DIVERSITY AND RISK ANALYSIS IN A RESTRUCTURED CALIFORNIA ELECTRICITY MARKET

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FINAL REPORT
DIVERSITY AND RISK ANALYSIS IN A RESTRUCTURED CALIFORNIA ELECTRICITY MARKET

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ABSTRACT

This report describes the results of Phase 2 of a study quantifying fuel and technology diversity in California=s electricity generation system. Phase 1 developed a method for quantifying the risk associated with generation cost and applied this method to recent California generation costs by technology. Using the Phase 1 model it is possible to analyze how changes in the generation-technology mix would affect total generation-cost risk. In the current Phase 2 study, these methods are expanded to encompass issues related to the restructured electricity market. These issues include the divergence between public and private risk mitigation options, and the divergence between the risks faced by consumers versus suppliers of electricity. A detailed spreadsheet model was developed which facilitates analysis of the interaction between technology mix, fuel and other. The model could be expanded by further exploring the relationship between market-clearing price and certain other exogenous variables, notably hydroelectric availability. The model provides a basis to monitor market-wide diversity effects as additional information is obtained about the restructured marketplace.

SUMMARY

The Phase 1 Diversity analysis[1] developed a method for measuring fuel and technology diversity in terms of the portfolio of generation technology costs. This method was applied to generation capacities and costs during the 1990 to 1995 period. For Phase 1 purposes, risk was limited to the cost of electrical generation under traditional rate-of-return regulation. The measurement approach defines risk in terms of the average cost and standard deviation of cost of the Aportfolio@ of available generation. The greater the portfolio standard deviation, the greater the volatility of electricity prices. Because the model is built up from cost models of each technology, it is possible to determine how changes in one or more technologies influence the risk of the entire portfolio. This methodology was then applied to actual historic data on the electricity generation system in California for 1990 to 1995.

Phase 2 of the diversity risk study effort expands the diversity risk analysis in several directions. First, the focus shifts from the historic application of risk evaluation methods (*ex post* analysis) to a prospective (*ex ante*) application. Phase 2 also expands the focus from generation cost risk to supplier revenue risk and consumer rate risk. As California moves from a traditional rate-of-return regulated environment to a market-based deregulated environment, many new issues arise. These issues include the divergence between public and private risk mitigation measures, as well as the difference between the risks faced by suppliers and consumers. Also, changes due to the deregulated environment provoked a re-evaluation of other diversity models from the ecological literature. These issues are briefly summarized in the following paragraphs.

In a market environment, generation cost influences but does not directly determine the prices paid by consumers and the variability of those prices. Rather prices are determined by the hourly market clearing price (MCP), as well as the still-regulated cost of transmission and distribution, and other regulatory factors. Consumers, energy service companies (ESCO=s) and suppliers all have differing risk mitigation options as shown on the following table:

Summary of Electricity Risk Mitigation Strategies

Mitigation Strategy	Large User	Small User	Generator	ESCO
DSM/Conservation/Self-generation	Yes	Yes	No	Maybe
Electricity Futures Market Participation	Yes	Difficult	Yes	Yes
Gas Futures Market Participation	Yes	Difficult	Yes	Maybe
Contractual Shifting of Risk	Yes	Yes	Yes	Yes
Increasing Supply Diversity	Maybe	Difficult	Maybe	Yes
Selecting Trading Institutions	Yes	No	Yes	Yes
Real-Time and Time of Use Metering	Yes	Maybe	No	Maybe
Self-Generation	Yes	Maybe	No	Maybe

Different consumer groups face different electricity rates, even though their rates are, in part, based on the same market-clearing prices. This is because the percentage of the rates due to market energy

[1]Marvin Feldman, *Diversity and Risk Analysis*. Consultant Report P500-97-008, Technology Assessment Office, Sacramento, California Energy Commission, June, 1997.

prices versus the still-regulated distribution, transmission and other service costs differs among groups. These differences are further accentuated by the effects of the rate reduction revenue bonds authorized in AB 1890. These effects tend to make residential and small commercial customers= rates relatively less sensitive to the MCP component, than are the rates of commercial and industrial users. All of these effects are quantified in the report.

Similarly, the revenues received by electricity sellers are influenced only indirectly by generation cost, insofar as these costs influence the market-clearing price. The relationship between revenues and total and variable costs faced by each generation technology is investigated in the report. In addition to the variations in costs, each technology differs with respect to the percentage of time which the technology is on and off peak. Using the preliminary MCP forecast published by the CEC,[2] the effects of these differences are assessed. In addition, the effects of subsidies available through AB 1890 are also evaluated with respect to renewable energy suppliers.

The divergence between public and private risk mitigation approaches, and differences in risk preferences are also evaluated in this report. A partial list of possible electricity price risk mitigation options available to California includes:

- X Shifting risk to other parties through long-term contracts;
- X Participating in futures markets for electricity and natural gas;
- X Increasing fuel diversity in the supply mix;
- X Increasing the fuel and technology diversity available to all parties through subsidies;
- X Funding public-good generation R&D;
- X Influencing the institutions for electric energy trading and transmission capacity;
- X Increasing interstate transmission capacity;
- X Promoting DSM; and
- X Using fiscal policies to mitigate risks.

[2] J. Klein: *Interim Staff Market Clearing Price Forecast for the California Energy Market: Forecast Methodology and Analytical Issues*. Electricity Analysis Office, California Energy Commission, Sacramento, December 10, 1997.

Of these nine options, only the first two, long-term contracting and futures market participation, are available to private parties without governmental support or approval. The third option, increasing fuel diversity in the supply mix, is potentially available to marketers and generation suppliers.[3] All other policies require governmental intervention. Each of these risk mitigation options is discussed in the report.

Using standard economic definitions and measurements of risk preference (the extent to which a party values being insulated from price variance), risk preference of various groups were estimated. Based on these estimates, it was determined that over the foreseeable range of annual average electricity price variations, risk aversion is a fairly minor factor for California households. The effect of discount rate and cost of capital are also evaluated from a public and private risk standpoint.

A spreadsheet model was developed to assist the CEC in evaluation of policy options and alternatives with respect to fuel and technology diversity. The model was constructed so that changes in assumption with respect to generation costs for each of 15 technologies, fuel costs, capacities of the technologies, and changes in capacity factors would be reflected throughout the model. A base case was estimated for the 1996 to 2010 period based on data from CEC forecasts and several other sources. Alternative cases examining variability of natural gas prices, coal and nuclear capacity, and intensity of demand-side management activities were developed.

The spreadsheet model was documented and instructions were added to enable users from the CEC to modify the data inputs. This will facilitate updating the model with better data as further experience with deregulation is obtained. In addition, analysts from the CEC will be able to use the model to assist policy-makers in evaluating alternative fuel and technology diversity policies.

[3]It might also be possible for consumers to become their own suppliers by owning wind or solar generation units, but under present technology, this is not yet economic. Demand-side management, which can also be thought of as a supply option, is a feasible option at the consumer level.

1.0 INTRODUCTION

1.1_ BACKGROUND AND PURPOSE

Since its formation, the California Energy Commission (CEC) has sought to promote fuel and technology diversity in California=s electricity industry. The success of this mission is revealed by the wide diversity of fuels and technologies which are used to power California=s 250 trillion kWh annual electrical demand. Eleven generation technologies are presently in use, with several others approaching commercial status.

The value of fuel and technology in reducing risks to generators, consumers and the state economy as a whole has great intuitive appeal. Previous study efforts by the CEC had addressed aspects of fuel price risk and mitigation strategies. Until recent years, however, there existed no precise definition of diversity, much less its quantitative impact on its risk mitigation efficacy.

The CEC commissioned Resource Decisions to lead a team to address this important issue. The study was conducted in two phases. In May 1996, Phase 1 commenced. This phase focused on evaluating potential methods for measuring diversity and risk. For Phase 1 purposes, risk was limited to the cost of electrical generation. After evaluating several possible approaches from both the investment portfolio analysis and biological diversity literature, an approach was selected. The selected approach, based on an insight by Markowitz[4] that an efficient investment portfolio is one whose risk cannot be decreased without decreasing its expected rate of return. Reasoning by analogy, we applied this definition to an efficient generation Aportfolio@ using the average cost and estimated standard deviation cost of a portfolio of generation alternatives. The greater the portfolio standard deviation, the greater the volatility of electricity prices. Because the model is built up from cost models of each technology, it is possible to determine how changes in one or more technologies

[4] Harry Markowitz, *Portfolio SelectionBEfficient Diversification of Investments*. New Haven: Yale University Press, 1959.

influence the risk of the entire portfolio. This methodology was then applied to actual historic data on the electricity generation system in California for 1990 to 1995. The approach, data and results of the Phase 1 study are reported in a Consultant Report published by the CEC in June 1997.[5]

Phase 2 of the diversity risk study effort commenced in May 1997. This phase, which is documented in the present report, expands the diversity risk analysis in several directions. First, the focus shifts from the historic application of risk evaluation methods (*ex post* analysis) to a prospective (*ex ante*) application. The advent of the statewide electricity market in April of this year provides a dynamic test-bed for the Phase 2 applications. Further, Phase 2 extends the risk analysis from the cost perspective to the price and revenue perspective faced by consumers and sellers in a restructured marketplace. In this context, generation cost influences but does not directly determine the prices paid by consumers and the variability of those prices. Rather prices are determined by the hourly market clearing price (MCP), as well as the still regulated cost of transmission and distribution and other regulatory factors. Similarly, the revenues received by electricity sellers are influenced only indirectly by generation cost and variance. Again, market-clearing price is a primary determinant of revenues.

Because of the timing of this report, during the early months of the competitive transition, the impacts of various exogenous forces on the market-clearing price could not be determined in many scenarios. Where this limitation occurs, we suggest ways to expand the model results at such time as this relationship can be estimated.

Other aspects of the Phase 2 analysis include evaluation of the divergence between public and private risk mitigation approaches, analysis of the expected impacts of the renewable technology incentives provided by AB 1890, and a further evaluation and comparison of all biological diversity index approaches.

1.2 ORGANIZATION OF THIS REPORT

The Phase 2 report is intended to expand and augment the Phase 1 analysis. Although insights derived from Phase 1 are reported here, we have not attempted to replicate the information reported in the Phase 1 report. Rather, the reader is directed to that report for further background and data

[5] Marvin Feldman, *Diversity and Risk Analysis*. Consultant Report P500-97-008, Technology Assessment Office, Sacramento, California Energy Commission, June 1997.

analysis. The Phase 2 report is submitted in two forms: this text report and a spreadsheet model implemented in Corel Quattro Pro (Version 8). Although we have made every reasonable effort to make this written report self-explanatory, anyone wishing to apply or expand on the model will need to access the spreadsheet model.

The Phase 2 written report is organized into seven sections. Following this introductory chapter, Section 2 describes the divergence between public and private risk perspectives, including such issues as risk preference and alternative time value of money perspectives. Section 3 presents the results of a comprehensive evaluation of biological diversity models and their applicability to electricity diversity risk analysis. Section 4 frames the basis for evaluating risk faced by electricity generation owners and risk faced by consumers in a restructured electricity market. In Section 5, the data needed to quantitatively estimate average prices and revenues in a restructured market are presented. Section 6 describes the results of the base case and alternative scenarios. Section 7 describes and documents the computer model of risk and diversity. Appendix A consists of an evaluation of the effects of AB1890 renewable subsidies.

2.0 SOCIAL VERSUS PRIVATE RISK

2.1 INTRODUCTION: RISK MANAGEMENT CONCEPTS AND STRATEGIES

Risk-management strategies generally use some type of financial or contractual methods to reduce the variability of future costs. Without any risk management efforts, all parties are subjected to cost variations inherent in the marketplace. Risk management strategies include participating in forward markets, vertical integration, horizontal integration, long-term contracting, commodities hedging on the natural gas and electricity markets and, of course, diversification of fuel supplies, suppliers and technologies. By not implementing any risk mitigation options, a party simply accepts the price variance associated with fluctuations in fuel prices and the availability of supply technologies.

In the Phase 1 diversity analysis,[6] Resource Decisions developed a methodology whereby risk was defined in terms of the standard deviation of the cost of a portfolio of electricity fuels and technologies.. In Phase 1, this method was applied to estimate supplier risk. In the present analysis, we extend this concept to both supplier and consumer or user risk, which is discussed in connection with Section 4. In this section, we focus on expanding this concept to the divergence between social and private risk.

Each risk mitigation strategy has a cost associated with its implementation. Each strategy can be differentiated with respect to its cost and its efficacy in mitigating risk under a restructured electricity marketplace, and its applicability to user versus supplier risks.

The benefit of risk mitigation is, in essence, the avoided cost of exposure to variable electricity costs. These avoided costs are related to the time value of money, the cost of alternatives sources of capital to the party in question (user or supplier), and the value of avoiding certain types of risk. This last component is the most difficult to measure because it varies greatly by individual and circumstances. In addition, the costs of risk avoidance can be mitigated by pooling across many individuals. We will explore the techniques of measuring the benefit (avoided cost) of a strategy with reference to the cost of capital associated with the party (user or supplier).

The cost of implementing risk mitigation strategies is more easily measured than the benefit. For policies which promote physical diversity, costs are associated with additional spending on a diverse generation mix (as opposed to the least-cost mix). For R&D, the cost is simply the cost of

[6] Marvin Feldman, *Diversity and Risk Analysis*. Consultant Report P500-97-008, Technology Assessment Office, Sacramento, California Energy Commission, June 1997.

the R&D subsidy program. For financial market-based risk reduction strategies, the cost consists of the transaction costs associated with brokerage commissions and the cost to administer the program.

In this task, we first review mitigation options, focusing primarily on risk premiums and cost of capital divergences between public and private entities. Secondary attention is given to futures market-based methods. The task concludes with a cost-benefit framework.

2.2 BASIS FOR DIVERGENCE BETWEEN PUBLIC AND PRIVATE RISK

In general, a desirable level of risk (whether private or social) can be defined as the level at which the marginal cost of accepting the risk of variability equals the marginal cost of the least costly mitigation strategy.

There are at least three factors which differentiate private from social risk mitigation costs:

X California has a different set mitigation options and costs from private entities;[7]
X California=s cost of capital differs from that of private parties; and
X California=s risk preference differs from that of private parties.

2.2.1 Mitigation Options

Pubic decision-makers have a broader choice set of policy options for mitigating electricity price risk than do private entities. Private entities are limited by the Afree-rider@ problem[8] and the problem of prohibitive transaction costs for many actions (especially in the case of residential consumers). Because of this more limited mitigation choice set, private entities face greater risk. A partial list of possible electricity price risk mitigation options available to California include:

X Shifting risk to other parties through long-term contracts;
X Participation in futures markets for electricity and natural gas;

[7] In this task we will focus on the consumer versus California=s risk mitigation. Under Task 4 we will differentiate further between consumers and generators.

