacific Gas & Electric Company, funded with California Public Goods Charge Energy Efficiency Funds, December, 2001. Residential sector results were developed through funding from the California Energy Commission, results forthcoming.

for estimates of potential in existing commercial and residential buildings. The current effort would not be possible without these recent underlying studies, and we thank the sponsors of those studies for their permission to build upon their work. To expand coverage to all sectors and vintages in the state for the 10-year forecast period, significant additional work was conducted in this study to estimate potentials for the industrial sector and for new buildings constructed between now and 2011.

The recent electricity crisis in California has led policy makers, utilities, planners, and the public to revisit the role that energy efficiency can play in heading off or minimizing the impacts of such crises in the future. For over two decades, California has been a leader in energy planning and was among the first states to formally recognize the value of energy efficiency. The State took some of the largest strides in treating energy-efficiency as an energy resource and went far toward institutionalizing efficiency as a viable alternative to conventional energy sources. In response to the market-oriented electricity restructuring process embarked on in California in the mid-1990s, formal resource planning in which energy efficiency could compete against conventional supply-side alternatives was abandoned. As a result, efficiency programs languished in the period just prior to the California energy crisis. Fortunately, enough of the efficiency infrastructure was left in place to allow the state to rapidly ramp up energy-efficiency expenditures in 2000 and 2001. These efforts, combined with conservation efforts, and regulatory interventions, tamed the crisis.

Of course, few are convinced that California's energy woes are over or that all of the underlying problems that led to price disruptions have been solved. This report does not offer a blueprint for resolving all of California's electricity problems. The report is part of the Hewlett Energy Initiative, a series of research papers and projects on the California power crisis to be released throughout 2002. The focus of this report is principally on characterization of the energy-efficiency resource in California. Our results point to the need to develop an energy resource planning process that balances appropriately among resources and formally recognizes the availability and value of energy efficiency as an alternative to unlimited power plant construction and a hedge against volatile energy prices.

This study builds on past research to examine what the potential is now for energy efficiency to help meet California's future energy needs. It builds upon prior studies and makes clear the case for formal incorporation of energy efficiency in energy resource planning activities and methods. We supplement prior research with new analysis to present a comprehensive assessment of the potential for efficiency improvements. We also describe the wide range of benefits associated with energy-efficiency improvements. These discussions provide the foundation for a discussion of the role that energy efficiency can play as one part of a robust response to future energy uncertainties. This study is not intended as the last, but rather the first, word on electric efficiency potential in the state. Additional research is needed to build upon, expand, and corroborate the results of this initial effort.

Consistent with our mid-term focus, the study is restricted to energy-efficiency measures and practices that are presently commercially available. These are the measures that are of most immediate interest to energy-efficiency program planners. The study data, framework, and models can be easily leveraged in the future to add estimates of potential for emerging technologies. In addition, the scope of this study is focused on measures that could be relatively easily substituted for or applied to existing technologies on a retrofit basis. As a result, measures and savings that might be achieved through integrated redesign of existing energy-using systems, as might be possible during major renovations or remodels, are not included. This is another area in which the current results can be expanded and improved upon.

Finally, note that the analysis for this study were conducted in 2001 and early 2002, a time characterized by unprecedented changes in energy consumption and behavior among consumers and businesses in California in response to the energy crisis. As a result, the estimates of potential presented in this study do not reflect the unusual level of energy conservation that occurred in 2001. The effects of 2001 were not well enough understood to incorporate into the study at the time that the primary analysis were conducted. Future updates of this study should incorporate revised energy consumption baseline information that accounts for any permanent changes in conservation resulting from the recent energy crisis.

2. METHODS AND SCENARIOS

In this chapter, we give a brief overview of the concepts, methods, and scenarios used to conduct this study. Additional methodological details are provided in Appendix B.

2.1 Characterizing the Energy-Efficiency Resource

Energy efficiency has been characterized for some time now as an alternative to energy supply options such as conventional power plants that produce electricity from fossil or nuclear fuels. In the early 1980s, researchers developed and popularized the use of a conservation supply curve paradigm to characterize the potential costs and benefits of energy conservation and efficiency. Under this framework, technologies or practices that reduced energy use through efficiency were characterized as "liberating 'supply' for other energy demands" and could therefore be thought of as a resource and plotted on an energy supply curve. The energy-efficiency resource paradigm argued simply that the more energy efficiency, or "nega-watts" produced, the fewer new plants would be needed to meet end users' power demands.

2.1.1 Defining Energy-Efficiency Potential

Energy-efficiency potential studies were popular throughout the utility industry from the late 1980s through the mid-1990s. This period coincided with the advent of what was called least-cost or integrated resource planning (IRP). Energy-efficiency potential studies became one of the primary means of characterizing the resource availability and value of energy efficiency within the overall resource planning process.

Like any resource, there are a number of ways in which the energy-efficiency resource can be estimated and characterized. Definitions of energy-efficiency potential are similar to definitions of potential developed for finite fossil fuel resources like coal, oil, and natural gas. For example, fossil fuel resources are typically characterized along two primary dimensions: the degree of geologic certainty with which resources may be found and the likelihood that extraction of the resource will be economic. This relationship is shown conceptually in Figure 2-1.

Somewhat analogously, this energy-efficiency potential study defines several different *types* of energy-efficiency *potential*, namely: technical, economic, achievable, program, and naturally occurring. These potentials are shown conceptually in Figure 2-2 and described below.

Technical potential is defined in this study as the *complete* penetration of all measures analyzed in applications where they were deemed *technically* feasible from an *engineering* perspective. **Economic potential** refers to the *technical potential* of those energy conservation measures that are cost-effective when compared to supply-side alternatives. **Maximum achievable potential** is defined as the amount of economic potential that could be achieved over time under the most aggressive program scenario possible. Achievable **program potential** refers to the amount of savings that would occur in response to specific program savings that would occur in response to specific program funding and measure incentive levels.

Savings associated with program potential are savings that are projected beyond those that would occur naturally in the absence of any market intervention. **Naturally occurring potential** refers to the amount of savings estimated to occur as a result of normal market forces, that is, in the absence of any utility or governmental intervention.

Figure 2-1

Conceptual Framework for Estimates of Fossil Fuel Resources

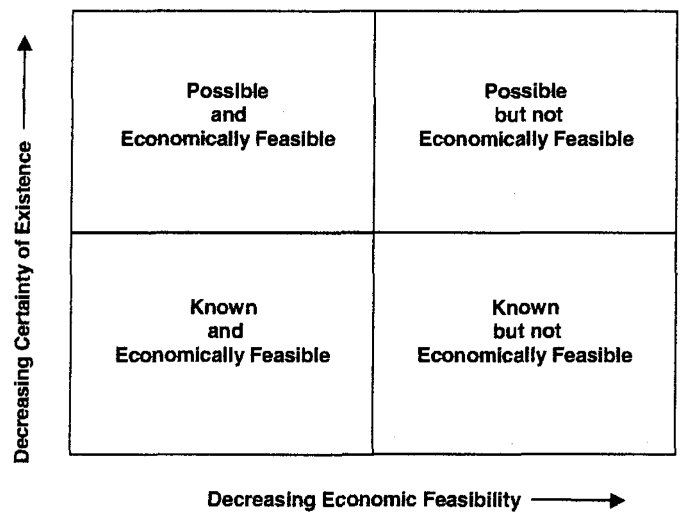
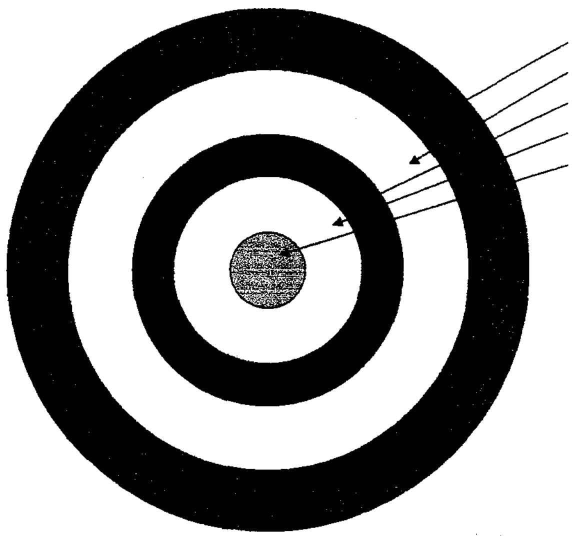


Figure 2-2

Conceptual Relationship Among Energy-Efficiency Potential Definitions



2.2 Summary of Analytical Steps Used in this Study

The crux of this study involves carrying out a number of basic analytical steps to produce estimates of the energy-efficiency potentials introduced above. The basic analytical steps for this study are shown in relation to one another in Figure 2-3. The bulk of the analytical process for this study was carried out in a model developed by XENERGY for conducting energy-efficiency potential studies. Details on the steps employed and analysis conducted are described in Appendix B. The model used, DSM ASSYST™, is an MS-Excel-based model that integrates technology-specific engineering and customer behavior data with utility market saturation data, load shapes, rate projections, and marginal costs into an easily updated data management system. The key steps implemented in this study are:

Step 1: Develop Initial Input Data

- Develop list of energy-efficiency measure opportunities to include in scope
- Gather and develop technical data (costs and savings) on efficient measure opportunities
- Gather, analyze, and develop information on building characteristics, including total square footage or total number of households, electricity consumption and intensity by end use, end-use consumption load

patterns by time of day and year (i.e., load shapes), market shares of key electric consuming equipment, and market shares of energy-efficiency technologies and practices.

Step 2: Estimate Technical Potential and Develop Supply Curves

• Match and integrate data on efficient measures to data on existing building characteristics to produce estimates of technical potential and energy-efficiency supply curves.

Step 3: Estimate Economic Potential

• Gather economic input data such as current and forecasted retail electric prices and current and forecasted costs of electricity generation, along with estimates of other potential benefits of reducing supply such as the value of reducing environmental impacts associated with electricity production

• Match and integrate measure and building data with economic assumptions to produce indicators of costs from different viewpoints (e.g., societal and consumer)

• Estimate total economic potential.

Step 4: Estimate Maximum Achievable, Program, and Naturally Occurring Potentials

• Gather and develop estimates of program costs (e.g., for administration and marketing) and historic program savings

• Develop estimates of customer adoption of energy-efficiency measures as a function of the economic attractiveness of the measures, barriers to their adoption, and the effects of program intervention

• Estimate maximum achievable, program, and naturally occurring potentials

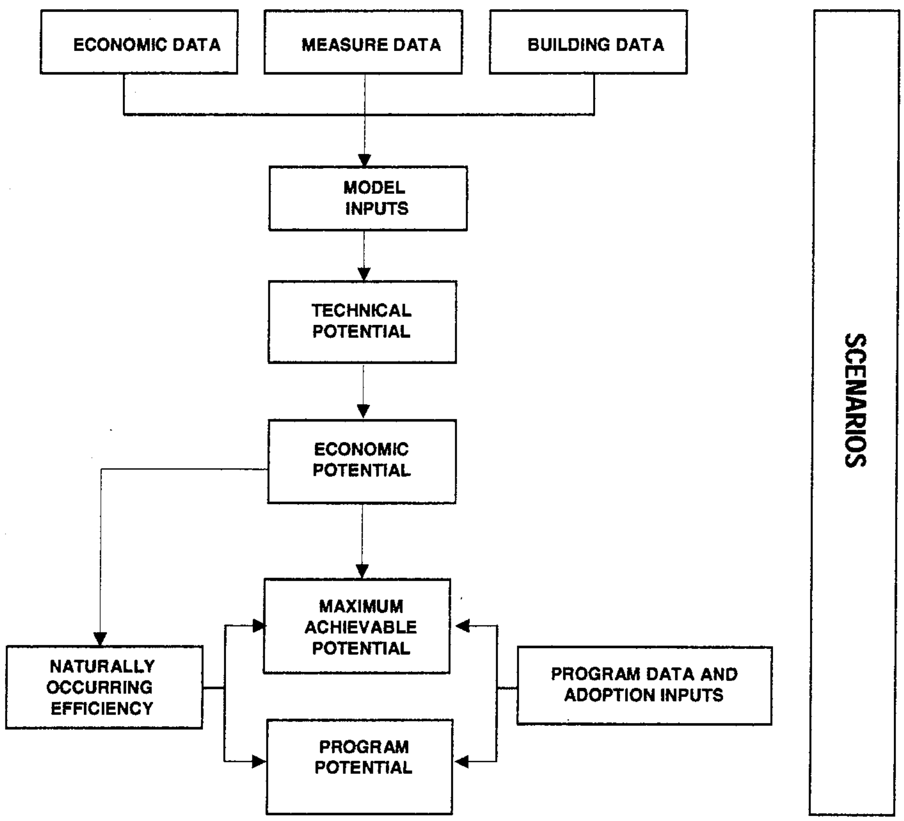
• Develop alternative economic estimates associated with alternative future scenarios.

Step 5: Scenario Analyses

• Recalculate potentials under alternate economic scenarios.

Figure 2-3

Conceptual Overview of Study Process



2.3 Scenario Analysis

In this section we describe scenarios under which we estimate energy-efficiency potential in this study. Scenario analysis is a tool commonly used to address uncertainty, which is inherent to forecasts. By constructing alternative scenarios, one can examine the sensitivity or robustness of one's predictions to changes in key underlying assumptions.

In this study, we construct scenarios of energy-efficiency potential for two key reasons. First, our estimates of potential are forecasts of future adoptions of energy-efficiency measures that are a function of data inputs and assumptions that are themselves forecasts. For example, as described earlier in this chapter, our estimates of potential depend on estimates of measure availability, measure costs, measure savings, measure saturation levels, electricity rates, and avoided costs. Each of the inputs to our analysis is subject to some uncertainty, though the amount of uncertainty varies among the inputs. The second key reason that we construct scenarios is that the final quantity with which we are most interested in this study, achievable potential, is by definition amenable to policy choices. Achievable potential is dependent on the level of resources and types of strategies employed to increase the level of measure adoption that would otherwise occur. In California, the level of resources and types of strategies are determined by policies and objectives of the institutions charged with enabling, governing, and administering public purpose energy-efficiency programs.[1] Over the past 20 years in California, funding levels for energy efficiency have changed dramatically over time.

Thus, we chose to develop scenarios to address uncertainty in factors over which one has limited direct control (e.g., future avoided costs and rates) as well as those that are controllable by definition (e.g., efficiency program funding levels).

2.3.1 Scenario Elements

As noted above, there is uncertainty associated with many of the inputs to our estimates of energy-efficiency potential. However, the level of uncertainty varies among inputs, and not all inputs are equally important to the final results. We determined that the greatest uncertainty in our estimates of economic and achievable potential (which are considered of more policy importance than estimates of technical potential) is that associated with future wholesale and retail electricity prices and future program funding levels. As a result, we limited the scenario analysis for the current study to these two dimensions. Each dimension, energy cost and funding level, is referred to as a scenario *element*. As discussed below, we developed three energy cost elements (Base, Low, and High) and three program funding level elements (Business-as-Usual, Advanced Efficiency, and Maximum Achievable Efficiency). These elements are then combined into nine achievable potential scenarios.

2.3.2 Overview of Energy Cost Scenarios

As noted above, we determined that a key uncertainty in our estimates of economic and achievable potential (which are considered of more policy importance than estimates of technical potential) is that associated with future wholesale and retail electricity prices. This study was conducted in the 2001-2002

[1] The minimum funding level for efficiency programs is determined by the public goods charge (PGC) authorized in Senate Bill (SB) 1194 and signed into law by Governor Gray Davis in 2000. Under SB 1194, the major investor-owned utilities (IOUs) in California are required to collect the PGC through a surcharge on customer bills. The California Public Utilities Commission (CPUC) has regulatory authority over how the IOUs administer the energy-efficiency funds.

time frame, a period that coincided with the recent California energy crisis. The advent of the energy crisis created considerable uncertainty in industry estimates of wholesale and retail electricity prices in California. As a result, we created three future energy cost scenarios: Base, Low, and High.

Base Energy Cost Scenario

The base avoided costs for energy and distribution are summarized in Figures 2-4 and 2-5, respectively. The base avoided-cost values also are provided in Appendix D. The energy avoided costs shown were required and approved by the CPUC for 2001 energy-efficiency programs. The California utilities derived their 2001 energy avoided-cost forecasts by applying CPUC-required on-peak multipliers to an avoided-cost forecast developed by the California Energy Commission (CEC) just prior to the California energy crisis. These multipliers were ordered by the CPUC in fall 2000 to account for the skyrocketing market clearing prices observed in summer 2000. The basis for the multipliers was a study conducted by JBS Energy Inc. in September 2000. Continued use of these multipliers has been required as part of the CPUC's energy-efficiency policy rules for PY2002. As can be seen from Figure 2-4, the primary effect of the multipliers was to significantly increase the summer period prices for the first 2 years of the forecasts. On-peak avoided costs are at 60 cents per kWh for 2001 and 2002 before dropping to roughly 26 cents in 2003.

Figure 2-4

Base Avoided Energy Costs

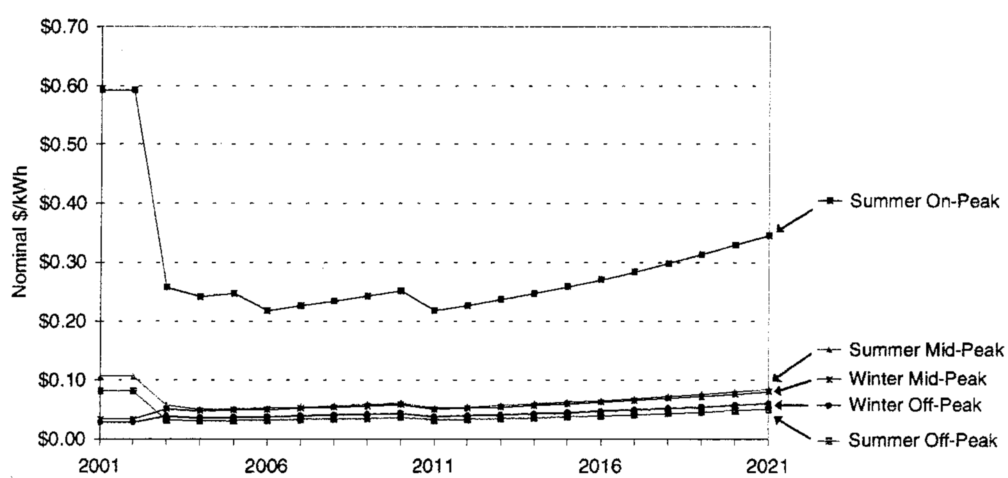
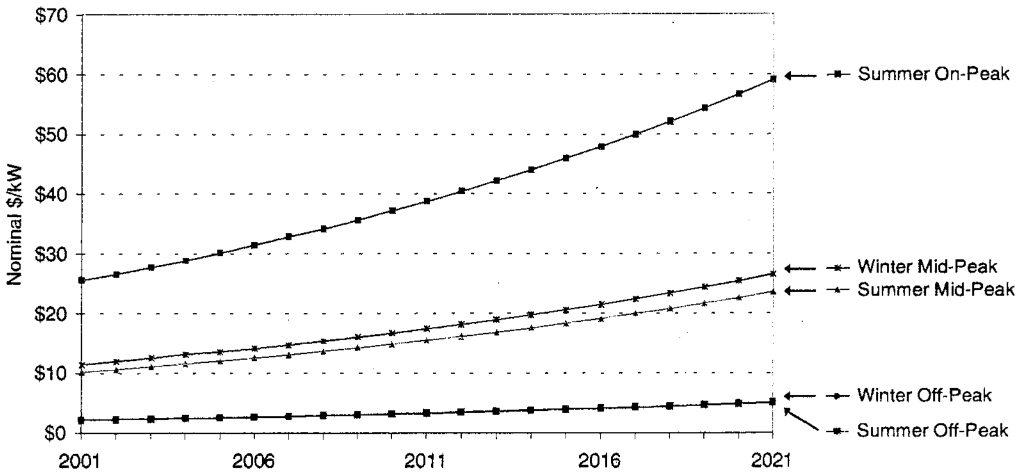


Figure 2-5

Base Avoided Transmission and Distribution Costs

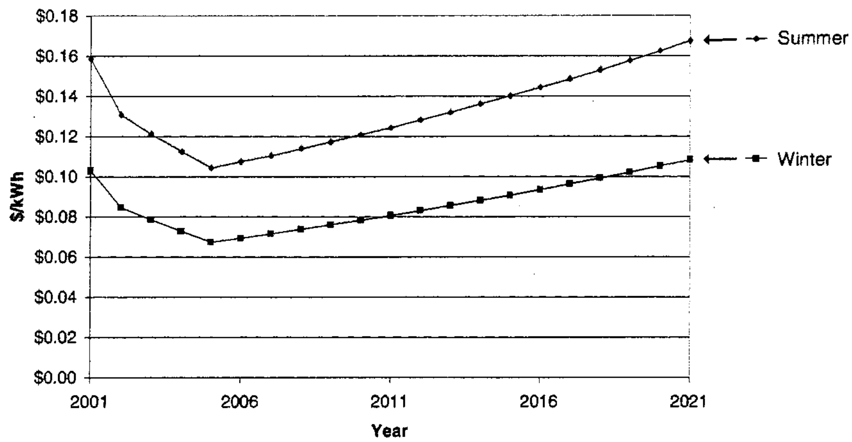


The base avoided-cost values, which average around 8.5 cents per kWh saved per year (in real terms) over the 20-year forecast period, are higher than those used in energy-efficiency cost-effectiveness analysis conducted prior to 2001. However, these base avoided costs are not far off from the average price of the long-term power contracts purchased by the California Department of Water Resources (DWR) during the height of the energy crisis, although they are lower than the wholesale market prices seen in Summer 2001.

An example of the Base rate forecasts used in this study is shown in Figure 3-3 for the commercial sector. We used average current rates as the starting point for each customer class. For the commercial and industrial sectors, our Base scenario rate forecast starts out at current levels and then declines to values that would be equivalent to levels that the pre-energy-crisis rates would have achieved by 2006 if they had increased by inflation. This assumption was taken directly from the CEC's October draft of their California Energy Outlook 2002-2012 report, the most defendable public rate forecast available at the time the commercial analysis was conducted. The residential rate forecast is from the CEC's Final California Energy Outlook 2002-2012 report (published in February 2002). The actual rate forecasts by scenario and sector are shown in Appendix D.

Figure 2-6

Example Base Run Rate Forecast—Commercial Sector



The base energy cost element is summarized in Table 2-1.

Table 2-1

Summary of Base Energy Cost Element

Cost Type	Description	Source
Avoided Costs	Annual energy avoided-cost averages roughly 7 cents per kWh saved. Avoided costs for transmission and demand equal roughly 1.5 cents per kWh saved. See Appendix B for specific values.	CPUC authorized avoided costs for major IOU's 2001 cost-effectiveness analysis (CPUC 2000)
Rates	Current commercial and industrial rates decrease to return to nominally normal levels by 2006, residential rates increase slightly over time.	CEC 2001a and 2002. CEC's Draft (October) and Final (February 2002) California Energy Outlook 2002-2012. Because of the timing of our analysis, the October rate forecast was used for commercial and industrial, and the February forecast for residential.

Low and High Energy Cost Scenarios

Because of the tremendous uncertainty around estimates of future wholesale and retail energy costs in California, we developed both Low and High energy cost scenarios as alternatives to the Base energy cost scenario. The purpose of developing the Low and High energy cost scenarios is to bind the Base energy costs by two moderately extreme cases. Although many different combinations of alternative future avoided costs and rates are possible, we choose to create two simple cases.

The Low avoided energy costs are simply half of the Base scenario avoided costs throughout the forecast period. The High avoided costs were set at 25 percent above the Base avoided costs throughout the forecast period. The high avoided-cost scenario captures possible futures in which energy efficiency has a very high value. This could be as a result of a future energy price spike, like the 2000-2001 experience, or because environmental impacts are valued more highly than they are today, for example, to meet a greenhouse gas reduction goal.

The Low retail rates were set at 1998 frozen levels and then increased from 2001 by inflation. In the High element, current retail rates continue to rise by inflation throughout the forecast period and do not return to pre-crisis levels; that is, the energy-crisis related rate increases of 2001 are permanent in the High element. The actual avoided cost and retail rates for the Low and High elements are provided in Appendix D. A summary of the elements is provided in Table 2-2.

Table 2-2

Summary of Low and High Energy Cost Elements

	Energy Costs Element	
Cost Type	Low	High
Avoided Costs	50 percent lower than Base energy avoided costs. Average 3.5 cents per kWh saved for energy (5 cents per kWh saved total including 1.5 cents per kWh saved for transmission and distribution).	25 percent higher than Base energy avoided costs. Average 9 cents per kWh saved for energy (10.5 cents per kWh saved total including 1.5 cents per kWh saved for transmission and distribution).
Retail Rates	1998 frozen rates escalated by inflation.	Current actual rates that persist throughout forecast period on a nominal basis.

The avoided-cost component of the Low energy cost element is fairly similar to the level of avoided costs that were in use prior to the energy crisis and, hence, are certainly a plausible bound on the low side. The rate component of the Low energy cost element is hypothetical by definition in that the rates are set at 1998 frozen values, putting them below what customers are currently experiencing. Nonetheless, the faster rates return to pre-crisis levels relative to our Base rate forecast, the more applicable the Low element would become.

The High element was developed when the energy crisis was still in full force, that is, before wholesale electricity prices had stabilized and fallen. It was designed to capture the possibility that extremely high market prices might continue or occur again in the near future. From today's vantage point, the High element seems unlikely; however, as mentioned above, there are a number of high-impact, low-probability events that could occur in an energy future reflected by the High element (e.g., a future energy crisis similar to the one just experienced, a mandate to reduce greenhouse gases, or a high market trading value for carbon dioxide or other power plant pollutants).

2.3.3 Efficiency Funding Scenarios

In this study, we constructed three different future funding level elements for California electric energy-efficiency programs. These program-funding elements are used to model achievable potential. Across all energy cost scenarios, the funding level elements are labeled *Business-as-Usual*, *Advanced Efficiency*, and *Maximum Efficiency*. Total program funding expenditures increase sequentially from Business-as-Usual to Maximum Efficiency. Business-as-Usual, the lowest expenditure level, generally approximates spending levels in recent years. Advanced Efficiency represents a 100-percent increase over Business-as-Usual. Maximum Efficiency, the highest expenditure element, is used to generate our estimates of maximum achievable potential. Maximum Efficiency funding equates to roughly a 400-percent increase over Business-as-Usual funding. The average program expenditures for each of the funding scenarios is shown, by component, in Table 2-3. These funding levels are discussed further below in the presentation of program potential results.

Table 2-3

Summary of Program Expenditures

(Average Expenditures Over the 10-Year Analysis Period in Millions of $ per Year)

	Cost Components				
Funding Level	Marketing	Administration	Incentives	Total	Average % of Measure Cost Paid*
Business-as-Usual	$66	$62	$116	$243	33%
Advanced Efficiency	$88	$124	$360	$572	66%
Maximum Efficiency	$124	$141	$763	$1,028	100%

Components

The components of program funding that vary under each of the program funding levels are:

1. Total marketing expenditures

2. The amount of incremental measure costs paid through incentives

3. Total administration expenditures.

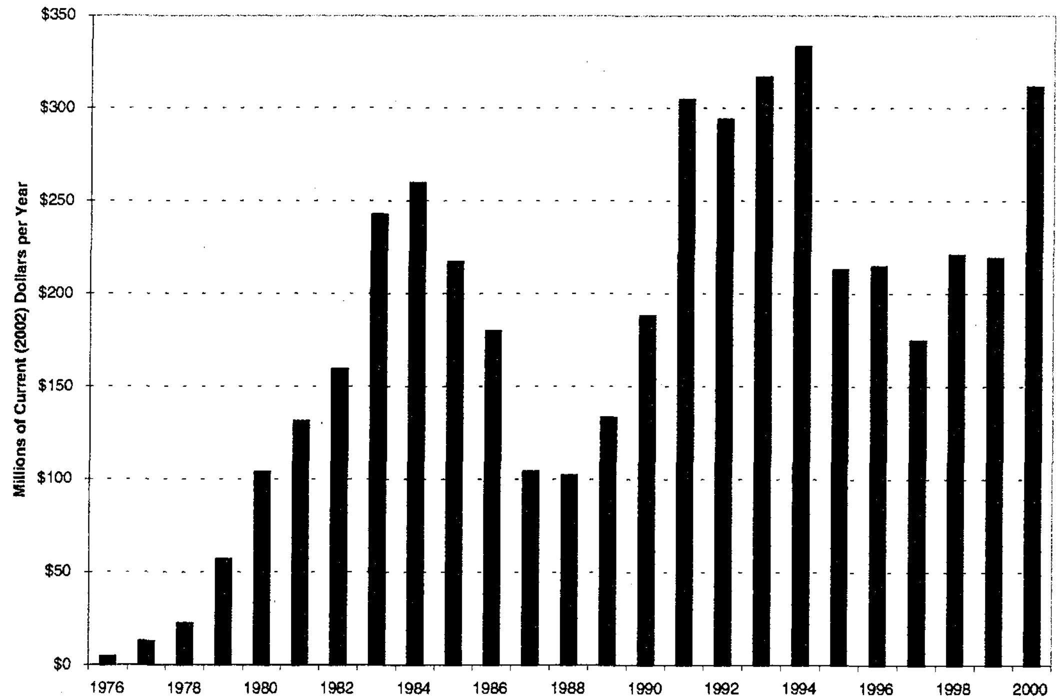
First, customers must be aware of efficiency measures and associated benefits in order to adopt those measures. In our analysis, program marketing expenditures are converted to increases in awareness. Thus, under higher levels of marketing expenditures, higher levels of awareness are achieved. Second, program-provided measure incentives lead to increased adoptions through increases in participants' benefit-cost ratios, as described in Appendix B. The higher the percentage of measure costs paid by the program, the higher the participant benefit-cost ratio and number of measure adoptions. Third, purely administrative costs, though necessary and important to the program process, do not directly lead to adoptions; however, they must be included in the program funding because they are an input to program benefit-cost tests.

Business as Usual Funding

For the Base energy cost scenario, our Business-as-Usual funding was constructed to reflect the level of expenditures for the major investor-owned utilities' (IOUs') programs at different points in time over the past 5 years. We reviewed actual expenditures reported in utility CPUC filings for residential and nonresidential programs. As shown in Figure 2-7, over the period 1996 to 2000, reported program expenditures for the three electric investor-owned utilities in California averaged roughly $200 million per year. Our Business-as-Usual funding is $240 million per year, which accounts for the fact that the electric IOUs represent about 82 percent of California's energy consumption. Thus, the $240 million per year figure assumes the non-IOUs devote the same amount proportionally to electric efficiency programs, as do the IOUs.

Figure 2-7

Annual Electric Energy-Efficiency Program Expenditures for Major IOUs (in current dollars)



Source: Historic data compiled by CEC staff. Smith 2002, deflated using GDP price deflator.

We reviewed the same sources identified above to estimate program administration and marketing costs. Precise estimates of these costs were difficult to make from the sources available at the time. In general, we estimated that program expenditures made up slightly less than half of the total program costs, under the Business-as-Usual case, with financial incentives making up the rest. Marketing costs average $66 million per year and administration costs $62 million.

The total incentives dollars are estimated directly in our model as a function of predicted adoptions. What we specify in the model is the percent of incremental measure cost paid by the program. We attempted to set these percentages as closely as possible to the utility incentive levels in recent years. While not exact due to actual variations in incentives across measures and across program years, we believe that the percent of measure costs paid in our Business-as-Usual funding element, which average about one-third of measure costs, reasonably approximates actual program incentive levels over the past few years. Total incentives average $116 million per year under the Business-as-Usual case.

In the Business-as-Usual funding element, total marketing costs increase by inflation over the 10-year analysis period. We set administration costs to vary slightly over time as a function of program activity levels. The percent of incremental measure costs paid over time is generally held constant (though incentive levels are ramped up over time under the higher funding scenarios).

Advanced Efficiency Funding

Advanced Efficiency represents a 100-percent increase in funding from Business-as-Usual. We increased funding levels by increasing both the total marketing expenditures and the per-unit incentive levels. Administration levels increase as a function of increases in program activity. Marketing costs average $88 million per year, and the average fraction of incremental costs paid for by incentives increases from roughly one-third in Business-as-Usual to approximately two-thirds in Advanced Efficiency.

Maximum Efficiency Funding

The Maximum Efficiency funding level is used to estimate maximum achievable potential. The key characteristic of this funding level is that 100 percent of incremental measure costs is paid for by the program (after a ramp-up from existing incentive levels over the first few forecast years). In addition, marketing costs increase to an average of $124 million per year.

3. Electric Efficiency Potential in California

In this section we present estimates of electric energy-efficiency potential under the scenarios described in Section 2. To provide context for these results, we begin with a brief introduction to forecasted peak demand for California for the study period 2002 to 2011.

3.1 Baseline Energy and Demand Forecasts

Before presenting our estimates of energy-efficiency potential, it is important for readers to be familiar with the baseline forecasts of peak demand and energy for California for the period 2002 to 2011. To estimate energy-efficiency potential over time, it is necessary to benchmark savings to a forecast of electricity consumption. Fortunately, in California there is a consistent statewide process in place for electricity forecasting at the California Energy Commission (CEC). The CEC has conducted such forecasts for many years.

On average, the CEC's forecasts have proven fairly accurate over time; however, like virtually all forecasts, the CEC's methods are not intended to predict extraordinary changes in usage associated with unexpected events like the energy crisis of the second half of 2000 and most of 2001. As has been documented extensively elsewhere, energy consumption and peak demand decreased dramatically in 2001. This reduction can be seen in Figure 3-1. This reduction occurred as the result of a combination of voluntary demand response from consumers and installation of energy-efficient equipment, spurred both by the crisis itself and increased energy-efficiency program efforts.[1,2] The relative share of the energy and demand savings in 2001 attributable to voluntary conservation efforts versus installation of major energy-efficient equipment[3] is not currently known with certainty. However, it is likely that the majority of the reduction (roughly 70 percent) was due to voluntary conservation efforts.[4]

In response to the extraordinary reduction in peak demand and consumption that occurred in 2001, the CEC developed several possible patterns of future electricity peak demand and consumption. These scenarios were based on alternative assumptions about the level and persistence of voluntary impacts and permanent,

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[1] For an analysis of the 2001 summer demand reduction, see *The Summer 2001 Conservation Report*, published by the California State and Consumer Services Agency, produced by the CEC under the direction of the Governor's Conservation Team, February 2002.

