PORTFOLIO ANALYSIS AND ITS POTENTIAL APPLICATION TO UTILITY LONG-TERM PLANNING

Mike Ringer
David Vidaver
Electricity Analysis Office
Electricity Supply Analysis Division
California Energy Commission

Steven Ostrover
Serkhan Bahceci
London Economics International LLC

DRAFT STAFF PAPER

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ABSTRACT

This report presents the results of a California Energy Commission staff investigation into the use of analytical methods based on Modern Portfolio Theory to characterize risks and costs associated with electric utility long-term resource plans. Its purpose is to provide information on state-of-the-art utility resource planning methods for the Energy Commission's Integrated Energy Policy Report Committee to consider as a basis for policy recommendations in the *2007 Integrated Energy Policy Report*.

The report presents information regarding the need for risk assessment and management considerations in long-term resource planning as well as current planning and evaluation methods used by California investor owned utilities. It also includes an explanation of Modern Portfolio Theory and how derivatives of it may be applied to utility planning, case studies of its application by selected utilities in other parts of the U.S., and implementation strategies for possible modifications to long-term utility planning in California.

Keywords: modern portfolio theory, portfolio analysis, integrated resource planning, energy planning

CHAPTER 1: INTRODUCTION AND BACKGROUND

Introduction

This paper explores the potential for California investor owned utilities (IOUs) such as Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) to incorporate an analytical method based on Modern Portfolio Theory into their electricity planning processes. It provides an overview of current IOU planning methods and long-term plans, describes Modern Portfolio Theory, discusses planning methods that selected utilities currently use, considers the potential application of portfolio analysis for utility planning, and explores how current IOU planning requirements might incorporate such a method. This paper will provide the foundation for a joint Integrated Energy Policy Report and Electricity Committee workshop to be held July 11.

The Changing Landscape

The process of planning and procuring electricity for consumers was once a far simpler task than it is currently. Planning was easier in the days prior to industry restructuring, when electric utilities were vertically integrated monopolies, since a utility – on its own schedule – could construct, own, and operate new capacity that would closely match both its generation and reliability needs. The utility customer base was dependable, with only growth and normal migration to be considered. Utility ownership of generation and transmission, combined with a guaranteed rate of return, also limited financial risks to the regulated company. Fewer generating technology and fuel options had to be considered, limited primarily to hydro, nuclear, and load-following or peaking oil or natural gas facilities. Since one of the primary goals was to minimize generation costs, the least expensive option was usually the most attractive when considering an addition to a utility's generation portfolio. Although fuel costs could be a significant portion of total costs, they were relatively low and less volatile than they are today. While fuel price increases led to higher rates, the absence of retail competition reduced the significance of fuel price risk in utility planning.

Supplying adequate energy to consumers has become significantly more complex and fraught with uncertainty. Beginning with the requirement to purchase energy from independent generators (qualifying facilities), utilities must now choose among a host of technology and fuel combinations and contract options when adding to their portfolios. In addition, non-generation options and environmental concerns add to the complexities and risks to be considered. Industry restructuring, along with the changes in regulatory requirements and the financial and economic considerations it has effected, has also greatly increased risks and added to the uncertainties that utilities and regulators must consider. These uncertainties include the potential of losing customers to competitors, thus increasing the risk of long-term financial commitments.

Today's environment calls for an analytical process that can include the variety of options, risks, and uncertainties that utilities must consider in evaluating potential resource additions. Choosing a resource addition based on current lowest cost projections is no longer adequate if the potential for dramatically higher prices is ignored. As Graves, et al., point out:

> In particular, the old IRP (Integrated Resource Planning) model generally did not incorporate risk management considerations akin to those now central to utility planning. Perhaps a few scenarios were evaluated, but there was no need to measure and manage dynamically shifting probability distributions for future market prices or utility costs. (Graves, et al., 2004, p. 19)
>
> The new procurement and planning problem combines traditional least-cost goals with new risk-management objectives. Least-cost planning involves developing a portfolio of resources that has the lowest expected future cost (i.e., on average), subject to achieving a given quality of service… Risk management, on the other hand, involves ensuring that the portfolio of power plants, contracts, and financial risk management instruments reduces foreseeable variance (or more generally, uncertainty) around the future expected cost. (Ibid., p. 21)

Modern Portfolio Theory (MPT) is one tool that may provide a basis upon which to analyze different combinations of actions that utilities can take to meet future demand. MPT enables a decision maker to assess potential changes to a portfolio's risks and costs brought about by adding assets that have their own individual risk and cost profiles. The resultant risks and costs of various combinations of assets can be quantified, and the most efficient portfolios can be recognized on a curve referred to as the "efficient frontier." That is, for any given level of risk, the least expensive portfolio can be determined. Conversely, for any given level of cost, there is an associated least-risk portfolio. When choosing among portfolios, MPT allows different risk preferences to be considered as well as varying trade-offs among risks and costs to be examined.

Planning Requirements

Assembly Bill 57 (Wright), Chapter 835, Statutes of 2002, requires the IOUs to submit proposed procurement plans to the California Public Utilities Commission (CPUC) every two years. The structure and contents of these plans were partially defined by AB 57 and refined by subsequent legislation and CPUC decisions. The law requires that the plans:

- Be of specific duration; the CPUC has established a 10-year planning horizon.
- Enumerate the electricity products that would be procured; The CPUC established a list of authorized products and transactional processes in decision D.02-10-062. The vast majority of these are contracts or financial derivatives

that are designed to be used for short-term energy and capacity needs, as well as fuel supply and risk management.

- Meet Renewable Portfolio Standard (RPS) goals; D.02-08-071 ordered each IOU to procure at least an additional 1 percent of its actual energy and capacity needs from renewable generation. In rulemaking R.04-04-026, the CPUC established a requirement that the utilities procure 20 percent of their total energy sales from renewable resources by 2010 and increase renewable procurement by at least 1 percent of total sales per year until 2010.
- Create or maintain a diversified procurement portfolio: given specific consideration of Renewable Portfolio Standard requirements elsewhere, this has generally been interpreted as a requirement for contract term and supplier diversity in energy and capacity procurement.
- Achieve fuel supply diversity: given specific consideration of Renewable Portfolio Standard requirements elsewhere, this has generally been interpreted as a requirement for contract term and supplier diversity in natural gas procurement.
- include a risk management policy: in D.03-12-062, the CPUC addressed risk management issues and authorized contract term duration and volume limits, and standards for procurement products and transactions. The risks considered are those that arise from exposure to near-term changes in the natural gas and wholesale electricity prices and are managed largely using instruments approved in D.02-10-062. (Please refer to Appendix 1 for a discussion of risk calculation and the methods IOUs use to report risk).

Subsequent CPUC rulings have required that the IOUs' procurement plans consider additional programs and policy goals that influence the need to procure energy and capacity, as well as prescribed threshold values for preferred resources.

D.04-01-050 established a requirement that the IOUs integrate energy efficiency, demand response, distributed generation, renewable generation, power from qualifying facilities, and non-renewable fuel diversity into their procurement plans. In addition, the IOUs were to include a range of forecast gas prices and total procurement costs stated in terms of present value revenue requirements. The plans were also to include a reliability component, including the need to provide for local reliability. D.04-01-050 adopted a framework for resource adequacy requirements that included a 15 to17 percent planning reserve margin.

D.04-10-035 mandated implementation of the 15 to17 percent planning reserve margin by June 1, 2006, and ordered that the IOUs have 90 percent of their next summer's peak requirements (May through September) fully resourced by September 30 of the prior year.

D.06-01-024 created the California Solar Initiative, an 11-year, $3.2 billion incentive program with the goal of installing 3,000 megawatts of new solar facilities on homes and businesses in California.

D.06-02-032 indicated the CPUC's intent to develop a load-based greenhouse gas (GHG) emissions cap, required by Senate Bill 1368 (Perata), Chapter 598, Statutes of 2006, which directs the CPUC and Energy Commission to establish greenhouse gas (GHG) emission performance standards by February 1, 2007. SB 1368 also prohibits load-serving entities and publicly-owned electric utilities from entering into long-term (i.e., five years or more) commitments for base-loaded generation unless they comply with GHG performance standards established by the CPUC and Energy Commission, respectively. A related measure is Assembly Bill 32 (Nunez), Chapter 488, Statutes of 2006, which establishes a comprehensive framework for the reduction of greenhouse gas emissions in California for all industries, including utilities, through emission limits, reporting requirements, and potential market-based compliance mechanisms.

D.06-06-064 established local procurement obligations for load-serving entities as part of the broader resource adequacy requirements program and required that all load-serving entities acquire 100 percent of their CPUC-determined year-ahead local procurement obligations for the following calendar year.

CHAPTER 2: CONCERNS WITH THE STATUS QUO

Dependence on Natural Gas

Modern combustion turbine and combined cycle technologies have evolved to allow utilities to meet both large- and small-scale needs cleanly, efficiently, and until recently, relatively cheaply. Thus, the construction of natural gas-fired electricity generation has proliferated over the last several years. For example, the percentage of natural gas used in California to generate electricity has risen from about 31 percent in 1996 to almost 42 percent in 2005 (California Energy Commission 2007). The trend of relying on natural gas to fuel electricity generation is expected to continue in California and throughout the West. The percentage of gas used to generate electricity in California is anticipated to remain around 41 percent through 2016 (Ibid.), while throughout the West, combined cycle and combustion turbines represent 59 percent of expected new capacity additions from 2006 – 2015 (WECC 2006, p. 9).

Over the next several years, California IOUs will have a significant amount of energy to procure, with a large percentage coming from “generic” sources (resources that are as yet undetermined). Table 1 shows the percentage of kilowatt-hour (kWh) needs that will be met using natural gas-based technologies compared with the percentage that will be procured from generic sources (generic resources may also include gas-based generation). Depending on the resources chosen to meet future electricity needs, California IOUs’ dependence on natural gas may remain near current levels or decrease to less than one-half. The path ultimately taken will profoundly affect the degree of fuel diversity in the state as well as the degree of price and supply risk to which ratepayers may be exposed.

Table 1: Percentage of Kilowatt Hours from Gas and Generic Resources – California IOUs

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Gas	47.0	46.7	38.4	32.0	21.9	20.4	20.4	20.0	19.7
Generic	2.5	3.9	9.6	14.6	23.9	25.4	26.0	25.3	25.5

Source: Energy Commission staff calculations based on IOU Long-Term Procurement Plans filed with the CPUC on December 11, 2006.

Since 2000, the price and volatility of natural gas has increased greatly. The resulting concern over fuel price effects manifests itself in calls for fuel and technology diversity. For example, at the 2005 National Regulatory Research Institute/National Association of Regulatory Utility Commissioners meeting of 55 state regulatory commissioners, attendees listed fuel diversity for electricity generation as one of the key regulatory issues they were likely to face in the near term (NRRI 2005, p. 2). This relates closely to one of the key issues listed during the previous year’s meeting: “The combination of increased volatility of natural gas prices and increasing dependence on natural gas for electricity generation” (Ibid.). In

2005, regulatory commissioners observed that the key issue was the lack of a comprehensive and balanced approach to addressing current fuel diversity issues and related price volatility (Ibid., p. 13). Other more general concerns included the observation that in restructured states, no locus of responsibility exists to ensure fuel diversity (Ibid., p. 14).

As a response to the perceived need for diversity, utilities have begun to include renewable resources, energy efficiency, demand response, and energy from small power producers in their resource plans. Notwithstanding the additions of these diverse sources of energy, the dependence on natural gas in the generation sector may not necessarily decrease.

Although diversity is widely perceived to be a worthy goal to pursue in the fight against high prices, regulatory risk, environmental issues, and potential reliability concerns, it is not an end in itself. Requiring specific levels of a variety of resources may create diversity, but what benefits are to be achieved and what are the costs of pursuing such diversity? What are the trade-offs among higher or lower levels of one resource versus another? If specific policy goals are to be met by creating a diverse resource mix in the most efficient manner, these and related questions must be addressed.

As a senior economist for the National Regulatory Research Institute pointed out:

> It cannot be taken for granted that achieving a higher degree of fuel diversity would have net benefits, or is socially desirable, especially if it is not carried out intelligently. Fuel diversity *per se* should not be perceived as an end, but only as a means that has the capability to generate benefits less costly than other alternatives in achieving the same objectives (Costello 2005, p. 8).