[8] The Afree-rider@ problem refers to the ability of some private parties to benefit from the action of other parties without bearing a share of their cost.

- X Increasing fuel diversity in the supply mix;
- X Increasing the fuel and technology diversity available to all parties through subsidies;
- X Funding public-good generation R&D;
- X Influencing the institutions for electric energy trading and transmission capacity;
- X Increasing interstate transmission capacity;
- X Promoting DSM; and
- X Using fiscal policies to mitigate risks.

Of these nine options, only the first two, long-term contracting and futures market participation, are available to private parties. The third option, increasing fuel diversity in the supply mix, is potentially available to marketers and generation suppliers.[9] The remaining options are not feasible for private entities because of externality problems associated with public goods.[10]

Long-Term Contracting: One means of avoiding risk is to structure a long-term contract in such a way as to cause another party to bear the risk. Thus, consumers might enter into a long-term contract with suppliers to provide electricity at a fixed or at least a capped price. Similarly, suppliers who are exposed to the volatile natural gas market can enter into long-term contracts with their gas suppliers. Generally, the party laying off the risk has to pay the party assuming the risk a higher than normal price. This price differential is called a Arisk premium.@ These issues will be treated in greater detail in Task 4.

[9]It might also be possible for consumers to become their own suppliers by owning wind or solar generation units, but under present technology, this is not yet economic. Demand-side management, which can also be thought of as a supply option, is a feasible option at the consumer level.

[10]Samuelson (1954) defined public goods as goods which do not diminish when they are consumed by individuals. The externality or market failure occurs because their production cannot necessarily be economically justified by private parties. P.A. Samuelson, AThe Pure Theory of Public Expenditures,@ *Review of Economics and Statistics*, vol. 36, no. 1.

Futures Markets: Organized markets exist for both electricity and natural gas.[11] Both futures and futures options are traded for both of these commodities. Futures contracts are offers to buy or sell standardized quantities of the commodity at a specified time and place. Options contracts are offers of the option (but not the obligation) to buy or sell futures contracts at a specified price within a specified period of time. Trading strategies which can be used to reduce price instabilities can be developed using these financial instruments. In practice, only a small fraction of futures trades results in physical delivery. In concept, this large volume of trades relative to the physical commodity can be used to cause the underlying commodity price to converge and stabilize by creating a Aliquid market.@

[11] Markets for petroleum and crude oil also exist, but these markets are less relevant to California=s electricity market because there is little reliance on these fuels.

The New York Mercantile Exchange (NYMEX) established electricity futures trading at two California hubs: the California Oregon Border (COB) and Palo Verde, Arizona. According to RCM Financial,[12] trading at both of these sites has been characterized by high price volatility.[13] COB has an annual volatility of 130 percent while Palo Verde has a volatility of 100 percent. These markets are still quite immature (they were established in Spring of 1996) and trading is still relatively light prior to electricity industry restructuring. The more mature natural gas futures markets are also created by NYMEX for delivery at Henry Hub, Alberta and Permian Gas. These well established markets also offer the possibility of hedging the volatility in natural gas, which is the most volatile fuel in California=s electricity mix.[14]

NYMEX suggests numerous ways to use futures and options trading to mitigate price risk. Power producers can use futures contracts to lock in future sales prices. They can buy put options (options to sell futures contracts) to put a floor under their selling price while participating in upward market swings. Large buyers (including California) can protect their purchase price with futures contracts or use call options (options to buy futures contracts) to place an upper limit on their purchase price while permitting them to gain from falling prices. Power marketers, who have exposure to both purchase and selling risks, can hedge either risk with futures contacts. They can also protect their market position with options contracts. Integrated utilities can use futures to help meet revenue objectives. Just as futures contracts protect against volatility in their underlying commodity, so too options contracts protect against volatility in their underlying futures contracts.

Although in theory any agent could participate in the futures market, in practice each agent has a different ability to participate because of the transactions costs of doing so. Generally, larger sales incur proportionally smaller transactions costs, such as broker fees and research and analysis costs.

Non Market-Based Mitigation Options: Generators with multiple plants or marketers who purchase and consolidate electricity contracts from several sources have the ability to create a portfolio of electricity resources. The measurement techniques for quantifying the risk reduction benefit of doing so was described in the Phase 1 report.

In general, other non-market-based options for decreasing price risk through R&D subsidies are only available to state government. Certain R&D spending is not feasible for private agents

[12] http://www.rcmfinancial.com/utilities1/tsld036.htm11/97

[13] Volatility can be defined as the tendency of a value to randomly fluctuate about its mean.

[14] See Resource Decisions=s Phase 1 report. Marvin Feldman, *Diversity and Risk Analysis*. Consultant Report P500-97-008, Technology Assessment Office, Sacramento, California Energy Commission, June, 1997.

because of the Afree-rider@ problem. This type of R&D spending is often called public-good R&D. This refers to the problem that agents producing the Apublic-good@ are either not able to capture enough of the benefits to justify the expenditure (as in the case of environmental improvement externalities), or that these goods are used by Afree-riding@ competitors.[15] This category will become more apparent when the distinction between user and supplier risks are made in Task 4.

Subsidies to promote technological diversity are also a risk mitigation method which is only available to California. Increasing fuel diversity through subsidies was discussed in the AB 1890 context in Task 1.

Finally, only FERC and the CPUC have the authority to establish the institutional framework to promote fuel and technology diversity, either directly or through a rule governing the Independent System Operator (ISO) and the Power Exchange (PX). Possible actions which could be taken include requirements for Agreen@ power, transmission and distribution pricing mechanisms which favor distributed generation and demand-side management, and localized congestion pricing. These issues will be addressed in connection with Task 4.

2.2.2 Discount Rates

In making policy decisions regarding which technologies are most advantageous from the standpoint of risk, tradeoffs between expected annualized cost and degree of risk or price volatility must be considered. Electricity generation investments are typically long-term (15 to 50 years) but the useful life varies with the technology. The annualized cost or price is very sensitive to the discount rate used. A higher discount rate favors technologies with higher immediate net benefits as opposed to longer- term investments.

[15] PG&E and other utilities have recently dropped out of the Electric Power Research Institute (EPRI) largely in response to emerging competitive forces. Under traditional rate-base regulation EPRI=s common purpose R&D could be justified. Under the emerging competitive industry structure, under which utilities will lose their service territory exclusivity for generation supplies, cooperative R&D could help potential competitors.

A literature search reveals a wide range of opinion within the economic community. Some authorities (Baumol, Warr & Wright, Newberry, Hirshleifer) suggest that the social discount rate and the pretax private rate should be the same. Others (Samuelson, Vickery) suggest using a social discount rate based on the private opportunity cost of capital less the risk premium. Arrow suggests using the weighted average of consumer and corporate discount rates. Stiglitz proposes different discount rates for different projects. Lind (1990) recommends that for long-term investments, government-funded projects use the expected long-term growth rate of capital (1-3 percent). For comparing two private investments he suggests the private cost of capital.

Although not specifically addressed in the literature reviewed thus far, the issue of technological obsolescence can also be considered in the discount rate. With rapidly developing new distributed generation technologies (fuel cells and photovoltaic. to name two) might soon reach a point at which adoption becomes widespread. If this occurs, owners of generation assets might find that some of these assets have become economically obsolete. This risk of technological obsolescence adds an additional risk factor to investment in long-term generation equipment (or long-term contracts). The discount rate for evaluating the present value of such assets will include an obsolescence factor. This factor could be reduced for projects which have shorter lives or shorter expected payback periods. Such short-payback period projects might, however, include an implicit risk premium in the form of higher expected average cost as compared with longer-term but riskier projects.

2.2.3 Risk Premiums

If public and private entities were risk-neutral, they would be indifferent between investments with risky outcomes and investments with certain outcomes, as long as each had the same expected value. Applied to electricity price, it would only be necessary to consider the expected average price, or for long-term consequences the expected present value of stream of future prices. The variance of price (the second statistical moment) would not be a matter of concern; however, this is not usually the case. Ratepayers, stockholders and the public are usually thought to be risk-averse. This means that given a choice between a certain price and a price with a lower expected value but with probability that the value might be higher or lower, they might choose the higher certain price rather than take the chance that they might face even higher prices.[16] This concept is illustrated in Figure 2-1 which illustrates risk-neutral and risk-averse utility functions.[17] The more convex or curved the decision-maker=s utility function, the more strongly risk-averse the decision-maker is said to be. The risk premium is the difference between the expected value of a risky outcome and its certainty equivalent

[16] Insurance purchasing is a classic example of risk aversion. Consumers pay the insurance premium which consists of the actuarial or expected value of the loss plus the insurance company=s administrative costs and profit, to be assured that a loss won=t exceed a certain amount.

[17] The third case, a risk-seeking utility function, is not relevant to this discussion, it is unlikely that even

The theoretical basis for risk aversion and its assessment are grounded in utility theory and decision analysis.[18] According to the generally accepted Arrow-Pratt paradigm, there are both relative and absolute concepts of risk aversion:[19]

(2.1) Absolute Risk Aversion: $R_a(y) = -UO(y)/UN(y)$

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someone who enjoys gambling would probably prefer to save his money for the gaming tables or the track rather than his utility bill.

[18]Levy Haim: A Absolute and Relative Risk Aversion: An Experimental Study@, *Journal of Risk and Uncertainty*; 8(3), May 1994, pages 289-307. aim, 1994; Kahn, E.P , CA Goldman etc. *Evaluation Methods in Competitive Bidding for Electric Power*. LBL-26924 Berkeley CA Lawrence Berkeley Lab, June 1989, 1989; J.M. J. Jacobs and T. Huntley, *Testimony on Valuation of Fuel Diversity*, for hearings on the 1992 Electricity Report Proceeding Pacific Gas & Electric, January1992.

[19]Haim, ibid.; K. Arrow, AThe Theory of Risk Aversion@, *In Essays In the Theory of Risk Bearing*, North Holland Publishing Co. 1970; J. Pratt, ARisk Aversion in the Small and in the Large in *Econometrica*, 32, 122-136, 1965.

(2.2) Relative Risk Aversion: $R_r(y) = - yUO(y)/UN(y)$

Figure 2-1

where y refers to the agent=s income (wealth is also often used) and U is the utility function.[20] Thus
relative risk aversion is dependent on the magnitude of the agent=s wealth, in addition to small changes in wealth. Absolute risk aversion is only dependent on the curvature of the utility function and does not change with wealth. The common wisdom is that absolute risk aversion is decreasing (DARA) in wealth, meaning that richer people are willing to accept larger risks in absolute terms. This is an extension of the notion of decreasing the marginal utility of money. In electricity price terms, a wealthier household is more tolerant of larger absolute swings in electricity costs. Relative risk aversion was assumed by Arrow to be increasing (IRRA). This assumption (which is contested by Haim and others) suggests that wealthier households would wish to risk a smaller percentage of their wealth than would poorer households.[21]

Several investigators[22] utilize an approximation of the certainty equivalent formula to determine the risk premium:

(2.3) $CE(c) = E(c) + \alpha/2 * var(c)$

where CE(c) is the certainty equivalent of cost, E(c) is the expected value of cost and α is the absolute risk aversion coefficient. Rearranging the terms we see that risk premium (the difference between the certainty equivalent and the expected value is :

(2.4) $CE(c) - E(c) = \alpha/2 * var(c)$

[20] The notation UN is the first derivative of the utility function , and UO is the second derivative.

[21] Arrow defends his assumption of IRRA on the basis of the tendency of wealthier individuals to hold a greater proportion of their wealth in cash assets.

[22] Brower et al., 1997; Jacobs, 1992; Kahn, 1989, op. cit..

Empirical estimation of α is fairly complex and is beyond the scope of the current investigation. One method is based on assessing the risk tolerance which is the inverse of the absolute risk aversion coefficient.[23] Converting to relative risk aversion terms (by multiplying by income) yields the relative risk aversion coefficient denoted by β. A risk neutral agent would have a zero value for beta. Arrow (1970) suggests that a typical value is 1. A highly risk-averse (or very poor) agent would have a β around two.[24] Kahn[25] expresses the risk premium as a function of the proportion of expenditure on electricity as:

(2.6) Premium/expenditure = $-\beta$ * CV(y) * CV(c) * Var(y,c)

where beta is the relative risk premium (y*α), y is total income of the agent, c is electricity cost, and CV coefficient of variation of cost or income (i.e., var(c)/E(c). Var (y,c) is the covariance of the income and electricity cost. This is probably the most practically useful form for expressing risk premiums.

[23]R. A. Howard, ADecision Analysis: Practice and Promise,@ in *Management Science* 34, No. 6, 1988.

[24]Kahn, 1989, op. cit. p. 4-14.

[25]Ibid.

Whose Risk? These risk aversion concepts provide a very direct application to differentiating public and private risk. Both the income and the absolute risk-aversion coefficient differ for different decision-makers or agents: the state government, residential consumers, industrial and commercial consumers, and shareholders of utility companies. While income and proportion of income which is associated with electrical generation can be determined for each of these agents, empirical determination of the risk-aversion coefficient for each of these agents is limited. Howard found relative risk tolerance for small, medium and large companies to be 1.25, 1.43 and 1.05, respectively, with an average of 1.24.[26] Pindyck estimates that investors= risk-aversion coefficient for stock market returns is 6 to 8.[27] As noted above, risk-aversion coefficients for individuals are generally estimated to range between 0.5 and 2. For purposes of estimating risk premiums, it will be useful to simply test the sensitivity of a range of outcomes. We will therefore parametrically vary the risk-aversion coefficient to determine if, within a reasonable range, the coefficient make a significant difference.

[26]R.A. Howard, 1988, op. cit. .

[27]R.S. Pindyck, ARisk Aversion and Determinants of Stock Market Behavior,@ The Review of Economics and Statistics, 70, (May 1988), 183-190 quoted in Brower, 1997.

2.3 POLICY IMPLICATIONS OF RISK PREMIUMS AND DISCOUNT RATES

Risk Premiums: A simple computation will be useful in determining the magnitude of the risk premium associated with residential electricity users. Table 2-1 shows the risk premium associated with a range of absolute risk aversion values from high to low risk-aversion values (alpha from 2.0 to 0.67). The average residential household using about 6200 kWh per year paid about $680 for electricity, of which only about 30 percent is associated with energy costs. Based on the variance of electricity costs from 1990 to 1996, the risk premium associated with removing all variance would have ranged between $6 and $24 per household. As these values are quite low, there is little need to consider their importance on a relative risk premium basis; even lower-income households could absorb this level of risk.[28]

T 2-1

[28]Low-income assistance programs are already in place for subsidizing the utility bills of households at 125 percent of the poverty level.