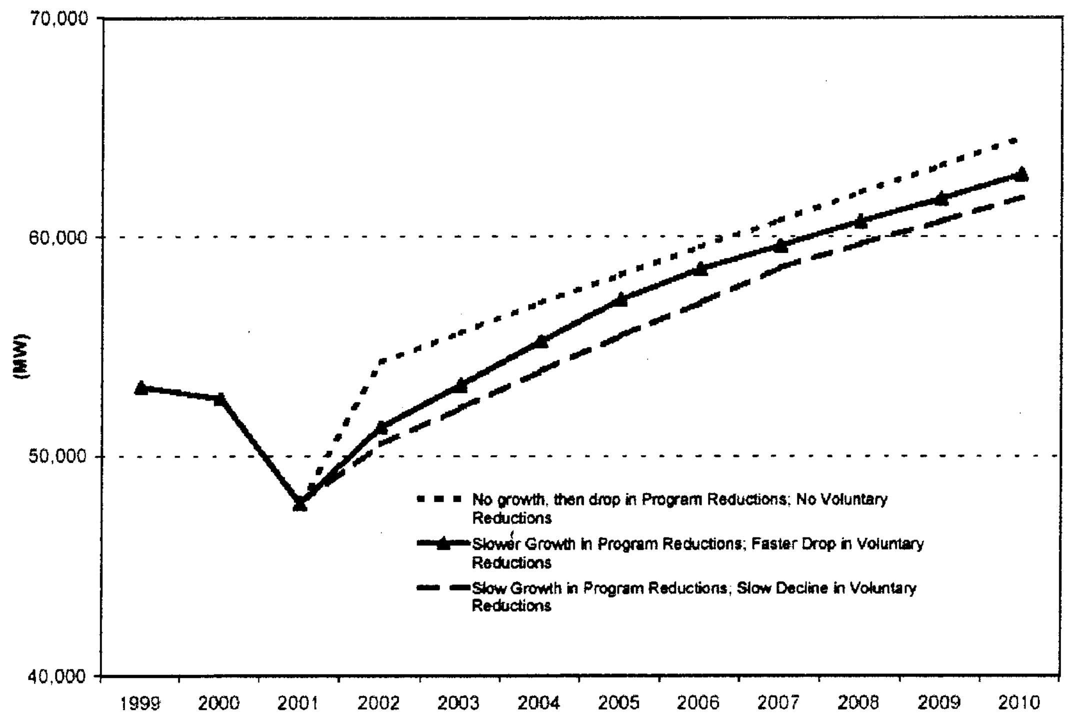
[2] According to CEC 2002, key factors driving both voluntary and hardware changes included demand reduction programs, electricity price increases, the 20/20 rebate program, winter rolling outages, and media exposure of the energy crisis and its potential costs to the State and consumers.

[3] *Conservation* refers here to behavioral changes in energy use, such as turning up thermostat settings during cooling periods; *efficiency* refers to permanent changes in equipment that result in increased energy service per unit of energy consumed, e.g., the installation of a more efficient air conditioner.

[4] See Goldman, Barbose, and Eto 2002, *California Customer Load Reductions during the Electricity Crisis: Did They Help To Keep the Lights On?*, Lawrence Berkeley National Laboratory, for an analysis of conservation and efficiency reactions to the energy crisis in 2001.

program impacts. *Program* impacts, as used in the CEC's forecast scenarios, refer to the emergency program efforts initiated in response to the State's energy crisis, that is, programs funded under SB 5X, AB 970, and AB 29X, not the public goods-charge-based efficiency programs administered by the State's electric utilities. As shown in Figure 3-1, the CEC developed three future scenarios, the middle of which was selected as the most likely case. Under the CEC's forecast, peak demand is projected to be roughly 63,000 MW and energy sales 320,000 GWh per year by 2011. We used the CEC's forecast data to provide the basis for our baseline estimates of energy consumption and peak demand. More information on the CEC's forecasts and the baseline data underlying our estimates of energy-efficiency potential is provided in Appendix A.

Figure 3-1
CEC Peak Demand Forecasts



Source: California Energy Commission (CEC) 2001a. *2002 – 2012 Electricity Outlook*. P700-01-004.

Figure 3-2
Technical and Economic Potential (2011)
Peak Demand Savings—MW

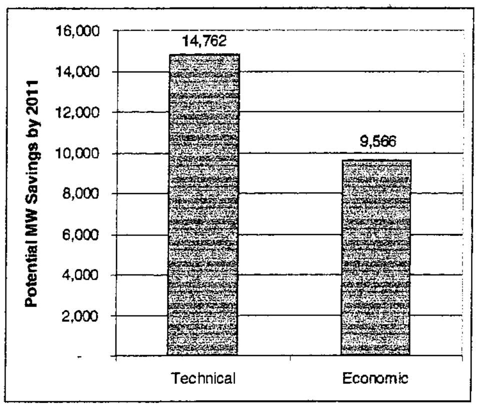
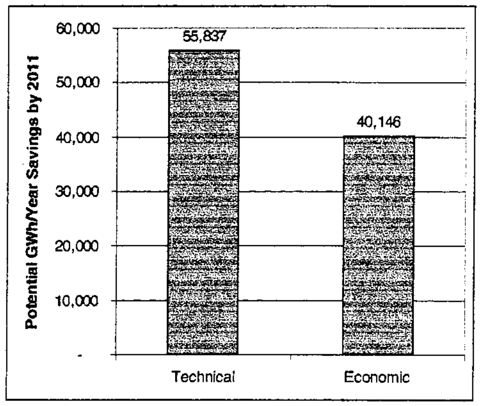


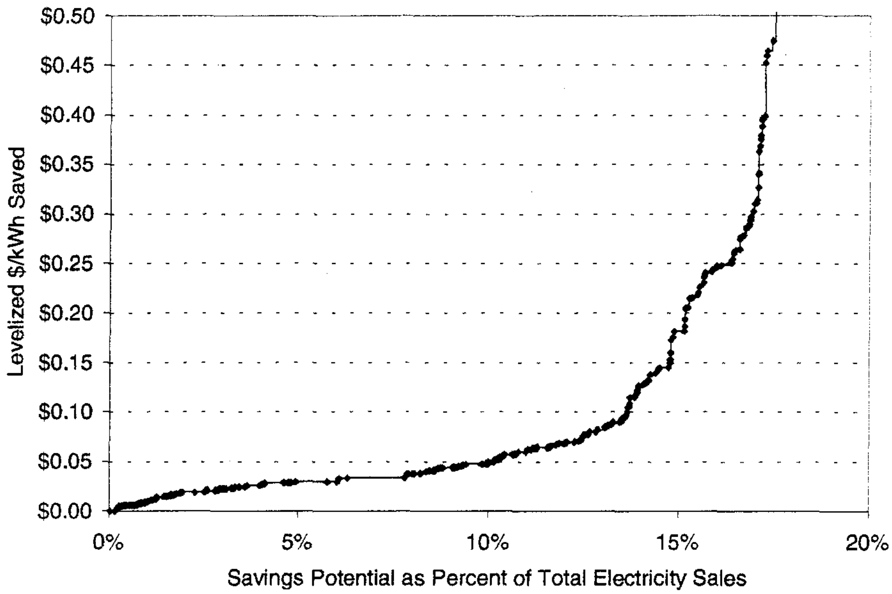
Figure 3-3
Technical and Economic Potential (2011)
Energy Savings—GWh per Year



A common way to illustrate the amount of energy-efficiency savings available for a given cost is to construct an energy-efficiency supply curve. A supply curve typically consists of two axes—one that captures the cost per unit of saving electricity (e.g., levelized $/kWh saved) and the other that shows the amount of savings that could be achieved at each level of cost. Measures are sorted on a least-cost basis, and total savings are calculated incrementally with respect to measures that precede them. The costs of the measures are levelized over the life of the savings achieved. (See Appendix C for more information on construction of efficiency supply curves.)

The overall energy-efficiency supply curve constructed for this study is shown in Figure 3-4. The curve is shown in terms of savings as a percentage of total energy consumption for the state in the year 2011. The curve shows that roughly 28,000 GWh per year of savings are available (9 percent of project consumption in 2011) from measures with levelized costs below 5 cents per kWh saved. Approximately 40,000 GWh per year of savings are available from measures with levelized costs below 8.5 cents per kWh saved (8.5 cents is roughly the break-even point for measures that pass the TRC benefit-cost test under the Base energy cost forecast). Savings potentials and levelized costs for the individual measures that comprise the supply curve are provided in Appendix C. End use and measure savings are discussed later in this chapter.

Figure 3-4
Energy-Efficiency Supply Curve—Potential in 2011*



*Levelized cost per kWh saved is calculated using an 8-percent nominal discount rate.

3.2.2 Achievable Potentials

In this section we present our overall achievable potential results under the Base energy cost scenario. In contrast to technical and economic potential estimates, achievable potential estimates take into account market and other factors that affect adoption of efficiency measures. Our method of estimating measure adoption takes into account market barriers and reflects actual consumer and business implicit discount rates (see Appendix B for this methodology). **Achievable potential** refers to the amount of savings that would occur in response to one or more specific program interventions. *Net* savings associated with program potential are savings that are projected beyond those that would occur naturally in the absence of any market intervention. Because achievable potential will vary significantly as a function of the specific type and degree of intervention applied, we develop estimates for multiple scenarios. As discussed in Section 2, the achievable potential scenarios analyzed for this study are Business-as-Usual, Advanced Efficiency, and Maximum Efficiency. The Business-as-Usual funding scenario represents continuation of the minimum funding level allowed by law under the legislation enabling California's IOUs to collect a public goods charge for energy-efficiency programs. The Advanced Efficiency scenario represents roughly a

3.2 Potential and Benefits 2002 to 2011—Base Energy Costs

This section presents overall energy-efficiency potential results under our Base energy cost forecast scenario. We begin by presenting estimates of technical and economic potential and then discuss our estimates of achievable potential. Definitions of the different types of potentials and our energy cost forecast scenarios are provided in Section 2 of this report and discussed further in Appendix B. Potentials were estimated using the bottom-up methodologies described in the same appendix. We analyzed potential for 232 unique measures across dozens of market segment applications.[5] Roughly 10,000 measure-market segment combinations were analyzed.

3.2.1 Technical and Economic Potential

In Figures 3-2 and 3-3 we present our overall estimates of total technical and economic potential for peak demand and electrical energy in California. **Technical potential** represents the sum of all savings achieved if all measures analyzed in this study were implemented in applications where they are deemed applicable and physically feasible. As described in Appendix B, **economic potential** is based on efficiency measures that are cost-effective based on the total resource cost (TRC) test, a benefit-cost test used by the California Public Utilities Commission and others to compare the value of avoided energy production and power plant construction to the costs of energy-efficiency measures and program activities necessary to deliver them. The value of both energy savings and peak demand reductions are incorporated into the TRC test.

If all measures analyzed in this study were implemented where technically feasible, we estimate that overall technical demand savings would be roughly 14,800 MW, about 22 percent of projected total peak demand in 2011. If all measures that pass the TRC test were implemented, economic potential savings would be 9,600 MW, about 15 percent of total base demand in 2011. These figures correspond to the equivalent of 30 and 19 mid-sized (500 MW) power plants. Technical energy savings potential is estimated to be roughly 56,000 GWh, about 18 percent of total commercial energy usage projected in 2011. Economic energy savings are estimated at 40,000 GWh, about 13 percent of base usage.

[5] Market segment applications included building types, utility service territories, climate zones, and building vintages.

doubling of funding as compared with the Business-as-Usual. **Maximum achievable efficiency potential** is the amount of economic potential that could be achieved over time under the most aggressive program scenario possible.[6] We estimate that the programmatic funding necessary in the Maximum Efficiency is about four times the Business-as-Usual spending.

We forecasted program energy and peak demand savings under each achievable potential scenario for a 10-year period beginning in 2002. We calibrated our energy-efficiency adoption model to actual program accomplishments over the historic period 1996 to 2000. Our estimates of achievable potentials and their affect on forecasted demand and energy consumption are shown in Figures 3-5 through 3-8.

As shown in Figure 3-5, by 2011 *net*[7] peak demand savings are projected to be roughly 1,800 MW under Business-as-Usual, 3,500 MW under Advanced Efficiency, and 5,900 MW under Maximum Efficiency futures. In Figure 3-6 we show how these savings would affect forecasted peak demand.

In Figure 3-7, we show projected net annual energy savings of 10,000 GWh under Business-as-Usual, 19,000 GWh under Advanced Efficiency, and 30,000 GWh under Maximum Efficiency futures. In Figure 3-8 we show how these savings would affect forecasted energy consumption.

[6] Experience with efficiency programs shows that maximum achievable potential will always be less than economic potential for two key reasons. First, even if 100 percent of the extra costs to customers of purchasing an energy-efficient product are paid for through program financial incentives such as rebates, not all customers will agree to install the efficient product. Second, delivering programs to customers requires additional expenditures for administration and marketing beyond the costs of the measures themselves. These added program costs reduce the amount of potential that it is economic to acquire.

[7] Again, *net* refers throughout this chapter to savings beyond those estimated to be naturally occurring, that is, from customer adoptions that would occur in the absence of any programs or standards.

Figure 3-5
Achievable Peak Demand Savings—MW

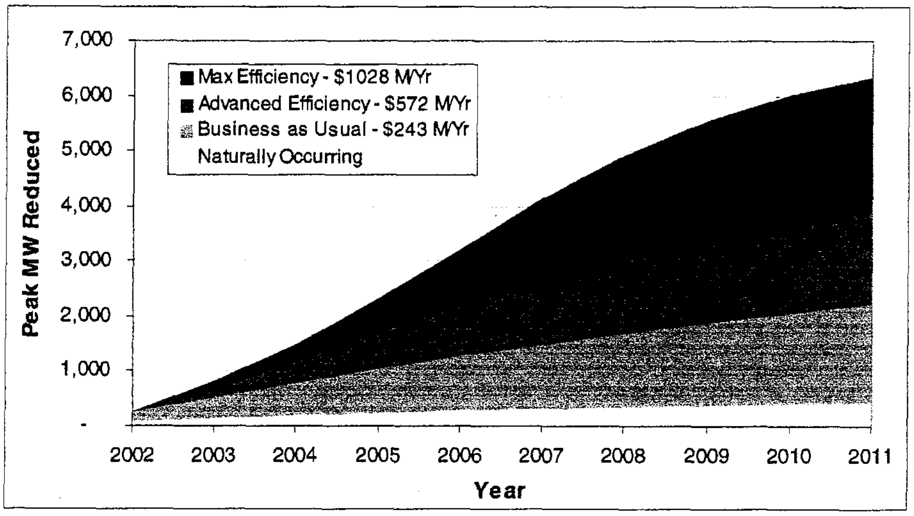
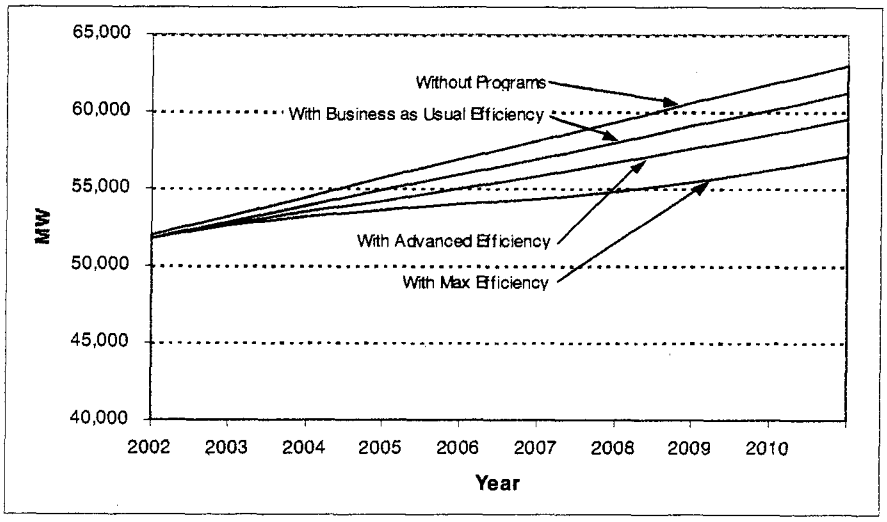


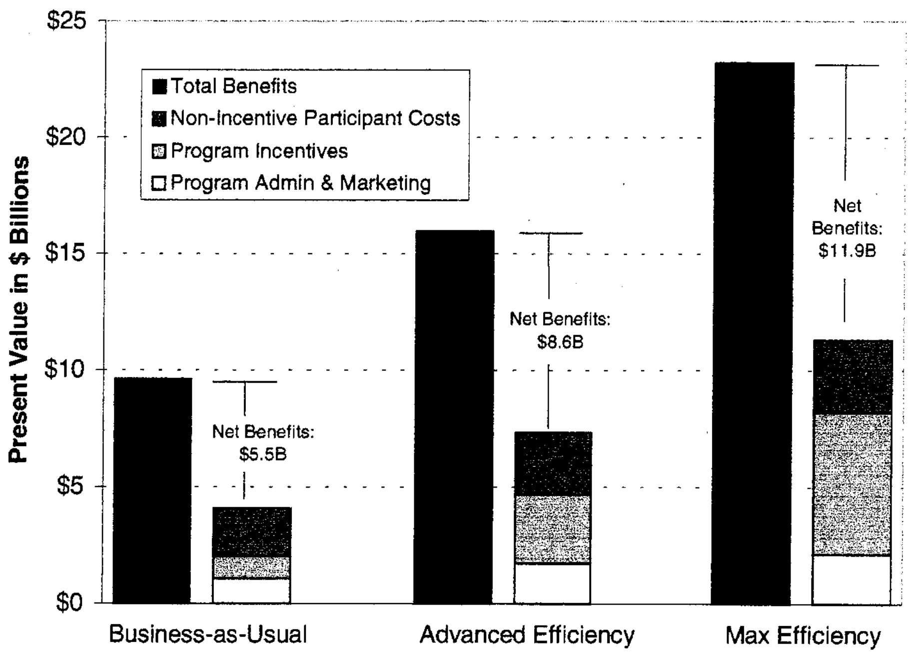
Figure 3-6
Peak Demand Forecast and Achievable Efficiency Potentials*



*No programs forecast based on CEC 2002.

The costs and benefits associated with the each funding scenario, under Base energy costs, over the 10-year period are shown in Figure 3-9. As shown in the figure, total program costs (administration, marketing, and incentives) are $2 billion under Business-as-Usual, $4.7 billion under Advanced Efficiency, and $8.2 billion under Max Efficiency. Total avoided-cost benefits are $9.6 billion under Business-as-Usual, $15.9 billion under Advanced Efficiency, and $23.2 billion under Max Efficiency. Net avoided-cost benefits, which are the difference between total avoided-cost benefits and total resource costs (which include participant costs in addition to program costs), are $5.5 billion under Business-as-Usual, $8.6 billion under Advanced Efficiency, and $11.9 billion under Max Efficiency.

Figure 3-9
Benefits and Costs of Electric Energy-Efficiency Savings—2002 to 2011*



*Present value of benefits and costs over normalized 20-year measure lives, nominal discount rate = 8 percent, inflation rate = 3 percent.

All of the funding scenarios are cost effective based on the TRC test, which is the principal test used in California to determine program cost effectiveness. The TRC benefit-cost ratios (under the Base energy cost forecast) are 2.4, 2.2, and 2.0 for the Business-as-Usual, Advanced Efficiency, and Max Efficiency scenarios, respectively. Key results from our efficiency scenario forecasts are summarized in Table 3-1.

Table 3-1
Summary of 10-Year Net Achievable Potential Results (2002-2011)*

Scenario	Result	Business-as-Usual	Advanced Efficiency	Max Efficiency
Base	Program Costs:	$2,003 M/Yr	$4,663 M/Yr	$8,196 M/Yr
	Participant Costs:	$2,052 M/Yr	$2,646 M/Yr	$3,111 M/Yr
	Benefits:	$9,604 M/Yr	$15,949 M/Yr	$23,203 M/Yr
	Net GWh Savings:	9,637	19,445	30,090
	Net MW Savings:	1,788	3,480	5,902
	Program TRC:	2.37	2.18	2.05

*Present value of benefits and costs over 20-year normalized measure lives for 10 program years (2002-2011), nominal discount rate = 8 percent, inflation rate = 3 percent, GWh and MW savings are cumulative through 2011.

3.3 Breakdown of Potential and Benefits

In this section we provide additional information on the estimates of electric efficiency potential developed for this study. We discuss results by customer class, vintage, end use, and type of measure. In Figures 3-10 and 3-11, we present estimates of technical and economic potential by customer class for peak demand and energy, respectively. For energy savings, technical and economic potential are similar by customer class and reflect that fact that each of the classes make up about a third of energy consumption in the state (a breakdown of consumption by class is provided in Appendix A). Peak demand technical and economic potential is skewed away from the industrial sector, which should be expected given the higher load factor of industrial customers. Residential customers have significant peak demand savings potential, driven primarily by residential air-conditioning usage, which is highly coincident with the state's summer peak.

Figure 3-10
Technical and Economic Potential (2011)
Demand Savings by Sector—MW

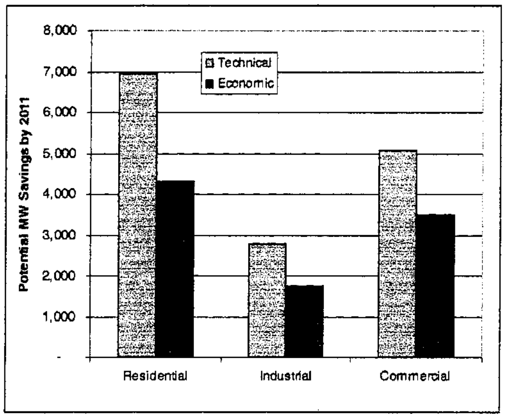
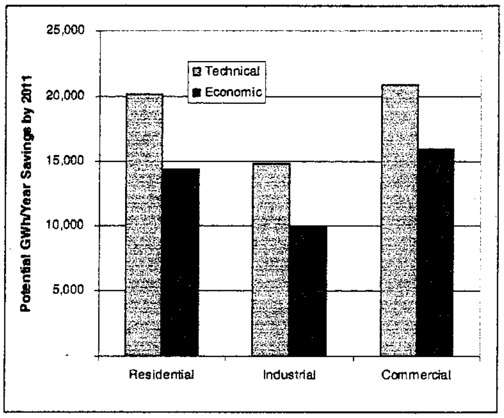


Figure 3-11
Technical and Economic Potential (2011)
Energy Savings by Sector—GWh per Year



Net achievable potential estimates by customer class for the period 2002 to 2011 are presented in Figures 3-12 and 3-13. These figures present the Business-as-Usual, Advanced Efficiency, and Maximum Efficiency funding scenarios. Note that under Business-as-Usual, the commercial sector dominates impacts, accounting for roughly 58 percent of savings, while the residential sector accounts for 24 percent and the industrial sector only 18 percent. As a percent of each sector's base-case consumption, the Business-as-Usual savings represent 6 percent of projected commercial consumption in 2011, 3 percent of residential consumption, and 2 percent of industrial. These forecasts are consistent with the historic pattern of efficiency program savings across customer classes (see Appendix A for a summary of historic program accomplishments). Under the Advanced efficiency scenario, residential savings increase over two-fold, industrial impacts about 70 percent, and commercial impacts only 50 percent. The large increase in residential impacts under the Advanced Efficiency funding is primarily attributable to high levels of projected adoption of compact fluorescent lamps and fixtures (CFLs). Under the Maximum Efficiency funding, residential and commercial impacts increase marginally as compared to Advanced Efficiency, whereas industrial savings increase dramatically.

Figure 3-12
Net Achievable Peak Demand Savings (2011) by Sector—MW

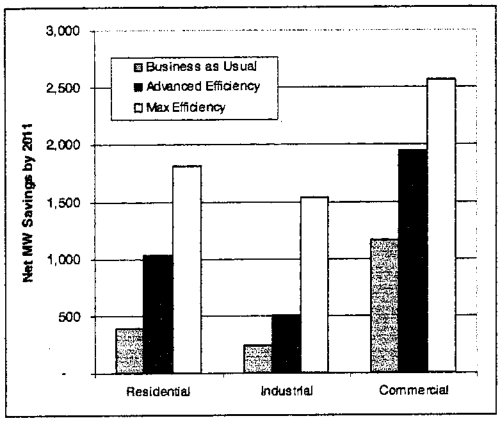
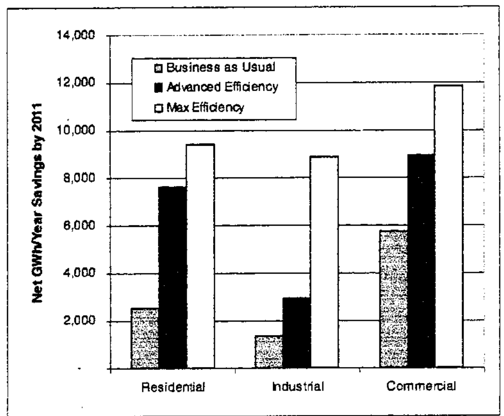
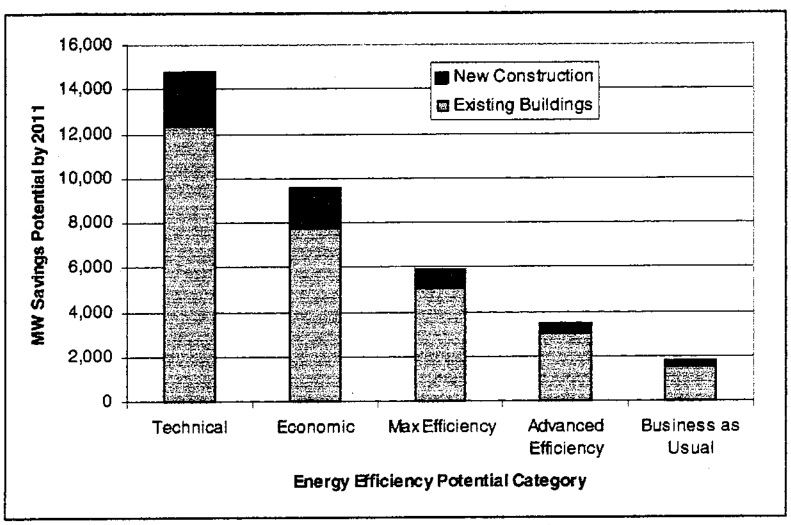


Figure 3-13
Net Achievable Energy Savings (2011) by Sector—GWh per Year



In Figure 3-14, we summarize the relative share of potential accounted for by existing versus new buildings over the 2002 to 2011 period. New construction represents roughly 10 to 15 percent of the estimated achievable potential. This range is consistent with the fraction of total program savings represented new construction throughout the 1990s in California (again, see Appendix A).

Figure 3-14
Potential Peak Demand Savings by Vintage (2011) - MW



In Figures 3-15 through 3-20, we present the distribution of economic efficiency potential by end use. Further detail on potential by individual measure is provided in Appendix C.

In the residential sector, lighting efficiency accounts for the majority of energy savings potential, while air conditioning measures account for 68 percent of potential peak demand savings. This follows somewhat from these end uses share of current energy and peak demand (see Appendix A). Lighting savings are represented by one key measure: CFLs. The contribution of this measure to total residential economic energy savings potential is large because per-unit CFL savings are very high (generally, 70 to 75 percent savings per incandescent lamp replaced). Prior to the energy crisis in 2001, the saturation of CFLs in California households was very low at about 1 percent of applicable incandescent lamps (RLW 2000 and RER 2002a). In the second quarter of 2001, the market share of CFLs shot up to 8 percent of medium screw-based lamp sales in California, before dropping to 6 percent in the third and fourth quarters. This was an unprecedented increase and accounts for a significant share of the energy-efficiency program savings that occurred in 2001. An important research question is whether the high penetration of CFLs can be maintained and increased with continued and expanded program efforts as simulated under our Advanced Efficiency scenario. With respect to peak demand opportunities, the residential measures with the most significant peak demand reduction potential are:

- Window efficiency improvements (new double-pane, low-e windows and retrofit window film)
- High-efficiency air conditioners (SEER 12, 13, and 14+)
- Improved diagnostics, repair, and maintenance
- Thermal expansion valves
- Cool roofs (high reflectivity roofs)
- Whole house fans (for off-peak and mid-peak cool down).

Figure 3-15
Residential Economic Demand Savings Potential by End Use (2011)

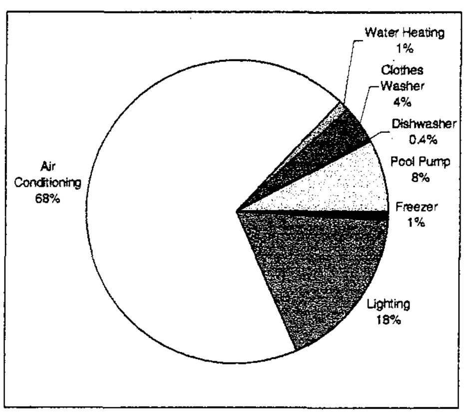
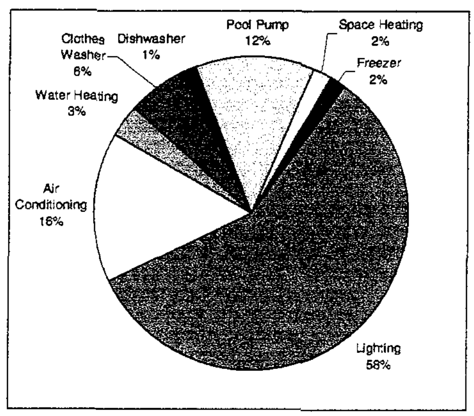


Figure 3-16
Residential Economic Energy Savings Potential by End Use (2011)



The industrial sector is notoriously heterogeneous, being composed of hundreds of different types of manufacturing, production, and assembly plants for thousands of different products. This distribution of potential industrial sector savings by end use is shown in Figures 3-17 and 3-18. The relative mix of end-use savings is fairly similar for both energy and peak demand. This is because the industrial sector has the highest load factor of all customer classes. Motor and process applications account for the majority of potential savings, followed by lighting, compressed air, and space cooling. These savings follow somewhat proportionally from the distribution of base consumption in the sector (see Appendix A for breakdown of industrial consumption by end use); however, lighting savings are higher as a proportion of base consumption as compared with other end uses.

Although there is a great need for more research to better understand industrial potential in California (in particular, little statistically representative data is available on current measure saturation levels), there were several recent sources available to help us with the initial estimates for this study. Key among these sources is a series of industry-specific efficiency potential studies conducted by Lawrence Berkeley National Laboratory (Martin, et al., 1999 – 2000b and Worrell, et al., 1999) and several recent studies conducted by XENERGY (XENERGY 2001d, 2000a, and 1998b). Details on industrial savings opportunities can be found in these references. Examples of key measures include variable-speed drive motor and pump applications, proper motor and pump sizing, redesign of pumping systems to reduce unnecessary flow restrictions, improved operations and maintenance, reducing compressed air system leaks, and optimizing compressed air storage configurations. Lighting and space cooling savings measures are similar to those in the commercial sector. In addition, there are hundreds of measures specific to individual industrial process applications.

Figure 3-17
Industrial Economic Demand Savings Potential by End Use (2011)

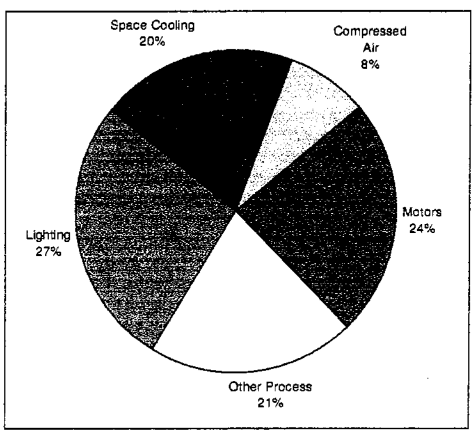
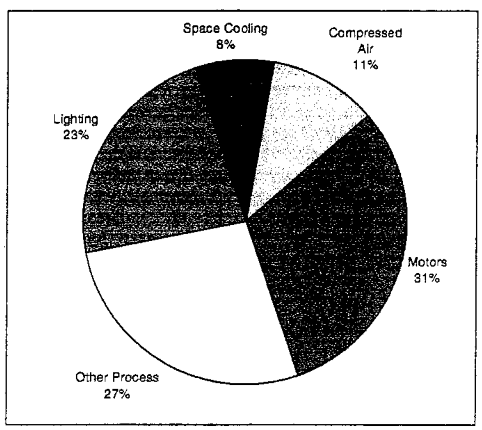


Figure 3-18
Industrial Economic Energy Savings Potential by End Use (2011)



This distribution of commercial sector savings by end use is shown in Figures 3-19 and 3-20. Despite the significant adoption of high-efficiency lighting throughout the 1990s, interior lighting still represents the largest end-use savings potential in absolute terms for both energy and peak demand. As expected, cooling potential represents a significant portion of the total peak demand savings potential.. Refrigeration energy savings potential is roughly equal to that of cooling but is significantly less important in terms of peak demand potential.

In terms of energy savings, the T8 lamp/electronic ballast (T8/EB) combination continues to hold the position it held at the outset of the 1990s as the measure with the largest potential, even though we estimate that current saturation levels are over 50 percent. Automated perimeter dimming represents a significant savings opportunity as well, though at a cost that generally puts it above the economic threshold. Refrigeration compressor and motor upgrades, occupancy sensors for lighting, office equipment power management, and CFLs round out the measures that represent the largest opportunities.

With respect to peak demand savings, perimeter dimming represents the largest demand savings opportunity, followed by the T8/EB combination. Cooling measures become more significant in terms of peak impacts with high-efficiency chillers and packaged units, as well as chiller tune-ups making up a large share of total potential demand savings. Occupancy sensors and T8/EB plus reflectors also capture at least 5 percent of the total demand savings potential, as they did with respect to energy savings. These measures, when combined, represent about two-thirds of demand reduction potential.