The proliferation of natural gas-fired generation has resulted in large part due to its economic advantage over other technologies; that is, it is commonly the least-cost addition to a utility's generation portfolio. The practice of adding least-cost resources continues in utility long-term procurement through the application of least-cost best-fit principles (CPUC D. 04-12-048, Order 26), where gas-fired resources typically dominate the Request for Offer (RFO) process, even considering current and future higher expected gas prices. Possible continued high levels of gas-fired generation raise the question of whether nonfossil fuels are being given due consideration as possible future energy sources for electric generation (Costello 2005, p. 17). Suitable public policies hinge on the reasons why the benefits from fuel diversity are not being fully exploited, if in fact that is the case (Ibid., p. 18).

Gas Price Risk

Any comparison of resource alternatives – whether of choices arising from response to an RFO or in a long-term planning exercise – is sensitive to assumptions regarding the future price of natural gas. This follows in part from the fact that in California, natural gas is the marginal fuel for electricity generation, its price establishing the cost of energy from the market in most hours of the year. It is all the more so given that investment in existing coal technologies and the construction of nuclear plants is prohibited by state law, and very few power plants in California can switch to fuel oil when gas prices increase (also, there are very few power plants in California that burn fuel oil that can be dispatched in lieu of plants that burn natural gas).

Forecasts of future gas prices can be drawn from many sources. Forward markets provide values for up to six years in the future, although market liquidity is lacking beyond 36 – 48 months. Informed commitments to new gas-fired capacity require price estimates that extend well beyond this, however, as gas-fired power plants have service lives of 30 years or more. Fundamentals models of the North American natural gas market can provide 20-year and longer price forecasts based on assumptions regarding the future demand for and supply of natural gas, the latter including projections regarding exploration, drilling and extraction costs, and the extent and costs of upgrades to the bulk pipeline system.

Short-Run Changes in the Price of Natural Gas

While these long-term natural gas price forecasts can be used to compare resource alternatives, resource planning must take into account natural gas price risk: the potential cost to ratepayers of future gas prices differing from those forecasted. In the shorter term, natural gas prices tend to be cyclical, with three underlying cycles of differing periodicity influencing prices:

- Very short-run (less than 2 weeks), with transient weather conditions such as heat storms in the summer and cold snaps in the winter, causing changes in price through changes in the demand for electric generation and gas heating.
- Short-run (less than 1 year), with hydro and gas storage conditions influencing both summer and winter prices, the former through changes in the demand for gas-fired generation.
- Medium-run (18 months – 3 years), based on the lagged relationship between prices and exploration and drilling and production.

It is likely that price volatility over these periods has permanently increased, due in large part to increased reliance on natural gas for electricity generation. In each of these cases, however, ratepayers can be protected from changes in gas prices to a greater or lesser extent. Financial derivatives and forward purchases protect ratepayers against high prices due to transient weather disturbances; utilities tend to be fully hedged against such disturbances in the very short-run. They also tend to be partially hedged against price run-ups due to low hydro years and below-average storage conditions, using both forward purchases and storage itself to do so. Protection against medium-run price changes is more costly due to the greater uncertainty surrounding prices further out in time.

Long-Run Changes in the Price of Natural Gas

The impact of longer-run changes in the price of natural gas cannot be mitigated using traditional financial instruments, nor do longer-run changes have the "predictability" of short-run changes. While prices can be modeled as reverting to an estimated mean value in the short- and medium terms, the price of natural gas over the longer term will depend on technological, economic, and political factors whose joint impact cannot be easily ascertained and whose empirical estimation may be considered by some to be little more than a guess. Long-run natural gas price volatility will likely increase over time for several reasons, including increased reliance on remote resources such as liquefied natural gas (LNG), Alaskan north slope, and Canadian Atlantic and other offshore production (Henning, et al., 2003). There is also the risk that with the implementation of green house gas emission restrictions in the U.S., gas consumption in the eastern U.S. could rise dramatically from the curtailment of coal-fired generation. This could further strain the tight U.S. natural gas supply situation leading to greater price volatility.

If procurement and resource planning are to use modern portfolio theory to incorporate concerns regarding gas price risk, a probability distribution for the price is necessary. The expected natural gas price influences the relative costs of portfolios that contain different levels of gas-fired resources; the distribution influences the relative risks of these portfolios. As the value of risk metric used to compare portfolios is usually driven by the highest cost futures (often a fixed percentage of the total number of futures evaluated), the outer, upper tail of the distribution must be specified with some degree of confidence.

For the near term, estimates of the natural gas price distribution can be compiled using historical data. This is generally done by selecting the period from which to draw historical data and assuming a functional form for the gas price (for example, log normal). Volatility parameters are then estimated and Monte Carlo draws can be used to create a distribution, with due attention being paid to the correlation of the gas price with other drivers, any mean reverting tendency that is assumed, and so forth. The accuracy of these estimates follows from the assumption that, in the near-term, the future will look something like the recent past. Even in the short-term, however, the outer tail of prices, as estimated, may be very sensitive to the historical data used and the functional form assumed.

Longer run price distributions cannot be formulated with such confidence. The expected long run price can be subject to dispute as noted above. Moreover, the bounds of the long-run price are subject to even greater uncertainty. Table 2 presents IOU estimates of the 95th percentile gas price during 2010 – 2016.

Table 2: Natural Gas Prices as Reported (95th Percentile, Nominal $)

	2010	2013	2016
PG&E	$17.09	$16.30	$17.21
SCE	$10.21	$10.61	$11.87
SDG&E	$11.06	$9.90	$9.36

Source: IOU Long-Term Procurement Plans filed with the CPUC December 11, 2006.

The difference in the estimated prices above may reflect different methodologies or input assumptions (for example, historical period used for data, functional form) or, to a small extent, reflect actual differences in the volatility of the gas price that each utility faces.

Recent Requests for Offers

A review of the all-source RFOs conducted by the IOUs since the passage of AB 57 indicates that the needs of the utilities are largely limited to capacity (especially to meet local reliability needs) and dispatchable energy products. The lack of need for baseload energy stems from the IOUs having sufficient baseload resources in their existing portfolios and mirrors the relative surplus of baseload resources in California as a whole. The state witnessed a dramatic expansion in baseload capacity during and immediately after the 2000 – 2001 energy crisis; about 11,000 MW of gas-fired baseload generation have come online in the past six years.[1]

The need for capacity and dispatchable energy makes direct comparison of gas-fired and other generation resources in utility RFOs infrequent. A large share of the renewable resources under consideration for development are wind projects, which cannot provide the dispatchability that IOUS call for in their solicitations. Other renewable resources, while dispatchable, may lie outside the local reliability area in which the IOUs have sought capacity. Finally, given the slow progress toward meeting the state's Renewable Portfolio Standard, renewable resources participating in all-source RFOs may be selected without, or in spite of, comparison to gas-fired alternatives.

Discount Rates – The Present Cost of Future Gas Prices

Developing cost estimates for various technologies in order to choose the least-cost alternative requires that future costs be presented on a comparable basis. Since technologies vary as to when costs are incurred (some have high up front capital costs, while others have lower initial costs followed by higher fuel costs over time, for example), expenditures from different time periods are commonly converted to present values through the use of discount rates. Typically, the discount rate chosen is equal to the firm's weighted average cost of capital. However, according to some observers, this approach fails to include the market risk associated with the

[1] Please see http://www.energy.ca.gov/sitingcases/all_projects.html

particular cost stream under consideration (Awerbuch 2003, p. 17). Such market risk must be included, they argue, according to the principles of the Capital Asset Pricing Model (Sharpe 1964). The Capital Asset Pricing Model says that the value of an investment is a function of not only the time value of money, but also of risk. The time value of money is represented by the risk-free rate and compensates the investors for placing money in any investment over a period of time. The amount of compensation the investor needs for taking on additional risk is calculated by taking a risk measure (beta) that compares the returns of the asset to the market over a period of time and to the market premium. Using an appropriate risk-adjusted discount rate yields present values that represent an estimate of the value at which a contract for these future cost streams would trade in the capital markets.

In most applications, where the risk of various project cost streams differs, each cost must be discounted at its own appropriate rate. A major source of systematic risk for fuel based generators is the fossil fuel outlay. Based on their negative correlation with gross domestic product and the returns to a broadly diversified market portfolio, Awerbuch argues that the correct fossil discount rate cannot exceed the risk-free rate, which is about three percent after tax (Ibid.). This raises the present value cost of fossil fuels relative to the estimates produced by traditional analyses. Thus, traditional cost of electricity analyses may discount gas and other fossil outlays much too heavily, thereby significantly understating their true cost. This subject is explored in more detail in the Energy Commission consultant report, *A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33% Renewables and Climate Change Goals* that will estimate proper discount rates for each of the cost streams in the market price referent model using Capital Asset Pricing Model-based econometric analysis. Results from this paper will be presented on July 11 at the Energy Commission Joint Committee workshop on Portfolio Analysis.

The Use of Unhedged Versus Hedged Gas Price Forecasts

Since natural gas price volatility poses a major risk, in order to achieve a fuel price risk profile similar to that of fixed-price renewable generation, either the buyer or seller of gas-fired generation must hedge away that risk (Bolinger, et. al 2003). If long-term price stability is valued, the prices that the buyer or seller can lock in through contracts (that is, forward prices) are therefore the appropriate fuel price input to resource acquisition, planning, and modeling studies that compare renewable to gas-fired generation. Utilities and others conducting such analyses, however, tend to rely primarily on uncertain long-term forecasts of spot natural gas prices, rather than on forward prices that they can lock in with certainty. If there is a cost to hedging, gas price forecasts do not capture and account for it. If gas price forecasts are at risk of being biased or out of tune with the market, they should not be used as the basis for investment decisions or resource comparisons if a better source of data (that is, forwards) existed.

Accordingly, the most comprehensive way to compare resource options would be to use forward natural gas price data as opposed to natural gas price forecasts. By their nature, renewable energy resources such as wind power carry no natural gas fuel price risk, and if the market values that attribute, the only appropriate comparison is to the hedged cost of natural gas-fired generation.

Least-Cost Planning

Least-cost planning emphasizes the addition of resources that result in the least expected cost of generation from a resource mix. However, the least-cost criterion reveals nothing about the variation in future prices, or level of risk, associated with the lowest-cost addition and the resulting resource mix. Although ratepayers prefer lower costs, the level of risk to which they are exposed is important, since there may be unacceptable price spikes (or even physical shortages), even with low expected costs (the CPUC recognizes the importance of managing risk when they require IOUs to prepare risk reports for their existing portfolios based on Value at Risk methods). Thus, risk management should be of paramount importance when considering resource additions. Unlike least-cost planning, risk management considers the variance in future costs of a portfolio of resources. As discussed in more detail in the section below on Modern Portfolio Theory, one cannot simultaneously lower both costs and risk of an efficient portfolio; costs can only be lowered with an increase in risk. Indeed, without the explicit consideration of both metrics, it is not possible to foretell the effects of adding the lowest expected cost resource to a portfolio. Without relying on the principles of Modern Portfolio Theory, a portfolio cannot be judged to be efficient or inefficient; in the case of an inefficient portfolio, it may be possible to simultaneously lower both cost and risk, but without considering both, it is not even possible to tell.

To the extent that utility long-term planning does analyze different portfolios and the effects of adding particular resources to the existing mix, the number of portfolios under consideration is frequently very limited and the ultimate metric remains lowest expected cost. Some observers believe there may be additional reasons why natural gas generation continues to fare well in the least-cost arena in spite of its seemingly high price: the present costs of future gas prices are underestimated because risk is not considered, and forecasted (unhedged) gas prices are used instead of hedged prices.

The Use of To-Expiration Value at Risk

Appendix 1 discusses the use of To-Expiration Value at Risk (TeVaR) and related methods by the IOUs to report on risk. TeVaR addresses primarily the level of fuel-related risk to which the IOU's existing portfolio is exposed and is used to provide guidance regarding the need for additional hedging activities. TeVaR is not used to construct and analyze a variety of portfolios with the goal of providing guidance regarding the efficiencies of those portfolios and the acquisition of new resources to add to an existing portfolio.

Consideration of Candidate Portfolios

One review of 12 western resource plans reveals that, in most cases, candidate resource portfolios are constructed by hand, featuring resources that are regionally available and that passed initial cost or performance screening tests (Bolinger and Wiser 2005, p. 20). Though this selection of candidate portfolios may simplify the modeling process, it also allows human bias to influence the outcome by limiting the universe from which the optimal portfolio emerges. If a broad range of candidate portfolios is not considered, the modeling outcome could be sub-optimal (Ibid.). Analysis of risk will be most informative if applied to a wide range of candidate resource portfolios that vary in their ability to mitigate those risks. The sequential, winnowing approach may lead to results that are more a function of the manner or order in which different risks were assessed—as well as the way in which handcrafted candidate scenarios were defined—rather than of the potential likelihood or magnitude of the risk itself (Ibid., p. 71).