At a state level, the cumulative risk premium is not insignificant, however. Depending on the assumed absolute risk-aversion coefficient assumed, the total risk premiums faced by residential consumers amounts to between $72 and $289 million per year, with a most likely value around $180 million. This represents the maximum value to residential customers of eliminating all electricity rate variability. Thus a policy which reduced risk by 10 percent and cost about $18 million could be regarded as having a benefit-cost ratio of one.

As noted above, the appropriate discount rate depends on the cost or opportunity cost of capital for the agent acquiring the capital. For residential utility customers, a very high discount rate, equal to the credit card rate (currently above 16 percent in this low inflation period), is probably appropriate. This implies that measure which are intended to reduce the current utility bills by means of capital expenditures (e.g., DSM measures, the electricity rate reduction bonds) should have a payback of at least 16 percent. From the state of California viewpoint, the short- to mid-term cost of capital be regarded as the interest rate on state bonds (presently about 7.5 percent), plus the cost to the state of the loss of tax revenues on these bonds if their interest is tax-free. Investments in capital equipment by suppliers or DSM capital expenditures by large users can be evaluated at their cost of capital which is equal to either the corporate bond rate (currently about 8.5 percent for high grade bonds) or the bank prime rate (currently 7.5 percent). Smaller or riskier ventures would face interest rates one to five points above the prime rate. In all cases the real interest rate is the difference between the above rates and the expected inflation rate. Thus, for example, if the expected interest rate is 3 percent, the real rate for a company issuing corporate bonds at 8.5 percent is 5.5 percent.

From a long-term societal point of view, the discount rate represents an intergenerational transfer of income. A real rate greater than zero suggests that the current generation is impatient to realize the benefits of its investments. But to the extent that the state invests in research and development which will sow the seed for future technological improvements, a low interest rate might be justified.

3.0 RELATIONSHIP BETWEEN THE DIVERSITY INDEX AND ELECTRICITY PORTFOLIO RISKS

While it has long been assumed that fuel and technology diversity influences electricity market risk, measurement of this influence is a relatively recent endeavor. Measurement techniques can be drawn from at least two different sources: investment portfolio risk from business management literature and ecological diversity measurement literature. The application of the risk associated with investment portfolios was described in the Phase 1 report. The recommended approach consists of measuring the standard deviation of a portfolio of energy sources. The diversity index approach was found in Phase 1 to be of limited value. In Phase 2 we have conducted a thorough literature search and uncovered a variety of diversity measurement techniques. These techniques are described in Section 3.1. Their potential application to electricity system diversity and risk is discussed in Section 3.2. A direct comparison of the portfolio and the Shannon-Weiner diversity index approach is presented in Section 3.3. Section 3.4 discusses conclusions regarding the efficacy of index versus portfolio approaches.

3.1 DIVERSITY MEASUREMENT TECHNIQUES

The ecological literature offers a wide range of diversity measurement models. These models can be categorized into species richness models, species abundance models and proportional abundance models and dominance models.[29]

3.1.1 Richness Indices

[29]This section draws heavily on a summary of diversity model presented in A. Magurran: *Ecological Diversity and Its Measurement*, Princeton University Press, Princeton, NJ, 1988, Chapter 2. According to personal communication (October, 1997) with Steve Beissinger, Associate Professor of Conservation Biology, University of California at Berkeley, Department of Environmental Science, Policy and Management, this is the definitive reference on quantitative ecological diversity models.

In their simplest form, richness indices simply count the number of species found in a given area. This approach is often too simplistic because it neglects the dimension of abundance of individuals within the species. Thus if two equal areas each contain ten species, they have the same richness index, despite the fact that one area might have only one individual of each of nine species and a thousand of the tenth (dominant) species.

Three richness index approaches have been developed to take abundance into account. Hulbert proposed a Ararefaction@ formula which provides an unbiased estimate of the number of richness of species expected in each sample, assuming all samples are of a standard size.[30] Williams, however, noted that this leads to a loss of information because the detailed information regarding abundance by species, which is an input to this formula, is lost. All that remains is the expected species abundance per standard sample.

Two other models include both richness and abundance information: the Margalef[31] index (D_{MG}) and the Menhinick[32] index (D_{ME}):[33]

$$D_{MG} = (S-1)/\ln N$$

$$D_{ME} = S/ N^{1/2}$$

where: N = the species abundance, summed over all species
S = the total number of species

Again, both of these indices lose the information associated with the number of individuals within each species.

3.1.2 Abundance Indices

A second set of diversity measurement models focuses on the abundance distribution. These models rely on various methods of plotting the abundance (number of individuals in the species)

[30] Hulbert, S.,1971. AThe Non-Concept of Species Diversity: a Critique and Alternative Parameters,@ in *Ecology* 52, 577-586.

[31] Clifford, H. and W. Stephenson, 1975. *An Introduction to Numerical Classification*, Academic Press, London.

[32] Whittaker, R.,1977. AEvolution of Species Diversity,@ in *Evolutionary Biology*, Vol. 10, pp. 1-67.

[33] Margurran, A.,1988. *Ecological Diversity and Its Measurement*, Princeton University Press, Princeton NJ, p. 11.

on the y-axis versus the ranking of the species on the x-axis. Depending on the scaling of the axes (linear or logarithmic to any of several bases) one obtains distributions which are geometric, log normal, log series, or Abroken stick@.[34] Based on certain characteristics of ecosystems, one expects varying degrees of species dominance or evenness of species abundance. In practice, the data are plotted and a curve or model is fitted to the data, based on the empirical distribution and the expected model.

3.1.3 Proportional Abundance Models

The third major category of models is the proportional abundance of species approach. This includes an index developed independently by Shannon and Weiner as well as a similar but more complex model called the Brillouin Index. These indices rely on the proportional abundance represented by each species. The Shannon index HN (often called the Shannon-Weiner index) is :

$$H' = - \sum_{\text{all species } I=1\ldots,S} p_i \ln p_i$$

where p_i is the percentage of the total abundance which is represented by species I.

[34]The broken stick distribution is roughly equivalent to a uniform distribution.

A Shannon index thus increases with increasing number of species and with the evenness of the distribution of individuals within species. For a system with a given number of species, it is possible to compute the maximum Shannon index HNmax which is the value which is obtained if all species are evenly distributed.[35] HNmax = ln S. Thus an evenness ratio HN/HNmax can be computed.

A second proportional index, the Brillouin index is functionally similar to the Shannon index and results in a similar index number:

$$HB = [\ln N! - 3 \ln n_i !] / N$$

where N is the total number of individuals and n_i is the abundance of the ith species. It is computationally more difficult, however, and can give misleading results because of its reliance on sample size. As a result, the Brillouin Index is not commonly used.[36]

Proportional abundance models, in particular the Shannon-Weiner index, have been used as a measure of electricity system diversity. Because of its apparent applicability to electricity modeling, the Shannon-Weiner index will be discussed in greater detail below.

3.1.4 Dominance Indices

Other indices, including the Simpson index, the MacIntosh U index and the Berger-Parker index are statistical methods for characterizing the degree of dominance of the commonest species. The latter is the most commonly used dominance measure:

$$d = Nmax/N$$

where Nmax is the number of individuals in the most common species. Because these indices have little prima facie applicability to electricity systems, they will not be further considered.

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[35]Pielou, E.,1969. *An Introduction to Mathematical Ecology*, Wiley, New York.

[36]Magurran, 1988, p. 39.

3.1.5 Variance of Diversity Measures

Finally, there are several statistical methods for computing the variance of diversity measurements. Several authors have concluded that a procedure called Ajack-knifing@ can improve the estimate of any diversity index as well as being the most appropriate method for computing variance of the index.[37] This method consists of sequentially eliminating one species from the data and then recomputing the diversity index, yielding a pseudo-value (or VP):

VPi = (nV) - [(n-1)(VJi)]

The best estimate of the diversity index (V) is then computed as the mean of the pseudo-values (VPi). The variance of the index measurement is computed as the variance of the pseudo-values. The standard error of VP is then:

standard error VP = var(VP)/S

with standard error equal to one minus the sample number.

[37] Magurran, 1988, p. 43; Adams, J. and E. McCune, 1979, AApplication of the Generalized Jack-knife to Shannon=s Measurement of Information Used as an Index of Diversity,@ in *Ecological Diversity in Theory and Practice*. International Co-operative Publishing House, Fairland, MD; Heltshe, J. and D. Bitz, 1979,@ Comparing Diversity Measures in Sampled Communities,@ in *Ecological Diversity in Theory and Practice*. International Co-operative Publishing House, Fairland, MD.

3.2 APPLICABILITY OF ECOLOGICAL DIVERSITY INDICES TO ELECTRICITY SYSTEM DIVERSITY

The analogy between species richness and the number of electrical generation system technologies is fairly obvious. There is, however, some ambiguity in deciding how finely to discriminate among technologies. For example, the question arises whether one should group all solar generation approaches together, or instead group photovoltaic technologies and solar-thermal generation separately. This somewhat arbitrary grouping could change the diversity measured by each of the indices described in Section 3.1. For purposes of demonstrating usefulness of the model, it is probably sufficient to confine the definition of technologies to the 12 technologies used in the Phase 1 study.

The electrical system analog for abundance is less apparent. Abundance could be interpreted as the capacity within each technology, the energy generated by each technology, or even the number of generating plants using this technology. Although there is some justification for considering the latter due to inter-plant differences, that option is probably impractical because of its data requirements. Data for either capacity or energy are readily available. From a policy standpoint, it is probably more relevant to consider capacity, because capacity is the most available policy handle. Energy is technologically related to capacity, albeit with considerable random variance.

3.2.1 Selection of Applicable Models

The richness models offer little insight into electricity diversity. Simply knowing how many technologies are available is essentially meaningless. The Menhinck and Margalef indices which derive an average expected abundance per technology make little sense in the electricity context. The distribution matching abundance approaches are similarly meaningless in the electricity context, since at best they might be descriptive of the data, but do not add anything to the understanding of diversity. Dominance models such as the Berger-Parker index can perhaps be useful in identifying the relative importance of the most abundant technology. This information by itself, however, is of very limited value in understanding electricity diversity.

The remaining models are the proportional abundance models--the Shannon-Weiner (S-W) and the Brillouin indices. Given the fact that the Brillouin is computationally complex and substantially equivalent to the S-W, we will focus on the latter. Not surprisingly, this is the model which has appeared in the energy literature as a means of evaluating electric system diversity.[38]

[38] Stirling, Andrew, ADiversity and Ignorance in Electricity Supply Investment,@ *Energy Policy*, March 1994, pp. 195-216.

The S-W index utilizes only the proportional abundance (capacity or energy) of each technology. By its construction the S-W reflects diversity both in terms of the number of technologies and the evenness of the distribution of generation over these technologies. If any of the ecological models can shed light on electricity diversity, it seems that the S-W model is the best choice.

3.3 COMPARISON OF THE SHANNON-WEINER MODEL AND THE PORTFOLIO RISK MODEL

Recall from the introduction that the portfolio variance model developed in Phase 1 consists of computing the annual standard deviation of the combination of generation technologies used in California=s electricity system. In this section, we will compare the values obtained by this method (which for brevity we will refer to as the ***R/D index***) and the Shannon-Weiner index (***S-W index***).
In comparing the efficacy of models, it will be useful to establish a set of criteria on which evaluation can be based. We propose the following criteria:

- X Sensitivity to difference in electricity cost or price risk;
- X Policy relevance in mitigating risk; and
- X Computation practicability.

Computationally, the S-W index is simple. We have computed the S-W index for the 6 years of annual data used in Phase 1 and have graphed and statistically analyzed the correlation between the S-W index and the portfolio variance.

Table 3-1, and the same information graphed as Figures 3-1 and 3-2, show a direct comparison of the results of the S-W index and the portfolio variance. Because the S-W index increases with increasing diversity, while portfolio variance decreases, we compare the inverse of the S-W index. Also to facilitate comparison, we present the relative change in each index with respect to a base case, which we define as that index=s 1990 to 1995 average.

First, consider the difference within the base period (1990 to 1995) as illustrated in Figure 3-1. As might be expected, there is not much variation from year to year,[39] as the capacity varied very little during that period. But where divergences do occur, they are much easier to explain in terms of portfolio standard deviation than they are in terms of the S-W index. For example, the S-W index for 1995 is almost equal to the base value, simply because the capacity was about equal. The R/D index is lower for 1995, reflecting the unusually high capacity factor for hydroelectric. Similarly, the R/D index rises (becomes more risky) from 1990 to 1991, reflecting the lower

[39] There is less than ∀2 percent difference in either of the indices.

capacity factors for hydro and nuclear in 1991. These changes could not be reflected in the S-W index because it is insensitive to capacity factor.

Even more telling is the comparison of scenarios which describe marked price variance changes or fairly drastic changes in generation capacity (see Figure 3-2). The high gas price variance scenario shows the effect of doubling the year-to-year variance of gas prices. The zero gas price variance shows the effect making each year=s gas price equal to the base period average. This produces marked changes in the R/D index, indicating the much higher or lower generation price risk associated with these changes. The S-W is again insensitive to these changes because it does not consider fuel price variation.

The ALow Nuke,@ ALow Coal,@ A10 percent DSM@ and AHi Renewables@ scenarios are described in Section 5 of the Phase 1 report. Because the R/D model responds not only to the changes in generation capacity proportions, but also to the covariances, price variances, and variations in capacity factors among the technologies, these hypothetical changes in the generation mix have a

Figure 3-1

Figure 3-2

fairly dramatic impact on the R/D index. As seen in Table 3-1 and Figure 3-2, the hypothetical scenarios result in a roughly 30 percent decrease in the portfolio standard deviation.

By contrast, these same scenarios cause only a modest (∀5 percent) difference in the S-W index. This is because the S-W index can only respond to proportional changes in generation capacity. Indeed, except in the High Renewables case, the index moves in a counter-intuitive direction (indicating higher risk or lower diversity). This Aperverse@ effect can be explained in that diversity as measured by the S-W index increases in response to evenness, which these scenarios decrease. The fact that the technologies which are reduced are the ones with high prices and high variability is not picked up by the S-W index.