Figure 3-19
Commercial Economic Demand Savings Potential by End Use (2011)

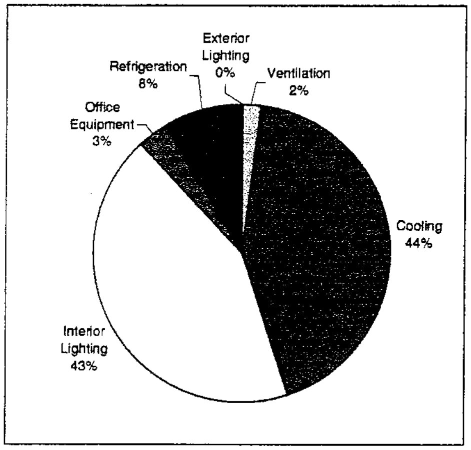
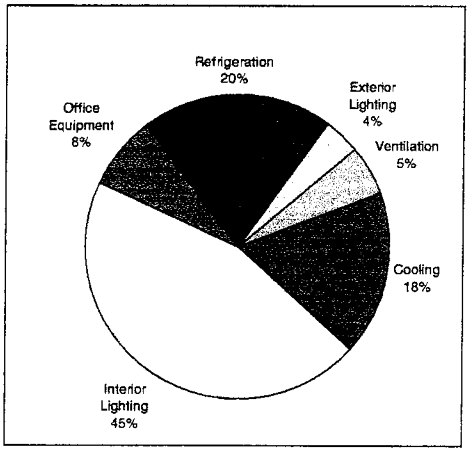


Figure 3-20
Commercial Economic Energy Savings Potential by End Use (2011)



3.4 Electric Efficiency Under Forecast Uncertainty

In this section we present estimates of energy-efficiency potential for several forecast scenarios. Scenario analysis is a tool commonly used to address uncertainty, which is inherent to forecasts. By constructing alternative scenarios, one can examine the sensitivity or robustness of one's predictions to changes in key underlying assumptions.

As defined in Section 2, we created three alternative energy cost forecasts for this study. The results for the Base energy cost scenario are presented above in Sections 3.2 and 3.3. The purpose of developing the Low and High energy cost scenarios is to provide a sensitivity analysis on the effect of uncertain rates and avoided energy costs on estimates of economic and achievable potential. Because of the tremendous uncertainty around estimates of future wholesale and retail energy costs in California, we developed both Low and High energy cost scenarios as alternatives to the Base energy cost scenario. The Low avoided energy costs are simply half of the Base scenario avoided costs throughout the forecast period. The High avoided costs were set at 25 percent above the Base avoided costs throughout the forecast period.

The High avoided-cost scenario captures possible futures in which energy efficiency has a very high value. This could be as a result of a future energy price spike, similar to the 2000-2001 experience, or because environmental impacts are valued more highly than they are today, for example, to meet a greenhouse gas reduction goal.

The Low retail rates were set at 1998 frozen levels and then increased from 2001 by inflation. In the High element, current retail rates continue to rise by inflation throughout the forecast period and do not return to pre-crisis levels; that is, the energy-crisis related rate increases of 2001 are permanent in the High element. The actual avoided-cost and retail rate values for the Low and High elements are provided in Appendix D and summarized further in Section 2.

In Figures 3-21 and 3-22 we present economic and net achievable potential results by energy cost scenario for peak demand reductions and energy savings, respectively. The first thing to notice on these figures is that economic potential is about 9 percent higher under the High scenario and roughly 16 percent lower under the Low scenario than economic potential under the Base avoided-cost forecast. The swing in economic potential is roughly 2,500 MW against Base economic potential of roughly 9,600 MW.

Figure 3-21
Potential Net Demand Savings Under Different Energy Cost Scenarios (2011)

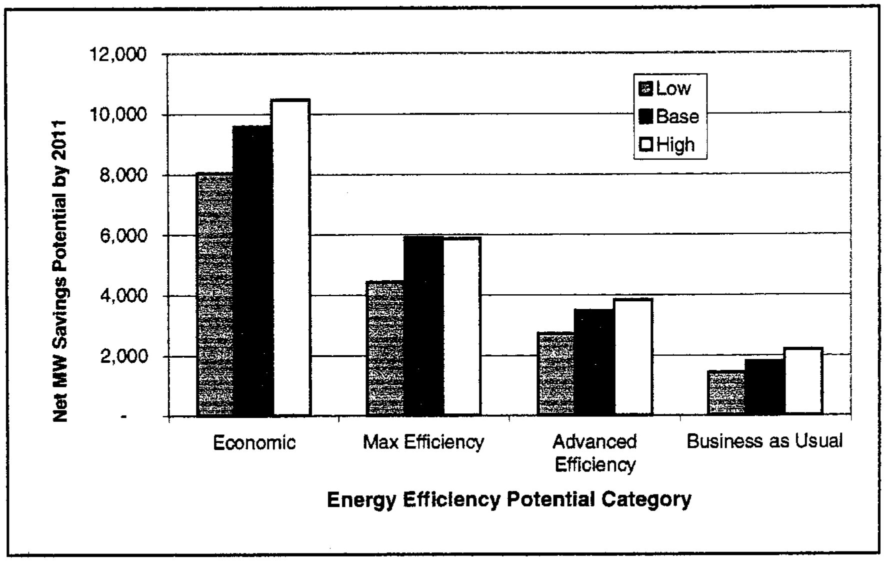
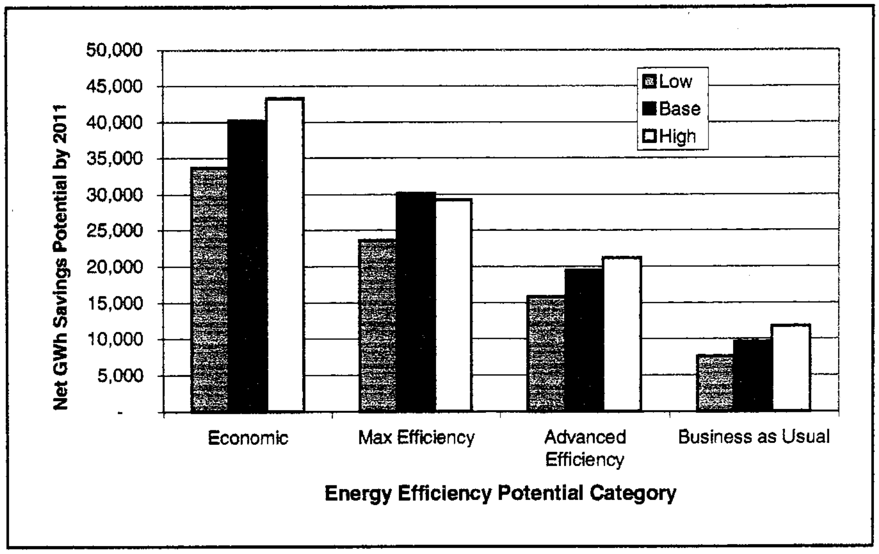
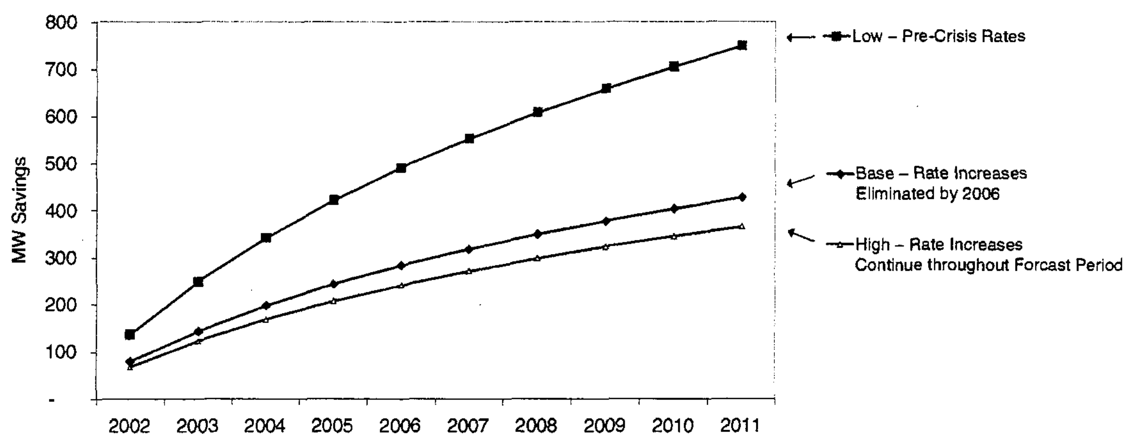


Figure 3-22
Potential Net Energy Savings Under Different Energy Cost Scenarios (2011)



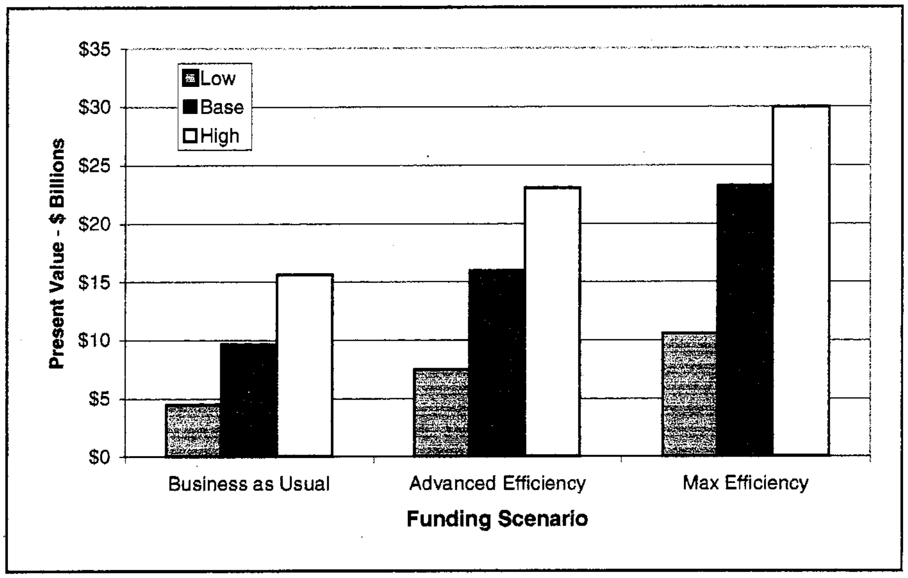
For the Business-as-Usual and Advanced Efficiency cases, the pattern of savings under the alternative energy cost scenarios is similar to the pattern of the economic potentials. However, for the Maximum Achievable case, estimated savings are proportionally lower under the Low scenario (that is, as would be expected given the relationship between the economic potentials), but not proportionally higher under the High scenario (net Maximum Achievable savings are actually very slightly *lower* under the High as compared to Base scenario). The reason for this is not immediately obvious: it is because naturally occurring energy-efficiency savings are significantly higher under the High as compared to Base energy costs. Naturally occurring savings are much higher under the High scenario because of the associated higher rate forecast. Under higher rates, more customers are forecasted to adopt measures in the absence of programs because measures become more economically attractive (paybacks are shorter and return on investments higher). This is shown in Figure 3-23. Naturally occurring peak demand savings are almost twice as high under the High as compared to Base energy cost scenarios (750 MW versus 430 MW by 2011). As a result, net Maximum Achievable savings are similar under the two scenarios.

Figure 3-23
Naturally Occurring Demand Savings Under Different Energy Cost Scenarios



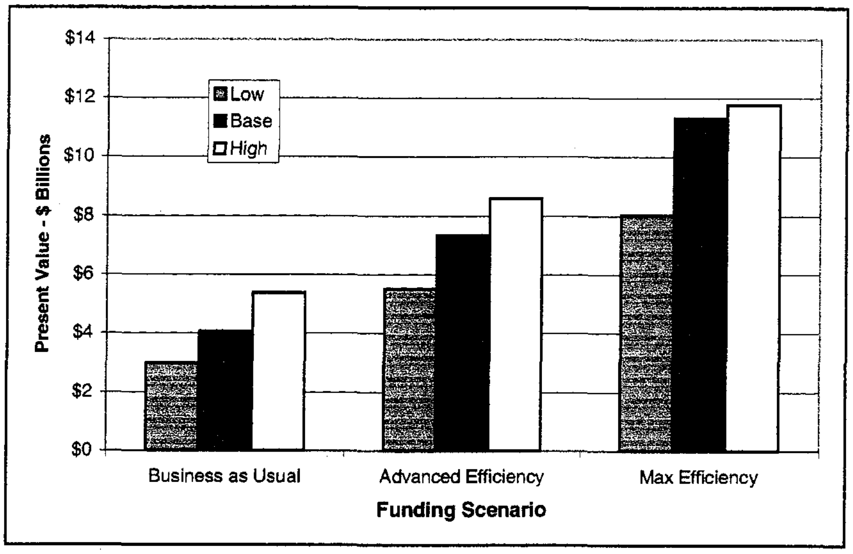
In Figure 3-24 we show total avoided cost savings for each achievable potential case under all three energy cost scenarios. A summary of the key scenario results is provided at the end of this section in Table 3-3. Total avoided cost savings are roughly 45 percent lower under the Low energy costs and 30 to 60 percent higher under the High scenario. Program costs under each scenario are shown in Figure 3-25. Program costs generally follow in proportion to the energy savings under each scenario. Net avoided-cost benefits, which are calculated as total avoided-cost benefits minus program costs and any remaining incremental measure costs to participants, are shown in Figure 3-26. The differences in net avoided costs are more extreme, with net avoided costs being 73 to 79 percent lower under the Low energy costs scenario and 53 to 85 percent higher under the High scenario. The net benefit scenario results are more extreme because the ratio of benefits to costs changes under each scenario, as does the amount of savings.

Figure 3-24
Total Avoided-Cost Benefits over 10 Years (2002-2011)*



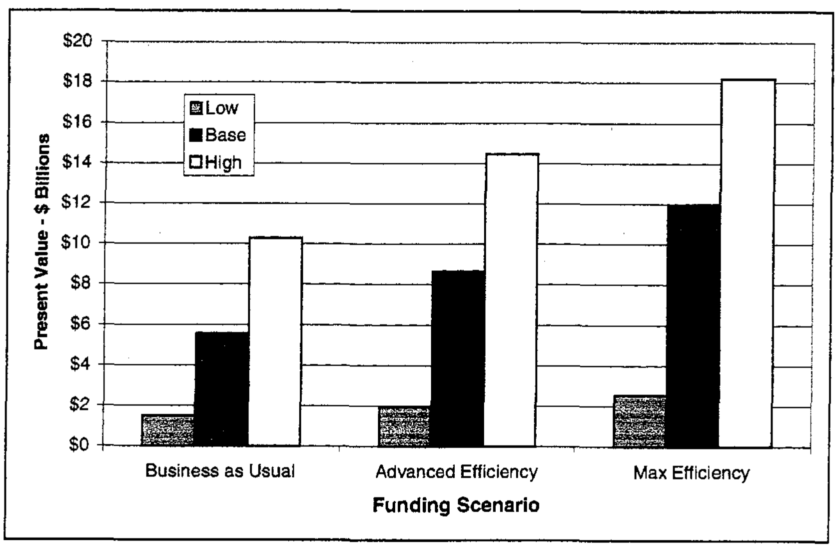
*Present value of avoided-cost benefits over normalized 20-year measure lives, nominal discount rate = 8 percent, inflation rate = 3 percent.

Figure 3-25
Total Program Costs over 10 Years (2002-2011)*



*Present value of program costs over normalized 20-year measure lives, nominal discount rate = 8 percent, inflation rate = 3 percent.

Figure 3-26
Net Avoided-Cost Benefits over 10 Years (2002-2011)*



*Present value of avoided cost benefits over normalized 20-year measure lives, nominal discount rate = 8 percent, inflation rate = 3 percent.

Figure 3-7
Achievable Electricity Savings—GWh per Year

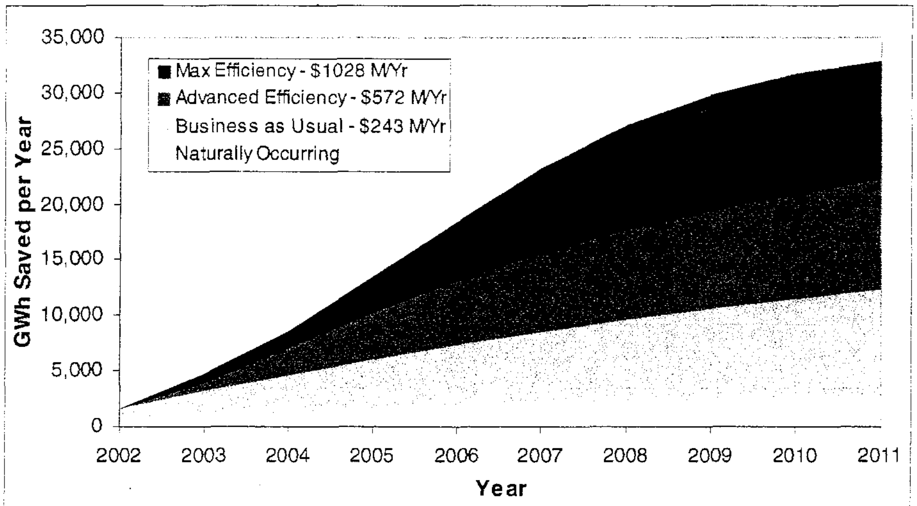
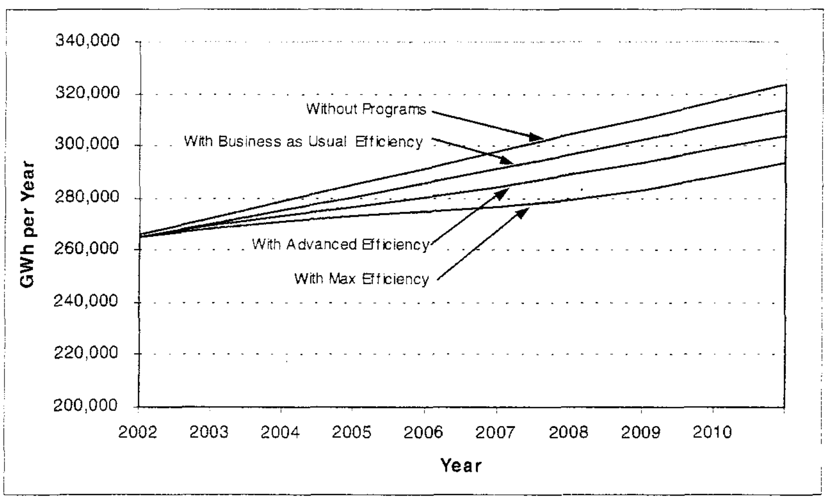


Figure 3-8
Electricity Forecast and Achievable Efficiency Potentials*



*No programs forecast based on CEC 2002.

Benefit-cost ratios are shown in Table 3-2. Benefit-cost ratios range from 2.4 to 2.1 under the Base scenario, to 1.5 to 1.3 under the Low cost scenario, to 2.9 to 2.5 under the High cost forecast. Perhaps somewhat surprisingly to some readers, even the Maximum Efficiency case is cost effective under all of the energy cost assumptions, even though virtually all of the measure costs are paid for by the efficiency program incentives. This is partly because incentives are treated as a societal transfer payment in the TRC test and do not affect it directly (see Appendix B for TRC definition). In addition, only those measures that pass the measure-level TRC test are included in the program forecasts.

Table 3-2
TRC Ratios under Different Scenarios

	Funding Level		
Cost Scenario	Business as Usual	Advanced Efficiency	Max Efficiency
Low	1.5	1.4	1.3
Base	2.4	2.2	2.1
High	2.9	2.7	2.5

While it is useful to know that all of the program potential forecasts were cost effective under all of our energy cost scenarios, cost-effectiveness screening does not answer the larger resource-planning question of how much energy efficiency is optimal from a societal or utility perspective. To determine the optimal mix of resources, a broader analytical framework is necessary, as we discuss in Section 5.

Table 3-3
Summary of 10-Year Net Achievable Potential Results (2002-2011) by Scenario*

Scenario	Result	Business-as-Usual	Advanced Efficiency	Max Efficiency
Base	Program Costs:	$2,003 M/Yr	$4,663 M/Yr	$8,196 M/Yr
	Participant Costs:	$2,052 M/Yr	$2,646 M/Yr	$3,111 M/Yr
	Benefits:	$9,604 M/Yr	$15,949 M/Yr	$23,203 M/Yr
	Net GWh Savings:	9,637	19,445	30,090
	Net MW Savings:	1,788	3,480	5,902
	Program TRC:	2.37	2.18	2.05
Low	Program Costs:	$1,569 M/Yr	$3,589 M/Yr	$5,917 M/Yr
	Participant Costs:	$1,394 M/Yr	$1,907 M/Yr	$2,089 M/Yr
	Benefits:	$4,454 M/Yr	$7,436 M/Yr	$10,542 M/Yr
	Net GWh Savings:	7,569	15,769	23,522
	Net MW Savings:	1,408	2,725	4,415
	Program TRC:	1.50	1.35	1.32
High	Program Costs:	$2,369 M/Yr	$5,098 M/Yr	$8,056 M/Yr
	Participant Costs:	$3,006 M/Yr	$3,478 M/Yr	$3,711 M/Yr
	Benefits:	$15,649 M/Yr	$23,036 M/Yr	$29,972 M/Yr
	Net GWh Savings:	11,733	21,146	29,199
	Net MW Savings:	2,178	3,824	5,862
	Program TRC:	2.91	2.69	2.55

*Present value of benefits and costs over 20-year normalized measure lives for 10 program years (2002-2011), nominal discount rate = 8 percent, inflation rate = 3 percent, GWh and MW savings are cumulative through 2011.

4. Conclusions, Implications, and Recommendations

In this section, we summarize our key conclusions from this study, discuss implications of the results for energy resource planning in California, and provide recommendations for further analysis and research.

4.1 Summary of Conclusions

Key conclusions from this study are summarized below:

- Over the next 10 years, there is significant remaining achievable and cost-effective potential for electric energy-efficiency[1] savings beyond the Business-as-Usual savings that are likely to occur under continuation of current public goods funding levels.

- Capturing this additional achievable potential would require an increase in public goods funding levels for energy-efficiency programs.

    - For example, doubling public goods funding levels could increase peak MW savings by 2011 from 1,800 MW (under the Business-as-Usual scenario) to roughly 3,500 MW (under the Advanced Efficiency scenario) and produce net benefits of $8.6 billion over the lives of the measures implemented.

- Most of the potential savings are obtainable from energy-efficiency measures that are readily available today, for example:

    - 1,400 MW from efficient fluorescent lighting in commercial/industrial facilities

    - 1,800 MW from high-efficiency air conditioners in all buildings and homes

    - 800 MW from compact fluorescent lamps in the residential sector

    - 1,500 MW from more efficient industrial processes and motor systems.

- There is considerable uncertainty in two of the principal forecasting inputs necessary for analyzing the cost-effectiveness of electric energy efficiency: the avoided-cost benefits of efficiency (that is, the energy purchases and investments in power plant capacity and transmission and distribution infrastructure that would be avoided if demand is decreased through greater efficiency)[2] and retail rates.

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[1] Recall that as defined in this study, in contrast to energy *conservation*, which often involves short-term behavioral changes, energy-*efficiency* opportunities are typically physical, long-lasting changes to buildings and equipment that result in decreased energy use while maintaining constant levels of energy service.

[2] See Appendix B for a presentation of the benefit-cost framework used for this study.

• Estimates of achievable potential under our Advanced Efficiency scenario are fairly robust when run against widely ranging scenarios of future energy costs; however, by definition, less of the technical potential for efficiency is cost effective under our Low energy cost scenario and more is cost effective under our High energy cost forecast.

• The largest gaps between our estimates of economic potential and Business-as-Usual achievable potential are in the residential and industrial sectors. That is, as compared with the commercial sector, a smaller percentage of the economic potential in the residential and industrial sectors is likely to be captured under the Business-as-Usual funding level.

• Although there was a significant amount of solid, empirical data upon which to build the analysis conducted for this study, several key data and methodological uncertainties require significant further work. The majority of these are discussed under the recommendations section at the end of this chapter.

4.2 Implications of Results for Energy Resource Planning

An issue of particular importance raised by this study is the need to move beyond static cost-effectiveness analysis of energy efficiency to a resource portfolio analysis in which the benefits and costs of all potential energy resources (demand and supply) are integrated.

4.2.1 What is the "Right" Amount of Efficiency Funding

As discussed in Section 3, all of the energy-efficiency funding scenarios analyzed in this study were cost effective based on the total resource cost (TRC) test, which the California Public Utilities Commission (CPUC) uses as its principal measure of the ratio of program benefits to program costs. (The TRC test is defined in Appendix B.) If all of the efficiency scenarios analyzed pass the TRC test, one may rightly wonder why current efficiency spending levels are only one-fourth of the highest level shown to be cost effective in this study.

There are several reasons for this. First, the amount of money spent on efficiency programs by the investor-owned utilities (IOUs) in California is directly related to the amount of money collected for such programs from the public goods charge (PGC) on customer bills. The PGC is authorized by SB 1194[3] at a minimum level of roughly $240 million per year. Although the law allows for the PGC to be increased, there is no clear process established for doing so. (Note that *short-term* funding for energy efficiency increased significantly in 2000 and 2001 through

[3] The minimum funding level for efficiency programs is determined by the PGC authorized in Senate Bill (SB) 1194 and signed into law by Governor Gray Davis in 2000. Under SB 1194, the major IOUs in California are required to collect the PGC through a surcharge on customer bills. The CPUC has regulatory authority over how the IOUs administer the funds.

special legislative action as the state faced an unprecedented supply shortage and price increases, but these were *one-time* temporary funding authorizations[4] separate from the PGC.)

Second, as shown in our scenario results, the amount of efficiency that is cost-effective to purchase is sensitive to assumptions about future avoided costs, about which there is considerable uncertainty. For example, economic potential under our Low energy cost forecast is about 16 percent lower than economic potential under the Base forecast. The uncertainty surrounding electricity and natural gas price forecasts and whether any of the California Department of Water Resources long-term power contracts can be restructured complicates analysis of the avoided-cost value of further reducing consumption in the future.

Third, as discussed below, use of a static cost-effectiveness test, like the TRC, does not provide all of the information necessary to determine the optimal level of investment in energy efficiency. Thus, although the Maximum Efficiency funding scenario in this study is shown to be cost effective based on the TRC test, policy makers and resource planners recognize that the test is designed to serve a *screening rather than optimization* function, and therefore would want to consider the option of increasing funds for efficiency programs against a full portfolio of other resource choices.

Thus, while it is useful to know that all of the achievable potential forecasts were cost effective under all of our future energy cost scenarios, static cost-effectiveness screening does not answer the larger resource-planning question of how much energy efficiency ought to be purchased through the public goods process. The TRC test, like other static benefit-cost tests, is useful for screening purposes but has a number of limitations when used as a basis for major resource planning decisions. For example, the TRC test uses fixed avoided-cost forecasts, does not explicitly consider the cost and availability of other resources (for example, renewable energy sources or demand response to time-differentiated pricing), does not consider location effects (e.g., areas facing transmission constraints), and does not take into account price volatility and risk. Ideally, avoided-cost values should change in a dynamic analytical process that allows response to changes in demand reduction, new power plant construction, supply from renewable energy, price-induced conservation behavior, and price volatilities. Clearly, in order to determine the optimal mix of resources, a broader analytical framework is necessary. Although developing such a framework is not a part of the current study, we see it as the next logical step in a process that is critical to putting California's mix of future electric resources back on track.

4.2.2 An Emerging Framework: Portfolio Management

Recently, a number of industry analysts have begun articulating a broad approach to resource planning that builds upon the lessons learned from both traditional resource planning and the results of electric restructuring. Among others, Harrington, et al., 2002, have articulated *portfolio management* as such an approach. They define portfolio management as:

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[4] These state funding bills included AB970, SB X1 5, and SB X1 29.

...the long run management of a diverse set of demand and supply side resources selected to minimize risks and long run costs, taking environmental costs into account. The essential characteristic of portfolio management is resource *diversity*. Not mindless diversity, but diversity carefully selected and managed to reduce risk, particularly the risk of price volatility, a salient feature of the wholesale markets.

Prior to electric industry restructuring, the objectives noted above for portfolio management would read reasonably well as the goals underlying the principal resource planning tool used in most of the United States: integrated resource planning (IRP). In that world, utilities were vertically integrated monopolies with the responsibility to build, own, and manage three key assets: generation, transmission, and distribution. Under IRP, many utilities were required to compare the costs, benefits, and functions of a wide array of demand- and supply-side resources, often under alternative future scenarios, to arrive at a well-balanced portfolio of resources that addressed multiple objectives, including minimization of long-term prices and the environmental impacts of electricity production and consumption.

With the advent of restructuring, many utilities, including California's IOUs, divested themselves of generation, and, in some cases, transmission. Under this unbundled market structure, no single entity could be seen as having control over the full suite of supply and demand resources as had been the case previously. Instead, virtually all resource choices were left to the restructured marketplace. This might not be a problem if the essential assumptions upon which theories of purely competitive markets are based were satisfied. Unfortunately, as described by Harrington, et al., 2002, there is strong evidence that these conditions have not been satisfied, and the results can be seen in a variety of failures including the fact that current markets "generally lack a demand response mechanism; transmission investments continue to be made on a planned socialized cost basis; no market participant is making trade-offs between supply- and demand-side options; and distribution companies in many states are trying to balance responsibilities between requirements for what may be very short-term generation needs versus longer-term distribution system operations."

Harrington, et al., 2002 go on to propose that the objectives of portfolio management are to obtain:

- System reliability
- Stable, affordable prices (including reduced price volatility)
- Minimized negative impact on the environment
- Markets untainted by market power
- System security
- The least costly mix of resources given the achievement of the preceding goals.

4.2.3 New Approaches Needed to Assess Risk-Reduction Benefits of Efficiency

We believe new analytical methods are needed to improve upon strategic resource planning processes developed during the period of IRP in the early 1990s. Research is needed that explicitly tackles the question of how investments in demand- and supply-side resources should be optimized in California. What is needed is an approach that builds on the lessons learned from both the IRP period of the late 1980s and early 1990s, and the market-based experiments of the last 6 years. Such an approach would require supply-side forecasts and integration analysis that explicitly incorporate price uncertainty, price volatility, and significant probabilities of future energy "events" such as supply shortages and concomitant price spikes.

Historically, as discussed above, the development of energy-efficiency strategy has been based on integrated resource plans. While this work was admirable, its core elements were based directly on supply planning, planning that was grounded on an investment paradigm that focused on the net present value of revenue and cost streams. By contrast, modern investment theory considers not only the revenue and cost streams, but also the uncertainty around those streams.

This consideration of risk causes modern finance to seek methods of risk mitigation that cause the risk taken to be commensurate with the likely return. The level of cost uncertainty or volatility seen in electricity markets is very high. To help protect ratepayers from future price uncertainty, we believe that energy providers and policy makers need to consider the full range of risk mitigation alternatives. Energy efficiency provides a clear risk management opportunity. The advantages of energy efficiency as a hedge should be analyzed against alternatives requiring market premiums within a process that achieves the overall goals of portfolio management.[5]

4.3 Recommendations for Further Efficiency Potential Research

Further research is needed to improve both the data and methods required for accurate estimation of electric energy-efficiency potential in California. The primary areas of research needed to reduce uncertainty in key inputs to efficiency potential estimates include the following:

- ***Improve estimates of current efficient measure saturation.*** Initial estimates of measure saturation data used for this study were obtained from sources for which data collection occurred in the mid-1990s (PG&E 1999, SDG&E 1999a, SCE 1996). These estimates of saturation were updated to our base year 2000 by estimating saturation accomplishments associated with the California utilities' programs from

[5] Renewable resources and price-responsive demand also appear to offer hedging benefits see, for example, Bolinger and Wiser, 2002 and Hirst 2002.

the mid-1990s to 2000. These estimates are uncertain. Fortunately, the California Energy Commission (CEC) is in the process of conducting two major updates to energy-efficiency saturation data for the commercial and residential sectors. New estimates of measure saturation that account for actions through 2002 will be available in the second half of 2003. Once available, these new saturation estimates should be used to update estimates of remaining potential in the state.

• ***Improve estimates of sustained conservation and efficiency resulting from 2001 energy crisis.*** As is well documented, the energy crisis of 2001 spawned a sharp drop in energy consumption and peak demand, much of which is hypothesized to be attributable to conservation behavior rather that efficient hardware improvements. For example, a recent study by Lawrence Berkeley National Laboratory (Goldman, Eto, Barbose 2002) estimates that about one-quarter of the 8-percent drop in peak demand in California in 2001 is attributable to equipment-based efficiency and on-site generation installations (which will persist for many years) while the remainder of the 2001 reduction in peak load (~3,000 MW) is attributable to behavioral and energy management practice changes for which it is difficult to predict the extent to which savings will persist. Because of the lack of adequate information available during the time of our study on the components and durability of energy and peak demand reductions in 2001, our study used 2000 as the base year for estimates of hardware-based electric efficiency. These estimates will need to be adjusted to account for both permanent efficiency improvements in 2001 (and 2002) and any sustained conservation behavior. On-going research is critically needed to better understand, characterize, and forecast the components of savings (that is, at the sector, end use, and measure level) associated with the 2001 energy crisis and the extent to which they persist.

• ***Improve estimates of efficiency potential for the industrial and new construction sectors.*** As noted in the introduction to this report, our study leverages two recent and comprehensive studies of efficiency potential (XENERGY 2002a and b) conducted for Pacific Gas & Electric Company (on behalf of the CPUC) and the CEC. These studies were conducted for the existing construction segment of the commercial and residential buildings sectors. Estimates of potential for the industrial and new construction sectors developed for the current study require significant expansion and enhancement to be on par with the research underlying the commercial and residential sectors. Fortunately, the CPUC has allocated funds in 2002 for developing and improving estimates of efficiency potential for these and other market segments.

• ***Improve forecasts and tracking of customer adoption of efficiency measures.*** Forecasting customer adoption of energy-efficient technologies and practices requires a strong empirical foundation. The key need in this area is further collection and development of historic and current measure penetration data to use as the basis for calibrating forecasting models like those used in this study (see Appendix B). A concurrent need is to develop a statewide database of measures adopted with public goods funds or other programmatic support. Currently, there is no measure-level database of all statewide program accomplishments available in a single, consistent format. There is also a need to improve tracking of measure adoption outside of programs (naturally occurring penetration as defined in Section 2 and Appendix B). Currently, there is a successful multi-year project to track the market share of energy-efficient products and practices in the residential sector (this work is managed by Southern California Edison on behalf of the CPUC with public goods funds, see RER 2002a and b); a related (though less comprehensive) project is in progress for the nonresidential sector (managed by the CEC also on behalf of the CPUC with public goods funds).

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APPENDIX A. ELECTRICITY USE IN CALIFORNIA

In this appendix we provide a background discussion of electricity use in California. We begin by presenting historical use for the State, and then focus on historic accomplishments of California energy-efficiency programs and policies. We then provide a short discussion comparing California energy use with the rest of the U.S. Finally, we discuss the California Energy Commission (CEC) electricity forecasts that form the base for our analysis.