Utility planners would ideally treat all meaningful risks in an integrated fashion, if possible; certain risks should generally not be relegated to lesser importance simply because they are assessed through scenario, rather than stochastic, analysis. If some risks are better suited for scenario rather than stochastic analysis, then steps should be taken to ensure that results from scenario analysis are integrated into the overall process (Ibid.). It should be recognized that the later in the planning process that stochastic analysis is employed, the greater the potential for sub-optimal results because low-risk portfolios may be screened out based on cost prior to the stochastic analysis (Ibid., p. 51).

CHAPTER 3: UTILITY PLANNING IN THE WESTERN UNITED STATES

Introduction

This section summarizes a review of western utility resource plans (Bolinger and Wiser 2005) with an emphasis on how risk and uncertainty were incorporated into the respective planning processes. It also discusses preliminary findings regarding the treatment of carbon risk from a follow-up study of western resource plans (Barbose and Wiser 2007). Bolinger and Wiser examined the treatment of renewable resources in the plans of 12 western utilities[1] in order to analyze how the resource planning process affects renewable energy choices and to suggest how the planning and evaluation processes might be improved. Barbose and Wiser are currently updating the 2005 study with more recent resource plans, including additional utilities not examined in the earlier study. Unless otherwise noted, discussions refer to the 2005 study. Please refer to Chapter 4 and Appendix 2 for a more complete discussion of California IOUs' proposed 2006 long-term resource plans.

Risk and Uncertainty

Utility resource plans typically analyzed a broad spectrum of risks, often using stochastic simulation and scenario analysis. Preferred resource portfolios were selected based not only on expected costs, but also based on the potential variability of those costs (see Table 3). Risks commonly evaluated in resource plans are:

- Natural gas price uncertainty
- Wholesale electricity price uncertainty
- Variations in retail load and departing load
- Hydropower output variability (that is, drought)
- Environmental regulatory risks.

Risks for which both the impact and probability of that risk can be quantified (even if imperfectly) are typically analyzed with stochastic modeling (for example, gas and wholesale electricity prices, variations in retail load, and hydropower output uncertainty). Where the risk impacts can be quantified, but probabilities cannot easily be assigned, scenario analysis is most common (for example, risk of future carbon regulation or of departing load). Where neither the impact nor the probability of a risk can be readily quantified, more qualitative approaches to describing the risks are typically used.

[1] Avista, Idaho Power, NorthWestern Energy, Portland General Electric, Puget Sound Energy, PacifiCorp, Public Service Company of Colorado, Nevada Power, Sierra Pacific, Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric.

Table 3: Western Utility Resource Plan Methods and Cost/Risk Tradeoffs

	Utility/ Year of Plan	Number of Candidate Portfolios	Definition of Cost	Definition of Risk	Cost/Risk Weighting
Stochastic	Avista 2003	used optimization process[2]	Average power supply expense over all Monte Carlo simulations	Coefficient of variation of cost	50%/50%
	North-Western 2004	12	Mean annual cost of portfolio over all Monte Carlo simulations	95^{th} percentile cost	70%/30%
	PacifiCorp 2003-04	24-26	Mean Present Value of Revenue Requirements (PVRR) over all Monte Carlo simulations	Focus on: 95^{th} percentile and 95^{th}-5^{th} percentile	Qualitative
	PGE 2004	26	Mean Net PVRR over 100 Monte Carlo iterations	Mean rate variability index (RVI)	Qualitative
	PSE 2003	91	Mean NPV of expected cost to customers over all Monte Carlo simulations	Coefficient of variation of cost	Qualitative
	PSE 2005	4	Mean 20-yr incremental portfolio cost (in $/MWh)	Mean of costs >90^{th} percentile – mean of all costs	Qualitative
	SDG&E 2004	1[1]	Mean PVRR	95% percentile cost 84% percentile cost 16% percentile cost 5% percentile cost	None
	SCE 2004	1[1]	Deterministic PVRR	95% percentile cost	None
	PG&E 2004	1[1]	Mean and deterministic PVRR	95% percentile cost	None
Scenarios	Idaho Power 2004	12	PV of portfolio power supply cost	Change in power portfolio supply cost	None
	PGE 2002-03	26	Weighted-average PVRR over 45 scenarios	Weighted-average rate variability index (RVI) over 45 scenarios	Qualitative
	PSCo 2003	used optimization process[2]	PVRR	Change in PVRR	Qualitative
	Nevada Power 2003	26	PVRR	Change in PVRR	Qualitative
	Sierra Pacific 2004	12	PVRR	Change in PVRR	Qualitative

Source: Bolinger and Wiser 2005, Tables 2 and 9.
[1] Developed slightly different candidate portfolios based on different load growth scenarios, but the portfolios did not significantly vary.
[2] For each scenario examined, a capacity expansion model optimized a single portfolio based on user-defined market conditions and constraints.

Utilities generally use some combination of stochastic and/or scenario analysis to address gas price uncertainty. Stochastic analysis is typically used to simulate volatility around an expected price. Scenario analysis is typically used in situations where prices follow a distinctly different path from, rather than fluctuating around, expected prices. Scenario analysis is often conducted external to the core analysis, in a way that is intended to inform, rather than be integral to, the decision-making process.

Reliance on scenario analysis to analyze gas price risk seems to be diminishing, with 10 of the 12 integrated resource plans(IRPs) reviewed employing some form of stochastic analysis either instead of, or in addition to, scenario analysis. Only two plans—Idaho Power and Public Service Company of Colorado (PSCo)—rely entirely on scenario analysis; two additional plans—Sierra Pacific and Nevada Power—rely primarily on scenario analysis, but conduct stochastic analysis for their short-term energy plans.

There is little consistency among IRPs in the way that stochastic prices are generated and applied. Some plans create stochastic gas prices in a fairly straightforward manner, clearly specifying assumptions about price distributions, standard deviations, interaction and correlation with other stochastic variables being modeled and degree of mean reversion built into the process. Others try to simplify, or complicate, the process, while still others are somewhat unclear on how the price distributions and probabilities are assigned. Three plans model multiple stochastic variables and consider the interaction and correlation among them (for example, gas prices and hydro availability), while others model stochastic gas prices in isolation.

There are also differences in the way that resource plans applied the resulting stochastic gas prices. Only a few plans subject all candidate portfolios to stochastic prices. Many employ stochastic analysis only after selecting a subset of “finalist” candidate portfolios. In three cases—Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)—the stochastic prices are only applied and results presented for the preferred portfolios. This narrower application often reflects computational constraints—that is, Monte Carlo simulation and analysis takes time and computing power. Analysis of fuel price risk would be most informative if applied to a wide range of candidate resource portfolios that vary in their ability to mitigate those risks. Many plans apply their fuel-risk analysis to only a subset of candidate portfolios. For purposes of analytic tractability, some portfolios may be screened out early in the process, because they are not least-cost, for example. This could generate results that are sub-optimal, if those portfolios that are screened out also happen to be low risk.

Table 3 also shows how the cost and risk metrics are defined in the various plans. Though costs are defined in slightly different terms, virtually every plan used either the present value of revenue requirements or some closely related derivation thereof to define costs. Where stochastic analysis (through Monte Carlo simulation) was utilized, the average or mean (rather than median) simulated portfolio cost was typically used. Also in those plans, portfolio risk was commonly defined as either the coefficient of variation of cost (the standard deviation divided by the mean of simulated costs) or else some other measure of the upper tail of the cost distribution, such as the 95th percentile cost or the mean of the 90th percentile tail—overall mean (a measure of the magnitude of potential cost increases). Though the coefficient of variation of cost is among the most traditional measures of uncertainty (where uncertainty is expressed as either higher or lower costs than the mean), the focus on the upper tail may be appropriate when concerns about extreme cost increases are paramount.

Risk/Cost Trade-Off

Each plan also evaluated the cost/risk trade-off differently. As shown in the first column of Table 3, most plans can be placed into one of two categories. Eight utilities—Avista, NorthWestern, PacifiCorp, Portland General Electric (PGE Final Action Plan), Puget Sound Energy (PSE 2003 and 2005), PG&E, SCE, and SDG&E —employed stochastic analysis to generate numerous cost outcomes for at least a subset of candidate portfolios. As a result, each candidate portfolio had an expected (mean) cost and risk associated with it. Avista's optimization process assigned equal weight to cost and risk while constructing the preferred portfolio. NorthWestern subjectively weighted cost 70 percent weight on the mean cost) higher than risk (30 percent weight on the 95th percentile cost) to arrive at a risk-adjusted cost for each candidate portfolio. PacifiCorp, PGE, and PSE evaluated the cost/risk trade-off more qualitatively and did not arrive at a single number or optimal portfolio. Instead, the expected cost and risk characteristics of each portfolio were reviewed, and the preferred portfolio was selected subjectively based on that review. Finally, with the notable exception of PSE (2005), which evaluated the expected cost and risk of each candidate portfolio under all six of its scenarios (as opposed to only under a single, base-case scenario), the rest of the plans made the cost/risk trade-off prior to consideration of any scenarios that were analyzed, thus seemingly relegating scenario analysis to a supporting role, rather than an integral part of the planning process.

Five utilities—Idaho Power, PGE (initial IRP), PSCo, Nevada Power, and Sierra Pacific—relied much more heavily on scenario analysis to manage the cost/risk trade-off. Idaho Power did not really make a trade-off at all; instead, the utility based portfolio selection on a scenario-weighted assessment of expected costs, with no apparent consideration given to the expected variability of those costs. PGE's initial IRP, meanwhile, assigned subjective probabilities to each of its scenarios, calculated a scenario-weighted cost and risk for each portfolio, and ultimately weighed cost against risk qualitatively (though given that the preferred portfolio had both the lowest cost and lowest risk, no trade-off was necessary). PSCo, Nevada Power, and Sierra Pacific did not assign probabilities to their scenarios, and therefore evaluated the cost/risk trade-off qualitatively.

With the apparent exceptions of Idaho Power and the three California utilities, each resource plan made some sort of trade-off between the expected cost and expected risk of each candidate portfolio. The optimal approach (selecting the candidate portfolio that fits most closely with the risk preferences of the majority of its customers), is rarely used. In all of the cases, the cost-risk trade-off (if made) was a subjective judgment call on the part of each utility, perhaps informed by any counsel provided by the utility's regulators or external stakeholders. Even for those plans that relied on stochastic analysis and clearly indicated a weighting for expected cost and risk (such as Avista and NorthWestern), the weightings themselves were subjectively determined.

Carbon Regulation

The 2005 Study of Western Resource Plans

Seven of the 12 utilities (Avista, Idaho Power, PacifiCorp, PGE, PSCo, PSE 2005, and PG&E) specifically analyzed the risk of future carbon regulations on portfolio selection. These seven utilities used scenario analysis to evaluate the impact of potential carbon regulations, taking three different approaches. Avista, PG&E, PSE 2005, and PSCo's original plan analyzed candidate portfolio performance under one or more carbon scenarios, but did not assign probabilities or weights to those scenarios. As such, the impact of the scenario analysis on portfolio selection is unclear.

Idaho Power and PGE conducted multiple carbon scenarios, assigning probabilities to those scenarios, thereby ensuring that carbon considerations will have at least some influence on portfolio selection. PacifiCorp and PSCo's settlement plan included carbon regulation in the base-case scenario, again ensuring at least some influence on portfolio selection. PacifiCorp also analyzed the impact of both more- and less-stringent carbon regulation (than assumed in the base case) through additional, unweighted scenarios. The five remaining utilities—NorthWestern, Nevada Power, Sierra Pacific, SCE, and SDG&E did not consider the risk of carbon regulation in their analysis.

The 2007 Study of Western Resource Plans

In an updated study still in progress, Barbose and Wiser found that 10 of 12 utilities quantitatively evaluated the potential cost of carbon regulations. Carbon cost projections were based on either studies of specific policy proposals or actual prices in existing carbon markets. The degree to which these evaluations may have affected final portfolio choices may be unclear in some cases, however. Some plans had undergone screening that eliminated or substantially modified candidate portfolios prior to evaluating performance under carbon regulation scenarios. Others relegated carbon analysis to a secondary or tangential role in the selection of the preferred portfolio. If low carbon portfolios are screened out too early in the analysis, the full range of options for mitigating exposure to carbon regulatory risk may not be considered properly. Barbose and Wiser conclude that given the likelihood of future carbon regulations, it would seem prudent for carbon cost analysis to play a more central role in portfolio selection.