3.4 CONCLUSIONS ON DIVERSITY INDEX APPROACHES

While there is some correlation between the S-W index approach and the portfolio standard deviation (R/D) approach, the instances in which the two approaches give divergent results illustrate the inherent weakness of the S-W method. The only datum used in the S-W approach is the proportion of generation by technology. The two methods diverge when cost of technologies and/or capacity factor is unusual for the time period. Because the S-W index does not consider cost, these differences are not reflected in the index. Furthermore, the units of the S-W index are arbitrary and do not reflect cost or price risk. By comparison, the units of the portfolio risk model directly indicate the standard deviation of cost Thus with regard to the first two criteria listed at the beginning of Section 3.3, the portfolio risk model seems dominant. Both models are computationally practicable, with the S-W index being far easier and having fewer data requirements. Because of its ease of computation, and because the required data are a subset of the data required by the portfolio risk model, there is no reason not to compute the S-W index along with the portfolio risk model, as long as there is some meaningful information which it can provide.

Stirling[40] claims that the S-W model is superior to risk based models insofar as the S-W index takes into consideration a range of certitude considerations beyond those which can be quantified as risk--namely uncertainty and ignorance. In this context risk refers to events which could affect the outcome which are influenced by random variances whose distributions can be estimated. Uncertainty refers to variance factors which can be specified in advance but whose variability cannot be meaningfully estimated. Ignorance refers to those factors which cannot be foreseen but which might influence the outcome. Stirling contends that risk-based methods alone are inferior to a pure diversity model (namely the S-W index) in dealing with uncertainty and ignorance factors.

[40] Andrew Sterling, 1994, op. cit.

We question Stirling=s presumption from an information theory standpoint. The portfolio risk model takes into consideration the information which drives the S-W index, namely the portion of generation by technology. In addition the portfolio model includes data or estimates of fuel price variance, variance in technological performance and variances in resource availability (the latter two factors are built into the capacity factor). There is no theoretical or practical basis for alleging that an under-specified model such the S-W index is more efficient at dealing with ignorance or uncertainty than is a more completely specified model such as the portfolio variance model. On the contrary, it is reasonable to expect that risk is at least a partial proxy for uncertainty.

Consider how each model deals with the risk, uncertainty and ignorance factors associated with variability of natural gas prices. It can be argued that gas prices are a function of factors which are certain, factors which can be estimated by risk analysis, uncertainty factors, and ignorance factors. The relatively certain factors might include cost of production reserves and market demand. Risk factors might include weather variability, and resource exploration and development success. Uncertain factors might include technological change in gas utilization or exploration and environmental regulatory changes such as changes in the Clean Air Act. Ignorance factors might include geopolitical changes such as the resurgence of OPEC or war with Iraq, as well as radical technological changes such as a major breakthrough in solar or fuel cell technology.

The portfolio approach allows price risk to be estimated based on historic price variability (as was done in the Phase 1 report) or by some model of reserves, production cost and market demand, such as the North American Resource Gas model (NARG) currently being used by the CEC to forecast gas prices. NARG attempts to integrate all certain and risk factors in a systematic way. A historic model might be said to include (although imperfectly) some of the uncertainty factors identified above.

By contrast the S-W index simply fails to account for the cost of fuels or their variability, except insofar as it can be assumed that different technologies rely on different fuels. If this were true, then a higher diversity index will equate to a lower risk. But this assumption reveals an important weakness of the S-W model. The definition of discrete technologies is arbitrary (i.e., gas or gas-steam and combustion turbine). The S-W model is very sensitive to the differences in definition. By comparison, the portfolio risk model, because it factors in the risk correlations among technologies, is much less sensitive to arbitrary technological distinctions.

Despite S-W susceptibility to arbitrary technology distinctions, it might be useful to consider computing the S-W evenness ratio and using this number as an additional indicator of the resilience of the electricity system. As long as the definition of the technologies remains consistent, it would be reasonable to compare the evenness of two scenarios. Presumably the higher the evenness ratio the more resilient the system might be to uncertain or ignorance factors. In any case it is a simple matter to compute this comparison.

4.0 SUPPLIER VERSUS GENERATOR RISK

4.1 INTRODUCTION: RISK MANAGEMENT CONCEPTS AND STRATEGIES!USER VERSUS SUPPLIER

As noted in Section 2.1, risk-management strategies generally use some type of financial or contractual methods to reduce the variability of future costs. Active risk management strategies include participating in forward markets, vertical integration, horizontal integration, long-term contracting, commodities hedging on the natural gas and electricity markets and, of course, diversification of fuel supplies, suppliers and technologies. Suppliers can also use fuel contracts to lock in supplies and prices. For users (and indirectly for energy service providers who manage users= energy) at least two other strategies exist!demand-side management (DSM) and self - generation.

In the Phase 1 diversity analysis,[41] Resource Decisions developed a methodology whereby risk was defined in terms of the standard deviation of the cost of a portfolio of electricity fuels and technologies. In Phase 1, this method was applied to estimate supplier risk. In Task 2 of this second phase, we expanded this concept to the divergence between social and private risk. In this Section 4, we examine the divergence between supplier (investor) and user (consumer) risk As pointed out in Task 2, the greater the portfolio standard deviation, the greater the volatility of electricity prices. As users face a different set of costs than suppliers face, so too do their portfolio risks differ. This section examines these risk differences.

Each risk mitigation strategy has a cost associated with its implementation. Each strategy can be differentiated with respect to its cost and efficacy in mitigating risk under a restructured electricity marketplace, and its applicability to user versus supplier risks.

[41] Marvin Feldman, *Diversity and Risk Analysis*. Consultant Report P500-97-008, Technology Assessment Office, Sacramento, California Energy Commission, June, 1997.

4.2 BASIS FOR DIVERGENCE BETWEEN USER AND SUPPLIER RISK

There is a fundamental asymmetry between supplier and user costs and risks. Suppliers face risks associated with electric energy production costs, and possibly risks associated with transmission congestion charges. Furthermore, PX or other spot market suppliers also face a bidding risk which influences their capacity utilization and therefore their average revenues. Users might or might not be exposed to those risks, depending on contractual assignment of risk. In addition, users face costs associated with the retail margin: distribution cost, competitive transition charges, bond repayment, public purpose programs, and nuclear decommissioning. However, those additional costs are largely fixed or vary only slightly from year to year. Assuming that energy production and congestion risks are shared equally between suppliers and users, the level of risk relative to total cost at risk is probably lower for users.
As noted in Section 2, a desirable level of risk (whether user or supplier risk) can be defined as the level at which the marginal cost of accepting the risk of variability equals the marginal cost of the least costly mitigation strategy.

Three sets of factors differentiate optimal supplier risk mitigation strategies from those which are optimal for users:

X Suppliers have a different set mitigation options and costs from users.
X Suppliers= cost of capital differs from that of users.
X Suppliers have a different risk preference from that of users.

4.2.1 Mitigation Options

Although we have so far discussed only users and suppliers, in fact there are several categories of users and suppliers, each with its own set of mitigation strategies. Among users, there is a very wide range of scale between small residential users and large commercial and industrial users. For simplicity, we will only make a distinction between large users and small users, ignoring whether these are residential, commercial, or industrial users. Middle-size users probably have a range of options somewhere between those of large and small users. Suppliers can include integrated portfolio generators, single plant owners, and energy service providers who may own generation or may purchase energy on a spot market or contract basis.

These groups of users and suppliers have some similar and some distinctly different risk mitigation options. The options available to large users, small users, generators, and energy service companies (ESCO), summarized in the following table:

Table 4-1: Summary of Electricity Risk Mitigation Strategies

Mitigation Strategy	Large	Small	Generator	ESCO

	User	User		
DSM/Conservation/Self-generation	Yes	Yes	No	Maybe
Electricity Futures Market Participation	Yes	Difficult	Yes	Yes
Gas Futures Market Participation	Yes	Difficult	Yes	Maybe
Contractual Shifting of Risk	Yes	Yes	Yes	Yes
Increasing Supply Diversity	Maybe	Difficult	Maybe	Yes
Selecting Trading Institutions	Yes	No	Yes	Yes
Real-Time and Time of Use Metering	Yes	Maybe	No	Maybe
Self-Generation	Yes	Maybe	No	Maybe

Demand-Side Management (DSM): DSM refers to actions which either reduce consumption or shift consumption to a time period of lower prices. This is a strategy which can be very cost-effective for consumers because it is a means of avoiding not only the energy costs and their associated risk, but also all other costs associated with the retail price of electricity. Energy costs are roughly 20 percent of the retail cost of electricity faced by residential consumers through the transition period. According to the utility consumer advocacy organization TURN, the following is a breakdown of a residential consumer=s electricity bill, based a consumption of 500 kWh per month:

Table 4-2: Composition of Typical Residential Electricity Bill--PG&E Service Area, 1998:[42]

Charges	Cents per kWh	Amount	Percent of Total
Energy	2.4	$12.00	19.2%
CTC (Stranded Capital Cost)	4.03	$20.15	32.2%
Bond Repayment	1.62	$8.10	13.0%
Transmission	0.4	$2.00	3.2%
Distribution	3.6	$18.00	28.8%
Public Programs	0.4	$2.00	3.2%
Nuclear Decommissioning	0.05	$0.25	0.4%
Subtotal	12.5	$62.50	100.0%
Less 10% Reduction	-1.25	($6.25)	
Total	11.25	$56.25	

[42] Based on PG&E Unbundled Tariff Filing CPUC, 1997 as reported in the *San Francisco Chronicle*, December 15, 1997 p. B-1.

By implementing DSM measures, which usually have a fixed cost and thus a low variance, the only uncertainty is with regard to the efficacy of the DSM measure. Apart from this factor, which would need to be evaluated for each particular DSM application, DSM adds a near zero risk element to an energy portfolio. However, the cost-effectiveness of DSM has a risk factor because it depends in part on the energy cost foregone, which in turn depends on the market clearing price (MCP).

Contractual Risk Shifting: As noted in Section 2, one means of avoiding risk is to structure a long-term contract in such a way as to cause another party to bear the risk. Thus, consumers might enter into a long-term contract with suppliers to provide electricity at a fixed or at least a capped price. Similarly, suppliers who are exposed to the volatile natural gas market can enter into long-term contracts with their gas suppliers. Generally, the party laying off the risk has to pay the party assuming the risk a higher than normal price. The risk premium paid to induce the other party to accept the risk will generally increase with the duration of the contract, and increasing spot market variance.

Residential User Risk: Customers who do not elect to change their energy provider are nominally exposed to price risk from the fluctuations of the PX spot market. In fact, at least during the competitive transition period (1998-2002), small user (residential and small commercial user) rates are capped at 90 percent of 1997 rates. If PX energy prices are higher, repayment of the CTC charge is correspondingly reduced, leaving rates at the cap. Similarly, if the PX energy prices are lower, the CTC repayment is correspondingly increased. Again, the residential ratepayer is not at risk during the transition. Residential users who select other energy companies also face the same zero risk, because the offers (at least those which are widely publicized) are based on the rate set by the rate cap.[43]

If at the conclusion of the transition period the CTC is not fully paid off by users (plus the bond repayment which extends another 5 years at a constant cost per kWh) the investor-owned utilities (IOUs) are at risk for the balance. If PX energy prices are lower than expected, the transition period ends sooner than 2002. Thus, at least through the end of the transition period, residential consumers have effectively laid off all of their risk to suppliers.

Supplier Risk: When bidding into a day-ahead market on an hour-by-hour basis, suppliers do not know the market clearing price in advance. When submitting their initial bid, they do not know if their bid will be accepted. After a first round, the Independent System Operator (ISO) determines and announces the initial dispatch for the following day. During a short period of time suppliers can

[43] According to their advertisements, Enron offers a discount in the form of 2 free weeks, but their rate is still set at the rate cap.

adjust their bids. After that, the ISO makes the final dispatch determination. Except by bidding a very low price, a supplier cannot be assured that a unit will be dispatched. But a very low bidder might wind up selling power at less than variable cost. A supplier whose unit is not dispatched has lower than optimal capacity utilization and thus higher average costs.

Energy suppliers seeking to avoid this dispatch risk and establish market share at the onset of restructuring have been offering inducements to potential customers. For example, Montana Power Trading and Marketing has made a deal with the California Manufacturers Association (CMA) whereby members who contract with Montana Power will receive energy at a discount to the PX price. To reward loyalty, the discount increases with increasing contract term. Under a one-year contract, customers receive a 6 percent discount. For an 18-month contract the discount is 7 percent and for a two-year contract the discount is 8 percent.[44] Note that under this arrangement, the risk is shared. Customers bear the risk inherent in the underlying variability of the PX market clearing price (MCP). Suppliers accept a known loss of the discount (they could instead be selling into the PX at full price) in exchange for reducing the bidding uncertainty of being nominated by the PX at any particular time.

Steam generators face a special problem bidding into the PX. Their heat rate and thus their variable cost depends on their level of output. Generally, the higher the output the lower the heat rate and marginal cost. They must eventually be able to recover at least their variable operating cost (dispatch gas price, gas transmission price and variable operating costs) as well as revenue for their fixed costs. However, they do not know their incremental fuel costs at any given hour, since that will depend on whether they must start up and the level of output. During low demand periods most or all of the power is provided by must-run units. The problem is further compounded by ISO contracts. There are three types of contracts for units which the ISO deems Amust-run@ due to system reliability considerations[45]:

- X AA@ Conditions: ISO can place these units Aon-call.@ When they are called upon as Amust-run@ they are paid by the ISO an agreed price per MWh for capacity and energy services. The rest of the time they can bid into the PX and retain all revenues.

- X AB@ Conditions: The same as AA@ Contracts except that all fixed costs for the unit are covered by the ISO.

- X AC@ Conditions: Fully dispatched by the ISO, cannot bid into PX, and all costs covered by ISO. This is equivalent to traditional cost-of-service regulation.

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[44] *California Energy Markets*, November 7, 1997, p. 6.

[45] ISO Filing to FERC of 31 March 1997, Executive Summary at page 36.

It is somewhat ironic to note that gas-fueled generation is less subject to gas supply-price variation than are other forms of generation. At most times (perhaps 50 to 90 percent of the year) gas-fired generation sets the market price, and presumably this MCP reflects current gas prices. Gas-fired suppliers are thus buffered from the effects of gas price variation. Of course, suppliers with long-term gas contracts are not subject to spot price fluctuations. If we can assume that the futures market is rational, such long-term contracts will presumably include the average price and a risk premium. Unless the supplier can beat the market, s/he is not better off trying to obtain long-term gas supplies. This might make the competitive market even more sensitive to spot variability of gas prices.

Although buffered from gas price fluctuations, gas-fired suppliers are subject to investment cost recovery risk. As marginal suppliers (see nomination risk, below), any plant=s capacity factor is uncertain. Furthermore, a high hydro year will mean less call for steam generation. As a result, gas generators are at risk for recovery of their capital costs.