A.1 Historic Electricity Consumption

California has long been one of the fastest growing states in the United States. Its population has grown from 20 million in 1970 to 34 million in 2000. The gross state product increased over the same period from $112 billion[1] to $1,260 billion. Because electricity use is strongly correlated with population and economic growth, the State's energy use has also increased over the past 40 years. The State's energy consumption and percent change in annual electricity use since 1960 are shown in Figure A-1. In the 13 years preceding the country's first energy crisis in 1973, electricity use in California almost tripled, from 50,000 GWh per year to almost 150,000 GWh per year. The annual rate of electricity growth during these years averaged over 5 percent per year. Over the following quarter century, the average rate of growth of electricity was significantly reduced in California. Electricity growth averaged 3.2 percent per year in the 1980s and only 2.2 percent per year in the 1990s.[2] In fact, while per capita electricity consumption has increased by 50 percent since 1973 in the United States[3] as a whole; remarkably, per capita use in California has been held constant. As a result, California is the nation's most efficient state in terms of per capita electricity consumption. As discussed in Section 3 of this report, much of this is likely a direct result of the State's conscious efforts to fund and promote energy efficiency through programs and state standards.

To understand and estimate the potential for further efficiency improvements in California's electrical energy use, it is important to understand how electricity is used in the State. Two key dimensions of electricity use are sector and end use. Sector refers to the type of customer using electricity (e.g., commercial, residential, etc.), while end use is a term used to refer to service desired by the electricity (e.g., lighting or cooling). Electricity use in California has long been dominated by

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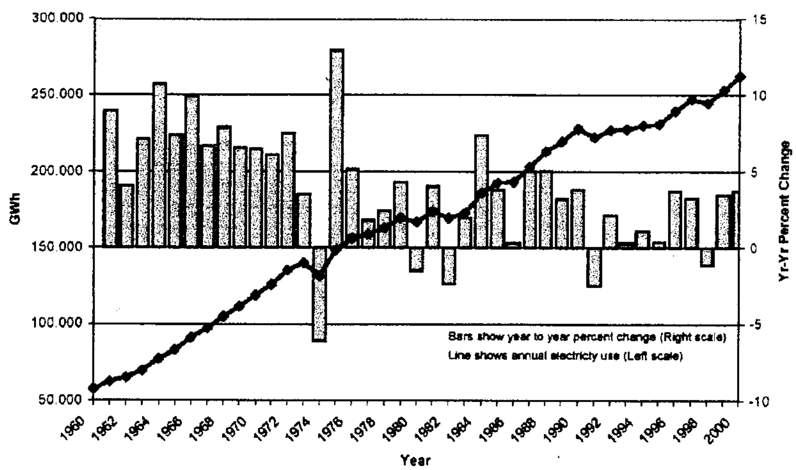
[1] Source: U.S. Department of Commerce, Bureau of Economic Analysis

[2] Brown, R.E. and Jonathan G. Koomey, 2002. *Electricity Use in California: Past Trends and Present Usage Patterns*, Review Draft, Lawrence Berkeley National Laboratory, LBNL-47992. January.

[3] Note that although per capita use in the US has grown significantly since the 1973 energy crisis, the 1.6 percent rate of growth was well below the 5 percent rate of annual growth in the fifteen years preceding the 1973 crisis.

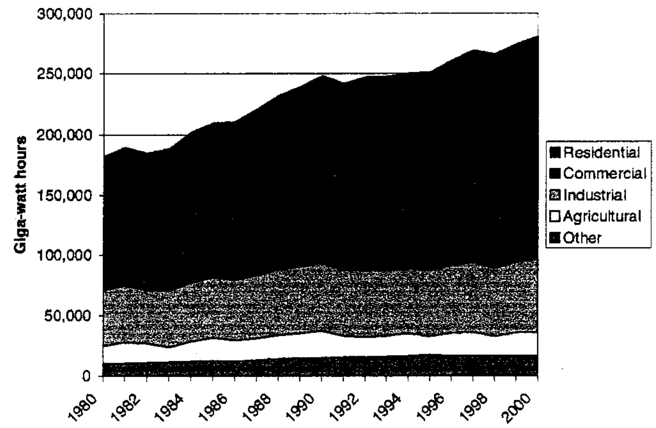
the residential, commercial, and industrial sectors, as shown in Figures A-2 and A-3. The commercial sector makes up the largest share of recent electricity consumption, representing 36 percent of the State's usage, followed by the residential sector at 30 percent and the industrial sector at 21 percent. The agricultural sector, which dominates the State's water use, makes up 7 percent of its electricity consumption, while other customers, such as transportation and street lighting accounted for the remaining 6 percent. In 1980, the commercial sector represented only 30 percent of total usage. Since 1980, the commercial sector has grown most rapidly, averaging 3 percent per year, while the industrial sector grew most slowly, averaging just 1.3 percent per year. Residential use grew by 2 percent per year over the same period.

Figure A-1
California Electricity Consumption: 1960 – 2000*



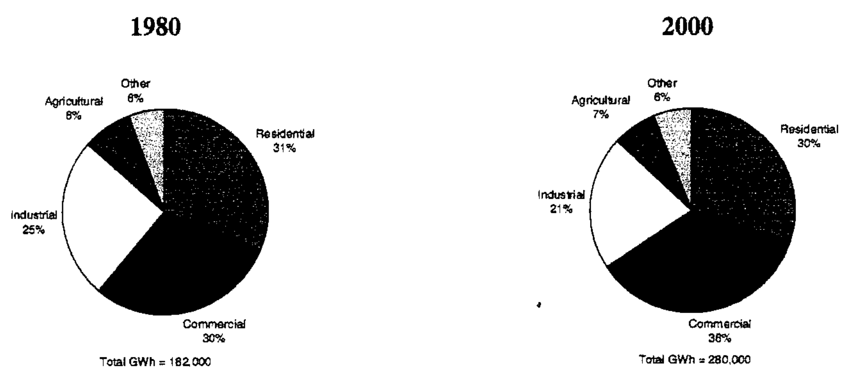
*Excludes line losses.
Source: California Energy Commission (CEC) 2001a. *2002 - 2012 Electricity Outlook*. P700-01-004.

Figure A-2
California Electricity Consumption by Sector: 1960 – 2000*



*Includes line losses.
Source: California Energy Commission (CEC) 2000. *California Energy Demand: 2000-2010*. P200-00-002.

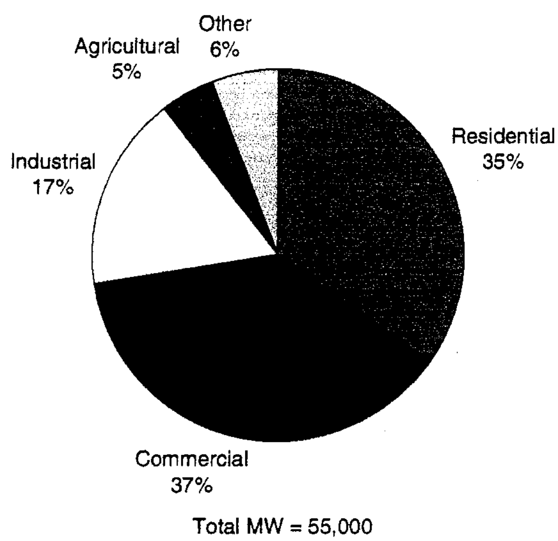
Figure A-3
Breakdown of California Electricity Use by Sector: 1980 and 2000



Source: Brown, R.E. and Jonathan G. Koomey, 2002 and CEC 2000. *California Energy Demand: 2000-2010*.

When we look at peak electrical demand in the State, shown in Figure A-4, we see that the commercial and residential sectors are even more significant, accounting for a combined 73 percent of peak load in 2000. Rates of growth for peak demand by sector have been similar to those for electricity consumption over the past 20 years.

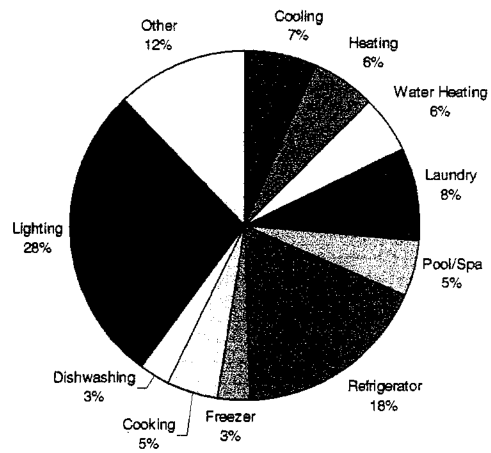
Figure A-4
California Peak Electricity Demand by Sector: 2000*



*Includes line losses.
Source: California Energy Commission (CEC) 2001a. *2002 - 2012 Electricity Outlook*. P700-01-004.

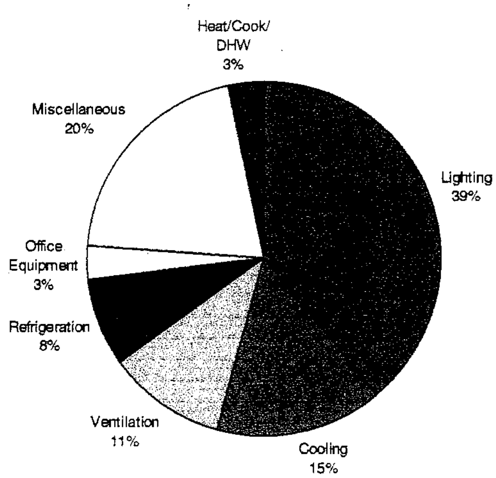
Electricity is used within each sector for a wide variety of purposes. For example, in the residential and commercial sectors, building occupants use electricity to obtain lighting, thermal comfort, refrigeration, and other services. In the industrial sector, electricity is used primarily to manufacture products that are used throughout all sectors of the economy. Agricultural electricity use provides for the pumping of water for crops and refrigeration for dairies. Electricity is used to provide street lighting and the movement of electric trains for mass transit systems. Figures A-5 through A-7 show the end-use breakdown for the three major energy consuming sectors: residential, commercial, and industrial.

Figure A-5
Residential Energy End-Use Breakdown, 2000



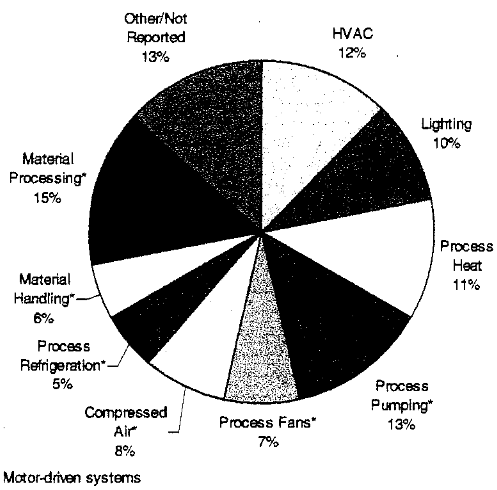
Source: CEC 2000. *California Energy Demand 2000-2010* and XENERGY analysis.

Figure A-6
Commercial Energy End-Use Breakdown, 2000



Source: CEC 2000. *California Energy Demand 2000-2010* and XENERGY analysis.

Figure A-7
Manufacturing Energy End-Use Breakdown, 2000



Source: U.S. DOE Manufacturing Energy Consumption Survey, Utility Billing Data, and XENERGY analysis.

Because California is a summer peaking state, that is, the maximum amount of electricity needed occurs during the hottest days of the summer, it should not be surprising that electricity to provide the cooling and ventilation of residential and commercial buildings accounts for the largest share of peak demand, roughly one-third of total, or approximately 16,000 MW of peak demand in 1999. Commercial lighting makes up the next single largest end-use share of peak demand at over 5,000 MW. Other key contributors to peak demand include industrial manufacturing (roughly 6,000 MW) and residential lighting and refrigerators (5,000 to 6,000 MW).[4] Key contributors to peak demand are presented graphically in Figure A-8.

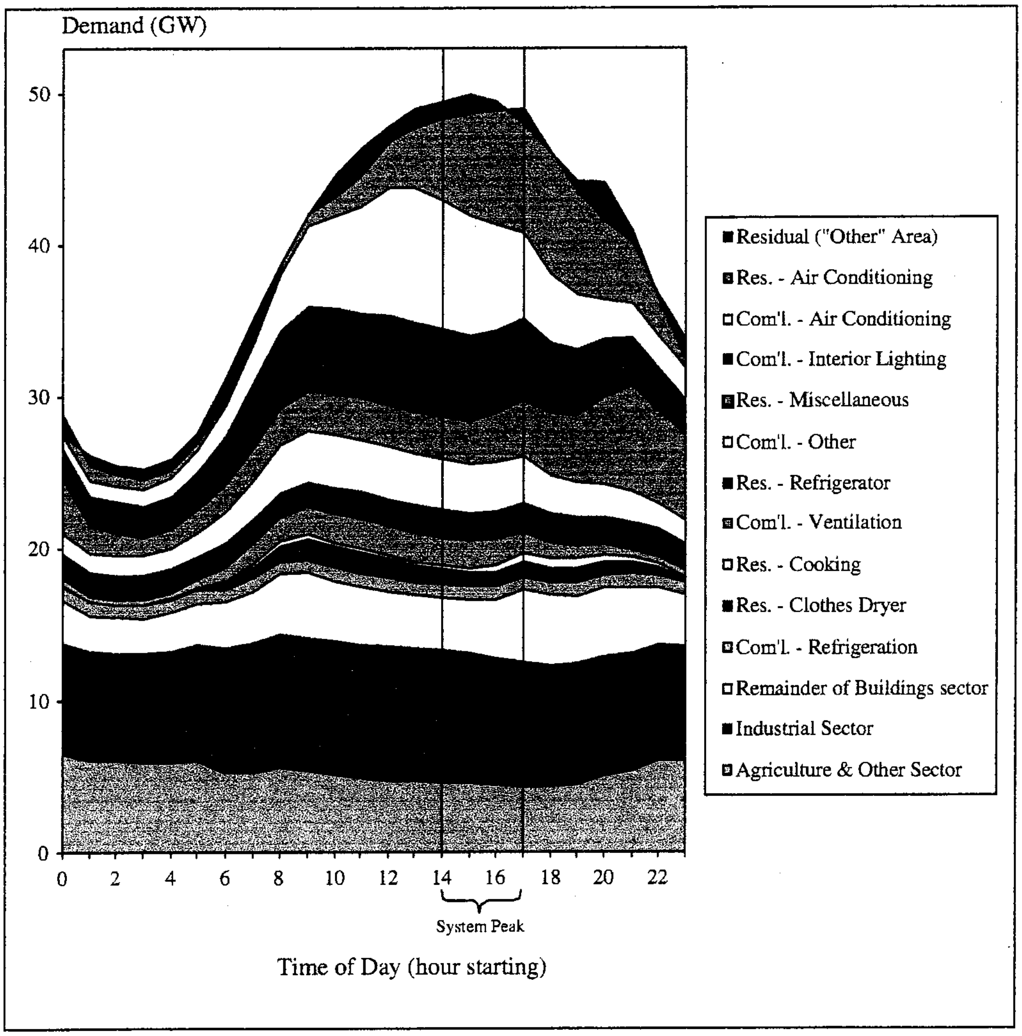
A.2 Historic Accomplishments of California Energy-Efficiency Programs and Policies

California has long been both a national and international leader in developing programs and policies aimed at increasing the efficiency with which electricity is used in the State's economy. Spending on programs, however, has increased and decreased, sometimes dramatically, over time. Some of the key milestones and trends in the 25-year history of efficiency programs in the State include the following:

[4] Figures cited are from Brown and Koomey's (2002) analysis of CEC and FERC data for 1999.

• In the mid-1970s, the State, through the CEC, developed comprehensive energy codes to require that new residential and commercial buildings and appliances meet minimum energy-efficiency standards. The CEC subsequently worked on 3-year cycles to continuously review and upgrade building standards. In 2001, the CEC adopted a set of emergency standards in response to the energy crisis.

Figure A-8
Largest Contributors to California Peak Demand



Source: Brown and Koomey 2002.

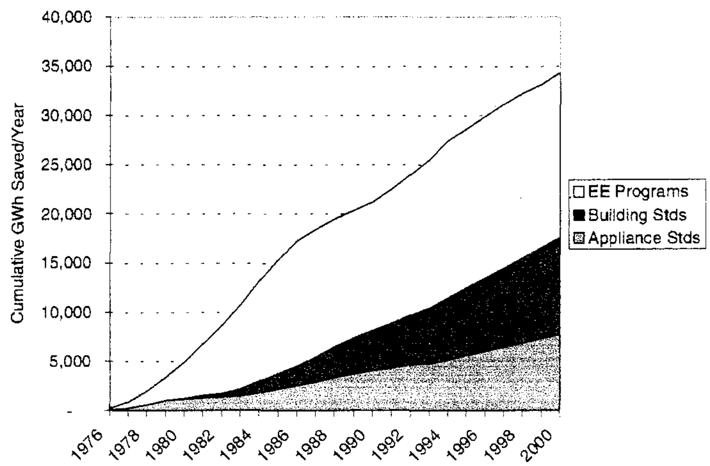
• In the late 1970s and 1980s, energy regulators and utilities developed and implemented the first utility-based energy savings programs for the State's major IOUs. These programs focused on squeezing out unnecessary energy waste and installing first-generation efficient equipment. Spending on these programs grew rapidly in the early 1980s but then plummeted in the late 80s as wholesale energy prices decreased.

• In the early 1990s, a group of government, utility, and public interest groups worked together to develop a process for reinvigorating investment in energy efficiency. The California Collaborative, as the group was known, developed an incentive mechanism that rewarded utilities for effective investments in energy-efficiency programs. The work of the Collaborative led to a new surge in efficiency investments that lasted until 1996, when the process of electric restructuring led to another dramatic drop in efficiency program spending.

• In the late 1990s, recognizing their long-term value to the State, California held programs and funding in place during restructuring, at a time when other states completely eliminated programs and funding. Nonetheless, programs in the late 1990s faced several challenges: funding levels were lower than during the earlier part of the decade, policy objectives shifted from resource acquisition to market transformation, and the nexus of program oversight shifted temporarily to the California Board for Energy Efficiency.

Savings from the State's appliance and building standards occur every year directly as a function of construction of new buildings and purchases of new appliances covered by the standards. Because standards require minimum efficiency levels, these savings are immediate and permanent and tend to follow building construction activity levels. Savings from efficiency programs, run primarily by utilities, vary over time mainly as a function of program expenditure levels. As shown in Figures A-9 and A-10, cumulative energy and peak demand savings from programs and standards were approximately 34,000 GWh per year and 9,000 MW, respectively, through the year 2000. Savings from energy-efficiency programs accounted for roughly half of the impacts.

Figure A-9
Energy Savings Impacts of Energy-Efficiency Programs and Standards

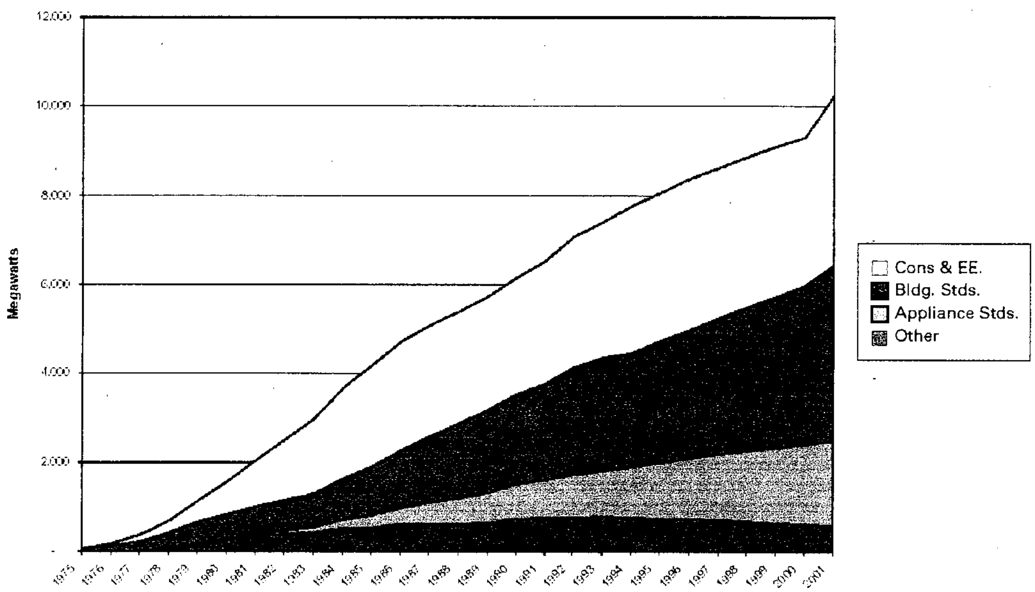


Source: Historic data compiled by CEC staff. Smith 2002.

Savings from energy-efficiency programs have varied widely throughout the past 25 years as a function of changes in annual funding levels. As shown in Figure A-11, spending levels have peaked twice, once in 1984 and once in 1993, while expenditure downturns and valleys occurred in the latter half of both the 1980s and the 1990s. These dramatic funding swings have reflected changes in policy makers' perceptions about energy prices and the need for new power plants, as well as philosophical shifts in the State's political and regulatory orientation. Expenditures increased in 2000 primarily because of the use of carryover funds that were not expended in previous years and a surge in program demand driven by the increase in wholesale and retail[5] electricity prices that occurred in the second half of the year.

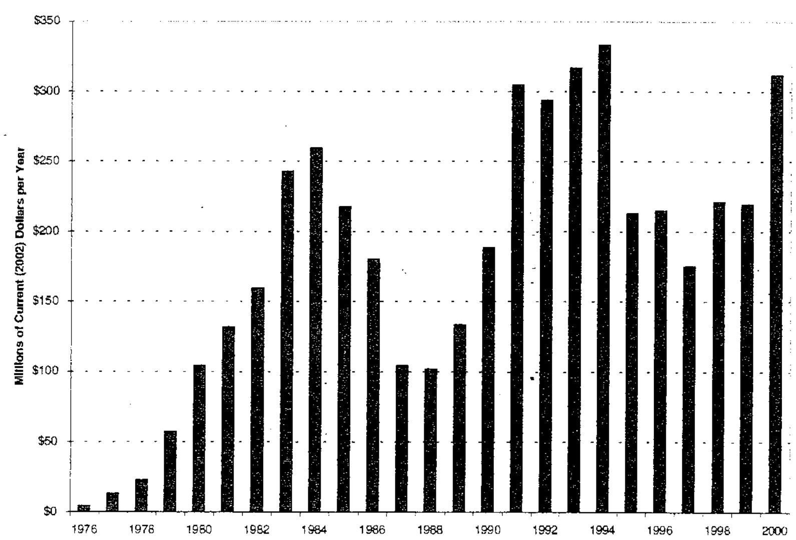
[5] Only customers in the SDG&E service territory were exposed to increased retail prices in the summer of 2000.

Figure A-10
Peak Demand Impacts of Energy-Efficiency Programs and Standards



Source: California State and Consumer Services Agency 2002

Figure A-11
Annual Electric Energy-Efficiency Program Expenditures for Major IOUs (in current dollars)



Source: Historic data compiled by CEC staff. Smith 2002.

Annual program impacts for major IOU electric efficiency programs are shown in Figures A-12 and A-13. The pattern of energy savings over time generally follows expenditure levels. First-year energy savings of 1,800 GWh have been achieved during spending peaks, but first-year savings have tended to average around 1,000 GWh. Peak demand savings have averaged around 200 MW but reached a peak of over 400 MW in 1994. Nonresidential program savings have accounted for an average of 80 percent of energy savings historically, but represented closer to 70 percent of savings in recent years.

Figure A-12
First-Year Electric Energy Savings for Major IOUs' Efficiency Programs

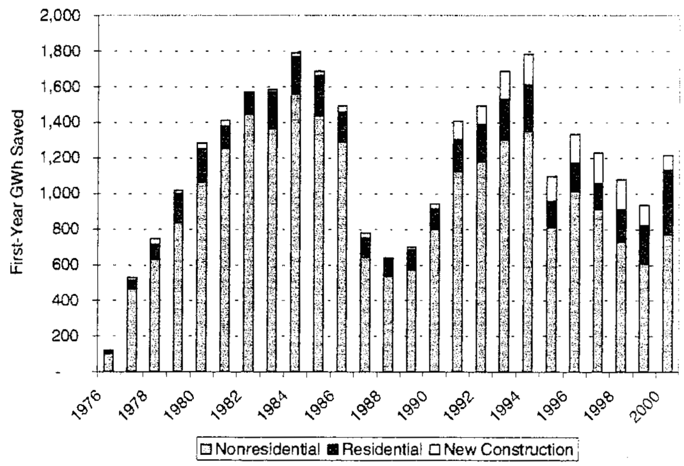
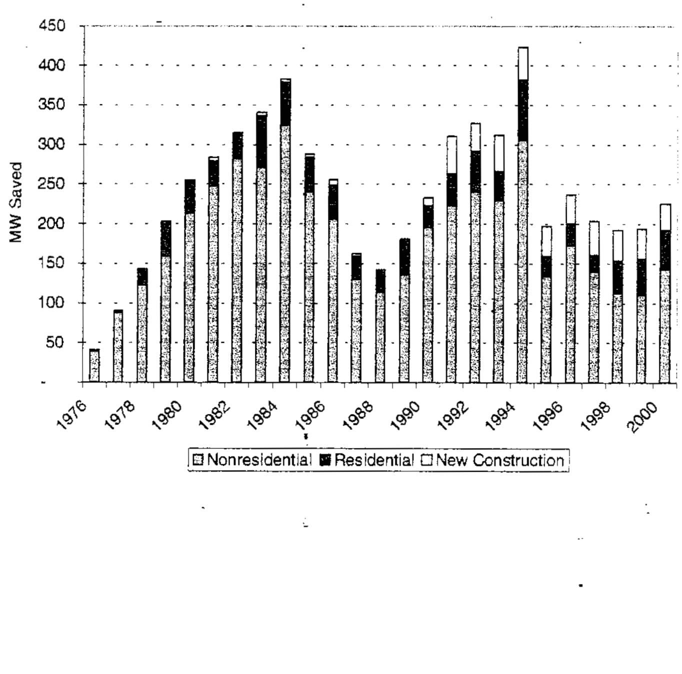
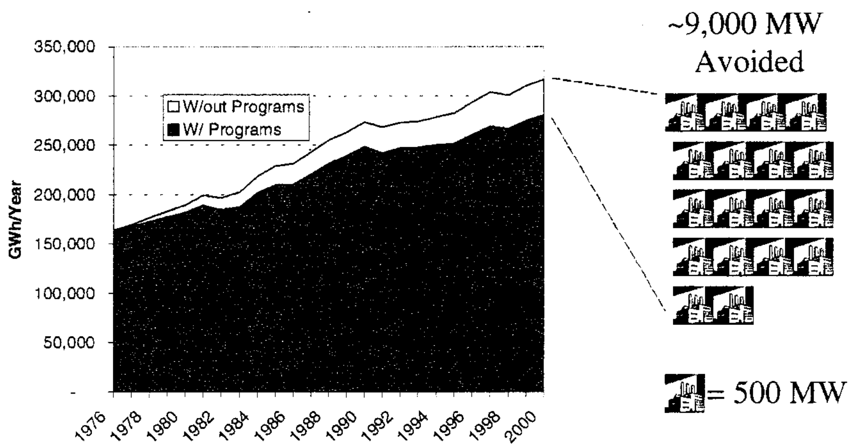


Figure A-13
First-Year Peak Demand Savings for Major IOUs' Efficiency Programs



The cumulative effect of California's efficiency programs and standards is shown in relation to actual energy consumption over the past 25 years in Figure A-14. According to CEC estimates, these programs and policies have resulted in savings of 9,000 MW, equivalent to avoiding construction of 18 500-MW power plants.

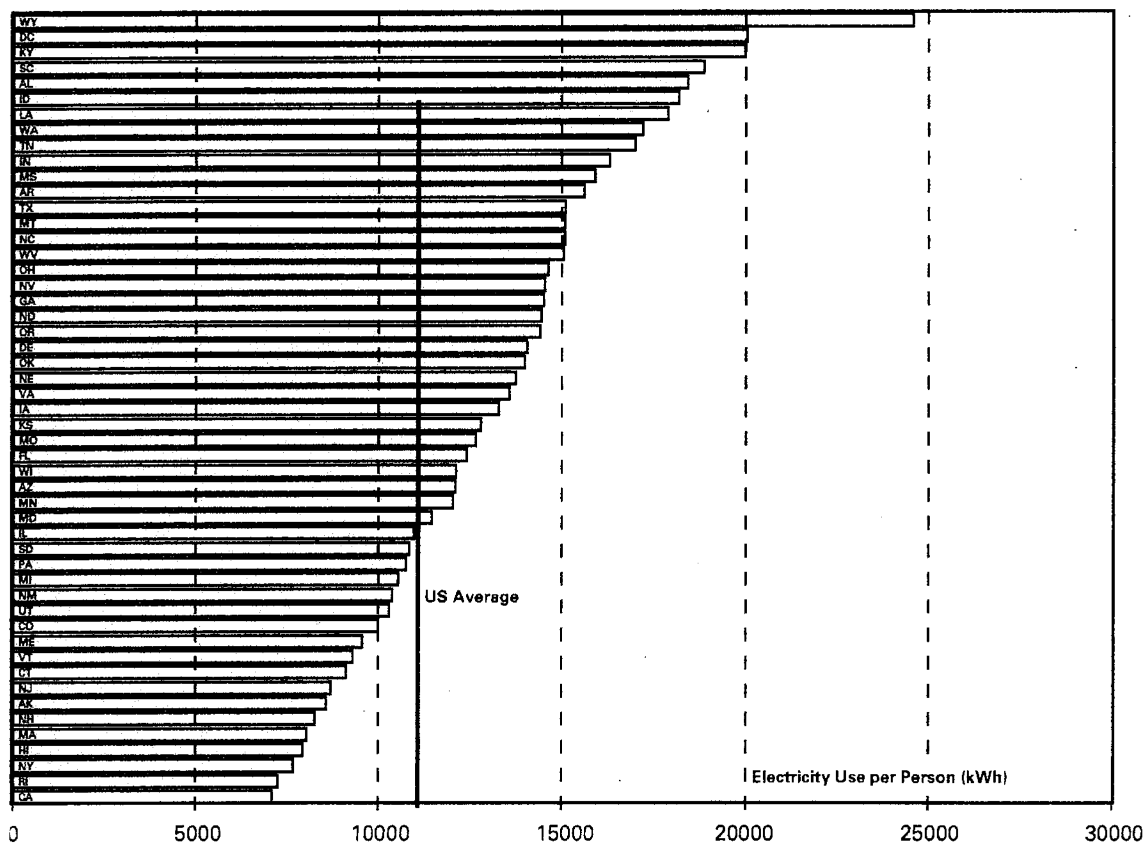
Figure A-14
Cumulative Impact of California Efficiency Programs and Standards



A.3 Efficiency of California Electrical Use Compared to Rest of U.S.

Partly as a result of the State's assertive energy programs and policies, California is the nation's most efficient state in terms of per capita electricity consumption, as shown in Figure A-15. Electricity use in California and the rest of the U.S. is a function of many factors. Generally, electricity use increases during times of increased economic activity and population growth and decreases or remains flat during periods of weak economic activity or net decreases in population growth. Electricity use changes as a result of another key factor: *efficiency*. Efficiency measures the amount of work or useful services that are obtained from a unit of energy consumed. The more efficient an energy-using system, the more work or useful service, such as light or heat, that is obtained per unit of energy consumed. Note that *efficiency* is not the same as *conservation*. Conservation involves using less of a resource, usually through behavioral changes, such as raising a thermostat setting from 75° to 78° F for air conditioning on a hot day. As a result of the availability of gains from efficiency and conservation, the relationship between economic growth and electricity use is far from constant.

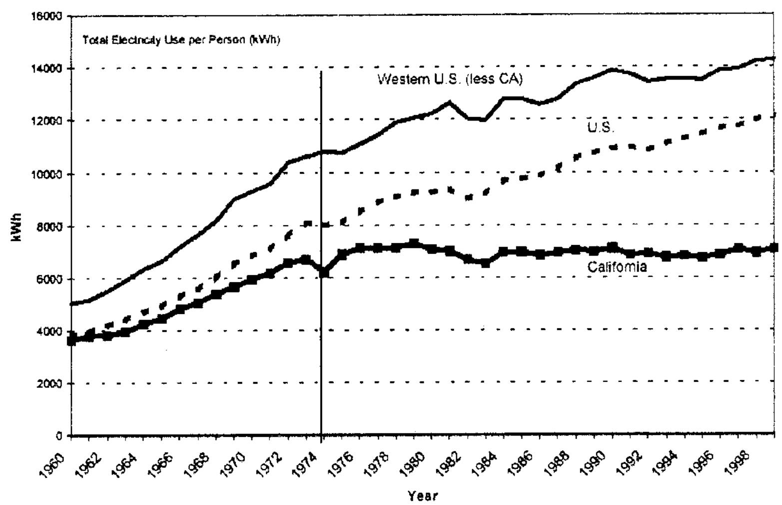
Figure A-15
California is Most Efficient: per Capita Electricity Consumption by State



Source: California Energy Commission (CEC) 2001a.2002 - *2012 Electricity Outlook*. P700-01-004.

As shown in Figure A-16, since 1974 electricity use per person in the U.S. has grown at an annual rate of 1.7 percent. Over the same time period, however, per capita electricity use in California has remained almost constant, growing at only 0.1 percent per year; while per capita use in the rest of the western U.S. grew at 1.2 percent. Because of its focus on continuously improving its energy standards and efficiency programs, California has become the nation's most efficient state in terms of per capita electricity use. Had California's per capita electricity use increased at the same rate as did the rest of the country's over the last quarter century, peak demand in the State would have been 15,000 MW higher than it was in 2000. This would have required the construction and siting of roughly 30 additional major power plants throughout the State.

Figure A-16
Electricity Consumption per Capita: 1960 - 2000



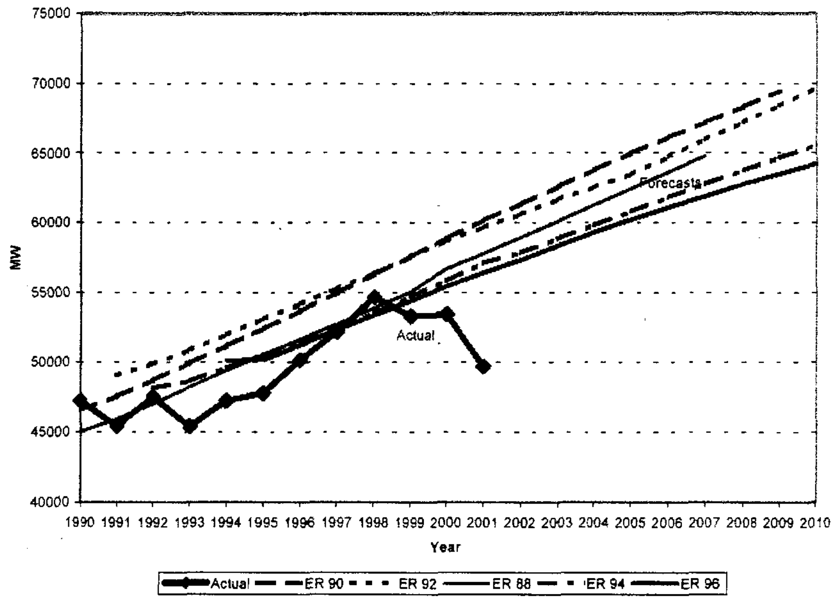
Source: California Energy Commission (CEC) 2001a. *2002 - 2012 Electricity Outlook*. P700-01-004.