Recent utility resource plans included carbon costs in four different ways:

1. Base case carbon cost, but no alternate scenarios
2. Base case carbon cost and alternate scenarios
3. Weighted scenarios using subjective probabilities
4. Carbon cost scenarios, but no base case carbon cost

Barbose and Wiser observe that options 2 and 3 are the only ones that can account for both expected carbon cost and its uncertainty. Notwithstanding the methods the utilities used to account for carbon costs, the levels of those expected costs were sometimes low, and utilities often excluded high carbon cost scenarios. Given the substantial uncertainty in the nature and timing of future carbon regulations, it seems critical to evaluate a wide range of scenarios.

Candidate Portfolios

Most utilities constructed candidate portfolios manually or by using an automated process involving simple rules and resources that are regionally available and that have passed initial cost or performance screening tests, rather than using, for example, a capacity expansion model. Many renewable resources are screened out early in the process due to perceived high costs or limited, project-specific opportunities. Limiting the universe of resource options may make analytical sense, particularly if open solicitations will ultimately be used to determine which resources are procured. On the other hand, such an approach forfeits any insights that might be gained by modeling specific resources and may hinder developers' ability to prepare and plan for specific utility needs prior to the issuance of solicitations that define those needs.

None of the California or Nevada plans publicly provide any economic analysis of the potential value of purchasing renewable energy at a level that exceeds the states' Renewable Portfolio Standards (RPS) requirements. Such analyses may be critical for transmission-dependent resources, such as wind and geothermal power and may also help to set the ground rules for subsequent all-source bid evaluations. In addition, with the notable exception of SDG&E, the utilities made few apparent efforts in these original plans to evaluate a broad range of renewable energy sources that might be used in achieving the RPS targets. Instead, the utilities often assumed RPS compliance largely with an unspecified mix of resources, under the presumption that the actual mix would be determined in subsequent competitive solicitations. Again, while this generalized approach is functional, especially in states with RPS requirements, it forfeits any insights (transmission upgrade needs, for example) that might be gained by modeling specific resources.

Preliminary Recommendations and Suggestions from the 2007 Study

Constructing Candidate Portfolios

- Consider a broad array of low carbon technologies, including wind, solar thermal electric, geothermal, biomass, solar photovoltaic, various forms of energy efficiency, integrated gasification combined-cycle, carbon capture and storage, and nuclear.
- Remove exogenous renewable energy caps and improving the analysis of cost, integration, and transmission of higher levels of penetration.
- Evaluate energy efficiency market potential based on avoided costs consistent with carbon regulation scenarios.
- Consider collaborative process to better define costs, timing, and market potential for integrated gasification combined-cycle, carbon capture and storage, and nuclear.
- Include multiple, diverse, low-carbon candidate portfolios with different combinations of low-carbon technologies.

Modeling Potential Carbon Regulations

- Incorporate carbon risk analysis as a central element of the overall portfolio analysis
- Do not eliminate low-carbon candidate portfolios before analysis of carbon regulations
- Include appropriate carbon costs in base case scenario and evaluate broad range of alternate scenarios
- Consider expanding analysis to evaluate early retirement or conversion of existing conventional coal plants
- Account for the possible impact of carbon regulations on natural gas and regional electricity prices.

Selecting the Preferred Portfolio

- Consider both the expected cost of carbon regulations and the uncertainty in those costs for each candidate portfolio.
- Use a transparent mechanism for incorporating carbon cost uncertainty into the process of selecting the preferred portfolio.

CHAPTER 4: CALIFORNIA INVESTOR-OWNED UTILITY RESOURCE PLANS

This chapter summarizes the planning activities and long-term procurement plans (LTPPs) filed by California IOUs at the CPUC on December 11, 2006. Energy Commission staff intends that these summaries describe, as precisely as possible, the information contained in the CPUC filings and therefore, has not added any information that might change the substance or context of the IOU filings. Differences in detail among the summaries reflect the level of information included in the respective filings. Appendix 2 presents additional information for each IOU that further describes selected aspects of their respective planning, procurement, and risk management processes.

Pacific Gas & Electric

Overview of PG&E's Planning Process

PG&E's analytical planning framework is composed of three main elements: scenarios, candidate plans, and metrics. Scenarios are combinations of uncertainties affecting PG&E's procurement activities. PG&E classifies uncertainties into three categories: short-term cyclical uncertainties, long-term structural uncertainties, and long-term commercial uncertainties. Candidate plans are alternative combinations of procurement actions that PG&E could pursue, including demand-side, supply-side, and transmission actions. Finally, metrics follow the state loading order and least-cost, best-fit principles and are used to determine feasibility and performance of the candidate plans under each scenario.

Short-Term Cyclical Uncertainties

Short-term cyclical uncertainties include weather, hydro conditions, resource forced outages, and the market price volatility of natural gas and electricity. Short-term cyclical uncertainties are partially covered by planning reserves and are represented probabilistically to estimate the price risk associated with each candidate plan.

PG&E developed its gas price forecast using commodity prices based on the closing price of forward contracts traded on the New York Mercantile Exchange plus location basis obtained from broker quotes for the period through December 2011, which at the time of the forecast, marked the end of New York Mercantile Exchange contract availability. For January 2012 and beyond, PG&E extrapolated gas prices using monthly electricity prices through 2015, maintaining the same monthly relationship between electricity and gas prices as in the 12 months prior to January 2012. Because broker quotes were not available for 2016 electricity prices, PG&E used the gas forecast adopted in the 2005 market price referent process starting 2016. The annual price for 2016 was shaped based on the monthly profile observed in 2011.

PG&E estimated its 95th percentile gas price levels using a large number of natural gas and electricity price scenarios in a Monte Carlo simulation. The volatilities and correlations for these simulations were obtained from broker provided and historical data.

Market price risk is analyzed in two different ways. Risk associated with fundamental shifts in the marketplace is covered through scenario analysis, and stochastic risk is analyzed using Monte Carlo simulations of power and gas prices. Both of these approaches rely on the volatilities of electricity and power prices and the correlations between them as well as Monte Carlo simulation approaches.

Long-Term Structural Uncertainties

Long-term structural uncertainties are not covered by planning reserves and include:

- Long-term load growth
- Direct access customers return or departure and community choice aggregation
- Structural changes in market prices—changes in technology, regulation, or environmental factors affecting the cost of electricity and natural gas
- Market availability of customer energy efficiency, demand response, renewables, and distributed generation
- Existing fossil retirements—two of PG&E's scenarios assume that all aging power plants retire by 2012 as proposed by the Energy Commission, and two scenarios assume a slower retirement schedule, with all aging plants retired by 2015
- Changes in Resource Adequacy (RA) rules—PG&E assumes the RA counting rules will increase its procurement needs by 500 MW in the planning horizon
- Recontracting of existing Qualifying Facilities, Irrigation District contracts, and Renewable Portfolio Standard (RPS) bilateral contracts—PG&E assumes that existing resources currently under contract with PG&E remain in operation at their contract expiration. When customers choose direct access, community choice aggregation, and non-core options, PG&E assumes fewer of its existing contracts will recontract to PG&E.

Long-Term Commercial Uncertainties

Long-term commercial uncertainties are also not covered by planning reserves and include:

- New generation lead times
- Project permitting execution risk, including delays and inability to obtain all required permits
- Project construction execution risk, including delays or project failures
- Timely regulatory approval of new generation or transmission projects

To capture the uncertainty associated with the commercial operation of new generation projects, PG&E assumed that a 500-MW resource, one of the proposed combined cycle resources, is cancelled or delayed.

Scenarios Used by PG&E in the 2006 LTPP

PG&E developed four scenarios to represent the conditions that its three candidate procurement plans will be exposed to over the next 10 years. Each scenario represents a collection of events, out of PG&E's control, which have a particular effect or stress condition.

Scenario 1 exposes PG&E's portfolio to stranded cost conditions triggered by low market prices and low demand for electricity. Scenarios 2 and 3 represent forward market prices and current demand growth outlook. The main difference between these two scenarios is the level of preferred resources available in the market. Scenario 4 is characterized by high market prices and high demand conditions where customers are less likely to exercise community choice aggregation and direct access options. Consequently, fewer of the expiring resources currently under contract with PG&E are likely to sign with direct access and community choice aggregation suppliers. Because of high market prices, more preferred resources are available in the market compared to the other three scenarios.

Scenarios 1 and 4 use sustained low and high gas price forecasts, respectively. These high and low gas price forecasts were developed using the results of 3,000 Monte Carlo simulations of the correlated on-peak electricity, off-peak electricity, and the gas prices at a monthly level. These forecasts were generated using simulation paths that exhibit sustained high prices and sustained low prices.

Using the price-risk scenario analysis, PG&E captured the effect of sustained high price and low price states of the world. However, because of the high volatility of power and gas prices, price levels can reach extremely high levels in a given month or year. The scenario analysis does not necessarily capture this effect since, in a given simulation path, the average price level for the 10 years may not be high, but prices in certain years can be extremely high. To capture this effect, because there are daily dispatch decisions for generating units, a daily Monte Carlo simulation uses daily volatilities and correlations between electricity and gas prices.

Resource Plans

PG&E considered three candidate resource plans to highlight policy trade-offs available to the CPUC with regard to the reliability, environment impacts, and cost of incremental procurement alternatives. PG&E quantified and evaluated the potential trade-offs between reliability and cost and between environmental impact and cost. Because the candidate plans use different planning reserve targets and different mixes of preferred versus conventional resources, their cost, risk, reliability, and environmental metrics are the basis to evaluate the trade-offs between the plans and associated resource and strategies.

PG&E considers the three candidate plans to be feasible and implementable. Feasibility metrics are threshold requirements which candidate plans need to meet. All plans:

- Meet the CPUC's current RA requirements under the June 2006 Energy Commission Staff Forecast of 2007 Peak Demand. The Basic Plan does not meet the current RA requirements under certain conditions that result in greater system stress than the current *IEPR* outlook.
- Comply with *Energy Action Plan II* (EAP II) loading order requirements. Subject to market availability of preferred resources, in all plans PG&E:
  - Procures, at a minimum, all available cost-effective customer energy efficiency, demand response, and non-photovoltaic distributed generation
  - Implements California Solar Initiative program of 3000 megawatts statewide by 2017
  - Procures at least a 20 percent RPS target, even if the resource cost is above market
  - Invests in new transmission to support its renewable procurement strategy
  - Procures new clean, dispatchable and operationally flexible resources to meet its residual needs.
- Provide sufficient amounts of the necessary power products to fit its energy and capacity product needs

Basic Procurement Plan

This plan meets all basic state and regulatory requirements currently in effect. Under the basic plan, PG&E procures sufficient resources to meet a 15 percent planning reserve margin under the high Energy Commission *IEPR* load growth projection. PG&E procures preferred resources consistent with the loading order, to the extent preferred resources are available in the market at or below their market value (with the two exceptions noted above regarding California Solar Initiative funding and RPS procurement).

Increased Reliability Plan

Under this plan, PG&E procures to a higher reliability requirement than the current CPUC-adopted RA requirement. The minimum reliability requirement in this plan is a 16 percent planning reserve margin for a 1-in-10 temperature expected peak demand. Because of this plan's higher reliability requirement, PG&E procures approximately 1,000 MW more of peaking or RA capacity products each year than under the first plan under all scenarios.

In this plan, PG&E procures the same amounts of preferred resources as in the Basic Reliability Plan. Since these two plans only differ with regard to their supply reliability, they allow the CPUC to consider the trade-off between higher reliability benefits and the higher costs of additional resources.

Increased Reliability and Preferred Resources

In the third plan, similar to the Increased Reliability Plan, PG&E procures to a higher reliability requirement than the current CPUC-adopted RA requirement—that is, to a 16 percent planning reserve margin for a 1-in-10 temperature expected peak demand. However in this plan, PG&E also procures more preferred resources than in the previous two plans, relaxing the restriction that discretionary preferred resources be cost effective. By increasing the amount of preferred resources relative to the Increased Reliability Plan, this plan provides useful information for the CPUC in considering the trade-off between the environmental benefits and higher costs of preferred resources.

In all plans, PG&E has chosen to procure dispatchable and operationally flexible resources and purchases to cover its baseload product needs from existing resources for two reasons. First, PG&E's baseload need is a contractual need arising from the expiration of its allocated Department of Water Resources contracts between 2010 and 2012. The resources supplying these contracts are expected to continue operating after their contracts expire and should be available to sell to PG&E. Second, new dispatchable and operationally flexible resources are needed to integrate incremental amounts of intermittent renewable generation that PG&E plans to add to its portfolio.