Non-gas-fired generation suppliers are subject to the risk of variability of the gas sensitivity of the MCP. According to Klein, the impact of gas price variation on the MCP can be estimated by the formula:[46]

$$MCP = 3.85*TGP_{PG\&E} + 5.70*TGP_{SCE} + 0.36*TGP_{cw} + 1.03*TGP_{SDG\&E}$$

where TGP = Total Gas Price in $ per MMBTU.

On the other hand, non-gas-fired generators are less subject to the investment risk because their dispatch is more certain.

Futures Markets: These were discussed in Section 2.2.1. As noted in Table 4-1, this option is not practical for small users, but is a viable option for large users, generators and energy service providers.

Real-Time and Time-of-Use Metering: Real-time metering refers to a system where consumption is measured hour-by-hour. Time-of-use (TOU) metering merely distinguishes between on-peak, off-peak and possibly shoulder hours for the billing period. Time metering is really a subset of contractual risk mitigation strategies. Under real-time metering, the actual cost during the exact period of the users= consumption as well as the energy used are recorded. This allows the user to be billed for the hourly cost prevailing at the time the usage takes place. With real-time metering, the uncertainty about load profile is removed for both parties. Users with unusually good (i.e., off-peak)

[46] J. Klein: *Interim Staff Market Clearing Price Forecast for the California Energy Market: Forecast Methodology and Analytical Issues*. Electricity Analysis Office, California Energy Commission, Sacramento, December 10, 1997., p. 21.

loads would probably do better with real-time metering than they could by any average pricing. Real-time metering only makes sense if the user is prepared to bear all of the temporal price variability risk.

TOU metering is intermediate between the conventional monthly meter reading and real-time metering. The supplier bears the risk of price variations within the on-peak and off-peak periods. The user bears the risk of average off-peak and on-peak price variation.

Without TOU metering, the user bears the risk for the average cost of power for time between meter readings. The supplier bears the risk that its customers will exhibit a load profile which parallels the average cost of obtaining supplies. The supplier can come out ahead if its customers= load profile involves less than average on-peak consumption. The reverse could also be true. The supplier can mitigate risk by carefully screening the loads it agrees to serve. The user can try to choose the best supply price.

The cost of installing real-time meters as well as administrative costs will limit real-time customers to the larger loads during the early years of competition; however, metering companies such as CellNet claim that remote metering of all hookups in an area can be done at a cost approaching that of monthly meter reading. If so, this would eventually make real-time metering available to all user classes. To be of use to users, however, real-time metering would have to be coupled with devices which monitor and record usage and real-time power costs to enable the user to react to charges in hourly prices. This is probably too complicated and expensive to be practical for average residential users in the near future.

If real-time and TOU metering become widespread, suppliers to the non-TOU load will eventually find that they have an increasingly adverse load, as the off-peak loads switch to TOU metering. They will need to adjust their average prices accordingly.

DSM/Conservation: The advantage of DSM and conservation to users is that the user avoids all of the costs associated with retail electricity prices, including the CTC (and in the case of residential consumers the bond repayment). This should create a more powerful incentive for users to reduce consumption. If coupled with TOU metering, users with loads that can be time shifted (notably heating and cooling loads) can use DSM most cost-effectively.

Greater DSM, especially if it is directed toward peak hours and becomes widespread, will lead to a reduction in the typical spread between off-peak and on-peak prices as the load begins to shape itself to the available supply. In this sense, DSM acts an automatic diversity risk mitigation measure, damping swings in price. This automatic adjustment mechanism would only work, however, if variations in cost of service are predictable and/or of short duration. If of short duration, TOU-metered loads can be anticipated or deferred. For example, central cooling can allow the temperature to increase a couple degrees for a high cost hour, but will eventually have to work harder. If the peak supply cost persists, there will be no avoiding it. The predictability factor means that users planning cost-effective investments in DSM will need to be able to know months and years in advance what cost savings will be. The technical energy savings and their costs are can be known with a fairly high degree of certainty. The resultant cost savings depend on the uncertainty inherent in the power market.

The decision process for selecting appropriate DSM measures imposes what is sometimes a significant transaction cost. In order to decide which DSM measures are appropriate and cost-effective involves some time and possibly expense for the user. This could be as simple as a few back-of-the-envelope calculations to determine whether a more energy-efficient refrigerator is worth its additional cost It could also involve engineering analysis of construction or retrofit options for energy conservation. In any case, these design costs should be included as part of the capital cost of implementing DSM measures.

Self-Generation (SG): The same risk factors described in regard to DSM apply to self-generation. The SG saves all of the components of retail cost associated with transmission, distribution and CTC. The avoided costs of SG are dependent on the market price which the user would have paid. In addition, the user/supplier faces the same fuel price risks facing the supplier. Thus a fuel-cell power self generator faces the full variability of the gas market. A photovoltaic SG, however, does not face any fuel cost variation (except the risk of unusual cloudy periods). Like other non-gas generators, self-generators face downside risk associated with gas price variability. Because gas generation generally sets MCP, if gas price are lower than expected, so too will savings from self-generation be lower than expected.

Self-generation is inherently dispersed generation and, as such, increases electricity system diversity. In recognition of this positive externality, provisions of AB 1890 and SB 90 include subsidies for renewable source generation. When combined with the incentives inherent in the avoided retail market price, it may be practical for even residential users to consider self-generation, depending on the individual=s cost of capital.

Energy Exchange Institutions: The ISO is the only operator of the transmission system. Suppliers in and to California have no choice but to use the ISO. Similarly, users have no choice but to use the regional distribution utility, the same distribution utility that they now have, be it an IOU or a municipal-owned utility. System and distribution costs will continue to be regulated on a cost-of-service basis, just as before competition. Only the energy service provider can be selected by the user. The risk-related issues pertaining to the energy service provider have already been discussed under contractual arrangements, and TOU metering.

Energy service providers and generation suppliers have a choice of institution from which they can buy or sell power. The publicly funded PX, mandated by AB 1890, has the first right of refusal for all power generation by IOUs during the transition period. Other exchanges have also begun or will soon begin operation. One institution, the Automated Power Exchange (APX), plans to begin operation in Spring 1998. APX plans to offer flexibility in scheduling for bilateral contracting between users and suppliers. Unlike the PX, APX will offer not only day-ahead but also longer-term scheduling of transactions. The nomination risk will thus be avoided, with the risk being worked out between the bilateral contracting parties. Physical scheduling of transactions will necessarily go through the ISO, but APX will serve as the middle-man in these transactions. Suppliers and large consumers will be able to participate in APX. The system is not set up for the small user market.

4.2.2 Cost of Capital

Cost of capital is a factor in assessing the risk associated with electricity diversity. Suppliers and users have differing costs of capital. Suppliers, whether generators or energy service companies, are usually at least medium size corporations. As such, they fund their investments through equity, corporate bonds, or commercial paper (i.e., loans). The following is a historic summary of interest rates for relevant sources of capital for the past 10 years:

Table 4-3: Interest Rates for Specified Source of Capital

	U.S. Treasury Bills		Municipal	Corporate	Prime Comm'l	Prime	Home	S&P 500
Year	3-Year	10-Year	Bond	Aaa Bonds	Paper	Rate	Mortgage	Yield
1987	7.68	8.39	7.73	9.38	6.85	8.21	9.31	5.20
1988	8.25	8.85	7.76	9.71	7.68	9.32	9.19	16.60
1989	8.55	8.49	7.24	9.26	8.80	10.87	10.13	31.50
1990	8.26	8.55	7.25	9.32	7.95	10.01	10.05	-3.20
1991	6.82	7.86	6.89	8.77	5.85	8.46	9.32	30.0
1992	5.30	7.01	6.41	8.14	3.80	6.25	8.24	7.60
1993	4.44	5.87	5.63	7.22	3.30	6.00	7.20	10.10
1994	6.27	7.09	6.19	7.97	4.93	7.15	7.49	1.30
1995	6.25	6.57	5.95	7.59	5.93	8.83	7.87	37.60
1996	5.99	6.44	5.75	7.37	5.42	8.27	7.80	22.90
1997*	6.31	6.63	5.72	7.50	5.63	8.40	7.90	20.60
10-Year Avg:	**6.74**	**7.43**	**6.59**	**8.38**	**6.01**	**8.34**	**8.59**	**16.38**
Stand.Dev.	**1.32**	**1.03**	**0.81**	**0.93**	**1.70**	**1.47**	**1.04**	**13.33**

Source: Council of Economic Advisors: **Economic Indicators**, June 1997, p. 30. S&P yield from Ibbotson Associates

* First half of 1997 average except for S&P).

The appropriate interest rate to use in evaluating the cost of capital depends on the generation or supply source in question and, to some extent, the ownership. Merchant powerplants, including those acquired by divestiture, face far greater uncertainty than did traditional regulated utilities. Traditional utilities were able to accept lower earnings and offer lower bonded interest rates than non-utility corporations. By contrast merchant plants, face higher than normal rates. In addition, lenders manage the greater risk posed by these plants by requiring 40 to 50 percent equity financing, compared with 20 percent which was typical of independent power producer (IPP) facilities.[47] Smaller, less diversified ventures will pay a premium over the Aaa corporate bond rate or the prime rate. Well established diversified energy service providers and the competitive subsidiaries of utility companies can borrow at prime or the Aaa bond rate. The commercial par rate is applicable mostly for short-term loans.

Users either pay their utility bills with cash or, increasingly, credit. PG&E allows payment of the utility bill by credit card with an added fee of $5.50 per transaction. According to a recent news report, two-thirds of all credit card customers carry balances from month to month and thus incur an interest rate averaging almost 17 percent. Consumers can reduce their bills through investments in DSM, and in some cases these costs are subsidized by utilities.

For long-term capital investments in DSM measures associated with buildings or major appliances, a long-term interest rate such as the mortgage interest rate or the 10-year T-bill rate is appropriate. For shorter-term investment, the 3-year T-bill rate would be applicable.

4.2.3 Risk Preference

Risk premiums were discussed in Section 2.2.3. Risk premium coefficients will be applied to risky investments by suppliers (for generation) or users (for self-generation and DSM investments). The appropriate risk premium coefficient will be applied depending on the typical financial position of the investor--large corporation (conventional generation), small to medium corporation (cogenerator, smaller scale renewables, DSM by energy service corporations), private individuals (DSM and self-generation).

4.3 USER VERSUS SUPPLIER RISK MODELING APPROACH

As discussed above, suppliers and users face different risks because they have different risk mitigation options, different costs of capital and different risk preferences. In order to model electricity price risk and its relationship to fuel and technology diversity it will be necessary to make separate estimates of risk from the two perspectives.

[47]Michael Zimmer: *Merchant Plant Financing: Risk Management and Strategies*. Reid and Priest, Washington, DC. In *Energy Central* ,web site: www.energycentral.com.

4.3.1 Supplier Risk

Supplier risk is obviously of great interest to each supplier.[48] Each generation type and indeed each plant faces a unique risk profile. It is not the purpose of this study to focus on the individual suppliers= risk, but rather to model how risks facing a supplier will affect the generation mix and therefore the aggregate costs for the system. Thus, we are interested only in how supplier risk might affect the suppliers decision to sell to the market, and how this might influence the market clearing price (MCP).

[48] As a useful simplification, suppliers are understood to be investors as well.

Unfortunately, there is a circularity problem associated with the MCP. The risk faced by suppliers depends not only on variability of fuel prices and other cost factors, but upon the MCP. The MCP (absent risk sharing with users) determines the suppliers= revenues. But the mix of suppliers affects the MCP. Furthermore, as discussed in the CEC Interim Staff Market Clearing Price Forecast,[49] the computation of the MCP is a complex and difficult task and is well beyond the scope of this study.

To solve this problem we will apply a comparative static solution.[50] We begin by taking the assumption and results of the Staff MCP as a given. We calculate the electricity diversity risk with this mix. We then analyze the costs and revenues for each supplier type to determine whether this supplier can remain viable, and what additional supplies will become economic when a new market entrant become viable. We then recalculate the risk with this new mix. Finally, we estimate the amount of subsidy required to meaningfully improve the fuel and technological diversity risk.

One of the key factors affecting the viability of each technology relates to the revenues the technology can expect to recover under the MCP. The MCP varies by time of day and season. The capacity factor of each technology will likewise vary by time of day and season. Using a simple market model developed by P-Plus we have estimated the on-peak and off-peak capacity factors by technology shown in Table 4-4.

The same information expressed in terms of percentage of energy is shown in Table 4-5.

The results of Table 4-4 and 4-5 together with the on-peak and off-peak MCP forecast in the Interim Staff Report enable us to calculate revenues by technology. The capacity factors together with the other cost components are then used to compute generation cost by technology. These costs are then compared to revenues.

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[49] J. Klein: *Interim Staff Market Clearing Price Forecast for the California Energy Market: Forecast Methodology and Analytical Issues*. Electricity Analysis Office, California Energy Commission, Sacramento, December 10, 1997.

[50] A comparative static approximation is one in which a solution is first determined while holding one set of variables constant. This solution is then compared to other solutions in which different sets of variables are held constant.

4.3.2 User Risk

As noted above, the price paid by users includes several costs which are essentially fixed, i.e., transmission, distribution, public purpose programs, CTC, and bond repayment costs. Except for the CTC, there is little risk associated with these costs, and what risk there is, is of a regulatory rather than a market nature. The repayment of the CTC hinges on a very complex set of issues, most of which will be legally and politically resolved. Resolution of the CTC is a good example of uncertainty as distinct from risk. It cannot be objectively quantified; any assessment depends on the subjective judgments of participants and observers. Essentially then, user risk is largely associated with energy costs. Users can avoid the full range of retail price components by self-generation or DSM.