A.4 CEC Forecasts of Future Consumption and Peak Demand

A.4.1 Historic Forecasts

To estimate energy-efficiency potential over time, it is necessary to benchmark savings to a forecast of electricity consumption. Fortunately, in California there is a consistent statewide process in place for electricity forecasting at the CEC. The CEC has conducted such forecasts for many years. Throughout much of the 1980s and 1990s, these forecasts were produced as part of biannual Electricity Reports (ER). Examples of forecasts produced for 1988 (ER88) through 1996 (ER96) are shown in Figure 2-11. Note that the historic forecasts assume normal weather and economic conditions. Actual consumption and peak demand in any given year can vary considerably in response to these to conditions.

Figure A-17
CEC Peak Demand Forecasts Versus Actual



Source: California Energy Commission (CEC) 2001a. *2002 - 2012 Electricity Outlook*. P700-01-004.

A.4.2 2001: An Extraordinary Year

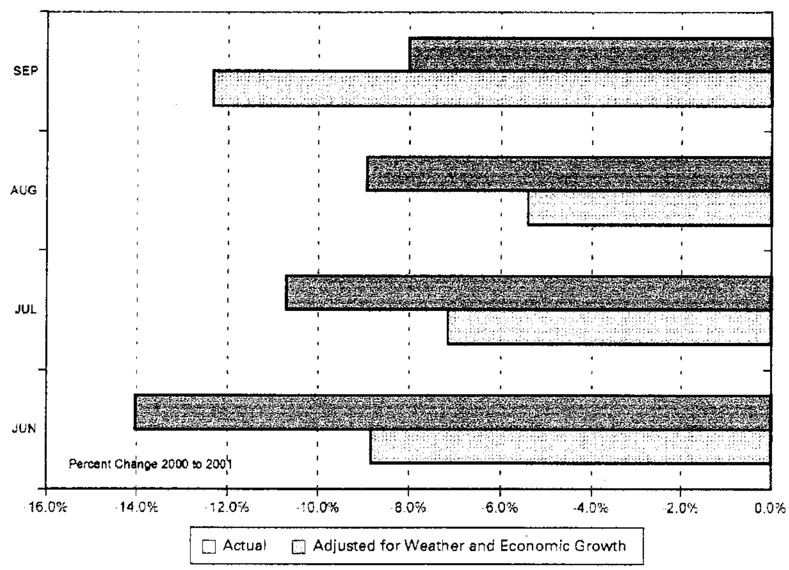
On average, the CEC's forecasts have proven fairly accurate over time; however, like virtually all forecasts, the CEC's methods are not intended to predict extraordinary changes in usage associated with unexpected events like the energy crisis experienced in the second half of 2000 and most of 2001. As has been documented extensively elsewhere, energy consumption and peak demand decreased dramatically in 2001. This reduction is shown on a monthly basis, normalized for changes in weather and economic conditions, in Figure A-18. This reduction occurred as the result of a combination of voluntary demand response from consumers and installation of energy-efficient equipment spurred both by the crisis itself and increased energy-efficiency program efforts.[6,7] The fraction

[6] For an analysis of the 2001 summer demand reduction, see *The Summer 2001 Conservation Report*, published by the California State and Consumer Services Agency, produced by the CEC under the direction of the Governor's Conservation Team, February 2002.

[7] According to CEC 2001a, key factors driving both voluntary and hardware changes included demand reduction programs, electricity price increases, the 20/20 rebate program, winter rolling outages, and media exposure of the energy crisis and its potential costs to the State and consumers.

of the reduction in 2001 attributable to voluntary conservation efforts versus installation of major energy-efficient equipment[8] is not currently known with certainty. However, it is likely that the majority of the reduction was due to voluntary conservation efforts. For example, Goldman et al. (2002), estimate that roughly 70 percent of Summer 2001 peak demand reduction was attributable to voluntary conservation efforts.

Figure A-18
Summer 2001 Peak Demand Reductions



Source: California Energy Commission (CEC) 2001a. *2002 - 2012 Electricity Outlook*. P700-01-004.

A.4.3 Current Forecast Scenarios

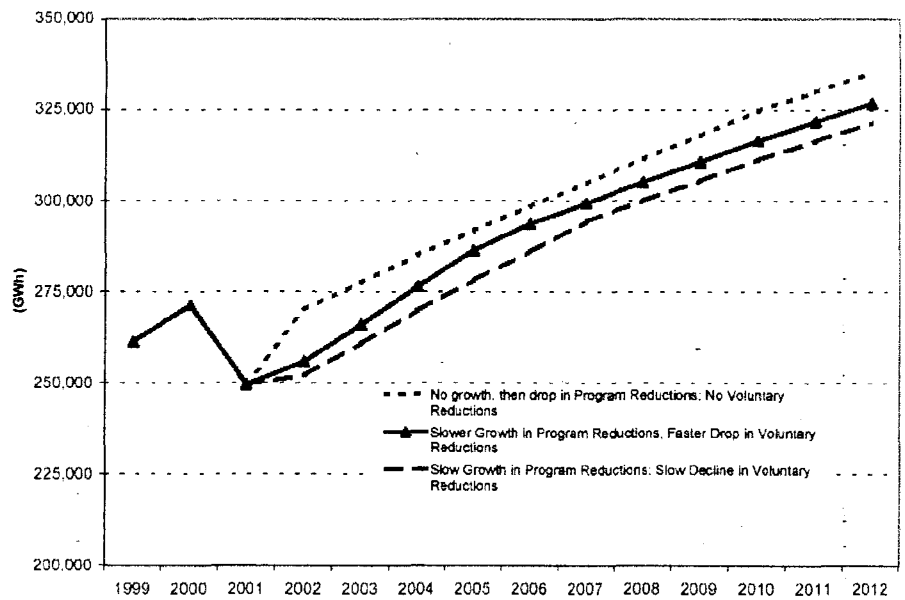
In response to the extraordinary reduction in peak demand and consumption that occurred in 2001, the CEC's latest forecast deviates from its previous forecasting approach, in that it focuses on scenarios rather than single-point estimates over time. According to the CEC (2001a):

[8] *Conservation* refers here to behavioral changes in energy use, such as turning up thermostat settings during cooling periods; *efficiency* refers to permanent changes in equipment that result in increased energy service per unit of energy consumed, e.g., the installation of a more efficient air conditioner.

The uncertainty about what caused the demand reduction in the summer of 2001, in particular, the uncertainty about how much was due to temporary, behavioral changes and how much was due to permanent, equipment changes, contributes to increased uncertainty about future electricity use trends. To capture this uncertainty about future electricity use, three scenarios were developed. These scenarios combine different levels of temporary and permanent reductions to capture a reasonable range of possible electricity futures.

The CEC developed several possible patterns of future trends in summer 2001 demand reductions. These patterns were based on alternative assumptions about the level and persistence of voluntary impacts and permanent, program impacts. (Note that *program* impacts, as used in the CEC's forecast scenarios, refer to the emergency program efforts initiated in response to the State's energy crisis, i.e., programs funded under SB 5X, AB 970, and AB 29X, not the public goods charge-based efficiency programs administered primarily by the State's major IOUs.) The CEC developed three scenarios, one of which was selected as the most likely case, while the other two scenarios represent higher and lower cases. Figures A-19 and A-20 show these energy and peak demand forecast scenarios.

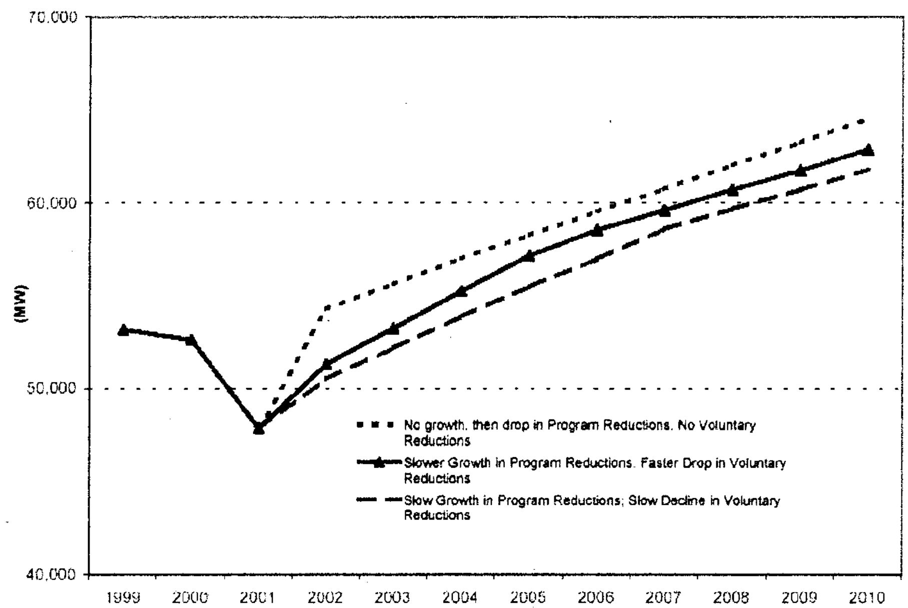
Figure A-19
CEC Energy Consumption Forecasts



Source: California Energy Commission (CEC) 2001a. *2002 - 2012 Electricity Outlook.* P700-01-004.

The electricity demand forecast scenario the CEC believes is the most likely scenario, is labeled "Slower Growth in Program Reductions; Faster Drop in Voluntary Reductions" and assumes that program impacts increase in 2002 but stay constant after that, while voluntary impacts decrease more rapidly. Under this scenario, 50 percent of the peak load reductions that occurred in 2001 persist for several years. The lower demand forecast scenario, labeled "Slow Growth in Program Reductions; Slow Decline in Voluntary Reductions," assumes that program impacts grow from 2001 to 2006 while impacts of voluntary reductions drop slowly over the period after an initial drop of 1,000 MW in 2002. Under the lower scenario, roughly 75 percent of 2001 reductions persist. The higher scenario, labeled, "No growth, then drop in Program Reductions; No Voluntary Reductions," assumes that there are no impacts from voluntary actions in 2002 and after, while impacts of programs stay constant until 2005 and then start declining. Under the higher scenario, only about 13 percent of the 2001 reductions persist.

Figure A-20
CEC Peak Demand Forecasts



Source: California Energy Commission (CEC) 2001a. *2002 - 2012 Electricity Outlook*. P700-01-004.

A.4.4 Use of 2000 for Base Energy and Peak Demand for this Study

Note that for this study we relied primarily on data from the CEC's previous energy forecast (CEC 2000), which predated the unprecedented drop in peak demand and energy use that occurred in response to the energy crisis. As a result, our estimates of efficiency potential presented in this report are exclusive of voluntary, behavioral reductions and efficiency improvements that occurred in 2001.

Appendix B. Methodology Details

B.1 Overview

In this section, we elaborate on the methods used to conduct this study that were introduced in Section 2. We explain the specific steps and methods employed at each stage of the analytical process necessary to produce the results presented in this report. As outlined in Section 2, these steps are:

1) Develop initial input data

2) Estimate technical potential and develop supply curves

3) Estimate economic potential

4) Estimate maximum achievable, program, and naturally occurring potentials

5) Perform scenario analysis.

B.2 Step 1: Develop Initial Input Data

B.2.1 Development of Measure List

This subsection briefly discusses how we developed the list of energy-efficiency measures included in the study for the residential, commercial, and industrial sectors. The study scope was restricted to energy-efficiency measures and practices that are presently commercially available. These are measures that are of most immediate interest to energy-efficiency program planners. The study data, framework, and models can be easily changed, however, to include estimates of potential for emerging technologies. In addition for the retrofit markets, the scope of this study was focused on measures that could be relatively easily substituted for or applied to existing technologies on a retrofit basis. Thus, measures and savings that might be achieved through integrated redesign of existing energy-using systems, as might be possible during major renovations or remodels, are not included. This is another area in which the current results can be expanded upon.

For the residential and commercial sectors, the measure lists were developed by starting with the list of measures included in the *DEER 2001 Update Study* (XENERGY 2001c), with some aggregation to prototypical applications. The measure list for the DEER Update study was developed in consultation with a CALMAC stakeholder group that included the major IOUs, California Energy Commission (CEC), and California Public Utilities Commission (CPUC). We then reviewed the recent program application filings of the major investor-owned utilities (IOUs) to the CPUC and added measures that might have significant potential but were not on the *DEER 2001 Update Study* list.

For the industrial lighting and space cooling end uses, the efficiency measures from the commercial measure list were employed, as we deemed the measures affecting these end uses to be sufficiently similar between the two sectors. Industrial motors, compressed air, and other process measures were developed from several sources including the *California Industrial Sector Market Characterization Study* (XENERGY 2001d), the *United States Industrial Motor Systems Market Opportunities Assessment* (XENERGY 1998b), the *Assessment of the Market for Compressed Air Services* (XENEGY 2000a), Lawrence Berkeley National Laboratories (LBNL) industry studies (Martin 1999, Martin 2000a, Martin 2000b, Worrell, 1998, Worrell 1999), and recent program filings submitted to the CPUC by IOUs and third parties.

B.2.2 Technical Data on Efficient Measure Opportunities

Estimating the potential for energy-efficiency improvements requires a comparison of the costs and savings of energy-efficiency measures as compared to standard equipment and practices. Standard equipment and practices are often referred to in energy-efficiency analysis as *base cases*. For the residential and commercial sectors, most of the measure cost data for this study were obtained from the *DEER 2001 Update Study*. Additional measure cost information was obtained from the work papers associated with the energy-efficiency program applications of the major IOUs for 2001, as well as other secondary sources and interviews with utility program managers and other industry experts. For the industrial sector, studies cited in the previous paragraph were also utilized to develop cost estimates.

Estimates of measure savings as a percentage of base equipment usage were developed from a variety of sources, including:

- Industry-standard engineering calculations
- Results from building energy simulation model analysis conducted for the California Conservation Inventory Group's *Technology Energy Savings Study* (NEOS 1994)
- Results from the *DEER 2001 Update Study* for residential measures
- A comprehensive refrigeration study conducted by LBNL (LBNL 1995)
- Energy-efficiency program applications to the CPUC
- Secondary sources.

B.2.3 Technical Data on Building Characteristics

As noted above, estimating the potential for energy-efficiency improvements involves comparison of the energy impacts of existing, standard-efficiency technologies with those of alternative high-efficiency equipment. This, in turn, dictates a relatively detailed understanding of the statewide energy characteristics of each energy-consuming sector. As described further in Section B.3, a variety of data are needed to estimate the average and total savings potential for individual measures across the entire California marketplace. The key data needed for our representation of California electricity consumption included:

- Total count of energy-consuming units (floor space of commercial buildings, number of residential dwellings, and the base kWh-consumption of industrial facilities)

- Annual energy consumption for each end use studied (both in terms of total consumption in GWh and normalized for intensity on a per-unit basis, e.g., kWh/ft^2)

- End-use load shapes (that describe the amount of energy used or power demand over certain times of the day and days of the year)

- The saturation of electric end uses (for example, the fraction of total commercial floor space with electric air conditioning)

- The market share of each base equipment type (for example, the fraction of total commercial floor space served by 4-foot fluorescent lighting fixtures (CFLs)

- Market share for each energy-efficiency measure in scope (for example, the fraction of total commercial floor space already served by CFLs).

These key data elements are discussed briefly in the following subsections.

Floor Space, Dwellings, and End-Use Energy Consumption

The primary source of commercial floor space, residential dwellings, and their associated end-use energy consumption data was the CEC end-use forecasting database. In the end-use forecasting approach, end-use energy consumption is expressed as the product of consuming units (building floor space/residential dwellings), the fraction of units associated with a given end use (the end-use saturation), and the energy intensity of the end use (commercial EUIs, expressed in kWh per square foot, and residential UECs, expressed in kWh per dwelling). These three data elements have been collected and estimated from various sources over time and form the foundation upon which the CEC energy demand forecasts are developed.

For the industrial sector, end use energy consumption was developed from the *California Industrial Sector Market Characterization Study*. In this study, end-use energy fractions developed from MECS (the U.S. DOE Manufacturing Energy Consumption Survey) were applied to utility billing data at the 2-digit SIC code level to provide end-use consumption estimates.

Load Shapes, Energy and Peak Factors

Load shape data was used to develop energy and peak factors. Energy and peak factors are used to allocate annual energy usage and associated measure impacts into utility costing periods and to provide estimates of peak demand savings based on cost period energy usage. The factors were developed by end-use, building type, and where possible, California IOU service area. The analysis by costing period is necessary because avoided-cost benefits (which are described later in this section) vary significantly by time of day, type of day, and month of year.

In the case of the electric energy factors, these factors are computed based on predefined costing periods (e.g., season, day of the week, and hours of the day) divided by annual energy use. The end result is a series of values for each period such that the sum of the periods is equal to one. Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric typically use costing definitions that differ very slightly from each other. To maintain consistency of our study's results across the utilities, we choose one utility's costing periods to use for our analysis. The costing period definitions used for this study are shown in Table B-1.

Table B-1
Costing Period Definitions Used for Electric Energy Factors

	Season	
Period	Summer (May 1 - Oct 31)	Winter (All Other Months)
Peak	1 P.M. to 6 P.M. Weekdays	(none)
Partial-Peak	9 A.M. to 12 P.M. Weekdays 7 P.M. to 9 P.M. Weekdays	9 P.M. to 9 P.M. Weekdays
Off-Peak	10 P.M. to 8 P.M. Weekdays All Weekends and Holidays	10 P.M. to 8 P.M. Weekdays All Weekends and Holidays

The peak factors are based on the same predefined periods as the energy factors. In this case, the peak demand within a cost period is divided by the average demand within that same period; that is, the peak factor is the ratio of peak to average demand in a period. This is done for both noncoincident demands as well as for coincident demands. In the case of coincident demands, the time of coincidence was set to be the time at which the California electric system typically peaked within each marginal costing period. The most important of these periods, from a cost and reliability perspective is the Summer Peak Period. Our analysis indicated that 4 P.M. corresponded to the maximum system peak as registered by the California Independent System Operator in 2000. Our estimates of peak demand by end use were developed to correspond to a 4 P.M. system peak.

Base Technology Shares (Applicability Factors)

The technology or equipment mix within an end use determines the applicability of energy-efficiency measures for that end use. For example, high-efficiency DX air conditioning measures are only applicable to the portion of the space cooling end use that is served by DX air conditioning (as opposed to other air conditioning equipment such as central plant chillers). Data on base technology shares were developed from a number of sources, including:

- The CEC end-use forecasting database
- Utility commercial end-use surveys (CEUS)
- Utility residential appliance saturation surveys (RASS)
- LBNL reports on commercial refrigeration (LBL-37397) and office equipment (LBL-37397)
- The *United States Industrial Motor Systems Market Opportunities Assessment*
- The *California Industrial Sector Market Characterization Study.*

Existing Energy-Efficient Measure Saturations

To assess the amount of energy-efficiency savings available, estimates of the current saturation of energy efficient measures are necessary. The primary sources of data used for the measure saturation estimates were:

- The utility CEUS studies
- The *Statewide Residential Lighting and Appliance Saturation Study* (RLW 2000)
- The California Residential Market Share Tracking Studies (RER 2000b, RER 2002a, RER 2002b)
- The *United States Industrial Motor Systems Market Opportunities Assessment.*

In some cases, judgmental adjustments to these saturation estimates were required to bring them up to date because the available sources were several years old. In these cases, we examined program tracking data to estimate increases in measure saturation that were likely to have occurred between the time each source-study was conducted and the present.

B.3 Step 2: Estimate Technical Potential and Develop Energy-Efficiency Supply Curves

As defined previously, **technical potential** refers to the amount of energy savings or peak demand reduction that would occur with the *complete* penetration of all measures analyzed in applications where they were deemed *technically* feasible from an *engineering* perspective. Total technical potential is developed from estimates of the technical potential of individual measures as they are applied to discrete market segments (commercial building types, residential dwelling types, etc.).

B.3.1 Core Equation

The core equation used to calculate the energy technical potential for each individual efficiency measure, by market segment, is shown below (using a commercial example):[1]

Technical Potential of Efficient Measure	=	Total Square Feet	X	Base Case Equipment EUI(kWh/ft^2)	X	Applicability Factor	X	Not Complete Factor	X	Feasibility Factor	X	Savings Factor

where:

- **Square feet** is the total floor space for all buildings in the market segment. For the residential analysis, the **number of dwelling units** is substituted for square feet.

- **Base-case equipment EUI** is the energy used per square foot by each base-case technology in each market segment. This is the consumption of the energy-using equipment that the efficient technology replaces or affects. For example, if the efficient measure were a CFL, the base EUI would be the annual kWh per square foot of an equivalent incandescent lamp. For the residential analysis, unit energy consumption (UECs), energy used per dwelling, are substituted for EUIs.

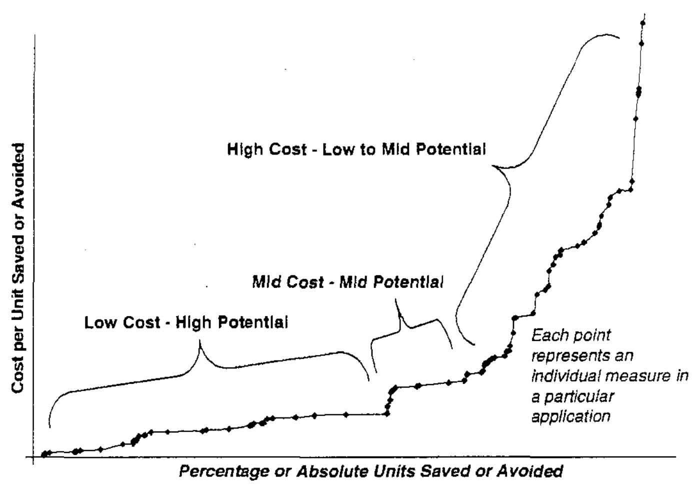
- **Applicability factor** is the fraction of the floor space (or dwelling units) that is applicable for the efficient technology in a given market segment, for the example above, the percentage of floor space lit by incandescent bulbs.

[1] Note that stock turnover is not accounted for in our estimates of technical and economic potential, stock turnover *is accounted for* in our estimates of achievable potential as described in Section B.5.1. Our definition of technical potential assumes instantaneous replacement of standard efficiency with high-efficiency measures.

B.3.2 Use of Supply Curves

In the second step cumulative technical potential is estimated using an energy-efficiency supply curve approach.[2] This method eliminates the double-counting problem. In Figure B-1, we present a generic example of a supply curve. As shown in the figure, a supply curve typically consists of two axes—one that captures the cost per unit of saving a resource or mitigating an impact (e.g., \$/kWh saved or \$/ton of carbon avoided) and the other that shows the amount of savings or mitigation that could be achieved at each level of cost. The curve is typically built up across individual measures that are applied to specific base-case practices or technologies by market segment. Savings or mitigation measures are sorted on a least-cost basis and total savings or impacts mitigated are calculated incrementally with respect to measures that precede them. Supply curves typically, but not always, end up reflecting diminishing returns, i.e., as costs increase rapidly and savings decrease significantly at the end of the curve.

Figure B-1
Generic Illustration of Energy-Efficiency Supply Curve



[2] This section describes conservation supply curves as they have been defined and implemented in numerous studies. Readers should note that Stoft 1995 describes several technical errors in the definition and implementation of conservation supply curves in the original and subsequent conservation supply curve studies. Stoft concludes that conservation supply curves are not "true" supply curves in the standard economic sense but can still be useful (albeit with his recommended improvements) for their intended purpose (demonstration of cost-effective conservation opportunities).

- **Not complete factor** is the fraction of applicable floor space (or dwelling units) that has not yet been converted to the efficient measure; that is, (one minus the fraction of floor space that already has the energy-efficiency measure installed).

- **Feasibility factor** is the fraction of the applicable floor space (or dwelling units) that is technically feasible for conversion to the efficient technology from an *engineering* perspective.

- **Savings factor** is the reduction in energy consumption resulting from application of the efficient technology.

Technical potential for peak demand reduction is calculated analogously.

An example of the core equation is shown in Table B-2 for the case of a prototypical 75-Watt incandescent lamp, which is replaced by an 18-Watt CFL in the office segment of the SCE service territory.

Table B-2
Example of Technical Potential Calculation – Replace 75-W Incandescent with 18-W CFL in the Office Segment of the SCE Service Territory

Technical Potential of Efficient Measure =	Total Square Feet	X Base Case Equipment EUI(kWh/ft²)	X Applicability Factor	X Not Complete Factor	X Feasibility Factor	X Savings Factor
7.7 Million kWh	471 million	11.4	0.011	0.20	0.90	0.72

Technical energy-efficiency potential is calculated in two steps. In the first step, all measures are treated *independently*; that is, the savings of each measure are not marginalized or otherwise adjusted for overlap between competing or synergistic measures. By treating measures independently, their relative economics are analyzed without making assumptions about the order or combinations in which they might be implemented in customer buildings. However, the total technical potential across measures cannot be estimated by summing the individual measure potentials directly. The cumulative savings cannot be estimated by adding the savings from the individual savings estimates because some savings would be double counted. For example, the savings from a measure that reduces heat gain into a building, such as window film, are partially dependent on other measures that affect the efficiency of the system being used to cool the building, such as a high-efficiency chiller; the more efficient the chiller, the less energy saved from the application of the window film.

As noted above, the cost dimension of most energy-efficiency supply curves is usually represented in dollars per unit of energy savings. Costs are usually annualized (often referred to as "levelized") in supply curves. For example, energy-efficiency supply curves usually present levelized costs per kWh or kW saved by multiplying the initial investment in an efficient technology or program by the "capital recovery rate" (CRR):

$$\text{CPR} = \frac{d}{1-(1+d)^{-n}}$$

where *d* is the real discount rate and *n* is the number of years over which the investment is written off (i.e., amortized).

Thus,

Levelized Cost per kWh Saved = Initial Cost x CRR/Annual Energy Savings

Levelized Cost per kW Saved = Initial Cost x CRR/Peak Demand Savings

The levelized cost per kWh and kW saved are useful because they allow simple comparison of the characteristics of energy efficiency with the characteristics of energy supply technologies. However, the levelized cost per kW saved is a biased indicator of cost-effectiveness because all of the efficiency measure costs are arbitrarily allocated to peak savings. To address this bias, Koomey, et al. (1990a and b) recommend calculation of the conservation load factor (CLF), which allows efficiency measures and supply options to be calculated together on a traditional energy supply screening curve. The CLF is calculated as:

CLF = Average Annual Load Savings/Peak Load Savings

where average annual load savings are the annual savings divided by 8,760 hours per year and peak savings are the reductions coincident with the system peak hour.

Our estimates of levelized costs per kWh and kW saved, along with estimates of CLF, are presented in Appendix C for each of the measures analyzed in this study.

Returning to the issue of energy-efficiency supply curves, Table B-3 shows a simplified numeric example of a supply curve calculation for several energy-efficiency measures applied to commercial lighting for a hypothetical population of buildings. What is important to note is that in an energy-efficiency supply curve, the measures are sorted by relative cost: from least to most expensive. In addition, the energy consumption of the system being affected by the efficiency measures goes down as each measure is applied. As a result, the savings attributable to each subsequent measure decrease if the measures are interactive. For example, the occupancy sensor measure shown in Table B-3 would save more at less cost per unit saved if it were applied to the base-case consumption before the T8 lamp and electronic ballast combination. Because the T8 electronic ballast combination is more cost-effective, however, it is applied first, reducing the energy savings potential for the occupancy sensor. Thus, in a typical energy-efficiency supply curve, the base-case end-use consumption is reduced with each unit of energy-efficiency that is acquired. Notice in Table B-3 that the total end-use GWh consumption is recalculated after each measure is implemented, thus reducing the base energy available to be saved by the next measure.

Table B-3 shows an example that would represent measures for one base-case technology in one market segment. These calculations are performed for all of the base-case technologies, market segments, and measure combinations in the scope of the study. The results are then ordered by levelized cost and the individual measure savings summed to produce the energy-efficiency potential for the entire sector (as presented in Section 3 of this report).

In the next subsection, we discuss how economic potential is estimated as a subset of the technical potential.

Table B-3
Sample Technical Potential Supply Curve Calculation for Commercial Lighting
(Note: Data are illustrative only)

Measure	Total End Use Consumption of population (GWh)	Applicable, Not Complete and feasible (1000s of ft^2)	Average kWh/ft^2 of population	Savings %	GWh Savings	Levelized Cost ($/kWh)
Base Case: T12 lamps with Magnetic Ballast	425	100,000	4.3	N/A	N/A	N/A
1. T8 w. Elec. Ballast	425	100,000	4.3	21%	89	$0.04
2. Occupancy Sensors	336	40,000	3.4	10%	13	$0.11
3. Perimeter Dimming	322	10,000	3.2	45%	14	$0.25
With all measures	309		3.1	27%	116	

B.4 Step 3: Estimate Economic Potential

Economic potential is typically used to refer to the *technical potential* of those energy conservation measures that are cost effective when compared to either supply-side alternatives or the price of energy. Economic potential takes into account the fact that many energy-efficiency measures cost more to purchase initially than do their standard-efficiency counterparts. The incremental costs of each efficiency measure are compared to the savings delivered by the measure to produce estimates of energy savings per unit of additional cost. These estimates of energy-efficiency resource costs can then be compared to estimates of other resources such as building and operating new power plants.

B.4.1 Cost Effectiveness Tests

To estimate economic potential, it is necessary to develop a method by which it can be determined that a measure or program is *economic.* There is a large body of literature in which the merits of different approaches to calculating whether a public purpose investment in energy efficiency is cost effective are debated (Chamberlin and Herman 1993, RER 2000, Ruff 1988, Stoft 1995, and Sutherland 2000). In this report, we adopt the cost-effectiveness criteria used by the CPUC in its decisions regarding the cost-effectiveness of energy-efficiency programs funded under the State's public goods charge. The CPUC uses the total resource cost (TRC) test, as defined in the California Standard Practice Manual (CASPM 2001), to assess cost effectiveness. The TRC is a form of societal benefit-cost test. Other tests that have been used in analysis of program cost-effectiveness by energy-efficiency analysts include the utility cost, ratepayer impact measure (RIM), and participant tests. These tests are discussed in detail the CASPM.

Before discussing the TRC test and how it is used in this study, we present below a brief introduction to the basic tests as described in the CASPM:[3]

- **Total Resource Cost Test** - The TRC test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The test is applicable to conservation, load management, and fuel substitution programs. For fuel substitution programs, the test measures the net effect of the impacts from the fuel not chosen versus the impacts from the fuel that is chosen as a result of the program. TRC test results for fuel substitution programs should be viewed as a measure of the economic efficiency implications of the total energy supply system (gas and electric). A variant on the TRC test is the societal test. The societal test differs from the TRC test in that it includes the effects of externalities (e.g. environmental, national security), excludes tax credit benefits, and uses a different (societal) discount rate.

[3] These definitions are direct excerpts from the California Standard Practice Manual, October 2001.

• **Participant Test** - The participant test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

• **Utility (Program Administrator) Test** - The program administrator cost test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits. Costs are defined more narrowly.

• **Ratepayer Impact Measure Test** - The ratepayer impact measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.

The key benefits and costs of the various cost-effectiveness tests are summarized in Table B-4.

Table B-4
Summary of Benefits and Costs of California Standard Practice Manual Tests

Test	Benefits	Costs
Total Resource Cost Test	Generation, transmission and distribution savings Participants avoided equipment costs (fuel switching only)	Generation costs Program costs paid by the administrator Participant measure costs
Participant Test	Bill reductions Incentives Participants avoided equipment costs (fuel switching only)	Bill increases Participants measure costs
Utility (Program Administrator) Test	Generation, transmission and distribution savings	Generation costs Program costs paid by the administrator Incentives
Ratepayer Impact Measure Test	Generation, transmission and distribution savings Revenue gain	Generation costs Revenue loss Program costs paid by the administrator Incentives

Generation, transmission and distribution savings (hereafter, energy benefits) are defined as the economic value of the energy and demand savings stimulated by the interventions being assessed. These benefits are typically measured as induced changes in energy consumption, valued using some mix of avoided costs. Statewide values of avoided costs are prescribed for use in implementing the test. Electricity benefits are valued using three types of avoided electricity costs: avoided distribution costs, avoided transmission costs, and avoided electricity generation costs.

Participant costs are comprised primarily of incremental measure costs. Incremental measure costs are essentially the costs of obtaining energy efficiency. In the case of an add-on device (say, an adjustable-speed drive or ceiling insulation), the incremental cost is simply the installed cost of the measure itself. In the case of equipment that is available in various levels of efficiency (e.g., a central air conditioner), the incremental cost is the excess of the cost of the high-efficiency unit over the cost of the base (reference) unit.

Administrative costs encompass the real resource costs of program administration, including the costs of administrative personnel, program promotions, overhead, measurement and evaluation, and shareholder incentives. In this context, administrative costs are not defined to include the costs of various incentives (e.g., customer rebates and salesperson incentives) that may be offered to encourage certain types of behavior. The exclusion of these incentive costs reflects the fact that they are essentially transfer payments. That is, from a societal perspective they involve offsetting costs (to the program administrator) and benefits (to the recipient).

B.4.2 Use of the Total Resource Cost to Estimate Economic Potential

We use the TRC test in two ways in this study. First, we develop an estimate of economic potential by calculating the TRC of individual measures and applying the methodology described below. Second, we develop estimates of whether different program scenarios are cost effective.

Economic potential can be defined either inclusively or exclusively of the costs of programs that are designed to increase the adoption rate of energy-efficiency measures. *In this study, we define economic potential to <u>exclude</u> program costs.* We do so primarily because program costs are dependent on a number of factors that vary significantly as a function of program delivery strategy. There is no single estimate of program costs that would accurately represent such costs across the wide range of program types and funding levels possible. Once an assumption is made about program costs, one must also link those assumptions to expectations about market response to the types of interventions assumed. Because of this, we believe it is more appropriate to factor program costs into our analysis of *maximum achievable and program potential*. Thus, our definition of *economic potential* is that portion of the technical potential that passes our economic screening test (described below) exclusive of program costs. Economic potential, like technical potential, is a theoretical quantity that will exceed the amount of potential we estimate to be achievable through current or more aggressive program activities.