Criteria for Selecting the Recommended Plan

After meeting minimum regulatory and feasibility requirements, PG&E used the following metrics to evaluate the performance of its candidate procurement plans.

Reliability

The plans were first tested for their ability to meet the CPUC's current resource adequacy requirements. For each year and under each scenario, PG&E compared the planning reserves available against the current RA requirements based on the 1-in-2 temperature expected peak forecast. PG&E also estimated the operating reserves available under each plan under a 1-in-10-year temperature. PG&E then counted the number of years when the plans would not meet the current minimum 15 percent planning reserve requirement, or typical Western Electric Coordinating Council minimum operating reliability criteria of 7 percent.

The Increased Reliability and Preferred Resources Plan and the Increased Reliability Plan both perform well under all scenarios. The Basic Procurement Plan fails in some years to meet the current RA requirement under Scenarios 3 and 4, assuming the actual load turns out to be the forecasted 1-in-2 temperature expected peak demand. This is the result of higher load growth or lower availability of RA qualifying capacity. If the actual load turns out to be equal to the forecasted 1-in-10 temperature peak demand, the Basic Procurement Plan fails to meet the 7 percent minimum operating reliability criteria requirements in four years in Scenarios 2 and 4. Consequently, PG&E found the Increased Reliability and Increased Reliability and Preferred Resources Plans to be superior to the Basic Procurement Plan in terms of system reliability.

PG&E also estimated the expected number of load loss days (as a loss of load probability - LOLP) in 10 years and energy not served (ENS) for 2014 using different planning reserve margins. Based on the relationship between planning reserves and LOLP and ENS, PG&E then estimated the LOLP and ENS of the candidate plans for year 2014 under all scenarios.

The Basic Procurement Plan fails to meet the industry standard 1 day in 10 year LOLP target under all scenarios, and the Basic Procurement Plan has significantly higher amounts of ENS than the other two plans that use 16 percent planning reserves on a 1-in-10 temperature peak. The other two plans meet the 1 day in 10 year LOLP target in all scenarios except for the higher load growth Scenario 4.

State Loading Order Metrics

Each plan was tested for its ability to meet CPUC-adopted goals for energy efficiency (combined savings from committed and uncommitted programs under all scenarios), demand response, and renewable goals (comparison of the renewable percentages in the portfolio in each year relative to the existing 20 percent RPS mandate and estimation of the percentage of renewable resources in each portfolio by the end of the planning horizon under each combination of plan and scenario).

Under the Increased Reliability and Preferred Resources Plan, PG&E meets the D.04-09-060 energy efficiency targets under all scenarios.

In D.03-06-032, the CPUC adopted a target for price responsive demand response equal to 5 percent of the utility's bundled peak load. PG&E has advocated counting all demand response programs toward this goal, including emergency or day-of programs. If emergency demand response programs do not count toward the demand response target, PG&E could only achieve the 5 percent target across all scenarios under the Increased Reliability and Preferred Resources Plan. PG&E would be considerably less successful in reaching the 5 percent target if it implemented the Basic Procurement Plan or the Increased Reliability Plan.

PG&E has also computed the percentage of demand response achieved assuming emergency programs count to meet the DR goal. Under this assumption, PG&E is able to meet the demand response target with the Increased Reliability and Preferred Resources Plan under all scenarios and in all years. Under the other two candidate plans, PG&E meets the demand response target in most years if the emergency programs are counted toward the demand response goal.

None of the three candidate plans achieves RPS deliveries to meet the 20 percent target by 2010 under any scenario. RPS deliveries are expected to reach 20 percent by 2012 under all candidate plans and scenarios. PG&E attributes the gap in 2010 to be a function of the market availability of renewable resources rather than its strategy. The gap ranges between approximately 1 percent and 2 percent, with the larger gap occurring in Scenario 4 because of the higher bundled sales included in that scenario. The differences in strategy among the plans do affect the percentage of renewables at the end of 2016. By then, the 20 percent target is achieved in all plans with the Increased Reliability and Preferred Resources Plan achieving the highest percentages.

Cost

PG&E estimated all generation revenue requirements by plan and scenario and added the cost of incremental customer energy efficiency by scenario, the cost of incremental demand response associated with its August 30, 2006 demand response program enhancement, and the additional transmission costs associated with meeting the RPS goal under each plan. The sum of these plan costs was then levelized over the 10-year planning horizon and expressed in cents per kilowatt-hour (cents/kWh).

Tables 4 and 5 present levelized costs for the three plans under each scenario in millions of dollars and cents/kWh, respectively. Table 5 shows that rates under the Increased Reliability Plan are about 0.1 to 0.2 cents/kWh (approximately 1 to 2 percent) higher than rates under the Basic Procurement Plan. The Increased Reliability and Preferred Resources Plan adds 0.05 to 0.16 cent/kWh (approximately 1 percent) to rates under the Increased Reliability Plan.

Table 4: PG&E Procurement Plan Levelized Costs (million $)

Plans	Scenarios			
	1	2	3	4
Basic Procurement	6,291	7,434	7,322	8,777
Increased Reliability	6,378	7,533	7,419	8,882
Increased Reliability and Preferred Resources	6,421	7,577	7,448	8,926

Source: PG&E 2006 Long-Term Procurement Plan Amendment vol. 1, table VIB-8.

Table 5: PG&E Procurement Plan Levelized Costs (cents/kWh)

Plans	Scenarios			
	1	2	3	4
Basic Procurement	8.3	9.1	9.0	10.2
Increased Reliability	8.5	9.2	9.1	10.3
Increased Reliability and Preferred Resources	8.6	9.3	9.2	10.4

Source: PG&E 2006 Long-Term Procurement Plan Amendment vol. 1, table VIB-9.

Price Risk

Costs customers pay for generation are subject to short-term fluctuations due to the volatility of electricity and natural gas prices, load, and hydro availability. Using Monte Carlo simulations, PG&E estimated the potential increase in customer costs due to these short-term variables at a 95 percent confidence level.

Table 6 shows that for 2016, the additional renewables in the Increased Reliability and Preferred Resources Plan produce a small decrease in price risk. For 2008, the renewable energy deliveries are essentially the same in all three candidate plans and therefore, the price risk is the same.

Table 6: PG&E Procurement Plan Cost and Additional Cost at 95th Percentile Risk in Scenario Two (cents/kWh)

Plans	2008		2016	
	Procurement Plan Cost	Additional Cost at 95th percentile risk	Procurement Plan Cost	Additional Cost at 95th percentile risk
Basic Procurement	8.8	0.9	9.0	3.4
Increased Reliability	8.8	0.9	9.2	3.4
Increased Reliability and Preferred Resources	8.9	0.9	9.5	3.1

Source: PG&E 2006 Long-Term Procurement Plan Amendment vol. 1, table VIB-10.

Carbon Dioxide Emission Levels

PG&E calculated two metrics for measuring the greenhouse gas (GHG) performance of its procurement plans: average annual tons per year of carbon dioxide (CO_2) emissions from each plan under the different scenarios and average carbon efficiency in pounds per megawatt-hour (lbs/MWh) of load plus avoided load associated with customer energy efficiency and DG included in the plan.

PG&E estimated the CO_2 emissions generated by its portfolio under each plan and scenario combination. PG&E calculated the CO_2 forecasts by adding CO_2 emissions for:

- The amount of natural gas used for PG&E's existing resources and contracts
- Fossil-fuel burning qualifying facilities
- Market purchases of electricity and new natural gas burning generic resources needed to cover the open position

As indicated in Table 7, the Increased Reliability and Preferred Resources Plan has slightly lower CO_2 emissions than the other two alternative plans at the end of the planning horizon. However, long-term changes in load and resources, which are represented in the scenarios, increase emission volumes by 15 to 25 percent.

Table 7: PG&E Procurement Plan GHG Metric (million metric tons of CO_2 emissions in 2016)

Plans	Scenarios			
	1	2	3	4
Basic Procurement	17.0	20.9	19.4	20.2
Increased Reliability	17.0	20.9	19.4	20.2
Increased Reliability and Preferred Resources	15.4	17.9	17.7	19.1

Source: PG&E 2006 Long-Term Procurement Plan Amendment vol. 1, table VIB-11.

Trade-Offs

PG&E's candidate plans highlight trade-offs among reliability, cost, and environmental impact. Because the candidate plans use different planning reserve targets and different combinations of preferred and conventional resources, the candidate plans have different values for the cost, risk, reliability, and environmental metrics.

A comparison between the Basic Procurement Plan and the Increased Reliability Plan highlights the trade-off between reliability and costs across scenarios. From that comparison, PG&E estimated the incremental cost per year associated with the improvement in reliability of the Increased Reliability Plan measured by standard planning reliability indices, the LOLP (expected load loss days in 10 years), and ENS.

Table 8: PG&E Trade-Off Between Reliability and Cost

	Scenarios			
	1	2	3	4
Cost - Levelized Annual Revenue Reqts				
Increased Reliability Plan (million $ per year)	6,378	7,533	7,419	8,882
Basic Procurement Plan (million $ per year)	6,291	7,434	7,322	8,777
Increased Reliability Cost, (million $ per year	87	99	97	105
Increased Reliability Cost (cents/kWh)[a]	0.1	0.1	0.1	0.1
Expected Energy Not Served (Levelized MWh per year)				
Basic Procurement	496	1,713	496	3,632
Increased Reliability	22	103	22	227
Reduced Energy Not Served	474	1,610	474	3,405
Expected load loss days in 10 years				
Basic Procurement	2.5	3.5	2.5	4.6
Increased Reliability	0.3	0.8	0.3	1.6
Reduced load loss days in 10 years	2.2	2.7	2.2	3.0

Source: PG&E 2006 Long-Term Procurement Plan Amendment vol. 1, table VIC-1.
[a] Difference in cost divided by bundled sales.

Compared to the Basic Procurement Plan, the more stringent planning reserves used for the Increased Reliability Plan and the Increased Reliability and Preferred Resource Plan cost customers on the order of $100 million per year in additional revenue requirements, or approximately 0.1 cent/kWh.

PG&E's LOLP analysis shows that the current planning reserve margin does not meet the industry standard 1 day in 10 year LOLP target under all scenarios and has significantly higher amounts of ENS than the other two plans that use 16 percent planning reserves on a 1-in-10 temperature peak.

Comparing the Increased Reliability Plan and the Increased Reliability and Preferred Resources Plan highlights the trade-off between environmental impact and costs. Table 9 shows the 2016 net cost of the incremental renewable and energy efficiency procured in the Increased Reliability and Preferred Resources Plan, relative to the Increased Reliability Plan. In Scenarios 1 and 3, the cost of the incremental renewable and energy efficiency measures is less than their increased value, leading to a benefit (or negative increased cost in the table) of $11 and $25 million, respectively. Conversely, in Scenarios 2 and 4, the cost of the incremental renewable and energy efficiency measures is greater than the increase in values, leading to an increased cost of $103 and $143 for the scenarios. The lower portion of the table shows the emission reductions of the two plans, enabling a comparison of costs and corresponding emissions reduction benefits for each scenario between the plans.

Table 9: Trade-Off Between Environmental Impact and Cost

	Scenarios			
	1	2	3	4
	$ millions			
2016 Increased Cost,	192	518	227	326
Increased Value	203	415	252	183
Increased Net Cost	-11	103	-25	143
2016 CO_2 Emission Reduction	million metric tons/yr			
Increased Reliability and Preferred Resources Plan	15.4	17.9	17.7	19.1
Increased Reliability Plan	17.0	20.9	19.4	20.2
Reduced CO_2 (million metric tons/yr)	1.59	2.99	1.69	1.04

Source: PG&E 2006 Long-Term Procurement Plan Amendment vol. 1, table VIC-2.

PG&E recommended the Energy Commission adopt the Increased Reliability and Preferred Resource Plan. In this plan, PG&E proposes to:

- Invest in all customer energy efficiency that is cost-effective and available in the market.
- Implement the CSI funding decision according to implementation details from the CPUC's on-going distributed generation Order Instituting Rulemaking, at the

lowest possible cost, and subject to market availability of distributed generation and photovoltaics.

- Procure sufficient demand response to meet the 5 percent target.
- Procure to a higher than 20 percent RPS target at the lowest possible cost, even if costs to some extent are above market, subject to market and transmission availability constraints.
- Procure up to 2,300 MW of new dispatchable and operationally flexible capacity to come online starting in 2011 to meet a 16 percent planning reserve margin on a 1-in-10 temperature expected peak demand. This amount includes 200 MW to replace the reduction in demand response associated with D.06-11-049, and 500 MW for commercial contingency.
- Procure additional energy and resource adequacy or capacity products from existing resources to meet the remaining open position.