Table 4-4: Generation by Technology, On-Peak, Off-Peak and Shoulder

	Total Hours	On- Peak Hours	Shoulder Hours	Off-Peak Hours
Max Possible:	8760	1825	3650	3285
CC	7829	1639	2949	3242
CT	48	27	21	0
Coal	6036	1258	2264	2514
Geothermal	7866	1639	2950	3278
Hydro	8062	1830	3285	2947
NW	7881	1824	3267	2791
NW-Econ	5491	1563	2860	1067
Nuclear	6753	1407	2532	2814
Biomass	7150	1490	2681	2979
SW	6910	1751	3156	2004
SW-Econ	3834	1230	2231	373
Solar	2306	1647	659	0
Steam	1002	383	584	36
Steam-Must-Run	7906	1647	2965	3294
Wind	1922	1373	549	0

Table 4-5: Percent of Generation Hours by Technology

	% Total Hours	%on Pk	% Shoulder	% Off Pk
CC	89.4%	18.7%	33.7%	37.0%

CT	0.5%	0.3%	0.2%	0.0%
Coal	68.9%	14.4%	25.8%	28.7%
Geothermal	89.8%	18.7%	33.7%	37.4%
Hydro	92.0%	20.9%	37.5%	33.6%
NW	90.0%	20.8%	37.3%	31.9%
NW-Econ	62.7%	17.8%	32.7%	12.2%
Nuke	77.1%	16.1%	28.9%	32.1%
Biomass	81.6%	17.0%	30.6%	34.0%
SW	78.9%	20.0%	36.0%	22.9%
SW-Econ	43.8%	14.0%	25.5%	4.3%
Solar	26.3%	18.8%	7.5%	0.0%
Steam	11.4%	4.4%	6.7%	0.4%
Steam-Must-run	90.2%	18.8%	33.8%	37.6%
Wind	21.9%	15.7%	6.3%	0.0%

User risk for residential and small commercial customers is limited by AB 1890 during the transition period. The price risk faced by these users until 2002 is essentially zero, because AB 1890 freezes the price for customers of the three major IOUs at 90 percent of the 1997 rates. The only price issue is the amount of stranded asset payments which will be funded by the Rate Reduction Bonds which these users will be paying off over the next 10 years. Many political and economic variables are involved in that computation.[51] Not all of them have as yet been resolved. Even if these issues could be sorted out, the result would not add much to the understanding of risk in the context of this study. Therefore, risk for small users during the transition period will not be addressed.

User risk for large users and small users after the transition period depends on the distribution of risk between suppliers and users. As a first approximation, we examine user risk assuming that users bear the full burden of uncertain and variable energy prices from viable suppliers. We then look at how contractual risk sharing would reduce the risk. We also determine at what price self-generation and DSM become cost-effective and what that implies for risk reduction.

For DSM, we use the retail price of electricity as the assumed average cost. Using average risk without additional DSM as a baseline, we will estimate how alternative DSM scenarios would lower system risk. For self-generation, we will work from an individual user=s perspective to determine the investment risk effects. We will estimate the expected cost and risk-adjusted cost for various self-

[51] For example, the CTC payment is based on the amount of stranded assets, which are in part based on the proceeds from divested assets. Recent asset sales have generally been bringing higher than book values, which results in stranded assets which are less than originally estimated.

generation alternatives (small photovoltaic, small-scale wind and, if data are available, small-scale fuel cells).

5.0 DATA SOURCES AND ASSUMPTIONS

5.1 INTRODUCTION

In this section the data to be used in the analysis of diversity from both the user and the supplier standpoints are presented and discussed. For each estimate of fuel diversity risk, each of the variables in Table 5-1 must be estimated. The data are provided for the following variables and parameters:

Table 5-1: Data Used in Estimating Fuel Diversity Average Cost and Risk

Variable	Unit	Series	Source
Fuel Prices:			
Natural gas	$/Mcf	Annual	CEC: ER-96
Coal	$/Ton	Annual	Phase I Report
Nuclear	Cents/kWh	Annual	Phase I Report
SW Economy/Firm	Cents/kWh	Annual averageBoff and on-peak	CEC Staff Forecast
NW Economy/Firm	Cents/kWh	Annual averageBoff and on-peak	CEC Staff Forecast
Capital & O&M Cost	Cents per kWh	Annual	Phase I Report
Capacity-factors	Percent	Annual, by scenario	Historic averages and scenario assumption
Energy Mix	Percent	Annual, by scenario	Historic averages and scenario assumption
Capacity Mix	Percent	Annual, by scenario	Historic averages and scenario assumption
Interest/Discount Rate	Percent	Annual, by affected party	Various
DSM	Capacity, Energy	Annual, by scenario	Historic averages, ER-96
Generation Cost	Cents per kWh, peak and off-peak	Annual, by scenario	Computed estimate
User cost	Same as above	Annual	CEC Staff Forecast + T&D

Each of the variables is discussed in more detail in the remainder of this section.

5.2 FUEL COSTS

The fuel costs for all fuels except natural gas are assumed to remain equal to their 1990 to 1995 historic averages. Natural gas prices are estimated based on the 1997 CEC Staff forecast and are consistent with the values used in Arakawa (1997).[52] The fuel costs are presented in the AFuel Cost@ module of the spreadsheet model and Table 5-2.

5.3 GENERATION MIX

The generation mix not directly input. Instead it is computed as a function of the capacity and the capacity-factor by technology and fuel source. Both of the latter inputs are variables. For the Base Case, we assume that the capacity-factors are equal to the average capacity-factor for each technology over the 1990 to 1995 period. The capacity starts in 1996 with the 1995 capacity by technology, as derived in the Phase 1 report. The capacity is modified based on the ER-96 forecasts of new plus committed capacity addition and retirements. This is determined from ER-96 Existing and Committed Resources for years 2000, 2003 and 2007.[53] Base Case capacity, capacity-factors and generation by technology for year 1996 to 2010 are shown in Tables 5-3 (Capacity), 5-4 (Cap Factor) and 5-5 (Generation), respectively. Values for intermediate years are linearly interpolated from the forecasted years. Spreadsheet module ER96 shows the basis for the calculations.[54] As new capacity is needed, starting in 2002, the Base Case assumes that these needs will be supplied from new merchant combined-cycle gas-fired plants. These plants are represented by a resource called Tech A in the model.

[52]Ben Arakawa, *Revised 1997 Retail Electricity Price Forecast*, CEC Electricity analysis Office, December 1997, Appendix C.

[53]*Electricity Report*, CEC, November 1997, p. 70.

[54]ER-96 presents forecasts for energy and required capacity, but only presents assumed actual total system capacity for years 2000, 2003, 2007 and 2015. The estimate of net capacity change was based on ER-96's forecast energy changes relative to 1995, assuming that the reserve margin remains constant. No breakout of capacity by

It should be noted that the Base Case assumes the demand, capacity and energy generation associated with the ER-96 Business-As-Usual demand-side management case (DSM is discussed further below). By assuming the capacity-factors and energy generation based on the average statewide 1990 to 1995 values, we implicitly assume that the hydroelectric generation and energy imports will continue at these historic rates. While the 1990 to 1995 period consisted of a range of wet and dry hydro years,

technology is forecast by the CEC. Note that after 2007, the generation predicted by Resource Decisions=s spreadsheet model and the ER-96 forecast diverge slightly. This is due to ER-96's forecast of constant system average capacity-factors which is inconsistent with the Staff Forecast=s assumption of increasing use of high capacity-factor merchant combined-cycle capacity.

t 5-2

t 5-3

t 5-4

t 5-5

by relying on an average, the variability of hydro availability is understated. This is discussed in more detail in Section 6.

5.4 GENERATION COSTS

The generation costs associated with each technology are a function of fuel costs, capital costs, operating costs and capacity-factors. The assumptions and computations associated with each of these technologies is contained in separate spreadsheet modules, one for each technology. The name of each module is self-explanatory. With few exceptions, these technology models were previously described in the Phase 1 report and will not be repeated here.

In addition to DSM, which is discussed bellow, two additional technologies were added to the Phase 1 Diversity model. Because these are intended as Aplace-holders@ to enhance modeling flexibility, we refer to these as ATech A@ and ATech B.@ In the Base Case, Tech A consists of new merchant combined-cycle capacity. A noted above, this capacity is assumed to fill the need for new technology after 2002. Tech B is at present non-must-run steam, although no capacity is assumed for this category and thus it has zero weight in the average cost and portfolio variance calculation.

5.5 MARKET CLEARING PRICES

Under the restructured energy environment, both user costs and supplier prices are dependent to a large extent on market clearing prices (MCP) which are set by the PX. Forecasting the MCP, especially at the time this is being written (the first months of PX operation), is a complex and uncertain undertaking. Fortunately, the CEC Electricity Analysis Office has undertaken a major modeling effort on this subject.[55] Unfortunately, this effort is still preliminary, and is thus limited in the extent to which the MCP forecast can be related to exogenous variables, such as fuel prices and resource availability of imported power and hydroelectric generation. This study relies on the Interim Staff MCP Forecast as the basis for forecasting user costs and supplier revenues. This analysis is consistent with both Klein (1997) and the companion retail price forecast.[56] The reader should refer to these publications for further information on underlying assumptions.

[55]Klein, 1997, op. cit.

[56]Ben Arakawa: *Revised 1997 Retail Electricity Forecast, December 1997*. Electricity Analysis Office, CEC, Sacramento. December 1997.

5.6 USER COSTS

In addition to the MCP, which is the energy portion of the retail users= cost, users= costs include transmission and distribution costs and, during the transition period, stranded investment costs. Additionally, in the case of residential and small commercial users, costs reflect the effects of the Revenue Repayment Bonds.

With the exception of DSM and distributed generation (see Section 5.8 below) the non-energy and thus non-MCP-related portion of user costs are essentially unaffected by fuel or technology diversity issues. Following this concept, we have separated the non-energy from the energy-related components of retail cost. Table 5-6 shows the components of the retail price, based on Arakawa (1997). By holding the T&D (transmission and distribution) component constant over time, and varying the energy component with the MCP, the model is able to forecast retail prices. Note that the relative and absolute T&D cost differs for the three classes of service (large commercial, residential and small commercial and industrial).

5.7 GENERATION REVENUES

Except for the capacity which is nominated must-run by the Independent System Operator (ISO), generators who sell to the PX can expect to receive only the MCP. Depending on the seasonal and diurnal pattern of their generation, however, different technologies can expect to receive different proportions of peak and off-peak prices.

P-Plus, one of the study team members, ran a simplified market model of California=s competitive market to analyze the percentage of time which the alternative technologies in the generation mix can be expected to receive diurnal peak and off-peak prices.[57] Table 5-7 (module ARetail@) presents the results of this model in terms of the number of hours each of the technologies runs in a typical year and the proportion of these hours which are on- and off-peak. While these proportions might vary gradually with changes in capacity and major shifts in dispatch, this table is a useful first approximation of on-peak proportions.

Another determinant of generation revenues is the range in prices between average, peak and off-peak. Although there is as yet little market experience on which to determine this relationship, we have again relied on the preliminary forecasts of the Electricity Analysis Office. Table 5-8

[57] Although the model was run for an entire typical year, it was summarized by year and thus does not reflect seasonal MCP variations, but rather provides a weighted annual average snapshot.

(MCPRev) presents the results of a recent model run showing the relationship between peak and off-peak prices[58]. The rightmost two columns show peak and off-peak MCP as a percentage of average MCP. While this proportion does vary from year to year, it does not appear to vary systematically over time. Thus it is reasonable to treat this proportion as cross-sectional data (as opposed to time series) with an average and a variance.

T 5-6

[58] Klein, 1997, op cit. Table T-1.

t 5-7

t 5-8

5.8 DEMAND-SIDE MANAGEMENT

Assumptions regarding DSM affect forecast generation mix through both the required capacity and the expected energy by technology. ER-96 specifies three DSM scenarios: Business-As-Usual, Declining DSM and Restored Funding (high DSM).[59] In the Base Case assumptions of the instant report, we have assumed the Business-As-Usual projections.

In order to estimate the effects of DSM on the average system cost and variance, we have also made assumptions regarding the capacity-factor and the cost of DSM. We assumed that the capacity-factor of DSM is equal to the system load factor in each year. We further assumed that the cost-effective DSM, as specified in AB 1890, can be understood as being available at a cost roughly equal to the retail cost of electricity. We have modeled DSM as another generation technology. We have assumed that DSM investments cost$300 per installed kW, have a variable O&M cost of $3 per MWh and a fixed O&M cost of $30 per kW-year. We assume a 7-year investment life.

[59] These scenarios are described in ER-96 p. 66.

6.0 SCENARIO ANALYSIS COST AND RISK

6.1 INTRODUCTION TO SCENARIOS

In this section we estimate and compare the impacts of alternative scenarios on users and suppliers of California=s electricity system. For each scenario we project generation costs, revenues to generation suppliers, and cost to users. We then estimate the fuel and technology risks to users and supplier under alternative risk distribution scenarios.

In the present context a scenario can be defined as a portfolio of generation capacity and energy available to California in a given year. All of the data summarized in Table 5-1 are needed to define one scenario. Thus scenario can be regarded as a snapshot of the California electricity system under one set of policy options. This snapshot includes average revenues, costs and risks to various parties as defined. The expected risk can be defined as the expected standard deviation of the portfolio of generation assets available and used by California. By defining different scenarios we can examine how certain decisions by California policy-makers, generators and consumers can affect the expected average costs, and risks faced by users and suppliers.

In order to provide a basis for comparison we have specified a Base Case which includes the most likely result of continuation of present trends. Alternative scenarios are compared with the Base Case, to show the impacts of alternative decisions and policies. Although we originally planned to limit the analysis to three representative future yearsC2000, 2004 and 2010Cfor greater flexibility we have expanded the results to cover each year through 2010.

In the Base Case, exogenous variables such as the market-clearing price, capacity, generation and fuel costs are all set at their default values and do not reflect possible variance. As the model is structured, however, this information can be readily obtained by modifying these exogenously varying variables from their default values. This will be demonstrated for varying gas prices. Methods for assessing the risk associated with the other exogenous variables will be discussed as well.

6.2 BASE CASE SCENARIO

The Base Case Scenario incorporates the best presently available median estimates of future MCPs, fuel prices and generation mix. Future demand and capacity is based on the ER-96 Business-as-Usual DSM scenario. The natural gas price reflects the ER-96 forecast. Existing and committed capacity is based on ER-96 forecasts. New capacity is assumed to consist entirely of low-cost, high-efficiency merchant combined-cycle natural gas-fueled plants.

6.2.1 Base Case Generation Cost and Revenue

Based on the technology models specified in the Phase 1 report, as well as the forecast fuel prices, Tables 6-1 and 6-2 present the projected full costs by year and technology as well as their impact on the system energy-weighted generation costs (module ACosts Full@) The same information is presented with respect to variable costs in Tables 6-3 and 6-4 (module ACost Var@). The revenues which generators will earn, based on the CEC interim Staff MCP forecast, adjusted for the peak and off-peak distribution of each technology=s expected generation profile, are shown on Table 6-5 (module AMCPRev@). The difference between the expected revenues and the full and variable operating costs are shown in Tables 6-6 and 6-7, respectively (module AMCPRev@). Note that these tables assume that the only compensation which the generator receives is the MCP. Generators who receive a contract-based capacity payment or subsidized energy payments would receive these in addition to the amounts shown on Tables 6-6 and 6-7. This applies to non-utility generators with QF (qualified facility) contracts, nuclear plants with special compensation contracts (notably PG&E=s Diablo Canyon plant) and generators with must-run or other reliability contracts with the ISO. Additional payments based on the recovery of stranded assets will also help erase some of the negative entries in the revenues net of full cost tables.