As implied in Table B-4 and defined in the CASPM 2001, the TRC focuses on resource savings and counts benefits as utility avoided supply costs and costs as participant costs and utility program costs. It ignores any impact on rates. It also treats financial incentives and rebates as transfer payments; i.e., the TRC is not affected by incentives. The somewhat simplified benefit and cost formulas for the TRC are presented in Equations B-1 and B-2 below.

$$\text{Benefits} = \sum_{t=1}^{N} \frac{\text{Avoided Costs of Supply}_{p,t}}{(1+d)^{t-1}} \qquad \textbf{Eqn. B-1}$$

$$\text{Costs} = \sum_{t=1}^{N} \frac{\text{Program cost}_t + \text{Participant Cost}_t}{(1+d)^{t-1}} \qquad \textbf{Eqn. B-2}$$

where
d = the discount rate
p = the costing period
t = time (in years)
n = 20 years

A nominal discount rate of 8 percent is used, as required by the CPUC for program filings by major IOUs in 2001.[4] We use a *normalized* measure life of 20 years to capture the benefit of long-lived measures. Measures with measure lives shorter than 20 years are "re-installed" in our analysis as many times as necessary to reach the normalized 20-year life of the analysis.

The avoided costs of supply are calculated by multiplying measure energy savings and peak demand impacts by per-unit avoided costs by costing period.[5] Energy savings are allocated to costing periods and peak impacts estimated using the load shape factors discussed in Section B.2.3.

As noted previously, in the *measure-level* TRC calculation used to estimate economic potential, program costs are excluded from Equation B-2. Using the supply curve methodology discussed previously, measures are ordered by TRC (highest to lowest) and then the *economic* potential is calculated by summing the energy savings for all of the technologies for which the marginal TRC test is greater than 1.0. In the example in Table B-5, the economic potential would include the savings for measures 1 and 2, but exclude saving for measure 3 because the TRC is less than 1.0 for measure 3. The supply curve methodology when combined with estimates of the TRC for individual measures produces estimates of the economic potential of efficiency improvements. By definition and intent, this estimate of economic potential is a theoretical quantity that will exceed the amount of potential we estimate to be achievable through program activities in the final steps of our analyses.

[4] We recognize that the 8-percent discount is much lower than the implicit discount rates at which customers are observed to adopt efficiency improvements. This is by intent since we seek at this stage of the analysis to estimate the potential that is cost-effective from primarily a societal perspective. The effect of implicit discount rates is incorporated into our estimates of program and naturally occurring potential.

[5] The per-unit avoided-cost values used in this study are shown in Appendix B.

Table B-5
Sample Use of Supply Curve Framework to Estimate Economic Potential
(Note: Data are illustrative only)

Measure	Total End Use Consumption of Population (GWh)	Applicable, Not Complete and Feasible Sq. Feet(000s)	Average kWh/ft² of Population	Savings %	GWh Savings	Total Resource Cost Test	Savings Included in Economic Potential?
Base Case: T12 lamps with Magnetic Ballast	425	100,000	4.3	N/A	N/A	N/A	N/A
1. T8 w. Elec. Ballast	425	100,000	4.3	21%	89	2.5	Yes
2. Occupancy Sensors	336	40,000	3.4	10%	13	1.3	Yes
3. Perimeter Dimming	322	10,000	3.2	45%	14	0.8	No
Technical Potential w. measures				27%	116		
Economic Potential w. measures for which TRC>1.0				24%	102		

B.5 Step 4: Estimate Maximum Achievable, Program, and Naturally occurring Potentials

In this section we present the method we employ to estimate the fraction of the market that adopts each energy-efficiency measure in the presence and absence of energy-efficiency programs. In Section 2 of this report we introduced the concepts of *maximum achievable*, program, and naturally occurring potentials. We defined:

- **Maximum achievable potential** as the amount of economic potential that could be achieved over time under the most aggressive program scenario possible

- **Program potential** as the amount of savings that would occur in response to one or more specific market interventions

- **Naturally occurring potential** as the amount of savings estimated to occur as a result of normal market forces, that is, in the absence of any utility or governmental intervention.

Our estimates of program potential are the most important results of this study. Estimating technical, economic, and maximum achievable potentials are necessary steps in the process from which important information can be obtained; however, the end goal of the process is better understanding how much of the remaining potential can be captured in programs, whether it would be cost-effective to increase program spending, and how program costs may be expected to change in response to measure adoption over time.

According to our definitions and the method described in this section, maximum achievable potential is really a type of program potential that defines the upper limit of savings from market interventions. Therefore, in the remainder of this section, we will often discuss our general method using the term "program potential" to represent both program and maximum achievable potential. The assumptions and data inputs used for the specific program scenarios and maximum achievable potential scenarios developed for this study are described in Section 3 of this report.

B.5.1 Adoption Method Overview

We use a method of estimating adoption of energy-efficiency measures that applies equally to be our program and naturally occurring analysis. Whether as a result of natural market forces or aided by a program intervention, the rate at which measures are adopted is modeled in our method as a function of the following factors:

- The availability of the adoption opportunity as a function of capital equipment turnover rates and changes in building stock over time
- Customer awareness of the efficiency measure
- The cost-effectiveness of the efficiency measure
- Market barriers associated with the efficiency measure.

The method we employ is executed in the measure penetration module of XENERGY's DSM ASSYST model.

In this study, only measures that pass the measure-level total resource cost test are put into the penetration module for estimation of customer adoption.

Availability

A crucial part of the model is a stock accounting algorithm that handles capital turnover and stock decay over a period of up to 20 years. In the first step of our achievable potential method, we first calculate the number of customers for whom each measure will apply. The input to this calculation is the total floor space available for the measure from the technical potential analysis, i.e., the total floor space multiplied by the applicability, not complete, and feasibility factors described previously. We call this the *eligible* stock. The stock algorithm keeps track of the amount of floor space available for each efficiency measure in each year based on the total eligible stock and whether the application is new construction, retrofit or replace-on-burnout.[6]

Retrofit measures are available for implementation by the entire eligible stock. The eligible stock is reduced over time as a function of adoptions[7] and building decay.[8] Replace-on-burnout measures are available only on an annual basis, approximated as equal to the inverse of the service life.[9] The annual portion of the eligible market that does not accept the replace-on-burnout measure does not have an opportunity again until the end of the service life.

New construction applications are available for implementation in the first year. Those customers that do not accept the measure are given subsequent opportunities corresponding to whether the measure is a replacement or retrofit-type measure.

Awareness

In our modeling framework, customers cannot adopt an efficient measure merely because there is stock available for conversion. Before they can make the adoption choice, they must be aware and informed about the efficiency measure. Thus, in the second stage of the process, the model calculates the portion of the available market that is *informed*. An initial user-specified parameter sets the initial level of awareness for all measures. Incremental awareness occurs in the model as a function of the amount of money spent on awareness/information building and how well those information-building resources are directed to

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[6] Replace-on-burnout measures are defined as the efficiency opportunities that are available only when the base equipment turns over at the end of its service life. For example, a high-efficiency chiller measure is usually only considered at the end of the life of an existing chiller. By contrast, retrofit measures are defined to be constantly available, for example, application of a window film to existing glazing.

[7] That is, each square foot that adopts the retrofit measure is removed from the eligible stock for retrofit in the subsequent year.

[8] Buildings do not last forever. An input to the model is the rate of decay of the existing floor space. Floor space typically decays at a very slow rate.

[9] For example, a base-case technology with a service life of 15 years is only available for replacement to a high-efficiency alternative each year at the rate of 1/15 times the total eligible stock. For example, the fraction of the market that does not adopt the high-efficiency measure in year t will not be available to adopt the efficient alternative again until year $t + 15$.

target markets. User-defined program characteristics determine how well information-building money is targeted. Well-targeted programs are those for which most of the money is spent informing only those customers that are in a position to implement a particular group of measures. Untargeted programs are those in which advertising cannot be well focused on the portion of the market that is available to implement particular measures. The penetration module in DSM ASSYST has a target effectiveness parameter that is used to adjust for differences in program advertising efficiency associated with alternative program types.

The model also controls for information retention. An information decay parameter in the model is used to control for the percentage of customers that will retain program information from one year to the next. Information retention is based on the characteristics of the target audience and the temporal effectiveness of the marketing techniques employed.

Adoption

The portion of the total market this is available and informed can now face the choice of whether or not to adopt a particular measure. Only those customers for whom a measure is available for implementation (stage 1) and, of those customers, only those who have been informed about the program/measure (stage 2), are in a position to make the implementation decision.

In the third stage of our penetration process, the model calculates the fraction of the market that adopts each efficiency measure as a function of the participant test. The participant test is a benefit-cost ratio that is calculated in this study as follows:

$$\text{Benefits} = \sum_{t=1}^{N} \frac{\text{Customer Bill Savings } (\$)_t}{(1+d)^{t-1}} \qquad \textbf{Eqn. B-3}$$

$$\text{Costs} = \sum_{t=1}^{N} \frac{\text{Participant Cost } (\$)_t}{(1+d)^{t-1}} \qquad \textbf{Eqn. B-4}$$

where
d = the discount rate
t = time (in years)
n = 20 years

We use a *normalized* measure life of 20 years in order to capture the benefits associated with long-lived measures. Measures with lives shorter than 20 years are "re-installed" in our analysis as many times as necessary to reach the normalized 20-year life of the analysis.

The bill reductions are calculated by multiplying measure energy savings and customer peak demand impacts by retail energy and demand rates.[10]

The model uses measure implementation curves to estimate the percentage of the informed market that will accept each measure based on the participant's benefit-cost ratio. The model provides enough flexibility so that each measure in each market segment can have a separate implementation rate curve. The functional form used for the implementation curves is:

$$y = \frac{a}{\left(1+e^{-1\ln\frac{x}{4}}\right) \times \left(1+e^{-c\ln(bx)}\right)}$$

where:

y = the fraction of the market that installs a measure in a given year from the pool of informed applicable customers;

x = the customer's benefit-cost ratio for the measure;

a = the maximum annual acceptance rate for the technology;

b = the inflection point of the curve. It is generally one over the benefit-cost ratio that will give a value of 1/2 the maximum value; and

c = the parameter that determines the general shape (slope) of the curve.

The primary curves utilized in this study are shown in Figure B-2. These curves produce base year program results that are calibrated to actual measure implementation results associated with major IOU commercial efficiency programs over the past several years. Different curves are used to reflect different levels of market barriers for different efficiency measures. A list of market barriers is shown in Table B-6. It is the existence of these barriers that necessitates program interventions to increase the adoption of energy efficiency measures. (For more information on market barriers see Eto, Prahl, Schlegel 1997, Golove and Eto 1996, DeCanio 2000, DeCanio 1998.)

[10] The retail rate values used in this study are shown in Section 2 and Appendix D.

Note that for the moderate, high barrier, and extremely high curves, the participant benefit-cost ratios have to be very high before significant adoption occurs. This is because the participant benefit-cost ratios are based on a 15-percent discount rate. This discount rate reflects likely adoption if there were no market barriers or market failures, as reflected in the no-barriers curve in the figure. Experience has shown, however, that actual adoption behavior correlates with implicit discount rates several times those that would be expected in a perfect market.[11]

The model estimates adoption under both naturally occurring and program intervention situations. There are only two differences between the naturally occurring and program analysis. First, in any program intervention case in which measure incentives are provided, the participant benefit-cost ratios are adjusted based on the incentives. Thus, if an incentive that pays 50 percent of the incremental measure cost is applied in the program analysis, the participant benefit-cost ratio for that measure will double (since the costs have been halved). The effect on the amount of adoption estimated will depend on where the pre- and post-incentive benefit-cost ratios fall on the curve. This effect is illustrated in Figure B-3.

In this study achievable potential energy-efficiency forecasts were developed for several scenarios ranging from base levels of program intervention, through moderate levels, up to an aggressive energy-efficiency acquisition scenario. Uncertainty in rates and avoided costs were also characterized in alternate scenarios. The final results produced are annual streams of achievable program impacts (energy and demand by time-of-use period) and all societal and participant costs (program costs plus end-user costs).

[11] For some, it is easier to consider adoption as a function of simple payback. However, the relationship between payback and the participant benefit-cost ratio varies depending on measure life and discount rate. For a long-lived measure of 15 years with a 15-percent discount rate, the equivalent payback at which half of the market would adopt a measure is roughly 6 months, based on the high barrier curve in Figure 4-3. At a 1-year payback, one-quarter of the market would adopt the measure. Adoption reaches near its maximum at a 3-month payback. The curves reflect the real-world observation that implicit discount rates can average up to 100 percent.

Figure B-2

Primary Measure Implementation Curves Used in Adoption Model

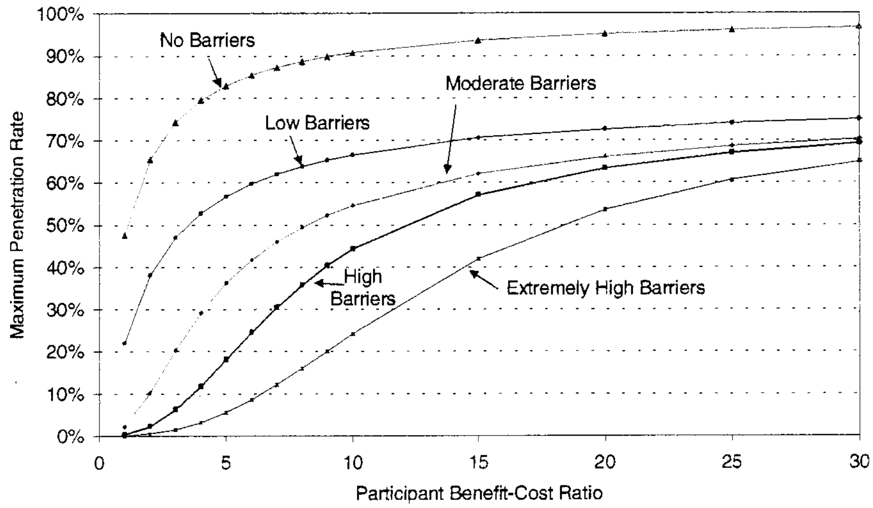

Figure B-3

Illustration of Effect of Incentives on Adoption Level as Characterized in Implementation Curves

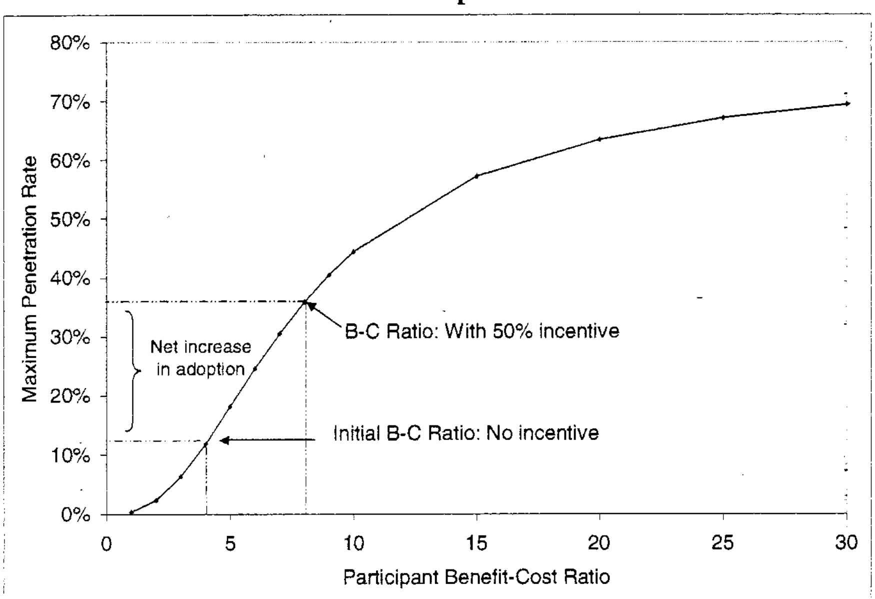

Table B-6
Summary Description of Market Barriers from Eto, Prahl, Schlegel 1997

Barrier	Description
Information or Search Costs	The costs of identifying energy-efficient products or services or of learning about energy-efficient practices, including the value of time spent finding out about or locating a product or service or hiring someone else to do so.
Performance Uncertainties	The difficulties consumers face in evaluating claims about future benefits. Closely related to high search costs, in that acquiring the information needed to evaluate claims regarding future performance is rarely costless.
Asymmetric Information and Opportunism	The tendency of sellers of energy-efficient products or services to have more and better information about their offerings than do consumers, which, combined with potential incentives to mislead, can lead to sub-optimal purchasing behavior.
Hassle or Transaction Costs	The indirect costs of acquiring energy efficiency, including the time, materials and labor involved in obtaining or contracting for an energy-efficient product or service. (Distinct from search costs in that it refers to what happens once a product has been located.)
Hidden Costs	Unexpected costs associated with reliance on or operation of energy-efficient products or services - for example, extra operating and maintenance costs.
Access to Financing	The difficulties associated with the lending industry's historic inability to account for the unique features of loans for energy savings products (i.e., that future reductions in utility bills increase the borrower's ability to repay a loan) in underwriting procedures.
Bounded Rationality	The behavior of an individual during the decision-making process that either seems or actually is inconsistent with the individual's goals.
Organization Practices or Customs	Organizational behavior or systems of practice that discourage or inhibit cost-effective energy-efficiency decisions, for example, procurement rules that make it difficult to act on energy-efficiency decisions based on economic merit.
Misplaced or Split incentives	Cases in which the incentives of an agent charged with purchasing energy efficiency are not aligned with those of the persons who would benefit from the purchase.
Product or Service Unavailability	The failure of manufacturers, distributors or vendors to make a product or service available in a given area or market. May result from collusion, bounded rationality, or supply constraints.
Externalities	Costs that are associated with transactions, but which are not reflected in the price paid in the transaction.
Non-externality Pricing	Factors other than externalities that move prices away from marginal cost. An example arises when utility commodity prices are set using ratemaking practices based on average (rather than marginal) costs.
Inseparability of Product Features	The difficulties consumers sometimes face in acquiring desirable energy-efficiency features in products without also acquiring (and paying for) additional undesired features that increase the total cost of the product beyond what the consumer is willing to pay.
Irreversibility	The difficulty of reversing a purchase decision in light of new information that may become available, which may deter the initial purchase, for example, if energy prices decline, one cannot resell insulation that has been blown into a wall.

B.6 Scenario Analysis

The various scenarios developed for this study are described in Section 2 of this report. For this step, we re-run our economic and achievable potential model multiple times utilizing the different energy-cost and program-expenditure assumptions associated with each scenario. Economic and naturally-occurring potentials vary across energy cost scenarios but remain constant across program-expenditure scenarios. Maximum-achievable and program potentials vary across both energy-cost and program expenditure scenarios.

Appendix C. Measure Potential Results

This appendix presents estimates of measure-specific energy-efficiency potential. Definitions and methods used to develop these estimates are provided in Appendix B.

DSM ASSYST ADDITIVE SUPPLY ANALYSIS — Year 2011

Vintage: Existing

Sector: Commercial Scenario: Base

End Use	Measure Number	Measure	GWH Savings	MW Savings	Levelized Cost per KWh Saved $/kWH	Levelized Cost per KW Saved $/kW	Total Resource Cost Test TRC	Conservation Load Factor (CLF)
Interior Lighting	114	RET 4L4'T8, 1EB	936.7	197.3	$0.04	$185	3.0	0.54
Interior Lighting	115	RET 2L4'T8, 1EB, Reflector	453.0	95.9	$0.01	$27	27.8	0.54
Interior Lighting	117	Occupancy Sensor, 4L4' Fluorescent Fixtures	509.6	137.2	$0.05	$167	3.2	0.42
Interior Lighting	118	Continuous Dimming, 5L4' Fluorescent Fixtures	727.2	333.8	$0.25	$536	0.8	0.25
Interior Lighting	133	RET 2L4'T8, 1EB	827.6	166.0	$0.07	$342	1.7	0.57
Interior Lighting	134	RET 1L4'T8, 1EB, Reflector OEM	270.9	54.6	$0.00	$12	21320.4	0.57
Interior Lighting	136	Occupancy Sensor, 8L4' Fluorescent Fixtures	590.1	153.6	$0.05	$173	3.2	0.44
Interior Lighting	137	Continuous Dimming, 10L4' Fluorescent Fixtures	825.8	370.7	$0.22	$499	0.8	0.25
Interior Lighting	153	RET 2L8'T12, 60W, 1EB	980.9	183.3	$0.07	$383	1.5	0.61
Interior Lighting	154	RET 1L8'T12, 60W, 1EB, Reflector	417.5	77.7	$0.01	$56	22.4	0.61
Interior Lighting	155	Occupancy Sensor, 4L8' Fluorescent Fixtures	148.2	37.0	$0.07	$290	1.9	0.46
Interior Lighting	156	Continuous Dimming, 5L8' Fluorescent Fixtures	364.7	164.5	$0.32	$708	0.6	0.25
Interior Lighting	166	CFL Screw-in, Modular 18W	818.2	140.1	$0.02	$144	4.1	0.67
Interior Lighting	176	Halogen PAR Flood, 90W	333.3	61.7	$0.14	$732	0.8	0.62
Interior Lighting	177	Metal Halide, 50W	308.9	57.3	$0.26	$1,427	0.4	0.62
Exterior Lighting	211	ROB 2L4'T8, 1EB	125.5	1.2	$0.06	$6,208	1.0	>1
Exterior Lighting	212	Outdoor Lighting Controls (Photocell/Timeclock)	53.0	0.0	$0.06	N/A	0.9	>1
Exterior Lighting	221	High Pressure Sodium 250W Lamp	360.1	3.1	$0.05	$6,151	1.1	>1
Exterior Lighting	222	Outdoor Lighting Controls (Photocell/Timeclock)	214.1	0.0	$0.02	N/A	2.6	>1
Space Cooling	301	Centrifugal Chiller, 0.51 kW/ton, 300 tons	540.3	356.1	$0.02	$26	11.5	0.17
Space Cooling	302	Window Film (Standard)	40.3	27.9	$0.22	$324	1.3	0.17
Space Cooling	303	EMS - Chiller	257.1	166.1	$0.10	$150	2.0	0.18
Space Cooling	304	Cool Roof - Chiller	32.6	18.4	$0.48	$857	0.5	0.20
Space Cooling	305	Chiller Tune Up/Diagnostics	16.0	25.8	$0.21	$128	1.8	0.07
Space Cooling	306	Cooling Circ. Pumps - VSD	124.7	82.2	$0.15	$224	1.3	0.17
Space Cooling	311	DX Tune Up/ Advanced Diagnostics	332.3	184.6	$0.23	$407	0.8	0.21
Space Cooling	312	DX Packaged System, EER=10.9, 10 tons	502.9	278.5	$0.07	$120	2.7	0.21
Space Cooling	313	Window Film (Standard)	212.9	111.8	$0.09	$168	2.8	0.22
Space Cooling	314	Evaporative Pre-Cooler	192.7	107.1	$0.33	$587	0.6	0.21
Space Cooling	315	Prog. Thermostat - DX	312.7	52.0	$0.02	$135	4.8	0.69
Space Cooling	316	Cool Roof - DX	186.0	89.3	$0.20	$406	1.2	0.24
Ventillation	401	Fan Motor, 5hp, 1800rpm, 89.5%	112.7	19.9	$0.09	$520	1.4	0.65
Ventillation	402	Variable Speed Drive Control, 5 HP	85.8	4.9	$0.07	$1,168	1.4	>1
Ventillation	411	Fan Motor, 15hp, 1800rpm, 92.4%	39.7	6.9	$0.02	$123	5.8	0.66
Ventillation	412	Variable Speed Drive Control, 15 HP	190.2	10.8	$0.04	$626	2.4	>1
Ventillation	421	Fan Motor, 40hp, 1800rpm, 94.1%	24.3	4.7	$0.05	$271	2.2	0.59
Ventillation	422	Variable Speed Drive Control, 40 HP	238.3	13.1	$0.02	$356	3.9	>1
Refrigeration	501	High-efficiency fan motors	678.6	93.2	$0.04	$297	2.1	0.83
Refrigeration	502	Strip curtains for walk-ins	84.7	11.6	$0.01	$102	6.2	0.83
Refrigeration	503	Night covers for display cases	310.7	0.0	$0.02	N/A	2.4	>1
Refrigeration	504	Evaporator fan controller for MT walk-ins	19.2	0.0	$0.12	N/A	0.4	>1
Refrigeration	505	Efficient compressor motor retrofit	407.9	56.0	$0.01	$46	13.7	0.83
Refrigeration	506	Compressor VSD retrofit	295.0	21.3	$0.05	$658	1.5	>1
Refrigeration	507	Floating head pressure controls	218.2	0.0	$0.01	N/A	6.8	>1
Refrigeration	508	Refrigeration Commissioning	127.0	17.5	$0.07	$520	1.2	0.83
Refrigeration	509	Demand Hot Gas Defrost	50.5	6.9	$0.01	$49	12.9	0.83
Refrigeration	510	Demand Defrost Electric	0.0	0.0	N/A	N/A	N/A	>1
Refrigeration	511	Anti-sweat (humidistat) controls	279.8	20.2	$0.02	$222	4.5	>1
Office Equipment	611	Power Management Enabling	329.6	34.7	$0.05	$516	2.7	>1
Office Equipment	621	Purchase LCD monitor	186.1	32.5	$5.98	$34,229	0.0	0.65
Office Equipment	623	Network Power Management Enabling	501.9	51.2	$0.01	$55	26.1	>1
Office Equipment	631	Power Management Enabling	144.2	11.5	$0.02	$298	5.6	>1
Office Equipment	641	External hardware control	176.0	0.0	$0.45	N/A	0.2	>1
Office Equipment	642	Nighttime shutdown	127.2	0.0	$2.03	N/A	0.0	>1

DSM ASSYST ADDITIVE SUPPLY ANALYSIS			Year 2011						
		Vintage: New Sector: Commercial Scenario: Base			Levelized Cost per KWh Saved	Levelized Cost per KW Saved	Total Resource Cost Test	Conservation Load Factor	
End Use	Measure Number	Measure	GWH Savings	MW Savings	$/kWH	$/kW	TRC	(CLF)	
Lighting	111	10 % More Efficient Design (Lighting)	822.6	165.9	$0.02	$98	7.2	0.57	
Lighting	112	20 % More Efficient Design (Lighting)	814.3	164.2	$0.03	$148	4.8	0.57	
Space Cooling	301	Centrifugal Chiller, 0.51 kW/ton, 500 tons	210.7	128.4	$0.01	$20	16.4	0.19	
Space Cooling	304	Cool Roof - Chiller	22.4	12.7	$0.30	$523	0.8	0.20	
Space Cooling	306	Centrifugal Chiller, Optimal Design, 0.4 kW/ton, 500 tons	101.9	61.6	$0.06	$97	5.1	0.19	
Space Cooling	312	DX Packaged System, EER=10.9, 10 tons	165.6	93.2	$0.06	$115	2.8	0.20	
Space Cooling	314	Evaporative Pre-Cooler	67.4	38.1	$0.31	$556	0.6	0.20	
Space Cooling	316	Cool Roof - DX	147.8	74.0	$0.10	$201	2.5	0.23	
Ventilation	401	Fan Motor, 5hp, 1800rpm, 89.5%	35.8	6.3	$0.09	$503	1.4	0.65	
Ventilation	402	Variable Speed Drive Control, 5 HP	45.9	2.4	$0.06	$1,212	1.4	>1	
Ventilation	411	Fan Motor, 15hp, 1800rpm, 92.4%	10.9	1.9	$0.02	$139	5.2	0.67	
Ventilation	412	Variable Speed Drive Control, 15 HP	97.8	5.2	$0.04	$667	2.3	>1	
Ventilation	421	Fan Motor, 40hp, 1800rpm, 94.1%	6.2	1.2	$0.07	$354	1.7	0.60	
Ventilation	422	Variable Speed Drive Control, 40 HP	155.2	8.3	$0.02	$424	3.4	>1	
Refrigeration	501	High-efficiency fan motors	214.5	29.5	$0.04	$319	2.0	0.83	
Refrigeration	502	Strip curtains for walk-ins	86.2	11.9	$0.01	$108	5.9	0.83	
Refrigeration	503	Night covers for display cases	48.1	0.0	$0.02	N/A	2.2	>1	
Refrigeration	504	Evaporator fan controller for MT walk-ins	7.2	0.0	$0.13	N/A	0.4	>1	
Refrigeration	505	Efficient compressor motor retrofit	160.9	22.1	$0.01	$47	13.7	0.83	
Refrigeration	506	Compressor VSD retrofit	46.5	3.4	$0.05	$710	1.4	>1	
Refrigeration	507	Floating head pressure controls	126.7	0.0	$0.01	N/A	6.3	>1	
Refrigeration	508	Refrigeration Commissioning	76.5	10.5	$0.08	$558	1.1	0.83	
Refrigeration	509	Demand Hot Gas Defrost	52.8	7.3	$0.01	$50	2.7	0.83	
Refrigeration	511	Anti-sweat (humidistat) controls	91.6	6.6	$0.02	$244	4.1	>1	
Office Equipment	611	Power Management Enabling	146.9	15.6	$0.05	$565	2.4	>1	
Office Equipment	621	Purchase LCD monitor	48.5	8.5	$10.37	$59,108	0.0	0.65	
Office Equipment	623	Network Power Management Enabling	228.8	23.5	$0.01	$96	14.3	>1	
Office Equipment	631	Power Management Enabling	85.0	6.8	$0.04	$479	3.4	>1	
Office Equipment	641	External hardware control	24.5	0.0	$1.03	N/A	0.1	>1	
Office Equipment	642	Nighttime shutdown	83.9	0.0	$0.00	N/A	99999.0	>1	

APPENDIX C

MEASURE LEVEL RESULTS

DSM ASSYST ADDITIVE SUPPLY ANALYSIS — Year 2011

Vintage: Existing
Sector: Industrial Scenario: Base

End Use	Measure Number	Measure	GWH Savings	MW Savings	Levelized Cost per KWh Saved $/kWH	Levelized Cost per KW Saved $/kW	Total Resource Cost Test TRC	Conservation Load Factor (CLF)
Motors	101	Replace 1-5 HP Motor	248.7	34.1	$0.10	$698	0.8	0.83
Motors	102	Add 1-5 HP VSD	447.1	61.3	$0.14	$1,019	0.6	0.83
Motors	103	Motor Practices Level 1	607.0	83.2	$0.06	$440	1.3	0.83
Motors	104	Motor Practices Level 2	539.1	73.9	$0.24	$1,764	0.3	0.83
Motors	121	Replace 21-50 HP Motor	78.1	10.7	$0.09	$661	0.9	0.83
Motors	122	Add 21-50 HP VSD	319.0	43.7	$0.04	$278	2.1	0.83
Motors	123	Motor Practices Level 1	404.3	55.4	$0.03	$211	2.7	0.83
Motors	124	Motor Practices Level 2	361.9	49.6	$0.12	$840	0.7	0.83
Motors	151	Replace 201-500 HP Motor	143.5	19.7	$0.03	$201	2.8	0.83
Motors	152	Add 201-500 HP VSD	516.6	70.8	$0.01	$106	5.4	0.83
Motors	153	Motor Practices Level 1	598.6	82.0	$0.02	$152	3.7	0.83
Motors	154	Motor Practices Level 2	554.9	76.0	$0.08	$586	1.0	0.83
Compressed Air	202	CAS Level 1	433.9	59.5	$0.02	$168	3.4	0.83
Compressed Air	203	CAS Level 2	453.6	62.2	$0.05	$362	1.6	0.83
Compressed Air	204	CAS Level 3	325.5	44.6	$0.13	$936	0.6	0.83
Other Process	301	Process Level 1	1,031.8	141.4	$0.03	$190	3.0	0.83
Other Process	302	Process Level 2	1,219.7	167.1	$0.05	$345	1.7	0.83
Other Process	303	Process Level 3	767.3	105.1	$0.25	$1,831	0.3	0.83
Lighting	401	RET 2L4'T8, 1EB	835.2	174.0	$0.04	$211	2.2	0.55
Lighting	402	Occupancy Sensor, 4L4' Fluorescent Fixtures	80.0	21.4	$0.07	$257	1.6	0.43
Lighting	403	Continuous Dimming, 5L4' Fluorescent Fixtures	235.2	115.3	$0.28	$567	0.6	0.23
Lighting	411	RET 2L8'T12, 60W, 1EB	371.8	77.5	$0.07	$328	1.4	0.55
Lighting	412	Occupancy Sensor, 4L8' Fluorescent Fixtures	52.3	14.0	$0.07	$246	1.7	0.43
Lighting	413	Continuous Dimming, 5L8' Fluorescent Fixtures	127.4	62.4	$0.31	$636	0.5	0.23
Lighting	421	CFL Hardwired, Modular 36W	561.1	116.9	$0.06	$277	1.7	0.55
Lighting	422	Metal Halide, 50W	149.5	31.2	$0.62	$2,965	0.2	0.55
Space Cooling	501	Centrifugal Chiller, 0.51 kW/ton, 500 tons	136.8	69.1	$0.02	$45	5.4	0.23
Space Cooling	502	Window Film (Standard)	40.8	20.6	$0.09	$170	1.4	0.23
Space Cooling	503	EMS - Chiller	62.5	31.5	$0.14	$287	0.9	0.23
Space Cooling	504	Cool Roof - Chiller	25.2	12.7	$0.29	$574	0.4	0.23
Space Cooling	505	Chiller Tune Up/Diagnostics	3.8	5.1	$0.13	$97	1.9	0.08
Space Cooling	506	Cooling Circ. Pumps - VSD	30.5	15.4	$0.21	$407	0.6	0.23
Space Cooling	511	DX Tune Up/ Advanced Diagnostics	132.7	67.0	$0.26	$516	0.5	0.23
Space Cooling	512	DX Packaged System, EER=10.9, 10 tons	202.0	102.0	$0.08	$151	1.7	0.23
Space Cooling	513	Window Film (Standard)	98.9	49.9	$0.04	$74	3.4	0.23
Space Cooling	514	Evaporative Pre-Cooler	77.1	38.9	$0.38	$744	0.3	0.23
Space Cooling	515	Prog. Thermostat - DX	108.3	16.9	$0.03	$171	2.8	0.73
Space Cooling	516	Cool Roof - DX	106.3	53.7	$0.13	$248	1.0	0.23