Southern California Edison

Resource Planning

SCE's first step in developing a new resource plan is to assess the current status of both the SCE portfolio and the broader system of which that portfolio is a component and then to account for any known or projected changes in future loads and resources. Next, this data is used to identify the need, subject to established planning criteria such as reserve margins. Resources are added to meet applicable statutory and regulatory requirements, such as the Renewables Portfolio Standard (RPS) and the CPUC's energy efficiency and demand-side management policies. Resources are added in loading order priority to meet the remaining need using a mix of resources and products that are likely viable and economic.

SCE developed and evaluated two candidate resource plans for the 2006 LTPP filing: the Required Plan and the Best Estimate Plan. SCE states that the Required Plan incorporates all existing CPUC directives and policies and meets all of the requirements specified in the Scoping Memo for the CPUC Long-Term Procurement Proceedings. SCE states its Best Estimate Plan achieves a mix of resource assumptions based on physical and economic viability, while achieving CPUC policies over the long-term and is based on procurement goals that are both achievable and cost effective. SCE characterizes the Best Estimate Plan as aggressively pursuing resources at or near the top of the state's loading order, but not to such an extent that those resources become a detriment to SCE's customers or to grid reliability. In the utility's description, the Required Plan is even more aggressive and purports to achieve levels of demand side management and renewables that SCE deems neither cost-effective nor feasible.

Both plans assume the same initial supply and demand conditions for 2007; both assume a constant state of direct access load throughout the analysis period; and both focus on developing a portfolio, first according to *Energy Action Plan* loading order policy preferences in meeting the RPS mandate. Further, both plans are designed to meet resource adequacy requirements and propose the actions necessary to achieve the goals set out for local area reliability requirements and greenhouse gas limitations. SCE's candidate plans assume that direct access will not be re-opened and no new community choice aggregation takes place.

The significant differences in assumptions in the two candidate plans are in the areas of renewable and demand-side resources. In its Best Estimate Plan, SCE assumed achieving the 20 percent RPS goal by 2011 and included maximum reliably achievable potential of cost-effective energy efficiency and demand response. In the Required Plan, SCE assumed achieving the 33 percent RPS goal by 2020 and the CPUC-ordered amounts of energy efficiency and demand response. SCE evaluated each plan under two different load forecasts: the latest available data from the Energy Commission and an SCE-developed load forecast.[1]

Both of the candidate plans and associated scenarios present outlooks for the SCE portfolio and the SP-26 region (previously referred to as SP-15), which are two different perspectives of the same underlying system.

Resource Trade-Off Assessment

To develop the candidate plans, SCE first included the maximum amount of cost-effective energy efficiency, demand response, and distributed generation that is expected to be developed in the future. Next, SCE added sufficient renewable resources to meet RPS requirements. These resources were only added as the appropriate transmission became available and, in most cases, were added as generic renewable resources because contracts have not yet been executed. Once the 20 percent RPS mandate was reached, new renewable resources continued to be added to maintain the applicable RPS target. Finally, SCE added supply-side resources that include future contracts or projects announced as being pursued by a utility.

Each of the demand- and supply-side additions to the portfolio are considered alongside the reality of the broader geographic region, such as generation physically available after construction or retirement, or transmission effects that limit the amount of generation that can be imported into the region. SCE did not, in either the Required Plan or the Best Estimate Plan, attempt to optimize costs or meet other goals by considering fewer renewable resources with these conventional resource types. Thus, SCE's analysis did not involve a trade-off analysis of the resources that were added or retired.

Evaluation of Resource Plans

SCE conducted its analysis of the candidate plans and associated load scenarios in consideration of key drivers that are expected to have the largest impact on

[1] Energy Commission staff believe that SCE misrepresented the Commission's load forecast and presented testimony to that effect in the CPUC's Long-Term Procurement Proceeding.

customer price risk and system reliability—two of the metrics by which the plans are evaluated. This analysis was performed using stochastic methods on forecast natural gas prices, marginal energy prices, weather uncertainty in customer demand, and resource availability (forced outages).

Ratepayer Cost

SCE examined the relative differences in total revenue requirements across the candidate plans and scenarios and estimated a net customer rate impact (see Table 10). Bundled service customer system average rate impacts were calculated by taking the total portfolio revenue requirement for each scenario and dividing it by the forecast of metered sales at the bundled customer level. This calculation provides an estimate for determining average rate impacts between scenarios. The primary drivers of the rate impact for each scenario are RPS requirements and associated transmission expansion costs, the level of energy efficiency and demand response, and the assumed penetration level of CSI.

Table 10: SCE Resource Cost and Customer Rate Impacts

	SCE Load Scenario		CEC Load Scenario	
	Best Estimate Plan	Required Plan	Best Estimate Plan	Required Plan
Present Value of Costs (billion $)	45.9	46.8	41.8	42.6
Levelized Customer Rates (¢/kWh)	8.11	8.34	7.95	8.19

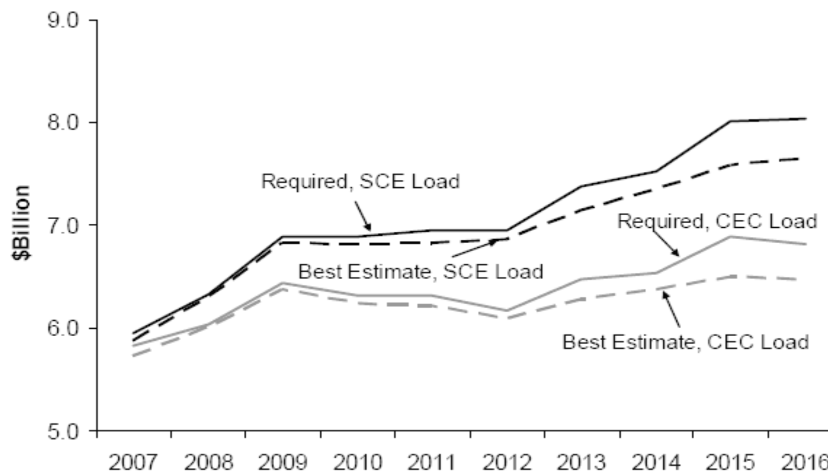
Source: SCE 2006 Long-Term Procurement Plan vol. 1B, table VI-15.

SCE found that the Best Estimate Plan yields a lower overall cost than the Required Plan due to the additional costs of the Required Plan, such as the additional transmission required to meet the 33 percent RPS goal, increased energy efficiency expenditures, and higher demand response capability in the immediate near term. Relative to the Best Estimate Plan, the Required Plan invests $1 billion more dollars in demand reduction (energy efficiency, demand response, and distributed generation) and $1.5 billion more in renewable generation, with its associated transmission expansion requirements. However, this increased spending is partially offset by a lesser need to procure resources through conventional procurement and a slight greenhouse gas adder benefit.

SCE believes that the foregoing comparison understates the lifecycle cost-difference between the candidate plans because it is limited to analyzing cost impacts over the 10-year planning horizon. Many of the commitments necessary to achieve the Required Plan are long-term commitments, with costs that will not be borne until after the planning horizon. In particular, the major cost impacts of enhanced investment in renewable generation, a key driver between plans, are not realized until nearly halfway through the 10-year planning horizon.

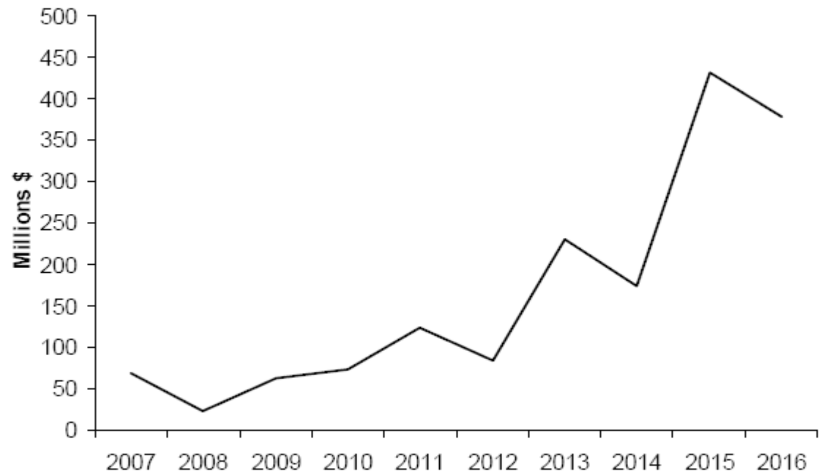
Figures 1 and 2 present annual total resource cost projections of, and annual cost differences between, the candidate plans for 2007 through 2016. While portfolio costs are similar in the early years, the disparity in costs increases greatly in the later years. By 2016, the annual portfolio costs of the Required Plan are nearly $400 million, approximately 5 percent, more per year than in the Best Estimate Plan. SCE estimates that the cost difference between the candidate plans would grow to nearly $600 million dollars annually by 2020. Continued aggressive demand-side and renewable investment would likely cost an additional $2.7 billion after 2016 on a 2007 present value basis. In total, the lifecycle-cost of the Required Plan could cost customers about $3.5 billion more than the Best Estimate Plan, with much of this cost being borne beyond the planning horizon.

Figure 1: SCE Annual Total Portfolio Cost



Source: SCE 2006 Long-Term Procurement Plan vol. 1B, figure VI-40.

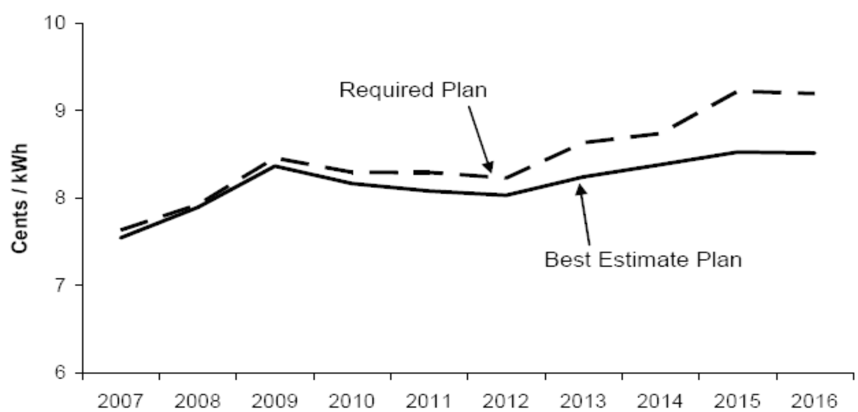
Figure 2: Change in Annual Total SCE Portfolio Cost
SCE Load Scenario - Required Plan Less Best Estimate Plan



Source: SCE 2006 Long-Term Procurement Plan vol. 1B, figure VI-41.

Just as the annual cost difference grows over the planning horizon, Figure 3 shows that the rate difference is also greater than the average by the end of the planning horizon.

Figure 3: Annual Customer Rate Analysis – SCE Load Scenarios

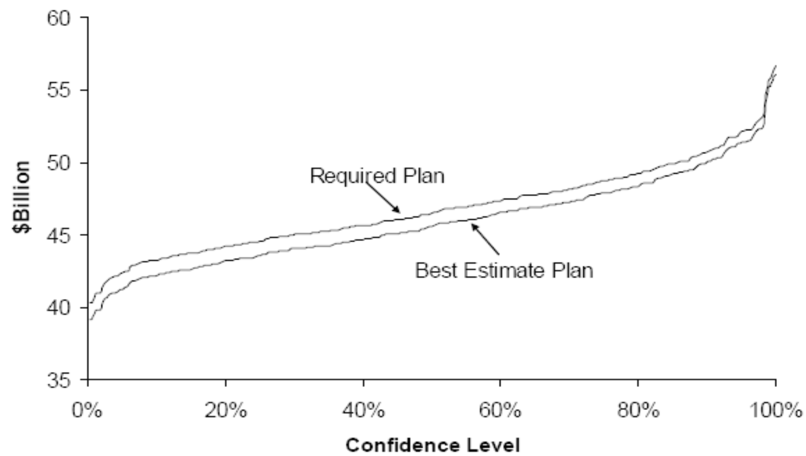


Source: SCE 2006 Long-Term Procurement Plan vol. 1B, figure VI-42.