6.2.2 Base Case User Cost

User costs are estimated as the sum of energy, transmission and distribution. As noted in Section 5, the model keeps these quantities separate, so that changes in MCP can directly affect retail cost. In the diversity model, it is assumed that the user cost reflects the full MCP (including 1 mill for the ISO operations) plus the T&D costs for that user group. Table 6-8 presents the cost for each user group service area and year under the Base Case MCP forecast.

6.2.3 Base Case Risk and Cost

As presently specified, the Base Case offers limited information about the portfolio risk faced by users and suppliers. As noted above, exogenous variables such as the market-clearing price, capacity, capacity-factor variation, generation by technology, and fuel costs are all set at their default values and do not reflect possible variance.

Nevertheless, the standard deviation and coefficient of variation in retail costs give a lower-bound estimate of the risks faced by users. To these risks must be added the effects on the MCP resulting from fuels cost variations, hydroelectric and import energy availability, unplanned transmission outages, and load factor fluctuations, to name only the major risk factors. Despite these caveats, it is interesting to note that the coefficient of variation on retail costs is quite moderateC15 percent for residential users, 18 percent for commercial users and 14 percent for industrial users for the 1998 to 2010 period.

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6.3 HIGH NATURAL GAS PRICE VARIANCE SCENARIO

The Base Case assumes the mean gas price forecast developed in ER-96. This forecast does not include the random variance characteristic of the natural gas market. Short-duration variances (daily, weekly and even monthly variations) probably tend to have only a minor impact on users because they balance out within a budget period. Annual variance could have a more significant effect on both users and suppliers.

To simulate the effect of natural gas price variance, the relationship between natural gas price and MCP was determined. Then the ER-96 gas price was perturbed by a monte carlo procedure using the variance observed during the period from 1990 to 1995. A second run examines the effect of doubling this variance. This procedure is explained in more detail below.

The relationship between the Staff Forecast MCP and the forecast natural gas price on which the MCP forecast was based was determined using linear regression. A very close correlation was found between these two factors (the r-squared is 87 percent).[60] The relationship between changes in gas price and changes in the MCP is built into the model predicting retail prices and generator revenues. Thus, by substituting the changed gas price, the user and supplier prices and their standard deviations are recalculated.

To perturb the gas price, first the standard deviation of the historic gas prices from 1990 to 1995 were calculated. Then a random price series was generated applying this historic standard deviation to the mean predicted gas price from 1998 to 2010. The user and supplier prices and variances were then recalculated. A second case using a simulated price series with twice the 1990 to 1995 variance was also calculated.

Note that in this analysis we have assumed that gas prices are mean-reverting, i.e., that there is no definite trend to prices, only random variations.

6.3.1 High Natural Gas Price Variance Generation Cost and Revenue

Table 6-9 summarizes the sensitivity of suppliers= net revenues to changes in the gas price variance. The middle panel of the table (horizontally) shows the mean and standard deviation of revenues accruing to each technology net of variable cost. The bottom panel shows mean and standard deviation of revenues net of full costs. The left third of the table (vertically) shows the mean standard deviation of revenues under the predicted gas price. The middle panel (vertically) shows the effect of the historic variance. The right-hand third shows the effects of doubling the historic variance. In all three cases, the mean remains approximately the same (by design);

[60] See module AMCPRisk@ for regression statistics.

however, by increasing the variance of natural gas prices, the standard deviation and coefficient of variation (standard deviation

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over mean) increases markedly. On a portfolio basis, the coefficient of variation with the historic variance is twice that of the Base Case. With twice the historic gas price variance, the coefficient of variation is three times that of the Base Case.

6.3.2 High Natural Gas Price Variance User Cost

In contrast to the high exposure of supplier to gas price variance risk, users whose energy cost is based on the MCP face only slight exposure to gas price risk. The variance and coefficient of variation do increase with increasing gas variance, but this effect is very much less pronounced than that experienced by suppliers. In part, this is due to the fact that only the energy portion of their cost, not the T&D portion, is exposed to any variance.

6.4 HIGH/LOW HYDRO SCENARIO

Because no analysis has yet been made available relating the effect of hydroelectric availability on MCP, it was not possible to analyze this effect for this study. However, the diversity model developed for this study is ideally suited to analyzing this relationship, as soon as the hydro/MCP relationship becomes available. Below we set out an outline of how the diversity model can be used for this analysis.

Hydro availability varies greatly from year to year based on annual rainfall. As noted in Section 4, not only is California=s hydro subject to this effect, but also the amount of NW economy imports tends to be closely correlated, as it is subject to the same regional seasonal rainfall. Thus from year to year, the amount of generation varies, while the capacity remains constant. This imposes a variability on the capacity-factors. While hydro and import capacity-factors decline in a dry year, their slack is taken up by several other technologiesCSW imports and, to some extent, coal increase. Also, and more significantly for the MCP, gas steam plants are marginal more of the time and have higher capacity-factors. This brings on more lower efficiency generation with a concomitant increase in system marginal cost and thus MCP.

Once the sensitivity of MCP to hydro availability is modeled, this information can be incorporated into the model by:

1. Imposing a random variation on the capacity-factors of the affected technologies; and
2. Altering the variable and full costs for the steam plants to reflect the use of less efficient generation resources.

Effect 1 can be modified through the use of the Scenarios tables which are discussed in more detail in the next section. Effect 2 can be reflected by appropriate modifications to the steam generation capacity. A dummy technology, Tech B, can be used for this purpose. Tech B, which is Awired@ into the model but not used, can be defined to include the lower efficiency steam units.

6.5 SENSITIVITY TO VARYING DSM LEVELS

Based on reported historic costs reported by California IOUs, DSM is a very low cost source of power. To approximate a cost of about 2.4 cents per MWh, which is the average cost of DSM reported by California IOUs from 1995 and 1996 and projected for 1997 and 2001 (see Table 6-10); low capital and operating costs are assumed in Module ADSM.@ These costs are at or below the wholesale MCP. Because, as mentioned above, the value to users of DSM is determined by their *retail* cost, DSM appears to be very cost-effective. Even doubling the capital cost to $600 per installed kW results in a total cost per kWh of less than 4 cents, which is less than half the retail cost.

It is interesting to note that the CTC bond creates a confusing set of price signals for potential residential and small commercial DSM users. During the transition period, the retail value of DSM reflects avoided CTC payments of up to 3 cents per kWh. In the 2005 to 2010 period, this bond repayment reduces retail cost and thus limits the value of DSM. The implication for potential DSM users is to institute DSM measures as soon as possible to maximize benefits.

The ER-96 DSM scenarios do not seem to reflect these incentives. Under the Business as Usual scenario, uncommitted DSM climbs from the current level of about 4000 MW to 4469 MW by 2000 and 6366 MW by 2007. The Declining DSM has DSM decreasing to about 3000 MW by 2007. Under the Restored Funding scenario, DSM rises to 8000 MW by 2007.[61]

A high DSM scenario was run to approximate the Restored Funding Scenario. The energy savings from increased. DSM is assumed to substitute for new combined-cycle generation. Under this scenario, the energy-weighted portfolio system average generation cost is decreased by 6.8 percent in 2003. It is beyond the scope of this analysis to predict how increased DSM would affect the MCP and thus user prices and supplier revenues.

From a user risk reduction standpoint, DSM is free of cost risk in that once the DSM measure is implemented, variable costs are low or nil and there are no fuel costs. DSM does still carry a possible performance risk, i.e., will the DSM measure perform as planned? Also the cost savings depend on the avoided cost of market power. DSM, by avoiding the full retail cost of power offers potentially substantial risk and cost reductions for users, however.

From a system-wide portfolio variance standpoint, substitution of DSM for combined-cycle capacity has a negligible impact.

[61] ER-96, Table 5, p. A-1.

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6.6 SENSITIVITY TO VARYING RENEWABLE GENERATION CAPACITY

Increased renewable energy capacity, whether due to AB 1890 funding or increased competitiveness of these technologies will have little impact on overall system costs and risks.

Two increased renewables scenarios were analyzed. In the first scenarioCRenewable ACwind capacity is assumed to increase by 10 percent per year from 1999 to 2001 and 20 percent per year in 2002 and 2003. In this scenario geothermal capacity is also assumed to increase by 10 percent per year from 1999 to 2003. In a second scenarioCRenewable BCgeothermal increases as in Renewable A, while wind energy, based on advanced technology, accounts for all new capacity (rather than the combined-cycle capacity assumed in the Base Case). In both renewable scenarios excess capacity and energy is assumed to be retired from gas-steam.

7.0 DOCUMENTING AND MONITORING

In this section we provide guidance to assist users of the spreadsheet model to modify both the input data and the assumptions on which the diversity model is based. In Section 7.1 the basic structure of the model is described. Section 7.2 describes each of the modules within the model.

7.1 DIVERSITY MODEL STRUCTURE

The Diversity model is implemented on Corel Quattro Pro spreadsheet software (Version 8). The spreadsheet is broken into interlinked spreadsheet pages or modules, each module dedicated to a separate component of the data, analysis or results. In general, any change in an entry will cause the spreadsheet to recalculate, and all computations which depend on that entry will be automatically updated.[62] The tables which appear in this report are contained in several of the modules. Because the tables are the result of various inputs and computations, they are spread throughout the spreadsheet model in the modules relating to the table=s subject. Each of the printed tables in this report lists in its lower left corner its source address within the spreadsheet. The derivation of the data on the tables can be traced by examining the formulas of the table cells. In Quattro Pro, this is facilitated by use of the auditing feature in the Tools menu.

The overall logic of the model is shown in the flowchart which comprises Figure 7-1. The logic of the derivation of the consumer prices and supplier revenues is shown in the Figure 7-2 and 7-3 flowcharts, respectively. Next to the boxes in each flowchart the modules and tables which that box describes are listed.

Within the spreadsheet model, a number of conventions are followed. All external references to other modules are specified by absolute module name references to avoid problems of altering the order of the modules. The cells within all modules are color-coded according to the following scheme:

Blue: Historical data 1990-1995.
Black: Statistical results or labels.

[62]It is important to exercise care in modifying entries. In general, entries which are numeric data inputs or are colored brown are primary data which can be modified as appropriate. Cells which have as their precedents other cell addresses should be modified only after giving careful thought to the logic of the model. If data are entered to override a previously computed entry, inconsistencies might result.

Magenta: Forecast data 1996 to 2010.
Red: These are values ***not formulas***. They will not change if inputs are modified.
Dark Green: Annotation.
Orange: Tab color for technology cost models.
Light Green: Tab color for the biodiversity module.
Brown: Identifies entries which might be modified by a user to develop a new scenario.

Figure 7-1

Figure 7-2

Figure 7-3

7.2 DESCRIPTION OF THE MODULES

The spreadsheet model is divided into modules (also known as sheets or pages) each with a separate purpose. The following table describes the purpose of each modules well as the report tables which are generated from it, their cell ranges, and the user input variables. In the absence of user input data, best estimate default values are supplied by the model.

Tab Name	Purpose	Report Tables Generated	Range	User Inputs	Range
Cover	Project Identification	none		none	
Contents	Identify tables and locations	List of Tables		none	
Summary	Summary tables of costs, revenues, risk	(several Chap 1)		none	
Scenarios	Allow user to specify future scenarios of capacities, capacity factors and fuel costs	none		capacity and capacity factor changes by technology, fuel cost scenario	M46..AB65
CostsFull	Summarizes information on the full generation cost by technology and year	6-1 6-2	L1..AA19 L61..AA79	none	
CostsVar	Summarizes information on the variable generation cost by technology and year	6-3 6-4	M1..AB19 M60..AB78	none	
Risk Full	Summarizes information on the generation cost risk by technology and year based on full costs	none		none	
Risk Var	Summarizes information on the generation cost risk by technology and year based on variable costs	none		none	
Capacity	Capacity by technology and year	5-3	L1..AA29	Capacity	M5..AA25
CapFactor	Capacity Factors by technology and year	5-4	M1..AB19	capacity factors	M5..AB18
Generation	Generation by technology and year	5-5	R1..AG24	none	
Fuel Costs	Generation fuel cost inputs	5-2	L1..AA14	fuel costs, variability of gas prices	M5..AA14 O22..AA23
Technology Models	Calculates unit and annual total costs by technology and year	none		heat rate variable O&M Fixed O&M capital costs capital cost esc O&M escalation	B3 B5 B6 B7 M13..AA13 M14..AA14

Tab Name	Purpose	Report Tables Generated	Range	User Inputs	Range
Cost of Cap	Input cost of capital for technology cost computation	none		cost of capital	J3..X3
CPI	Indices for adjusting dollar values to constant 1996 dollars	none		CPI forecast	VARIOUS
Gas Wt	Determines the breakdown of gas-fired generation among CT, CC, Steam	none		gas proportion by technology	C5..C7
Risk Prem	Computes the risk premium for users and suppliers	2-1	B22..L51	risk premium coefficient	C6..C21
AB1890	Renewable technology costs net of subsidies	A-1	A2..P41	none	
SW	Computes Shannon-Weiner diversity coefficients	none		none	
Retail	Computes retail prices by user class, year and service area. Separates energy, T&D and CTC components	5-6 6-8	A1..H28 A30..S88	proportion of energy, T&D by service area	B8..H10
ER96	Input data on peak load and required capacity from ER-96	none		adjust peak capacity forecast	C9..R9
MCPRisk	Computes sensitivity of retail prices and revenues to changes in the variability of natural gas prices	6-9	A84..J131	none: adjust gas price variance in the fuel cost module	
Peak	Computes the percent of time technologies operate during peak periods	5-7	C184..J205	Adjust input data on peak period generation	E54..G113
MCPRev	Computes generation revenues by year and technology	5-8 6-5 6-6 6-7	A1..P18 B19..T37 B61..T79 B40..T58	Adjust peak/average MCP price ratio	O17..P17

Appendix A: EFFECTS OF AB 1890 RENEWABLE FUNDING ON DIVERSITY-RELATED ELECTRICITY PRICE RISK

A.1 BACKGROUND AND ANALYTICAL FRAMEWORK

AB 1890 mandated the CEC to develop a program to encourage renewable energy technologies in electricity generation. This program was to include a procedure for allocating $540 million to be collected from Investor-Owned Utility (IOU) customers to support existing, new and emerging renewable electricity generation technologies. A recently issued policy report responds to this mandate. This report specifies guidelines for the allocation of funding between new and emerging and among several technologies within the existing technologies category. The report also specifies temporal allocation guidelines; the specification of funding is at a general policy level.

The proposed procedure for analyzing the impact of AB 1890 on generation price risk involves the following steps:

- Estimate a base case renewable generation technology scenarios;
- Describe likely changes to this scenario which will result from AB 1890 funding;
- Estimate price risk to electricity suppliers with and without funding; and
- Estimate user price risk with and without AB 1890 funding.