APPENDIX C **MEASURE LEVEL RESULTS**

DSM ASSYST ADDITIVE SUPPLY ANALYSIS — Year 2011
Vintage: New
Sector: Industrial Scenario: Base

End Use	Measure Number	Measure	GWH Savings	MW Savings	Levelized Cost per KWh Saved $/kWH	Levelized Cost per KW Saved $/kW	Total Resource Cost Test TRC	Conservation Load Factor (CLF)
Motors	101	Replace 1-5 HP Motor	39.2	5.4	$0.10	$709	0.8	0.83
Motors	102	Add 1-5 HP VSD	85.0	11.6	$0.12	$858	0.7	0.83
Motors	103	Motor Practices Level 1	130.0	17.8	$0.05	$329	1.7	0.83
Motors	104	Motor Practices Level 2	84.3	11.5	$0.25	$1,805	0.3	0.83
Motors	121	Replace 21-50 HP Motor	13.7	1.9	$0.09	$676	0.8	0.83
Motors	122	Add 21-50 HP VSD	67.7	9.3	$0.03	$235	2.4	0.83
Motors	123	Motor Practices Level 1	96.9	13.3	$0.02	$158	3.6	0.83
Motors	124	Motor Practices Level 2	63.3	8.7	$0.12	$860	0.7	0.83
Motors	151	Replace 201-500 HP Motor	25.3	3.5	$0.03	$205	2.8	0.83
Motors	152	Add 201-500 HP VSD	112.2	15.4	$0.01	$88	6.5	0.83
Motors	153	Motor Practices Level 1	143.7	19.7	$0.02	$115	5.0	0.83
Motors	154	Motor Practices Level 2	98.0	13.4	$0.08	$599	1.0	0.83
Compressed Air	202	CAS Level 1	113.4	15.5	$0.02	$111	5.1	0.83
Compressed Air	203	CAS Level 2	75.6	10.4	$0.05	$375	1.5	0.83
Compressed Air	204	CAS Level 3	54.2	7.4	$0.13	$968	0.6	0.83
Other Process	301	Process Level 1	179.4	24.6	$0.03	$190	3.0	0.83
Other Process	302	Process Level 2	212.1	29.1	$0.05	$345	1.7	0.83
Other Process	303	Process Level 3	133.4	18.3	$0.25	$1,831	0.3	0.83
Lighting	401	RET 2L4'T8, 1EB	143.8	30.0	$0.04	$211	2.2	0.55
Lighting	402	Occupancy Sensor, 4L4' Fluorescent Fixtures	13.8	3.7	$0.07	$257	1.6	0.43
Lighting	403	Continuous Dimming, 5L4' Fluorescent Fixtures	40.5	19.9	$0.28	$566	0.6	0.23
Lighting	411	RET 2L8'T12, 60W, 1EB	64.0	13.3	$0.07	$328	1.4	0.55
Lighting	412	Occupancy Sensor, 4L8' Fluorescent Fixtures	9.0	2.4	$0.07	$246	1.7	0.43
Lighting	413	Continuous Dimming, 5L8' Fluorescent Fixtures	21.9	10.8	$0.31	$635	0.5	0.23
Lighting	421	CFL Hardwired, Modular 36W	96.6	20.1	$0.06	$276	1.7	0.55
Lighting	422	Metal Halide, 50W	25.7	5.4	$0.62	$2,961	0.2	0.55
Space Cooling	501	Centrifugal Chiller, 0.51 kW/ton, 500 tons	24.7	12.5	$0.02	$45	5.4	0.23
Space Cooling	502	Window Film (Standard)	7.4	3.7	$0.09	$170	1.4	0.23
Space Cooling	503	EMS - Chiller	11.3	5.7	$0.14	$287	0.9	0.23
Space Cooling	504	Cool Roof - Chiller	4.5	2.3	$0.29	$575	0.4	0.23
Space Cooling	505	Chiller Tune Up/Diagnostics	0.7	0.9	$0.13	$97	1.9	0.08
Space Cooling	506	Cooling Circ. Pumps - VSD	5.5	2.8	$0.21	$407	0.6	0.23
Space Cooling	511	DX Tune Up/ Advanced Diagnostics	22.5	11.4	$0.26	$521	0.5	0.23
Space Cooling	512	DX Packaged System, EER=10.9, 10 tons	34.3	17.3	$0.08	$152	1.6	0.23
Space Cooling	513	Window Film (Standard)	16.8	8.5	$0.04	$75	3.4	0.23
Space Cooling	514	Evaporative Pre-Cooler	13.1	6.6	$0.38	$752	0.3	0.23
Space Cooling	515	Prog. Thermostat - DX	18.4	2.9	$0.03	$172	2.8	0.73
Space Cooling	516	Cool Roof - DX	18.0	9.1	$0.13	$251	1.0	0.23

APPENDIX C **MEASURE LEVEL RESULTS**

DSM ASSYST ADDITIVE SUPPLY ANALYSIS End Use	Measure Number	Vintage: Existing Sector: Residential Scenario: Base Measure	Year GWH Savings	2011 MW Savings	Levelized Cost per KWh Saved $/kWH	Levelized Cost per KW Saved $/kW	Total Resource Cost Test TRC	Conservation Load Factor (CLF)
Central AC	101	10 to 12 SEER Split-System Air Conditioner	329.7	413.4	$0.26	$211	1.4	0.09
Central AC	102	10 to 13 SEER Split-System Air Conditioner	115.6	140.2	$1.16	$960	0.4	0.09
Central AC	103	10 to 14 SEER Split-System Air Conditioner	83.5	103.9	$4.87	$3,910	0.1	0.09
Central AC	105	TXV	148.5	192.0	$0.13	$100	2.9	0.09
Central AC	109	Programmable Thermostat (0.4)	25.0	47.2	$0.24	$128	2.2	0.06
Central AC	110	Ceiling Fans	21.0	14.1	$1.91	$2,839	0.2	0.17
Central AC	111	Whole House Fans	229.5	170.5	$0.56	$749	0.5	0.15
Central AC	112	Attic Venting	76.2	79.8	$0.63	$601	0.9	0.11
Central AC	113	Basic HVAC Diagnostic Testing And Repair	187.8	240.4	$0.21	$161	1.9	0.09
Central AC	114	Duct Repair (0.32)	99.0	121.4	$0.26	$214	1.6	0.09
Central AC	115	Duct insulation (0.4)	34.7	46.0	$0.10	$79	3.1	0.09
Central AC	116	Cool roofs	117.7	124.0	$12.96	$12,301	0.0	0.11
Central AC	118	Default Window With Sunscreen	454.5	589.2	$0.47	$366	0.5	0.09
Central AC	119	Double Pane Clear Windows to Double Pane, Med Low-E Coating	1,007.5	1,317.5	$0.02	$15	13.3	0.09
Central AC	120	Ceiling R-0 to R-19 Insulation-Batts (0.29)	66.2	68.6	$0.12	$116	2.7	0.11
Central AC	121	Ceiling R-19 to R-38 Insulation-Batts (0.27)	23.5	21.3	$2.64	$2,910	0.1	0.13
Central AC	122	Wall 2x4 R-0 to Blow-In R-13 Insulation (0.14)	41.3	60.6	$0.34	$232	1.2	0.08
Central AC	123	Infiltration Reduction (0.4)	7.1	12.1	$2.49	$1,469	0.2	0.07
Room AC	141	HE Room Air Conditioner - SEER 10.3	56.4	82.3	$0.46	$315	0.7	0.08
Room AC	142	Direct Evaporative Cooler	245.1	354.0	$0.72	$501	0.5	0.08
Room AC	143	Programmable Thermostat	4.1	8.6	$0.78	$371	0.6	0.05
Room AC	144	Ceiling Fans	1.1	0.9	$14.10	$17,385	0.0	0.14
Room AC	145	Whole House Fans	10.7	9.9	$4.56	$4,941	0.1	0.12
Room AC	146	Attic Venting	2.6	3.3	$7.03	$5,593	0.1	0.09
Room AC	147	Basic HVAC Diagnostic Testing And Repair	14.2	20.8	$1.03	$704	0.5	0.08
Room AC	148	Cool roofs	4.9	6.2	$105.47	$84,475	0.0	0.09
Room AC	150	Default Window With Sunscreen	27.9	40.3	$2.36	$1,634	0.3	0.08
Room AC	151	Double Pane Clear Windows to Double Pane, Med Low-E Coating	122.9	175.6	$0.05	$32	6.0	0.08
Room AC	152	Ceiling R-0 to R-19 Insulation-Batts	10.8	13.6	$0.40	$317	1.5	0.09
Room AC	153	Ceiling R-19 to R-38 Insulation-Batts	0.9	1.0	$22.07	$20,024	0.0	0.10
Room AC	154	Wall 2x4 R-0 to Blow-In R-13 Insulation	1.1	1.9	$6.59	$3,723	0.1	0.06
Room AC	155	Infiltration Reduction	0.3	0.6	$26.46	$13,459	0.0	0.06
Space Heating	181	Heat Pump Space Heater	553.8	0.0	$0.08	N/A	0.8	>1
Space Heating	182	Programmable Thermostat	33.1	0.0	$0.20	N/A	0.4	>1
Space Heating	183	Ceiling R-0 to R-19 Insulation-Batts	152.5	0.0	$0.06	N/A	0.8	>1
Space Heating	184	Ceiling R-19 to R-38 Insulation-Batts	71.0	0.0	$0.88	N/A	0.1	>1
Space Heating	185	Floor R-0 to R-19 Insulation-Batts	31.5	0.0	$0.39	N/A	0.1	>1
Space Heating	186	Wall 2x4 R-0 to Blow-In R-13 Insulation	233.6	0.0	$0.14	N/A	0.3	>1
Space Heating	187	Infiltration Reduction	13.3	0.0	$1.31	N/A	0.1	>1
Lighting	201	CFL, 0.5 hr/day	521.5	45.6	$0.09	$1,033	0.7	>1
Lighting	211	CFL, 2.5 hr/day	4,636.8	405.1	$0.03	$385	2.5	>1
Lighting	221	CFL, 6.0 hr/day	2,515.4	219.7	$0.03	$342	2.8	>1
Refrigerator	301	HE Refrigerator - Energy Star	849.8	110.3	$0.18	$1,400	0.5	0.88
Freezer	401	HE Freezer	208.0	28.3	$0.06	$470	1.4	0.84
Water Heating	501	Heat Pump Water Heater (EF=2.9)	754.1	72.3	$0.15	$1,516	0.6	>1
Water Heating	502	HE Water Heater (EF=0.93)	117.8	11.3	$0.06	$602	1.5	>1
Water Heating	503	Solar Water Heat	311.8	29.9	$0.66	$6,835	0.1	>1
Water Heating	504	Low Flow Showerhead	53.8	5.2	$0.03	$280	3.2	>1
Water Heating	505	Pipe Wrap	29.5	2.8	$0.02	$166	5.3	>1
Water Heating	506	Faucent Aerators	35.0	3.4	$0.02	$253	3.5	>1
Water Heating	507	Water Heater Blanket	152.8	14.6	$0.01	$88	10.0	>1
Clothes Washer	602	SEHA CW Tier 2 (EF=3.25)	784.3	143.9	$0.06	$350	1.6	0.62
Clothes Dryer	701	HE Clothes Dryer (EF=.52)	201.3	29.0	$0.29	$2,004	0.4	0.79
Dishwasher	801	Energy Star DW (EF=0.58)	234.8	20.4	$0.09	$1,009	1.1	>1
Pool	901	High Efficiency Pool Pump and Motor	1,527.0	271.8	$0.03	$161	3.7	0.64

APPENDIX C **MEASURE LEVEL RESULTS**

DSM ASSYST ADDITIVE SUPPLY ANALYSIS		Vintage: New Sector: Residential Scenario: Base	Year 2011					
End Use	Measure Number	Measure	GWH Savings	MW Savings	Levelized Cost per KWh Saved $/KWH	Levelized Cost per KW Saved $/kW	Total Resource Cost Test TRC	Conservation Load Factor (CLF)
HVAC	101	AB970	391.2	521.2	$0.00	$0	99999.0	0.09
HVAC	102	15% Above AB970	185.8	229.9	$0.40	$322	0.8	0.09
HVAC	103	20% Above AB970	64.8	85.7	$1.99	$1,509	0.1	0.09
Lighting	201	CFL, 0.5 hr/day	78.5	6.9	$0.09	$1,033	0.7	>1
Lighting	211	CFL, 2.5 hr/day	697.9	61.0	$0.03	$385	2.5	>1
Lighting	221	CFL, 6.0 hr/day	378.6	33.1	$0.03	$342	2.8	>1
Refrigerator	301	HE Refrigerator - Energy Star	124.3	16.1	$0.18	$1,396	0.5	0.88
Freezer	401	HE Freezer	32.6	4.4	$0.06	$470	1.4	0.84
Water Heating	501	Heat Pump Water Heater (EF=2.9)	114.2	10.9	$0.14	$1,442	0.6	>1
Water Heating	502	HE Water Heater (EF=0.93)	17.8	1.7	$0.05	$573	1.5	>1
Water Heating	503	Solar Water Heat	48.8	4.7	$0.63	$6,521	0.1	>1
Water Heating	505	Pipe Wrap	4.3	0.4	$0.02	$164	5.4	>1
Water Heating	507	Water Heater Blanket	22.3	2.1	$0.01	$87	10.1	>1
Clothes Washer	602	SEHA CW Tier 2 (EF=3.25)	116.8	21.4	$0.06	$346	1.6	0.62
Clothes Dryer	701	HE Clothes Dryer (EF=.52)	29.9	4.3	$0.28	$1,935	0.4	0.79
Dishwasher	801	Energy Star DW (EF=0.58)	35.8	3.1	$0.09	$992	1.1	>1
Pool	901	High Efficiency Pool Pump and Motor	216.7	38.6	$0.03	$164	3.6	0.64

APPENDIX D. ENERGY COST DATA

This appendix presents the energy cost and retail rate forecasts used to assess measure and program cost-effectiveness for each customer sector. These forecasts are described in Section 2.

ECONOMIC PARAMETERS

BASE ECONOMIC SCENARIO

UTILITY NAME	Statewide
SECTOR	Commercial
BATCH #	1
UTILITY DISCOUNT RATE	8.0%
CUSTOMER DISCOUNT RATE	15.0%
GENERAL INFLATION RATE (Measure)	3.0%
BASE YEAR	2001
START YEAR	2001
DIFFERENCE	0
UTILITY LINE LOSS RATE	8.5%

ENERGY COSTS AND RATES

RATE TYPE	COMMERCIAL
ENERGY UNITS	$/KWh
DEMAND UNITS	$/KW

Rate/Time Periods	1	2	3	4	5	
Name	Summer On-Peak	Partial-Peak	Summer Off-Peak	Partial Peak	Winter Off-Peak	
Abbreviation	SOP	SPP	SOFF	WPP	WOFF	TOTAL
Hours	768	896	2752	1638	2706	8760
Monthly Adjustment fo	6	0	0	6	0	

	AVOIDED ENERGY COSTS BY TIME PERIOD					AVOIDED DEMAND COSTS BY TIME PERIOD					COMMERCIAL ENERGY RATES					COMMERCIAL DEMAND RATES					Environmental Adder to be Subtracted for RIM
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF	
Year	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW	$/KWh
2001	0.59	0.11	0.08	0.03	0.03	25.63	10.21	2.23	11.45	2.21	0.16	0.16	0.16	0.10	0.10	6.70	0.00	0.00	1.65	0.00	0.01
2002	0.59	0.11	0.08	0.03	0.03	26.65	10.65	2.33	12.01	2.30	0.13	0.13	0.13	0.08	0.08	6.90	0.00	0.00	1.70	0.00	0.01
2003	0.26	0.06	0.03	0.05	0.04	27.73	11.11	2.43	12.58	2.40	0.12	0.12	0.12	0.08	0.08	7.11	0.00	0.00	1.75	0.00	0.01
2004	0.24	0.05	0.03	0.05	0.04	28.88	11.58	2.53	13.16	2.50	0.11	0.11	0.11	0.07	0.07	7.32	0.00	0.00	1.80	0.00	0.01
2005	0.25	0.05	0.03	0.05	0.04	30.20	12.08	2.64	13.63	2.61	0.10	0.10	0.10	0.07	0.07	6.79	0.00	0.00	1.67	0.00	0.01
2006	0.22	0.05	0.03	0.05	0.04	31.49	12.59	2.75	14.22	2.72	0.11	0.11	0.11	0.07	0.07	6.29	0.00	0.00	1.55	0.00	0.01
2007	0.23	0.06	0.03	0.05	0.04	32.90	13.13	2.87	14.76	2.84	0.11	0.11	0.11	0.07	0.07	5.83	0.00	0.00	1.44	0.00	0.01
2008	0.23	0.06	0.03	0.05	0.04	34.24	13.69	2.99	15.48	2.96	0.11	0.11	0.11	0.07	0.07	6.01	0.00	0.00	1.48	0.00	0.01
2009	0.24	0.06	0.04	0.06	0.04	35.69	14.28	3.12	16.14	3.08	0.12	0.12	0.12	0.08	0.08	6.19	0.00	0.00	1.52	0.00	0.01
2010	0.25	0.06	0.04	0.06	0.04	37.27	14.89	3.25	16.78	3.22	0.12	0.12	0.12	0.08	0.08	6.37	0.00	0.00	1.57	0.00	0.01
2011	0.22	0.05	0.03	0.05	0.04	38.86	15.52	3.39	17.51	3.35	0.12	0.12	0.12	0.08	0.08	6.56	0.00	0.00	1.62	0.00	0.01
2012	0.23	0.06	0.03	0.05	0.04	40.54	16.18	3.53	18.23	3.50	0.13	0.13	0.13	0.08	0.08	6.76	0.00	0.00	1.67	0.00	0.01
2013	0.24	0.06	0.03	0.06	0.04	42.28	16.88	3.68	19.00	3.65	0.13	0.13	0.13	0.09	0.09	6.96	0.00	0.00	1.71	0.00	0.01
2014	0.25	0.06	0.04	0.06	0.04	44.09	17.61	3.84	19.81	3.80	0.14	0.14	0.14	0.09	0.09	7.17	0.00	0.00	1.77	0.00	0.01
2015	0.26	0.06	0.04	0.06	0.05	45.98	18.36	4.01	20.66	3.97	0.14	0.14	0.14	0.09	0.09	7.39	0.00	0.00	1.82	0.00	0.02
2016	0.27	0.07	0.04	0.06	0.05	47.94	19.15	4.18	21.54	4.14	0.14	0.14	0.14	0.09	0.09	7.61	0.00	0.00	1.87	0.00	0.02
2017	0.28	0.07	0.04	0.07	0.05	49.99	19.97	4.35	22.47	4.31	0.15	0.15	0.15	0.10	0.10	7.84	0.00	0.00	1.93	0.00	0.02
2018	0.30	0.07	0.04	0.07	0.05	52.13	20.82	4.54	23.43	4.50	0.15	0.15	0.15	0.10	0.10	8.07	0.00	0.00	1.99	0.00	0.02
2019	0.31	0.08	0.05	0.07	0.06	54.36	21.71	4.73	24.43	4.69	0.16	0.16	0.16	0.10	0.10	8.32	0.00	0.00	2.05	0.00	0.02
2020	0.33	0.08	0.05	0.08	0.06	56.68	22.64	4.94	25.48	4.89	0.16	0.16	0.16	0.11	0.11	8.56	0.00	0.00	2.11	0.00	0.02
2021	0.35	0.08	0.05	0.08	0.06	59.10	23.61	5.15	26.57	5.10	0.17	0.17	0.17	0.11	0.11	8.82	0.00	0.00	2.17	0.00	0.02

ECONOMIC PARAMETERS

HIGH ECONOMIC SCENARIO

UTILITY NAME	All Statewide
SECTOR	COM Commercial
BATCH #	1
UTILITY DISCOUNT RATE	8.0%
CUSTOMER DISCOUNT RATE	15.0%
GENERAL INFLATION RATE (Measure)	3.0%
BASE YEAR	2001
START YEAR	2001
DIFFERENCE	0
UTILITY LINE LOSS RATE	8.5%

ENERGY COSTS AND RATES

RATE TYPE	COMMERCIAL
ENERGY UNITS	$/KWh
DEMAND UNITS	$/KW

Rate/Time Periods	1	2	3	4	5	
Name	Summer On-Peak	Partial-Peak	Summer Off-Peak	Partial Peak	Winter Off-Peak	
Abbreviation	SOP	SPP	SOFF	WPP	WOFF	TOTAL
Hours	768	896	2752	1638	2706	8760
Monthly Adjustment fo	6	0	0	6	0	

	AVOIDED ENERGY COSTS BY TIME PERIOD					AVOIDED DEMAND COSTS BY TIME PERIOD				
Year	SOP $/KWh	SPP $/KWh	SOFF $/KWh	WPP $/KWh	WOFF $/KWh	SOP $/KW	SPP $/KW	SOFF $/KW	WPP $/KW	WOFF $/KW
2001	0.74	0.13	0.10	0.04	0.04	25.63	10.21	2.23	11.45	2.21
2002	0.74	0.13	0.10	0.04	0.04	26.65	10.65	2.33	12.01	2.30
2003	0.32	0.07	0.04	0.06	0.05	27.73	11.11	2.43	12.58	2.40
2004	0.30	0.06	0.04	0.06	0.05	28.88	11.58	2.53	13.16	2.50
2005	0.31	0.06	0.04	0.06	0.05	30.20	12.08	2.64	13.63	2.61
2006	0.27	0.07	0.04	0.06	0.05	31.49	12.59	2.75	14.22	2.72
2007	0.28	0.07	0.04	0.07	0.05	32.90	13.13	2.87	14.76	2.84
2008	0.29	0.07	0.04	0.07	0.05	34.24	13.69	2.99	15.46	2.96
2009	0.30	0.07	0.04	0.07	0.05	35.69	14.28	3.12	16.14	3.08
2010	0.31	0.08	0.05	0.07	0.06	37.27	14.89	3.25	16.78	3.22
2011	0.27	0.07	0.04	0.06	0.05	38.86	15.52	3.39	17.51	3.35
2012	0.28	0.07	0.04	0.07	0.05	40.54	16.18	3.53	18.23	3.50
2013	0.30	0.07	0.04	0.07	0.05	42.28	16.88	3.68	19.00	3.65
2014	0.31	0.08	0.05	0.07	0.05	44.09	17.61	3.84	19.81	3.80
2015	0.32	0.08	0.05	0.08	0.06	45.98	18.36	4.01	20.66	3.97
2016	0.34	0.08	0.05	0.08	0.06	47.94	19.15	4.18	21.54	4.14
2017	0.35	0.09	0.05	0.08	0.06	49.99	19.97	4.35	22.47	4.31
2018	0.37	0.09	0.05	0.09	0.07	52.13	20.82	4.54	23.43	4.50
2019	0.39	0.10	0.06	0.09	0.07	54.36	21.71	4.73	24.43	4.69
2020	0.41	0.10	0.06	0.10	0.07	56.68	22.64	4.94	25.48	4.89
2021	0.43	0.11	0.06	0.10	0.08	59.10	23.61	5.15	26.57	5.10

	COMMERCIAL ENERGY RATES					COMMERCIAL DEMAND RATES					Environmental Adder to be Subtracted for RIM
Year	SOP $/KWh	SPP $/KWh	SOFF $/KWh	WPP $/KWh	WOFF $/KWh	SOP $/KW	SPP $/KW	SOFF $/KW	WPP $/KW	WOFF $/KW	$/KWh
2001	0.16	0.16	0.16	0.10	0.10	6.70	0.00	0.00	1.65	0.00	0.01
2002	0.16	0.16	0.16	0.11	0.11	6.90	0.00	0.00	1.70	0.00	0.01
2003	0.17	0.17	0.17	0.11	0.11	7.11	0.00	0.00	1.75	0.00	0.01
2004	0.17	0.17	0.17	0.11	0.11	7.32	0.00	0.00	1.80	0.00	0.01
2005	0.18	0.18	0.18	0.12	0.12	7.54	0.00	0.00	1.86	0.00	0.01
2006	0.18	0.18	0.18	0.12	0.12	7.77	0.00	0.00	1.91	0.00	0.01
2007	0.19	0.19	0.19	0.12	0.12	8.00	0.00	0.00	1.97	0.00	0.01
2008	0.20	0.20	0.20	0.13	0.13	8.24	0.00	0.00	2.03	0.00	0.01
2009	0.20	0.20	0.20	0.13	0.13	8.49	0.00	0.00	2.09	0.00	0.01
2010	0.21	0.21	0.21	0.13	0.13	8.74	0.00	0.00	2.15	0.00	0.01
2011	0.21	0.21	0.21	0.14	0.14	9.00	0.00	0.00	2.22	0.00	0.01
2012	0.22	0.22	0.22	0.14	0.14	9.27	0.00	0.00	2.28	0.00	0.01
2013	0.23	0.23	0.23	0.15	0.15	9.55	0.00	0.00	2.35	0.00	0.01
2014	0.23	0.23	0.23	0.15	0.15	9.84	0.00	0.00	2.42	0.00	0.01
2015	0.24	0.24	0.24	0.16	0.16	10.13	0.00	0.00	2.50	0.00	0.02
2016	0.25	0.25	0.25	0.16	0.16	10.44	0.00	0.00	2.57	0.00	0.02
2017	0.26	0.26	0.26	0.17	0.17	10.75	0.00	0.00	2.65	0.00	0.02
2018	0.26	0.26	0.26	0.17	0.17	11.07	0.00	0.00	2.73	0.00	0.02
2019	0.27	0.27	0.27	0.18	0.18	11.41	0.00	0.00	2.81	0.00	0.02
2020	0.28	0.28	0.28	0.18	0.18	11.75	0.00	0.00	2.89	0.00	0.02
2021	0.29	0.29	0.29	0.19	0.19	12.10	0.00	0.00	2.98	0.00	0.02

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ECONOMIC PARAMETERS

LOW ECONOMIC SCENARIO

UTILITY NAME	All Statewide
SECTOR	COM Commercial
BATCH #	1
UTILITY DISCOUNT RATE	8.0%
CUSTOMER DISCOUNT RATE	15.0%
GENERAL INFLATION RATE (Measure)	3.0%
BASE YEAR	2001
START YEAR	2001
DIFFERENCE	0
UTILITY LINE LOSS RATE	8.5%

ENERGY COSTS AND RATES

RATE TYPE	COMMERCIAL
ENERGY UNITS	$/KWh
DEMAND UNITS	$/KW

Rate/Time Periods	1	2	3	4	5	
Name	Summer On-Peak	Partial-Peak	Summer Off-Peak	Partial Peak	Winter Off-Peak	
Abbreviation	SOP	SPP	SOFF	WPP	WOFF	TOTAL
Hours	768	896	2752	1638	2706	8760
Monthly Adjustment fo	6	0	0	6	0	

	AVOIDED ENERGY COSTS BY TIME PERIOD					AVOIDED DEMAND COSTS BY TIME PERIOD				
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF
Year	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW
2001	0.30	0.05	0.04	0.02	0.01	25.63	10.21	2.23	11.45	2.21
2002	0.30	0.05	0.04	0.02	0.01	26.65	10.65	2.33	12.01	2.30
2003	0.13	0.03	0.02	0.03	0.02	27.73	11.11	2.43	12.58	2.40
2004	0.12	0.03	0.02	0.02	0.02	28.88	11.58	2.53	13.16	2.50
2005	0.12	0.03	0.02	0.02	0.02	30.20	12.08	2.64	13.63	2.61
2006	0.11	0.03	0.02	0.03	0.02	31.49	12.59	2.75	14.22	2.72
2007	0.11	0.03	0.02	0.03	0.02	32.90	13.13	2.87	14.76	2.84
2008	0.12	0.03	0.02	0.03	0.02	34.24	13.69	2.99	15.46	2.96
2009	0.12	0.03	0.02	0.03	0.02	35.69	14.28	3.12	16.14	3.08
2010	0.13	0.03	0.02	0.03	0.02	37.27	14.89	3.25	16.78	3.22
2011	0.11	0.03	0.02	0.03	0.02	38.86	15.52	3.39	17.51	3.35
2012	0.11	0.03	0.02	0.03	0.02	40.54	16.18	3.53	18.23	3.50
2013	0.12	0.03	0.02	0.03	0.02	42.28	16.88	3.68	19.00	3.65
2014	0.12	0.03	0.02	0.03	0.02	44.09	17.61	3.84	19.81	3.80
2015	0.13	0.03	0.02	0.03	0.02	45.98	18.36	4.01	20.66	3.97
2016	0.14	0.03	0.02	0.03	0.02	47.94	19.15	4.18	21.54	4.14
2017	0.14	0.03	0.02	0.03	0.02	49.99	19.97	4.35	22.47	4.31
2018	0.15	0.04	0.02	0.03	0.03	52.13	20.82	4.54	23.43	4.50
2019	0.16	0.04	0.02	0.04	0.03	54.36	21.71	4.73	24.43	4.69
2020	0.16	0.04	0.02	0.04	0.03	56.68	22.64	4.94	25.48	4.89
2021	0.17	0.04	0.03	0.04	0.03	59.10	23.61	5.15	26.57	5.10

	COMMERCIAL ENERGY RATES					COMMERCIAL DEMAND RATES					Environmental Adder to be
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF	Subtracted for HIM
Year	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW	$/KWh
2001	0.09	0.09	0.09	0.07	0.07	6.70	0.00	0.00	1.65	0.00	0.01
2002	0.09	0.09	0.09	0.08	0.08	6.90	0.00	0.00	1.70	0.00	0.01
2003	0.09	0.09	0.09	0.08	0.08	7.11	0.00	0.00	1.75	0.00	0.01
2004	0.10	0.10	0.10	0.08	0.08	7.32	0.00	0.00	1.80	0.00	0.01
2005	0.10	0.10	0.10	0.08	0.08	7.54	0.00	0.00	1.86	0.00	0.01
2006	0.10	0.10	0.10	0.08	0.08	7.77	0.00	0.00	1.91	0.00	0.01
2007	0.11	0.11	0.11	0.09	0.09	8.00	0.00	0.00	1.97	0.00	0.01
2008	0.11	0.11	0.11	0.09	0.09	8.24	0.00	0.00	2.03	0.00	0.01
2009	0.11	0.11	0.11	0.09	0.09	8.49	0.00	0.00	2.09	0.00	0.01
2010	0.12	0.12	0.12	0.10	0.10	8.74	0.00	0.00	2.15	0.00	0.01
2011	0.12	0.12	0.12	0.10	0.10	9.00	0.00	0.00	2.22	0.00	0.01
2012	0.12	0.12	0.12	0.10	0.10	9.27	0.00	0.00	2.28	0.00	0.01
2013	0.13	0.13	0.13	0.10	0.10	9.55	0.00	0.00	2.35	0.00	0.01
2014	0.13	0.13	0.13	0.11	0.11	9.84	0.00	0.00	2.42	0.00	0.01
2015	0.13	0.13	0.13	0.11	0.11	10.13	0.00	0.00	2.50	0.00	0.02
2016	0.14	0.14	0.14	0.11	0.11	10.44	0.00	0.00	2.57	0.00	0.02
2017	0.14	0.14	0.14	0.12	0.12	10.75	0.00	0.00	2.65	0.00	0.02
2018	0.15	0.15	0.15	0.12	0.12	11.07	0.00	0.00	2.73	0.00	0.02
2019	0.15	0.15	0.15	0.12	0.12	11.41	0.00	0.00	2.81	0.00	0.02
2020	0.16	0.16	0.16	0.13	0.13	11.75	0.00	0.00	2.89	0.00	0.02
2021	0.16	0.16	0.16	0.13	0.13	12.10	0.00	0.00	2.98	0.00	0.02

ECONOMIC PARAMETERS

BASE ECONOMIC SCENARIO

UTILITY NAME	**Statewide**
SECTOR	Industrial
BATCH #	1
UTILITY DISCOUNT RATE	8.0%
CUSTOMER DISCOUNT RATE	15.0%
GENERAL INFLATION RATE (Measure)	3.0%
BASE YEAR	2001
START YEAR	2001
DIFFERENCE	0
UTILITY LINE LOSS RATE	5.0%

ENERGY COSTS AND RATES

RATE TYPE	INDUSTRIAL
ENERGY UNITS	$/KWh
DEMAND UNITS	$/KW

Rate/Time Periods	1	2	3	4	5	
Name	Summer On-Peak	Partial-Peak	Summer Off-Peak	Partial Peak	Winter Off-Peak	
Abbreviation	SOP	SPP	SOFF	WPP	WOFF	TOTAL
Hours	768	896	2752	1638	2706	8760
Monthly Adjustment to	6	0	0	6	0	

	AVOIDED ENERGY COSTS BY TIME PERIOD					AVOIDED DEMAND COSTS BY TIME PERIOD				
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF
Year	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW
2001	0.59	0.11	0.08	0.03	0.03	25.63	10.21	2.23	11.45	2.21
2002	0.59	0.11	0.08	0.03	0.03	26.65	10.65	2.33	12.01	2.30
2003	0.26	0.06	0.03	0.05	0.04	27.73	11.11	2.43	12.58	2.40
2004	0.24	0.05	0.03	0.05	0.04	28.88	11.58	2.53	13.16	2.50
2005	0.25	0.05	0.03	0.05	0.04	30.20	12.08	2.64	13.63	2.61
2006	0.22	0.05	0.03	0.05	0.04	31.49	12.59	2.75	14.22	2.72
2007	0.23	0.06	0.03	0.05	0.04	32.90	13.13	2.87	14.76	2.84
2008	0.23	0.06	0.03	0.05	0.04	34.24	13.69	2.99	15.46	2.96
2009	0.24	0.06	0.04	0.06	0.04	35.69	14.28	3.12	16.14	3.08
2010	0.25	0.06	0.04	0.06	0.04	37.27	14.89	3.25	16.78	3.22
2011	0.22	0.05	0.03	0.05	0.04	38.86	15.52	3.39	17.51	3.35
2012	0.23	0.06	0.03	0.05	0.04	40.54	16.18	3.53	18.23	3.50
2013	0.24	0.06	0.03	0.06	0.04	42.28	16.88	3.68	19.00	3.65
2014	0.25	0.06	0.04	0.06	0.04	44.09	17.61	3.84	19.81	3.80
2015	0.26	0.06	0.04	0.06	0.05	45.98	18.36	4.01	20.66	3.97
2016	0.27	0.07	0.04	0.06	0.05	47.94	19.15	4.18	21.54	4.14
2017	0.28	0.07	0.04	0.07	0.05	49.99	19.97	4.35	22.47	4.31
2018	0.30	0.07	0.04	0.07	0.05	52.13	20.82	4.54	23.43	4.50
2019	0.31	0.08	0.05	0.07	0.06	54.36	21.71	4.73	24.43	4.69
2020	0.33	0.08	0.05	0.08	0.06	56.68	22.64	4.94	25.48	4.89
2021	0.35	0.08	0.05	0.08	0.06	59.10	23.61	5.15	26.57	5.10