Distribution of Costs

In order to analyze the price-risk impacts of the two candidate plans, SCE examined variations in its portfolio revenue requirement associated with uncertainties in natural gas prices, electricity prices, customer demand, and forced outages. Varying these parameters results in a distribution of revenue requirement outcomes for each of the candidate plans (Figure 4). (Although the market price referent fluctuates with natural gas prices, the cost of new renewable generation was assumed not to fluctuate with gas prices.)

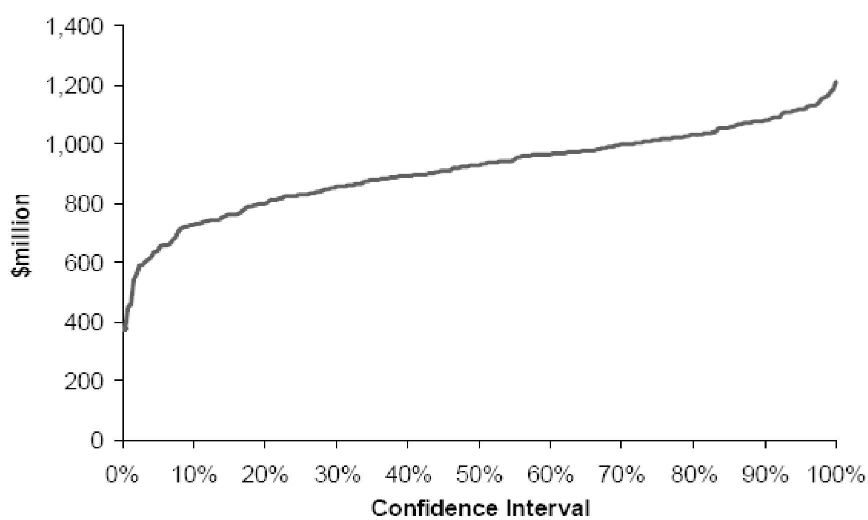
Figure 4: Distribution of Present Value of Total Portfolio Costs (250 Stochastic Iterations, 2007–2016)



Source: SCE 2006 Long-Term Procurement Plan vol. 1B, figure VI-44.

Figure 5 shows the present value of the difference in revenue requirements (based on a 10 percent discount rate) between the Required Plan and the Best Estimate Plan.

Figure 5: Distribution of Difference in Present Value of Total Portfolio Costs (250 Stochastic Iterations, 2007–2016)



Source: SCE 2006 Long-Term Procurement Plan vol. 1B, figure VI-45.

SCE found that the Best Estimate Plan yields a lower overall cost at all confidence levels. Both candidate plans exhibit a wide range of total portfolio costs based on the parameters that were varied. The major drivers of portfolio cost variability are natural gas and power prices. In the very high natural gas and power scenarios represented by the highest confidence levels, the candidate plans have nearly the same costs. At the lower natural gas price levels represented by the lowest confidence levels, the cost differences between the candidate plans become more substantial. This result is caused largely by the additional renewable and demand-side programs associated with the Required Plan, which shelter a portion of the portfolio from the impact of natural gas price volatility. Much of this dampening would dissipate if future renewable projects develop pricing based on the market price referent, which is heavily dependent on gas price forecasts, rather than based on actual costs to develop and operate renewable projects.

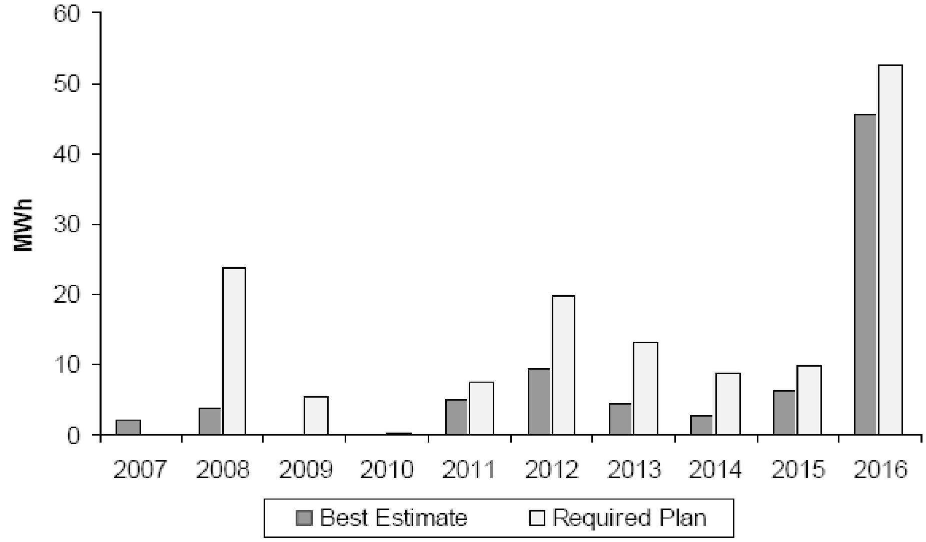
Impacts on System Reliability

SCE views system reliability as being primarily related to the amount of generation reserves that are available—that is, the amount of supply that exceeds peak demand and the proximity of generation with respect to load, because generation that is closer to the load served usually has a higher intrinsic value (in part because of voltage and other operating considerations).

In both candidate plans, and in both load scenarios, SCE developed the supply and demand balance of the various portfolios to meet minimum resource adequacy and local area reliability requirements as they are currently defined by the CPUC. SCE identified the expected energy not served associated with each of the candidate plans. Expected ENS is the probability-weighted average capacity shortfall of the system, measured in MWh, over the analysis period.

Figure 6 shows that in both candidate plans, the expected quantity of the unserved energy is very low, reaching a maximum of only about 50 MWh in the highest year. In 90 percent of the stochastic iterations, there was zero unserved energy in all years. In all years but 2007, the Required Plan has more unserved energy than the Best Estimate Plan. This trend is most likely a result of increased reliance on intermittent renewable resources and demand reduction programs that have limited availability, as opposed to tolling and dispatchable products that have enhanced flexibility. Overall, SCE determined that the portfolio in the Best Estimate Plan contributes more to grid reliability and better meets SCE’s bundled service customer demand than the portfolio in the Required Plan.

Figure 6: Energy Not Served (MWh)



Source: SCE 2006 Long-Term Procurement Plan vol. 1B, figure VI-46.

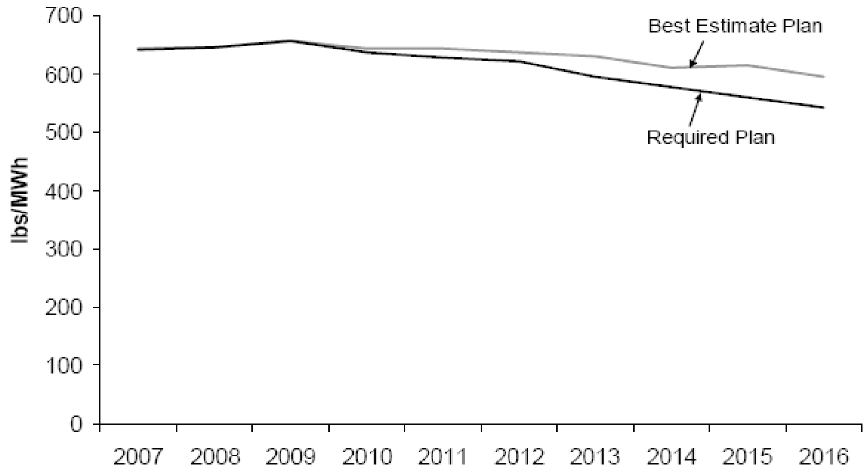
Environmental Impacts

SCE examined how its candidate plans perform under four separate environmental metrics:

1. Reduction of portfolio emissions
2. Ability to meet RPS goals
3. Levels of demand response yielded by the plans
4. Amount of energy efficiency yielded by the plans

For each candidate plan, SCE measured the total portfolio emissions of CO_2, which was used as a proxy for the overall greenhouse gas emissions of the portfolio. Figure 7 shows that the Required Plan generates a lower CO_2 emissions rate than the Best Estimate Plan, mainly due to its greater use of renewable resources and its increased energy efficiency assumptions. In 2016, the Required Plan yields an emissions rate of 544 lbs/MWh, which is 9 percent lower than the Best Estimate Plan's emissions rate of 599 lbs/MWh.

Figure 7: CO_2 Emission Comparison—SCE Load Scenario



Source: SCE 2006 Long-Term Procurement Plan vol. 1B, figure VI-47.

Comparison of the total CO_2 reduction estimates for the Required Plan and the Best Estimate Plan at the end of the planning horizon indicates that the cost to achieve the Required Plan's additional CO_2 reductions is $131 per ton of CO_2 reduced using the SCE load forecast, or $116 per ton of CO_2 reduced using the Energy Commission load forecast.

SCE compared the levels of renewable power procured under each of its candidate plans (33 percent by 2020 for the Required Plan or 20 percent by 2011 for the Best Estimate Plan) in terms of the percentage of total retail energy sales over the 10-year planning horizon. Table 11 shows that the Required Plan has a higher level of total retail sales from eligible renewable resources than the Best Estimate Plan, ranging from a difference of 1.5 to 1.6 percent in 2010 (depending on the load scenario) to 6.6 to 7 percent in 2016.

Table 11: Annual Percentage of Total SCE Retail Sales from Eligible Renewable Resources (percent)

	Required Plan		Best Estimate Plan	
	CEC Load Scenario	SCE Load Scenario	CEC Load Scenario	SCE Load Scenario
2007	17.8	17.4	17.8	17.4
2008	18.5	17.9	18.5	17.9
2009	20.2	19.2	20.1	19.1
2010	21.9	20.3	21.0	19.5
2011	23.1	21.4	21.8	20.0
2012	24.3	22.4	22.5	20.5
2013	27.6	25.3	23.8	21.5
2014	28.2	25.7	24.9	22.3
2015	32.1	29.4	25.8	22.8
2016	32.7	29.8	26.1	22.8

Source: SCE 2006 Long-Term Procurement Plan vol. 1B, table VI-16.

SCE forecasted its total demand response portfolio (price responsive and dispatchable/load control) measured in MW contribution to resource adequacy over the 10-year planning horizon. The Required Plan shows a higher level of demand response, but SEC believes this level is achieved only by including demand response programs that are unlikely to materialize.

Table 12: Cumulative Committed and Uncommitted Demand Response (MW)

	Required Plan		Best Estimate Plan	
	CEC Load Scenario	SCE Load Scenario	CEC Load Scenario	SCE Load Scenario
2007	2,189	redacted	1,313	redacted
2008	2,185	redacted	1,290	redacted
2009	2,167	redacted	1,318	redacted
2010	2,148	2,294	1,411	1,451
2011	2,131	2,298	1,517	1,560
2012	2,117	2,292	1,616	1,662
2013	2,101	2,285	1,693	1,743
2014	2,087	2,279	1,754	1,806
2015	2,075	2,278	1,796	1,850
2016	2,063	2,277	1,814	1,869

Source: SCE 2006 Long-Term Procurement Plan vol. 1B, table VI-17.
Note: Does not include adjustments for planning reserve margins required when counted as a supply-side resource.

SCE concluded that while the Required Plan appears to result in greater levels of energy efficiency, the level of reduction in demand due to energy efficiency cannot be relied upon. Table 13 shows SCE's forecast of its cumulative energy efficiency portfolio reduction in bundled service customer demand for each candidate plan over the 10-year planning horizon. For a given candidate plan, the load scenarios have different impacts only because of the different allocation between bundled service customers and direct access. The total system impacts of the programs are the same for both load scenarios for a given plan.

Table 13: Cumulative Future Energy Efficiency (Uncommitted 2009–2016, billion kWh)

	Required Plan		Best Estimate Plan	
	CEC Load Scenario	SCE Load Scenario	CEC Load Scenario	SCE Load Scenario
2009	1.1	1.1	1.0	1.0
2010	2.2	2.3	1.8	1.9
2011	3.3	3.4	2.7	2.7
2012	4.4	4.5	3.5	3.6
2013	5.5	5.6	4.3	4.4
2014	6.6	6.8	5.1	5.3
2015	7.6	7.9	5.8	6.0
2016	8.7	9.0	6.4	6.6

Source: SCE 2006 Long-Term Procurement Plan vol. 1B, table VI-19.

SCE requested that the CPUC adopt the Best Estimate Plan as SCE's Procurement Plan, based on overall cost to SCE's customers at all confidence levels, higher system reliability, and energy efficiency and demand response levels SCE believes to be realistic. Although SCE acknowledges that the Best Estimate Plan yields slightly higher CO_2 emissions than the Required Plan, it maintains that the cost of achieving the modest incremental CO_2 reduction of the Required Plan is prohibitive and that the increased level of intermittent renewables associated with the Required Plan could negatively impact system reliability and increase integration costs.