A.2 BASE CASE RENEWABLE GENERATION TECHNOLOGY

Although it is impossible to accurately predict the wholesale price of electricity under restructuring, it is unlikely that prices will change significantly during the transition period (1998 to 2001). The share of certain renewable technologies is, however, likely to decrease (absent the AB 1890 subsidies) due to the termination of fixed energy price clauses in certain renewable energy project contracts. The current (1995) levels of renewable energy technology dependable capacity and energy are shown in Table A-1.The Interim Standard Offer 4 (ISO4) contract provides for a fixed energy payment for generation during the first 10 years of project operation. These fixed payments are quite high compared with current market prices. After the initial period, energy prices drop to essentially current avoided cost.

Biomass Generation: The fixed 10-year period for most fixed-energy-payment cogenerators has ended or will end in the next few years. The drop in energy payments between the end of the fixed price period and the beginning of the SRAC-pricing period is dramatic, especially for biomass QFs (Qualified facilities) and cogenerators. A typical natural gas cogenerator facing the "cliff" in 1999 will see capacity plus energy payments fall from 5.4 cents per kWh to 3.9 cents, a 27 percent drop according to energy price forecasts. A typical biomass QF, receiving 100 percent fixed-energy prices, will see a price drop from 13.14 cents to 3.9 cents, a 70 percent drop.[1] All QFs still operating under ISO4 EPO1 and EPO2 contracts will be affected. These include almost all biomass QFs.

According to CPUC estimates, 54 biomass, biogas and municipal solid waste (MSW) fueled QFs and 10 biomass cogenerators in California with a combined capacity of 992 MW will be affected by the end of the other fixed price period[2] This represents 10 percent of all QF capacity and 2.3 percent of all 1991 installed capacity of California utilities. The concentration of biomass QFs and cogenerators affected is especially high in the PG&E service area, where these technologies represent 17 percent of QF capacity. In all, 89 percent of the installed capacity of biomass QFs will be affected.

The generic generation cost analysis conducted as part of Phase 1 of this study[3] indicated that the full cost of biomass generation averaged approximately 7 cents per kWh. Even after the ISO4 price cliff, QFs will receive about 2 cents per kWh in capacity payments in addition to the 2.5 to 3 cent market value of their energy, for a total revenue of 4.5 to 5 cents per kWh. At this level no new biomass generation would be competitive without additional subsidy.

From a variable cost standpoint, however, existing average cost biomass plants should remain viable, even without additional subsidy. Historic biomass variable costs have averaged 3.75 cents per kWh from 1990 to 1995. These costs should be recoverable under competition, with some surplus available for partial capital cost repayment.

Biogas generators face higher than average capital costs but probably lower operating costs; however, the costs faced by biogas plants vary greatly from site to site. To the extent that biogas plant site is comparable to biomass costs, existing plants should remain viable.[4]

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[1]Kitto, S. *Analysis of the Impact of the End of the Fixed Energy Price Period Under the Interim Standard Offer 4 Contracts.* Prepared for the CPUC, DRA. San Francisco, February 14, 1992, page 17.

[2]Ibid., page 22.

[3]Marvin Feldman, *Diversity and Risk Analysis*. Consultant Report P500-97-008, Technology Assessment Office, Sacramento, California Energy Commission, June, 1997. 1997, Tables 5-1 and 5-6.

[4]Huffaker (CEC/Technology Assessment Office, personal communication 8/97) reports that the CEC has

On this basis we estimate that all biomass generators having a captive waste stream or a low cost fuel source will remain in production over the next four years. Absent AB 1890 subsidy, a rough estimate is that biomass generation will decline by 10 percent in 1997 through 2001.

Solar Thermal Generation: Solar thermal could compete in the distributed generation market. As such, revenues could be considered at their retail level (i.e., about 10 cents per kWh). Alternatively, solar generation could be a QF and thus eligible for capacity payments of about 2 cents per kWh. In either case, however, solar is even less competitive than biomass generation. At a full cost of over 20 cents per kWh, there is virtually no prospect of unsubsidized new solar thermal projects, which would have to cover capital as well as operating costs. One possible exception is use in very high cost areas (i.e., off-grid applications). For existing installations which can take advantage of QF payments, the estimated historic variable cost of 3.6 cents plus the capacity payment make continued unsubsidized operation of existing plants feasible. Such facilities would be able to partially recover investment costs. Considering that about a third of solar generation occurs during peak demand periods, existing solar capacity should remain competitive without AB 1890 subsidy.

Wind Generation: The picture for wind generation is more favorable. At a full cost of almost 10 cents per kWh for traditional wind turbines, no new capacity is likely to be built during the transition period. However, new turbines are now in the design stage which should be able to produce power at about 3 to 5 cents per kWh. At this price, and a QF subsidy of 2 cents per kWh, new capacity would become commercially viable. In any case. with a variable cost of 1 cent per kWh, all existing wind plants should remain in production, even without AB 1890 subsidy.

Geothermal Generation: There is potential undeveloped geothermal capacity of about 1,000 MWh in the Imperial Valley. Without QF or AB 1890 subsidy, new geothermal plants (whose full costs averaged almost 4 cents per kWh) are not likely to be built during the transition period. Existing plants with QF capacity contracts can easily compete at variable costs of 1.2 cents.

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received applications for 50 MW of new, non-subsidized biogas plants. These should at least replace the loss of higher cost plants.

New and Emerging Technologies: Several new and emerging technologies show promise of commercial viability in the near future due to cost breakthroughs. For example, proton exchange membrane (PEM) fuel cells, amorphous film photovoltaic, and new generation wind systems[5] are all displaying rapid cost decreases. Several factors militate against the inclusion of new and emerging technologies in the resource mix until after the transition period, however. First, during the transition period, all generation from existing IOUs must be bid into the Power Exchange (PX). This power, under most circumstances, will be offered at a price close to variable cost. There is presently an excess of capacity available to California. Under this price regime, new and emerging technologies will not likely be competitive.[6] Thus we assume for baseline purposes that there will be no new or emerging technology generation in the resource mix during the transition period, absent AB 1890 subsidy. Emerging technology funds can be paid out over a longer period as well.

A.3 LIKELY IMPACT OF AB 1890 FUNDING

While detailed mechanisms for distribution of funds are still being specified, the Policy Report is sufficient to provide a basis for making some informed estimates about likely scenarios for future renewable technology generation.

AB 1890 makes provisions for funding existing technologies: biomass and solar thermal ($135 million); wind ($70.2 million); geothermal, small hydro, biogas ($37.8 million). AB 1890 also provides for funding new technologies ($162 million); emerging technologies ($54 million); and consumer-side renewable energy rebates ($81 million). Funding is to be dispersed over the four-

[5]Daily Journal of Commerce, Seattle, 7/22/97.

[6]The analysis previously conducted by the principal author for the CEC (Feldman, M.. and R. McCann, 1995. *The Effects of California Electricity Market Restructuring on Emerging Technologies*. Prepared for the Research Development and Demonstration Office of the California Energy Commission, Sacramento) supports this contention and is still relevant

year transition period (1998 to 2001) with two exceptions. The distribution of funds for new technologies will continue for several years after the end of the transition period as new projects come on line. Unused funds (if any) will be used to fund additional emerging technology projects after the transition period as well.

The distribution mechanisms vary depending on the account. The existing technologies accounts (all three tiers) will be allocated to the projects based on the gap between the market price (presumably the PX spot market price) and a target price set for each tier. The maximum subsidy varies from 1.5 to 1.0 cents per kWh depending on the technology and the year.

Table A-1 shows the subsidy by tier and year. The table is divided into six sections. The upper half of the table shows the full cost of generation form each technology based on the analysis performed as part of Phase 1. Generation costs reflect the average cost for each technology from 1990 to 1995. The table also shows the cost for each technology net of the maximum subsidy in each transition year. The lower section of the table shows the same data but includes only variable costs, ignoring sunk capital recovery costs.

The left third of Table A-1 shows generation costs for renewables assuming that a 2 cent per kWh QF capacity payment is available. This applies to almost all existing renewable generation, but not to new renewables. The center third of the table shows the costs net of the maximum AB 1890 payment, assuming that the funds are not oversubscribed. This section is applicable to new renewable generators or existing generators who do not have QF capacity contracts. The rightmost third of the table shows costs net of both the maximum AB 1890 subsidy and the QF capacity contract.

For all the Table A-1 entries, a positive net cost indicates the portion of costs which will need to be covered by energy revenue payments, i.e., the competitive energy price. Technologies which have net costs greater than 3.5 cents are not likely to be economic. Some green energy purchasers might, however, be willing to pay a premium above the market energy price for renewable energy.

New Geothermal Capacity: A new project would have to be competitive based on the full generation cost net of QF subsidy. Geothermal power costs approximately 3.9 cents per kWh without subsidy. This price is most likely higher than the competitive market price, suggesting that unsubsidized geothermal projects with average project economics will not be viable. With the 1.0 cent per kWh subsidy, the price falls to 2.9 cents per kWh, at least during the transition period. Even though the subsidy will be eliminated after 2001, the effect of AB 1890 should be sufficient to bring new geothermal projects on line.

The maximum geothermal capacity resulting from AB 1890 can be estimated by assuming that \$60 million per year is used to subsidize new geothermal capacity. This would be sufficient to subsidize 6,000 gWh per year, which is almost 40 percent of existing geothermal energy. Given resource constraints and the limited ability to bring new capacity on line in a short time, half this energy is a more realistic upper bound. This corresponds to a capacity of 300 megawatts of new capacity. Given the short lead times, the five year limitation on the subsidy, uncertainties facing the electricity market and resource constraints, it is possible that only those geothermal projects which are already in the design stage would be affected by the subsidy. This could include a substantial portion of the undeveloped Imperial Valley potential resource.

Other Renewable Technology New Capacity: As defined by the renewables program, all plants which were not on line by September 23, 1996 can qualify as new capacity. Repowered existing renewables, provided that they do not retain their ISO4 contracts, are also eligible for new capacity payments. Wind energy projects are the only non-geothermal technology which appears to have a chance of becoming economic due to AB 1890 funding (see the middle two panels of Table A-1). Based on avoided disposal costs and application received by the Energy Commission, however, it appears that certain biogas resources could also become economic. Based on historic average costs, biomass projects would not cover full costs, even with maximum AB 1890 subsidy. They would, however, cover variable costs, which suggests that certain low-cost repowering might be economic. Solar thermal, at a cost in excess of 20 cents per kWh, does not appear at all competitive.

Emerging Technologies: As far as the renewables program is concerned, renewable technologies have come to include only small-scale distributed technologies. These technologies were not included in Table A-1 because historical cost data are lacking, due to the evolving nature and limited application of these technologies. As noted above, distributed technologies save their users the full retail cost of power (possibly less the cost of backup capacity). This means that at least during the five years during which subsidies will be available, distributed generation which costs less than about 12 cents per kWh would be economic. However, there are no sources which can meet this criterion at present.[7]

[7] S. Miller, CEC, personal communication, April 1998.

Continuing Operation of Existing Renewable Technology Capacity: The lower panels of Table A-1 reflect the economics of continued production from existing renewable technology projects because sunk costs are ignored.[8] Even without AB 1890 subsidy, variable costs for all listed technologies are economic, assuming that they are able to receive the 2 cent per kWh capacity payment and a market energy revenue of about 3 cents per kWh (see the lower left panel of Table A-1). Additional subsidies from AB 1890, if available, would help cover full investment costs. In any case, no existing renewable technologies appear to need AB 1890 to remain in operation.

New and Emerging Technologies: The uncertainties discussed under the baseline section for new and emerging technologies make it unlikely that significant capacity of these technologies will be on line during the transition period even with AB 1890 subsidies. Undoubtedly some renewable projects which have borderline economics will become commercial based on the AB 1890 subsidies. But due to uncertainties and development lead times, this will likely occur after the transition period (post 2001).

A.4 NET IMPACTS OF AB 1890 RENEWABLES FUNDING

AB 1890 essentially imposes a $540 million tax on electricity users and transfers these payments to renewable technology generators. In the short run this increases the cost of electricity. Although the intent of this program is to increase diversity and thus reduce risk, and eventually cost, there is no definitive way to estimate whether these effects will be realized. Some general tendencies from the user and supplier standpoints are discussed below. More quantitative analysis appears in a subsequent section of this report.

A.4.1 AB 1890 Impacts at the Supplier Level

Supporting renewables will keep existing plants of technologies with the highest variable costs (biomass and solar thermal) in operation for at least the transition period. Since the variable costs will continue to be high after the transition period, these will still be the most at-risk technologies when new capacity comes on line. For existing plants with QF contracts which also qualify for AB 1890 subsidy, continuing operation offers investors the opportunity to recover more of the capital costs, although, at least in the case of solar thermal, full costs still far exceed subsidized

[8] From an economic standpoint, it is appropriate to ignore sunk costs for existing capacity. The Competitive Transition Charge (CTC) should cover uneconomic investments. Even if it doesn=t, unrecovered sunk costs affect the net value of the project, but should not influence whether it continues to operate. All things being equal, only variable costs should determine operational viability.

recovery. For the lower cost renewables (wind and geothermal), AB 1890 subsidy will increase both the assured recovery of capital costs and reduction of revenue uncertainty risks. Thus the subsidy should result in significant increases in new capacity of these technologies.

A.4.2 AB 1890 Impacts at the User Level

At least initially, average user costs will be slightly higher due to the cost of the subsidy, which is entirely derived from users. Costs will be higher with the subsidy than they would be without it. In the short run, the effect on the variance of the cost or risk will be minimal from the user standpoint. The energy cost in the competitive environment is set by the marginal bid. Because it is unlikely that renewable technologies will set the market-clearing price, there is probably little direct effect on user risk due to the renewables program. In any case, the effect of energy price variance accounts for only part of the total cost faced by users.

In the longer run, it can be argued that by increasing diversity, the Renewables Program decreases risk. As discussed in the Phase 1 report,[9] each technology exerts a different leverage on the portfolio variance. Increasing the proportion of a very variable technology increases the portfolio variance, and vice versa. Increased diversity does not decrease variance or risk per se. The specific effects of changes in technology proportions on risk is quantitatively evaluated in Chapter 6.

[9] See Feldman, 1997 op. cit., Chapter 5 and Appendix A.

Pasteups

Table 2-1: Risk Premium for Residential Electricity Users

Table 3-1: Shannon-Weiner Index versus R/D Index

Table 4-1: Summary of Electricity Risk Mitigation Strategies

Table 4-2: Composition of Typical Residential Electricity BillCPG&E Service Area, 1998

Table 4-3: Interest Rates for Specified Source of Capital

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