	INDUSTRIAL ENERGY RATES					INDUSTRIAL DEMAND RATES					Environmental Adder to be Subtracted for RIM
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF	
Year	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW	$/KWh
2001	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.01
2002	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.01
2003	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.01
2004	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.01
2005	0.06	0.06	0.06	0.06	0.06	0.00	0.00	0.00	0.00	0.00	0.01
2006	0.06	0.06	0.06	0.06	0.06	0.00	0.00	0.00	0.00	0.00	0.01
2007	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.01
2008	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.01
2009	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.01
2010	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.01
2011	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.01
2012	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.01
2013	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.01
2014	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.01
2015	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.02
2016	0.09	0.09	0.09	0.09	0.09	0.00	0.00	0.00	0.00	0.00	0.02
2017	0.09	0.09	0.09	0.09	0.09	0.00	0.00	0.00	0.00	0.00	0.02
2018	0.09	0.09	0.09	0.09	0.09	0.00	0.00	0.00	0.00	0.00	0.02
2019	0.09	0.09	0.09	0.09	0.09	0.00	0.00	0.00	0.00	0.00	0.02
2020	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.02
2021	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.02

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ECONOMIC PARAMETERS

HIGH ECONOMIC SCENARIO

UTILITY NAME	**Statewide**
SECTOR	Industrial
BATCH #	1
UTILITY DISCOUNT RATE	8.0%
CUSTOMER DISCOUNT RATE	15.0%
GENERAL INFLATION RATE (Measure)	3.0%
BASE YEAR	2001
START YEAR	2001
DIFFERENCE	0
UTILITY LINE LOSS RATE	5.0%

ENERGY COSTS AND RATES

RATE TYPE	INDUSTRIAL
ENERGY UNITS	$/KWh
DEMAND UNITS	$/KW

Rate/Time Periods	1	2	3	4	5	
Name	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak	
Abbreviation	SOP	SPP	SOFF	WPP	WOFF	TOTAL
Hours	768	896	2752	1638	2706	8760
Monthly Adjustment for r	6	0	0	6	0	

	AVOIDED ENERGY COSTS BY TIME PERIOD					AVOIDED DEMAND COSTS BY TIME PERIOD					INDUSTRIAL ENERGY RATES **Need to work out GS-2 as proxy**					INDUSTRIAL DEMAND RATES					Environmental Adder to be Subtracted for RIM
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF	
Year	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW	$/KWh
2001	0.74	0.13	0.10	0.04	0.04	25.63	10.21	2.23	11.45	2.21	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.01
2002	0.74	0.13	0.10	0.04	0.04	26.65	10.65	2.33	12.01	2.30	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.01
2003	0.32	0.07	0.04	0.06	0.05	27.73	11.11	2.43	12.58	2.40	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.01
2004	0.30	0.06	0.04	0.06	0.05	28.88	11.58	2.53	13.16	2.50	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.01
2005	0.31	0.06	0.04	0.06	0.05	30.20	12.08	2.64	13.63	2.61	0.11	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.00	0.00	0.01
2006	0.27	0.07	0.04	0.06	0.05	31.49	12.59	2.75	14.22	2.72	0.11	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.00	0.00	0.01
2007	0.28	0.07	0.04	0.07	0.05	32.90	13.13	2.87	14.76	2.84	0.11	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.00	0.00	0.01
2008	0.29	0.07	0.04	0.07	0.05	34.24	13.69	2.99	15.46	2.96	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.01
2009	0.30	0.07	0.04	0.07	0.05	35.69	14.28	3.12	16.14	3.08	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.01
2010	0.31	0.08	0.05	0.07	0.06	37.27	14.89	3.25	16.78	3.22	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.01
2011	0.27	0.07	0.04	0.06	0.05	38.86	15.52	3.39	17.51	3.35	0.13	0.13	0.13	0.13	0.13	0.00	0.00	0.00	0.00	0.00	0.01
2012	0.28	0.07	0.04	0.07	0.05	40.54	16.18	3.53	18.23	3.50	0.13	0.13	0.13	0.13	0.13	0.00	0.00	0.00	0.00	0.00	0.01
2013	0.30	0.07	0.04	0.07	0.05	42.28	16.88	3.68	19.00	3.65	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2014	0.31	0.08	0.05	0.07	0.05	44.09	17.61	3.84	19.81	3.80	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2015	0.32	0.08	0.05	0.08	0.06	45.98	18.36	4.01	20.66	3.97	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.02
2016	0.34	0.08	0.05	0.08	0.06	47.94	19.15	4.18	21.54	4.14	0.15	0.15	0.15	0.15	0.15	0.00	0.00	0.00	0.00	0.00	0.02
2017	0.35	0.09	0.05	0.08	0.06	49.99	19.97	4.35	22.47	4.31	0.15	0.15	0.15	0.15	0.15	0.00	0.00	0.00	0.00	0.00	0.02
2018	0.37	0.09	0.05	0.09	0.07	52.13	20.82	4.54	23.43	4.50	0.16	0.16	0.16	0.16	0.16	0.00	0.00	0.00	0.00	0.00	0.02
2019	0.39	0.10	0.06	0.09	0.07	54.36	21.71	4.73	24.43	4.69	0.16	0.16	0.16	0.16	0.16	0.00	0.00	0.00	0.00	0.00	0.02
2020	0.41	0.10	0.06	0.10	0.07	56.68	22.64	4.94	25.48	4.89	0.17	0.17	0.17	0.17	0.17	0.00	0.00	0.00	0.00	0.00	0.02
2021	0.43	0.11	0.06	0.10	0.08	59.10	23.61	5.15	26.57	5.10	0.17	0.17	0.17	0.17	0.17	0.00	0.00	0.00	0.00	0.00	0.02

ECONOMIC PARAMETERS

LOW ECONOMIC SCENARIO

UTILITY NAME	Statewide
SECTOR	Industrial
BATCH #	1
UTILITY DISCOUNT RATE	8.0%
CUSTOMER DISCOUNT RATE	15.0%
GENERAL INFLATION RATE (Measure)	3.0%
BASE YEAR	2001
START YEAR	2001
DIFFERENCE	0
UTILITY LINE LOSS RATE	5.0%

ENERGY COSTS AND RATES

RATE TYPE	INDUSTRIAL
ENERGY UNITS	$/KWh
DEMAND UNITS	$/KW

Rate/Time Periods	1	2	3	4	5	
Name	Summer On Peak	Partial-Peak	Summer Off-Peak	Partial Peak	Winter Off Peak	
Abbreviation	SOP	SPP	SOFF	WPP	WOFF	TOTAL
Hours	768	896	2752	1638	2706	8760
Monthly Adjustment fc	6	0	0	6	0	

	AVOIDED ENERGY COSTS BY TIME PERIOD					AVOIDED DEMAND COSTS BY TIME PERIOD				
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF
Year	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW
2001	0.30	0.05	0.04	0.02	0.01	25.63	10.21	2.23	11.45	2.21
2002	0.30	0.05	0.04	0.02	0.01	26.65	10.65	2.33	12.01	2.30
2003	0.13	0.03	0.02	0.03	0.02	27.73	11.11	2.43	12.58	2.40
2004	0.12	0.03	0.02	0.02	0.02	28.88	11.58	2.53	13.16	2.50
2005	0.12	0.03	0.02	0.02	0.02	30.20	12.08	2.64	13.63	2.61
2006	0.11	0.03	0.02	0.03	0.02	31.49	12.59	2.75	14.22	2.72
2007	0.11	0.03	0.02	0.03	0.02	32.90	13.13	2.87	14.76	2.84
2008	0.12	0.03	0.02	0.03	0.02	34.24	13.69	2.99	15.46	2.96
2009	0.12	0.03	0.02	0.03	0.02	35.69	14.28	3.12	16.14	3.08
2010	0.13	0.03	0.02	0.03	0.02	37.27	14.89	3.25	16.78	3.22
2011	0.11	0.03	0.02	0.03	0.02	38.86	15.52	3.39	17.51	3.35
2012	0.11	0.03	0.02	0.03	0.02	40.54	16.18	3.53	18.23	3.50
2013	0.12	0.03	0.02	0.03	0.02	42.28	16.88	3.68	19.00	3.65
2014	0.12	0.03	0.02	0.03	0.02	44.09	17.61	3.84	19.81	3.80
2015	0.13	0.03	0.02	0.03	0.02	45.98	18.36	4.01	20.66	3.97
2016	0.14	0.03	0.02	0.03	0.02	47.94	19.15	4.18	21.54	4.14
2017	0.14	0.03	0.02	0.03	0.02	49.99	19.97	4.35	22.47	4.31
2018	0.15	0.04	0.02	0.03	0.03	52.13	20.82	4.54	23.43	4.50
2019	0.16	0.04	0.02	0.04	0.03	54.36	21.71	4.73	24.43	4.69
2020	0.16	0.04	0.02	0.04	0.03	56.68	22.64	4.94	25.48	4.89
2021	0.17	0.04	0.03	0.04	0.03	59.10	23.61	5.15	26.57	5.10

	INDUSTRIAL ENERGY RATES					INDUSTRIAL DEMAND RATES					Environmental Adder to be Subtracted for RIM
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF	
Year	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW	$/KWh
2001	0.06	0.06	0.06	0.06	0.06	0.00	0.00	0.00	0.00	0.00	0.01
2002	0.06	0.06	0.06	0.06	0.06	0.00	0.00	0.00	0.00	0.00	0.01
2003	0.06	0.06	0.06	0.06	0.06	0.00	0.00	0.00	0.00	0.00	0.01
2004	0.06	0.06	0.06	0.06	0.06	0.00	0.00	0.00	0.00	0.00	0.01
2005	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.01
2006	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.01
2007	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.01
2008	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.01
2009	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.01
2010	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.01
2011	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.01
2012	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.01
2013	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.01
2014	0.09	0.09	0.09	0.09	0.09	0.00	0.00	0.00	0.00	0.00	0.01
2015	0.09	0.09	0.09	0.09	0.09	0.00	0.00	0.00	0.00	0.00	0.02
2016	0.09	0.09	0.09	0.09	0.09	0.00	0.00	0.00	0.00	0.00	0.02
2017	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.02
2018	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.02
2019	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.02
2020	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.02
2021	0.11	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.00	0.00	0.02

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ECONOMIC PARAMETERS

BASE ECONOMIC SCENARIO

UTILITY NAME	**Statewide**
SECTOR	Residential
BATCH #	1
UTILITY DISCOUNT RATE	8.0%
CUSTOMER DISCOUNT RATE	15.0%
GENERAL INFLATION RATE (Measure)	3.0%
BASE YEAR	2001
START YEAR	2001
DIFFERENCE	0
UTILITY LINE LOSS RATE	8.5%

ENERGY COSTS AND RATES

RATE TYPE	RESIDENTIAL
ENERGY UNITS	$/KWh
DEMAND UNITS	$/KW

Rate/Time Periods	1	2	3	4	5	
Name	Summer On-Peak	Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak	
Abbreviation	SOP	SPP	SOFF	WPP	WOFF	TOTAL
Hours	768	896	2752	1638	2706	8760
Monthly Adjustment fo	6	0	0	6	0	

	AVOIDED ENERGY COSTS BY TIME PERIOD					AVOIDED DEMAND COSTS BY TIME PERIOD				
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF
Year	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW
2001	0.59	0.11	0.08	0.03	0.03	25.63	10.21	2.23	11.45	2.21
2002	0.59	0.11	0.08	0.03	0.03	26.65	10.65	2.33	12.01	2.30
2003	0.26	0.06	0.03	0.05	0.04	27.73	11.11	2.43	12.58	2.40
2004	0.24	0.05	0.03	0.05	0.04	28.88	11.58	2.53	13.16	2.50
2005	0.25	0.05	0.03	0.05	0.04	30.20	12.08	2.64	13.63	2.61
2006	0.22	0.05	0.03	0.05	0.04	31.49	12.59	2.75	14.22	2.72
2007	0.23	0.06	0.03	0.05	0.04	32.90	13.13	2.87	14.76	2.84
2008	0.23	0.06	0.03	0.05	0.04	34.24	13.69	2.99	15.46	2.96
2009	0.24	0.06	0.04	0.06	0.04	35.69	14.28	3.12	16.14	3.08
2010	0.25	0.06	0.04	0.06	0.04	37.27	14.89	3.25	16.78	3.22
2011	0.22	0.05	0.03	0.05	0.04	38.86	15.52	3.39	17.51	3.35
2012	0.23	0.06	0.03	0.05	0.04	40.54	16.18	3.53	18.23	3.50
2013	0.24	0.06	0.03	0.06	0.04	42.28	16.88	3.68	19.00	3.65
2014	0.25	0.06	0.04	0.06	0.04	44.09	17.61	3.84	19.81	3.80
2015	0.26	0.06	0.04	0.06	0.05	45.98	18.38	4.01	20.66	3.97
2016	0.27	0.07	0.04	0.06	0.05	47.94	19.15	4.18	21.54	4.14
2017	0.28	0.07	0.04	0.07	0.05	49.99	19.97	4.35	22.47	4.31
2018	0.30	0.07	0.04	0.07	0.05	52.13	20.82	4.54	23.43	4.50
2019	0.31	0.08	0.05	0.07	0.06	54.38	21.71	4.73	24.43	4.69
2020	0.33	0.08	0.05	0.08	0.06	56.68	22.64	4.94	25.48	4.89
2021	0.35	0.08	0.05	0.08	0.06	59.10	23.61	5.15	26.57	5.10

	RESIDENTIAL ENERGY RATES					RESIDENTIAL DEMAND RATES					Environmental Adder to be Subtracted for RIM
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF	
Year	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW	$/KWh
2001	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.01
2002	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.01
2003	0.13	0.13	0.13	0.13	0.13	0.00	0.00	0.00	0.00	0.00	0.01
2004	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2005	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2006	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2007	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2008	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2009	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2010	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2011	0.15	0.15	0.15	0.15	0.15	0.00	0.00	0.00	0.00	0.00	0.01
2012	0.15	0.15	0.15	0.15	0.15	0.00	0.00	0.00	0.00	0.00	0.01
2013	0.16	0.16	0.16	0.16	0.16	0.00	0.00	0.00	0.00	0.00	0.01
2014	0.16	0.16	0.16	0.16	0.16	0.00	0.00	0.00	0.00	0.00	0.01
2015	0.17	0.17	0.17	0.17	0.17	0.00	0.00	0.00	0.00	0.00	0.02
2016	0.17	0.17	0.17	0.17	0.17	0.00	0.00	0.00	0.00	0.00	0.02
2017	0.18	0.18	0.18	0.18	0.18	0.00	0.00	0.00	0.00	0.00	0.02
2018	0.18	0.18	0.18	0.18	0.18	0.00	0.00	0.00	0.00	0.00	0.02
2019	0.19	0.19	0.19	0.19	0.19	0.00	0.00	0.00	0.00	0.00	0.02
2020	0.19	0.19	0.19	0.19	0.19	0.00	0.00	0.00	0.00	0.00	0.02
2021	0.20	0.20	0.20	0.20	0.20	0.00	0.00	0.00		0.00	0.02

ECONOMIC PARAMETERS

HIGH ECONOMIC SCENARIO

UTILITY NAME	Statewide
SECTOR	Residential
BATCH #	1
UTILITY DISCOUNT RATE	8.0%
CUSTOMER DISCOUNT RATE	15.0%
GENERAL INFLATION RATE (Measure)	3.0%
BASE YEAR	2001
START YEAR	2001
DIFFERENCE	0
UTILITY LINE LOSS RATE	8.5%

ENERGY COSTS AND RATES

RATE TYPE	RESIDENTIAL
ENERGY UNITS	S/KWh
DEMAND UNITS	S/KW

Rate/Time Periods	1	2	3	4	5	
Name	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak	
Abbreviation	SOP	SPP	SOFF	WPP	WOFF	TOTAL
Hours	768	896	2752	1638	2706	8760
Monthly Adjustment for rat	6	0	0	6	0	

	AVOIDED ENERGY COSTS BY TIME PERIOD					AVOIDED DEMAND COSTS BY TIME PERIOD				
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF
Year	S/KWh	S/KWh	S/KWh	S/KWh	S/KWh	S/KW	S/KW	S/KW	S/KW	S/KW
2001	0.74	0.13	0.10	0.04	0.04	25.63	10.21	2.23	11.45	2.21
2002	0.74	0.13	0.10	0.04	0.04	26.65	10.65	2.33	12.01	2.30
2003	0.32	0.07	0.04	0.06	0.05	27.73	11.11	2.43	12.58	2.40
2004	0.30	0.06	0.04	0.06	0.05	28.88	11.58	2.53	13.16	2.50
2005	0.31	0.06	0.04	0.06	0.05	30.20	12.08	2.64	13.63	2.61
2006	0.27	0.07	0.04	0.06	0.05	31.49	12.59	2.75	14.22	2.72
2007	0.28	0.07	0.04	0.07	0.05	32.90	13.13	2.87	14.76	2.84
2008	0.29	0.07	0.04	0.07	0.05	34.24	13.69	2.99	15.46	2.96
2009	0.30	0.07	0.04	0.07	0.05	35.69	14.28	3.12	16.14	3.08
2010	0.31	0.08	0.05	0.07	0.06	37.27	14.89	3.25	16.78	3.22
2011	0.27	0.07	0.04	0.06	0.05	38.86	15.52	3.39	17.51	3.35
2012	0.28	0.07	0.04	0.07	0.05	40.54	16.18	3.53	18.23	3.50
2013	0.30	0.07	0.04	0.07	0.05	42.28	16.88	3.68	19.00	3.65
2014	0.31	0.08	0.05	0.07	0.05	44.09	17.61	3.84	19.81	3.80
2015	0.32	0.08	0.05	0.08	0.06	45.98	18.36	4.01	20.68	3.97
2016	0.34	0.08	0.05	0.08	0.06	47.94	19.15	4.18	21.54	4.14
2017	0.35	0.09	0.05	0.08	0.06	49.99	19.97	4.35	22.47	4.31
2018	0.37	0.09	0.05	0.09	0.07	52.13	20.82	4.54	23.43	4.50
2019	0.39	0.10	0.06	0.09	0.07	54.36	21.71	4.73	24.43	4.69
2020	0.41	0.10	0.06	0.10	0.07	56.68	22.64	4.94	25.48	4.89
2021	0.43	0.11	0.06	0.10	0.08	59.10	23.61	5.15	26.57	5.10

	RESIDENTIAL ENERGY RATES					RESIDENTIAL DEMAND RATES					Environmental Adder to be Subtracted for RIM
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF	
Year	S/KWh	S/KWh	S/KWh	S/KWh	S/KWh	S/KW	S/KW	S/KW	S/KW	S/KW	S/KWh
2001	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.01
2002	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.01
2003	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.01
2004	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.01
2005	0.13	0.13	0.13	0.13	0.13	0.00	0.00	0.00	0.00	0.00	0.01
2006	0.13	0.13	0.13	0.13	0.13	0.00	0.00	0.00	0.00	0.00	0.01
2007	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2008	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2009	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2010	0.15	0.15	0.15	0.15	0.15	0.00	0.00	0.00	0.00	0.00	0.01
2011	0.15	0.15	0.15	0.15	0.15	0.00	0.00	0.00	0.00	0.00	0.01
2012	0.16	0.16	0.16	0.16	0.16	0.00	0.00	0.00	0.00	0.00	0.01
2013	0.16	0.16	0.16	0.16	0.16	0.00	0.00	0.00	0.00	0.00	0.01
2014	0.17	0.17	0.17	0.17	0.17	0.00	0.00	0.00	0.00	0.00	0.01
2015	0.17	0.17	0.17	0.17	0.17	0.00	0.00	0.00	0.00	0.00	0.02
2016	0.18	0.18	0.18	0.18	0.18	0.00	0.00	0.00	0.00	0.00	0.02
2017	0.18	0.18	0.18	0.18	0.18	0.00	0.00	0.00	0.00	0.00	0.02
2018	0.19	0.19	0.19	0.19	0.19	0.00	0.00	0.00	0.00	0.00	0.02
2019	0.19	0.19	0.19	0.19	0.19	0.00	0.00	0.00	0.00	0.00	0.02
2020	0.20	0.20	0.20	0.20	0.20	0.00	0.00	0.00	0.00	0.00	0.02
2021	0.20	0.20	0.20	0.20	0.20	0.00	0.00	0.00	0.00	0.00	0.02

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XENERGY

ECONOMIC PARAMETERS

LOW ECONOMIC SCENARIO

UTILITY NAME	Statewide
SECTOR	Residential
BATCH #	1
UTILITY DISCOUNT RATE	8.0%
CUSTOMER DISCOUNT RATE	15.0%
GENERAL INFLATION RATE (Measure)	3.0%
BASE YEAR	2001
START YEAR	2001
DIFFERENCE	0
UTILITY LINE LOSS RATE	8.5%

ENERGY COSTS AND RATES

RATE TYPE	RESIDENTIAL
ENERGY UNITS	$/KWh
DEMAND UNITS	$/KW

Rate/Time Periods	1	2	3	4	5	
Name	Summer On-Peak	Summer Partial-Peak	Summer Off-Peak	Winter Partial Peak	Winter Off-Peak	
Abbreviation	SOP	SPP	SOFF	WPP	WOFF	TOTAL
Hours	768	896	2752	1638	2706	8760
Monthly Adjustment for	6	0	0	6	0	

	AVOIDED ENERGY COSTS BY TIME PERIOD					AVOIDED DEMAND COSTS BY TIME PERIOD				
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF
Year	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW
2001	0.30	0.05	0.04	0.02	0.01	25.63	10.21	2.23	11.45	2.21
2002	0.30	0.05	0.04	0.02	0.01	26.65	10.65	2.33	12.01	2.30
2003	0.13	0.03	0.02	0.03	0.02	27.73	11.11	2.43	12.58	2.40
2004	0.12	0.03	0.02	0.02	0.02	28.88	11.58	2.53	13.16	2.50
2005	0.12	0.03	0.02	0.02	0.02	30.20	12.08	2.64	13.63	2.61
2006	0.11	0.03	0.02	0.03	0.02	31.49	12.59	2.75	14.22	2.72
2007	0.11	0.03	0.02	0.03	0.02	32.90	13.13	2.87	14.76	2.84
2008	0.12	0.03	0.02	0.03	0.02	34.24	13.69	2.99	15.46	2.96
2009	0.12	0.03	0.02	0.03	0.02	35.69	14.28	3.12	16.14	3.08
2010	0.13	0.03	0.02	0.03	0.02	37.27	14.89	3.25	16.78	3.22
2011	0.11	0.03	0.02	0.03	0.02	38.86	15.52	3.39	17.51	3.35
2012	0.11	0.03	0.02	0.03	0.02	40.54	16.18	3.53	18.23	3.50
2013	0.12	0.03	0.02	0.03	0.02	42.28	16.88	3.68	19.00	3.65
2014	0.12	0.03	0.02	0.03	0.02	44.09	17.61	3.84	19.81	3.80
2015	0.13	0.03	0.02	0.03	0.02	45.98	18.36	4.01	20.66	3.97
2016	0.14	0.03	0.02	0.03	0.02	47.94	19.15	4.18	21.54	4.14
2017	0.14	0.03	0.02	0.03	0.02	49.99	19.97	4.35	22.47	4.31
2018	0.15	0.04	0.02	0.03	0.03	52.13	20.82	4.54	23.43	4.50
2019	0.16	0.04	0.02	0.04	0.03	54.36	21.71	4.73	24.43	4.69
2020	0.16	0.04	0.02	0.04	0.03	56.68	22.64	4.94	25.48	4.89
2021	0.17	0:04	0.03	0.04	0.03	59.10	23.61	5.15	26.57	5.10

	RESIDENTIAL ENERGY RATES					RESIDENTIAL DEMAND RATES					Environmentel Adder to be Subtracted for RIM
	SOP	SPP	SOFF	WPP	WOFF	SOP	SPP	SOFF	WPP	WOFF	
Year	$/KWh	$/KWh	$/KWh	$/KWh	$/KWh	$/KW	$/KW	$/KW	$/KW	$/KW	$/KWh
2001	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.01
2002	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.01
2003	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.01
2004	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.01
2005	0.11	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.00	0.00	0.01
2006	0.11	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.00	0.00	0.01
2007	0.11	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.00	0.00	0.01
2008	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.01
2009	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.01
2010	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.01
2011	0.13	0.13	0.13	0.13	0.13	0.00	0.00	0.00	0.00	0.00	0.01
2012	0.13	0.13	0.13	0.13	0.13	0.00	0.00	0.00	0.00	0.00	0.01
2013	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2014	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.01
2015	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.02
2016	0.15	0.15	0.15	0.15	0.15	0.00	0.00	0.00	0.00	0.00	0.02
2017	0.15	0.15	0.15	0.15	0.15	0.00	0.00	0.00	0.00	0.00	0.02
2018	0.16	0.16	0.16	0.16	0.16	0.00	0.00	0.00	0.00	0.00	0.02
2019	0.16	0.16	0.16	0.16	0.16	0.00	0.00	0.00	0.00	0.00	0.02
2020	0.17	0.17	0.17	0.17	0.17	0.00	0.00	0.00	0.00	0.00	0.02
2021	0.17	0.17	0.17	0.17	0.17	0.00	0.00	0.00	0.00	0.00	0.02

Appendix E. Price Spike Scenario Comparison

As discussed in Section 2 of this report, alternate future energy cost scenarios are developed to test the sensitivity and robustness of energy efficiency to wide ranging estimates of future avoided costs. Our High cost scenario, which increases avoided costs by 25 percent as compared to the Base energy cost scenario, was intended to capture the effect of a high-price energy future. The high-price energy future might result from a future energy crisis or an increase in the value associated with greenhouse gas and other pollutant reductions (for example, because of public or market incentives associated with a greenhouse gas reduction commitment). In this appendix, we present the results of a very simple comparison of our High energy cost scenario with simulated energy cost futures that include price spikes that mimic the recent energy crisis. These simulations are intended to capture the effect of price spikes similar to those that occurred in California from late 2000 through 2001. Ultimately, the energy-efficiency potential of the price spike scenarios was not estimated because the avoided costs in the High scenario roughly matched the price spike scenarios, as discussed below.

The price spike scenarios are 3X Price Spike and 6X Price Spike. These were created using the Base scenario as the starting point (see Appendix D for energy cost data). In the 3X scenario, the avoided energy costs in 2005 and 2006 were multiplied by a factor of 3. Similarly, in the 6X scenario the Base avoided energy costs for 2005 and 2006 were multiplied by a factor of 6. For example, the annual summer peak prices for the scenarios are shown in Figure E-1.

The effects of the 3X and 6X price spikes are dramatic. However, using an 8-percent nominal rate, the discounted value of the price spike scenarios are muted. The discounted annual peak prices for the scenarios are shown in Figure E-2. The 20-year, rolling average, discounted, annual summer peak prices for the scenarios are shown in Figure E-3. The 20-year, rolling sums, discounted annual summer peak prices are shown in Figure E-4. Over the 20-year forecast period, the effect of the price spikes in 2005 and 2006 are largely averaged out. As it turns out, the 3X scenario is actually about 10 percent less than the High scenario on a present-value basis (i.e., summing the sums across the forecast period). The 6X scenario is roughly 10 percent more than the High scenario on a present-value basis.

As a result, we conclude that the High scenario reasonable captures the range of potential costs associated with another energy crisis that might occur in the near term.

Figure E-1

Forecasted Summer Peak Nominal Avoided Energy Cost Scenarios

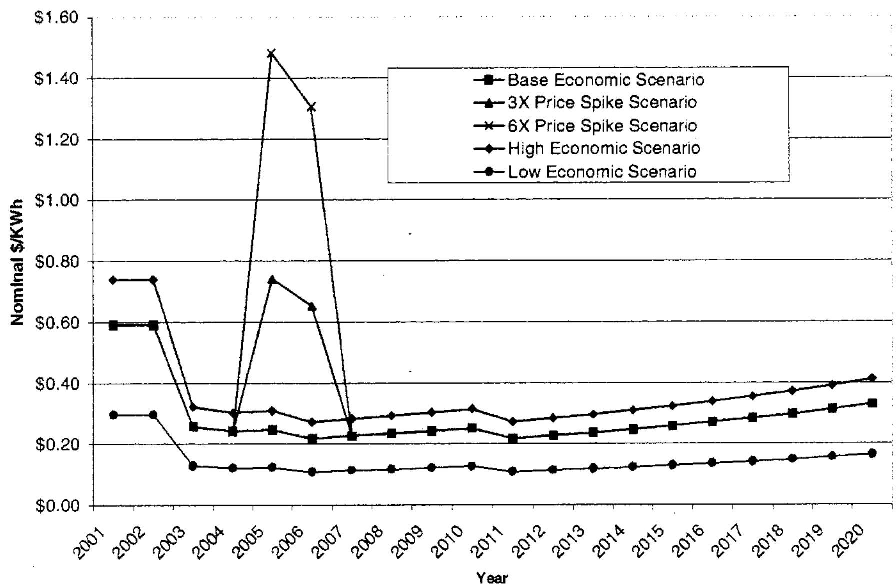


Figure E-2

Forecasted Summer Peak Discounted Avoided Energy Cost Scenarios

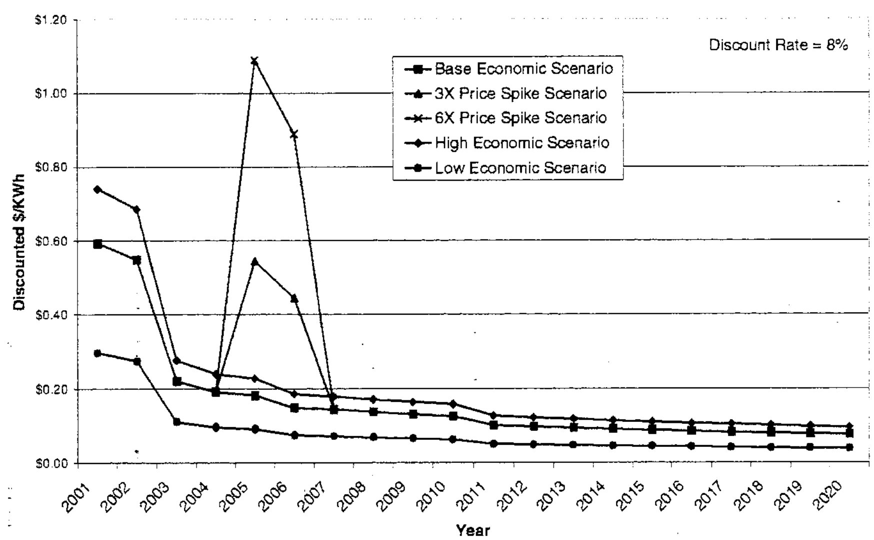


Figure E-3

20-Year Rolling Avg. Discounted Summer Peak Avoided Energy Costs

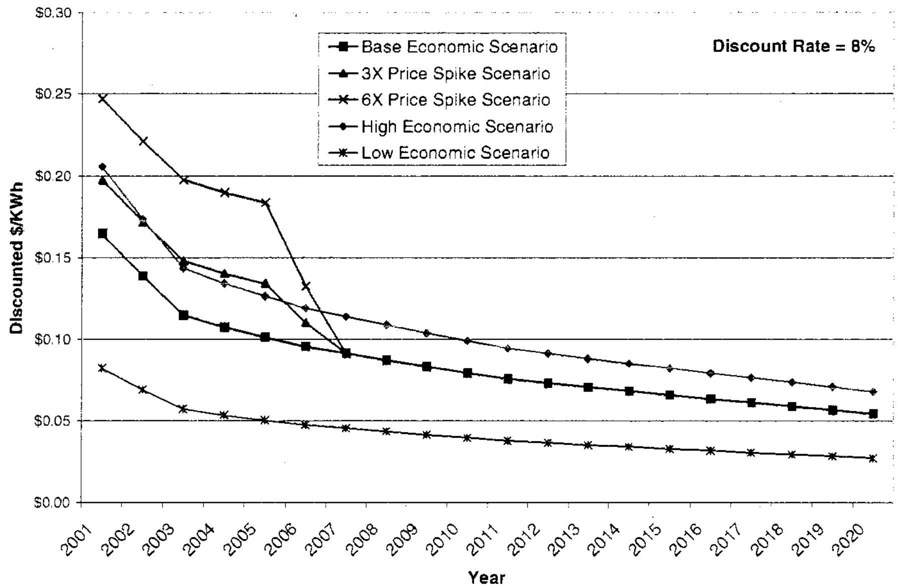
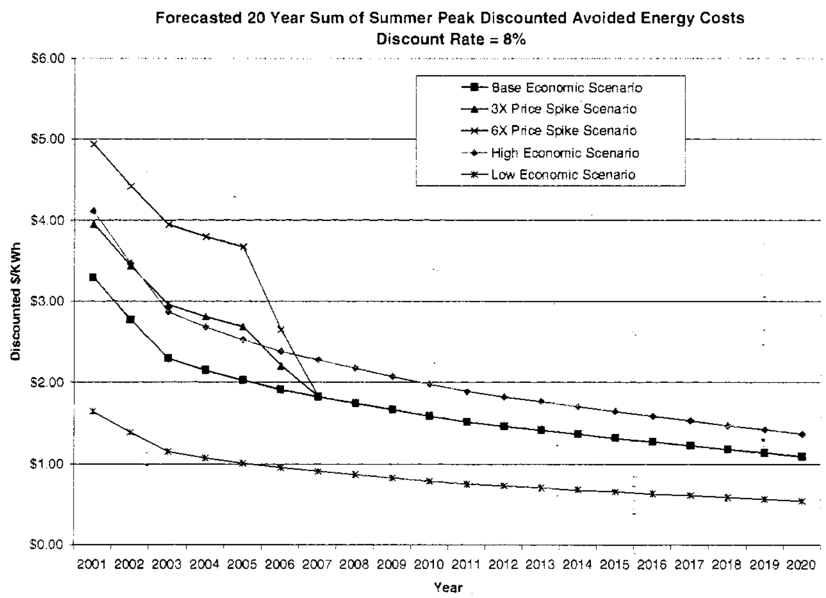


Table E-4

20-Year Rolling Sums of Summer Peak Avoided Costs



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