San Diego Gas & Electric

SDG&E maintains the ProSym planning model to obtain a long-term (multi-year) forward view of its resource portfolio parameters, such as the short positions, gas burns, and need for resource/infrastructure addition. SDG&E plans to meet its load requirement in a least-cost dispatch manner that begins with the planning for must-take renewables, utility retained generation, and California Department of Water Resources generation in comparison to SDG&E's customer load. The load that has not been filled by must-take energy is met through a combination of dispatchable units and market purchases. The relative quantities of each are determined through economic dispatch. The optimal portfolio solution maximizes ratepayer value, minimizes ratepayer cost, and meets all portfolio targets such as RPS and GHG goals.

The objective of SDG&E's long-term planning process is to provide reliable electric supply at the lowest possible cost, while simultaneously meeting the state's preferred loading order for resources and reducing the GHG emissions associated with the portfolio. Energy savings and demand reductions from the energy efficiency programs are based on the CPUC’s adopted targets. SDG&E is also adopting the Energy Commission's forecast for DG installed and used by customers, often referred to as self-served load. SDG&E further reduces the need for conventional resources by the impacts from the California Solar Initiative and DR programs. Efforts to achieve 20 percent of the energy mix from renewable power by 2010 and then increasing the amount of energy from renewables after that means SDG&E will aggressively add renewable resources to the plan. Additional resources will be used to meet the remaining need, plus maintain a planning reserve margin of 15 to 17 percent. Once the total supply balance is determined, SDG&E analyzes the constraints that may limit how and where it obtains the needed resources.

Planning Scenarios

To determine the range of need, SDG&E’s plan provided the CPUC with three need scenarios (base, high, and low). Because SDG&E's service area is a single load pocket that is currently operating near the grid reliability limits, resources needed to meet grid reliability and to meet local RA requirements create the largest uncertainties in SDG&E's plan. Another substantial uncertainty in SDG&E's resource plan is the extent to which new transmission becomes available to deliver the needed resources.

In designing the portfolios, SDG&E attempted to accomplish a number of objectives. First, each scenario was designed to meet a planning reserve margin of 15 to 17 percent. Second, each scenario was designed to ensure that it would meet the California Independent System Operator's grid reliability criteria and SDG&E's obligation to meet local resource adequacy requirements. Third, each scenario used the adopted targets for energy efficiency and demand response, as well as adding renewable power to meet the goal of 20 percent by 2010 and then continuing to add renewable resources.

SDG&E has made various assumptions in the scenarios it analyzed:

- Sufficient renewable power will be available at prices no higher than the market price referent.
- The South Bay Power plant will retire at the end of 2009. The extent to which other older generation can be retired varies under each of the scenarios.
- There is some risk of contract failure associated with a number of power contracts, particularly those that are contingent on transmission additions. Should any of the signed contracts not materialize, SDG&E would need to replace the power from an additional source with similar characteristics.

- SDG&E's overall procurement activities are greatly dependent on the outcome of the Sunrise Powerlink Application, currently pending before the CPUC. SDG&E’s need will change with and without this line.

The scenarios presented in this plan are scenarios to determine a base, high, and low need.

The base need scenario is derived using the assumptions defined in the CPUC Long Term Procurement Proceeding Scoping Memo. This case uses a modified Energy Commission load forecast and the CPUC-adopted goals for energy efficiency and demand response. SDG&E assumes direct access load will remain as it does today.

The high need scenario is derived using a combination of assumptions that could lead to a higher resource requirement for SDG&E's bundled customers. The high need case is based on the higher bundled load forecast. On the supply side, SDG&E assumed that the Otay Mesa Power plant's on-line date would be delayed one year to 2010.

The low need scenario is derived using a combination of assumptions that could lead to a lower resource requirement for SDG&E's bundled customers. The low need case is based on the lower bundled load forecast.

For each of the three scenarios described above, SDG&E determined a resource need for its bundled customer load. Need is determined by subtracting all energy efficiency and demand response programs, both committed and uncommitted, and existing and planned supply resources from the forecasted load.

Resource Trade-Off Assessment

SDG&E comments that the quantities of many of the resources have been determined by the CPUC in other proceedings or by state law. Thus, a substantial portion of the resource trade-offs that typically take place in some resource planning processes are not done in the LTPP proceeding. The process SDG&E follows in filling its need is one that adds resources in the order outlined in the *Energy Action Plan*. The key trade-off for SDG&E is to assess what resources should be added to maintain grid reliability, given the uncertainty in loads and the uncertainty in several other key infrastructure investments. The first and most important trade-off is to what extent and in what years new capacity should be added to meet grid reliability criteria.

SDG&E analyzes resource trade-offs in the evaluation step in each of the Request for Offers (RFO) described in the LTPP. As an example, the plan has identified a need for additional renewable power. Their CPUC filing does not select the specific contract or resource to meet that need. Rather, a Request for Offer is held, and the resources that best meet that need at the lowest cost to customers will be selected in that process.

Request for Offer analysis determines the portfolio need and best products to fill that need given all constraints that exist on procurement, including GHG emissions, the RPS mandate, intra-zonal congestion, resource adequacy requirements, and grid reliability. Request for Offers will generally be all-source, to ensure that ratepayers get the broadest possible selection of supply options. Some instances where SDG&E may limit participation include set-asides where regulatory or statutory targets created a need to buy certain resources such as renewables, and price is a secondary consideration. Another example may be GHG, where the supply option must be low GHG-emitting in order to meet GHG goals. Grid reliability is another form of set-aside where the concerns regarding the pure economics of procurement may be outweighed by an on-system, grid need. Such a grid reliability need may also dictate that the incremental supply be new construction.

The RFO includes a detailed description of products sought and any requirements which those products must meet, term of products, the minimum or maximum quantities being sought, a description of the data that must be returned with a valid, conforming offer, a draft term sheet that outlines the commercial arrangements that will form an eventual contract with the successful bidder, and the administrative schedule of the solicitation.

Bid evaluation criteria are prepared in order to have an established method for evaluation of offers, which will vary in accordance with the nature of the products being solicited.

In the past, SDG&E has conducted RFOs for conventional resources separately from those for renewable resources. As SDG&E anticipates achieving the required 20 percent RPS level in 2010, SDG&E plans that all-source RFOs will be the standard procurement process beyond that time. SDG&E plans to continue renewables procurement beyond 20 percent. Just as with procurement limitations such as grid reliability and local and system RA requirements, the need to add renewable power can also be included in an RFO, as either a specific set-aside or to meet GHG emissions goals.

SDG&E does not employ a proscriptive, formulaic method that requires specific quantities of physical procurement to be undertaken at specific times. SDG&E's position is that these transactions require much planning and negotiating and the milestones in development of these additions contain elements whose timing is often outside the utility's control. Formulas for when to conduct such transactions are impossible to construct with certainty and would require constant revision. Identified need is filled through these RFOs—either sized to conduct all procurement in a single RFO, or spread out over time—both for averaging of market prices as well as managing workload.

Loading Order

In conducting procurement, SDG&E takes the loading order into account by treating loading order resource goals as floors, not caps. SDG&E will continue to treat loading order resources as set-asides until CPUC goals are met for each type of resource. That is, the cost-effectiveness test will be relaxed for any resource until SDG&E has met the CPUC target for that resource. After meeting CPUC targets for a particular resource, new procurement of that resource will be selected only if the resource passes the least-cost, best- fit evaluation in competition with other resources in all-source solicitations.

Evaluation of Resource Plan

SDG&E estimates that its Preferred Resource Plan will result in a substantial reduction in the total greenhouse gas emissions of the portfolio, provide a relatively flat cost outlook over the time frame after the fixed costs of the Department of Water Resources contracts are paid off, and target resources in the load pocket to meet local reliability concerns. The plan estimates emissions will drop by over 1,000 metric tons over the planning period. The average emissions rate of the portfolio will drop by almost 33 percent.

Table 14 shows the estimated total (metric tons/year) and rate (tons/GWh) of greenhouse gas emissions.

Table 14: Greenhouse Gas Emissions for SDG&E's Preferred Resource Plan

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total CO_2 Emissions (1000 tons)	5028	4575	4719	4787	4387	4402	4341	3961	3911	3947
CO_2 Emission Rate (tons/GWHr)	277	247	251	250	227	225	220	199	194	193

Source: SDG&E 2007-2016 Long-Term Procurement Plan, volume 1, table VI-1.

Table 15 shows the forecasted annual total cost and annual average cost in $/MWhr of the Preferred Plan. This total includes costs for energy, capacity, fuel, and Independent System Operator costs associated with the bundled portfolio.

Table 15: Costs for SDG&E's Preferred Resource Plan

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total Costs (million $)	1377	1666	1668	1581	1627	1548	1547	1551	1560	1594
Average Cost (total cost/sales)	8.12	9.63	9.49	8.86	9.00	8.47	8.4	8.33	8.29	8.36

Source: SDG&E 2007-2016 Long-Term Procurement Plan, volume 1, table VI-2.

Table 16 shows how the total costs and average costs change, based on using natural gas and market prices at the 95th percentile. The 95th percentile was developed looking at the prices from January 2003 to September 2006. These costs do not include any existing gas hedges or future hedges.

Table 16: Costs for SDG&E's Preferred Resource Plan at 95th Percentile

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total Costs (million $)	1629	2014	1970	1865	1932	1821	1809	1814	1818	1861
Average Cost (total cost/sales)	9.60	11.64	11.21	10.45	10.69	9.97	9.82	9.75	9.66	9.75

Source: SDG&E 2007-2016 Long-Term Procurement Plan, volume 1, table VI-3.

SDG&E notes that the prices and costs in the 95th percentile case assume no change in the cost of renewable power. Renewable developers tend to offer their projects at the costs avoided by the utility; thus, higher gas prices tend to lead to higher offers for future renewable power.

CHAPTER 5: MODERN PORTFOLIO THEORY IN FINANCE AND AS APPLIED TO THE ELECTRICITY INDUSTRY[2]

Modern Portfolio Theory in Finance

Introduction

Modern Portfolio Theory (MPT) was introduced by Harry Markowitz in 1952[3], later supplemented by William Sharpe and Merton Miller. The three were awarded the Nobel Prize for Economics in 1990 for their contributions.

The method Markowitz proposed shifted the focus of investor risk-return analysis from individual financial securities to combinations (portfolios) of securities. Before the introduction of MPT, the standard approach to choosing among competing investment alternatives was to identify individual securities, each independently offering the best opportunity for gain with the least risk and, subject to a prevailing budget constraint, construct a portfolio from these without any consideration of their interaction (that is, the manner in which their returns are expected to be correlated over time). Because the contribution of any single security to an existing portfolio depends not only on the characteristics of that security in isolation, but also the way in which it interacts with the securities comprising the existing portfolio, the

> Harry M. Markowitz, Merton H. Miller and William F. Sharpe were awarded the Nobel Prize for Economics in 1990 for their theories on evaluating stock-market risk and reward and valuing corporate stocks and bonds.
> **Markowitz** developed what is known as Modern Portfolio Theory by shifting analytical attention away from individual stocks in favor of the aggregate portfolio and highlighting the importance of diversification. This work provided a foundation for the contributions of Sharpe and Miller.
> **Sharpe** developed the "capital asset pricing model," which distinguishes idiosyncratic security risk (associated with changes in returns over time that are uncorrelated with movements in the overall market), which can be eliminated through diversification, from a more systematic risk that cannot be diversified away.
> **Miller** explored the relationships between a company's capital structure, dividend policy, market value and cost of capital. Along with Franco Modigliani, he showed that, absent the distorting impact of taxes, a firm's market value is independent of its capital structure; i.e., its value is determined entirely by the risk-reward characteristics of its portfolio of business assets.

[2] This chapter was written by London Economics International LLC.
[3] Harry Markowitz, "Portfolio Selection", Journal of Finance 7, No. 1 (March 1952), pp. 77-91.

appropriate focus of analysis in constructing a portfolio is the return and risk characteristics of the overall portfolio rather than its constituent securities. Investors will aim to create efficient portfolios, which, for a given risk tolerance (i.e., willingness to accept risk, as measured by the standard deviation of past returns) offers the highest possible level of expected return. There is no single efficient portfolio. Any set of securities can be combined in different ways to create a range of efficient portfolios, each associated with an alternative risk tolerance. The "science" of MPT can identify the range of efficient portfolios. The choice among the efficient options results from a subjective judgment by the owner of the portfolio.

MPT has profoundly shaped how financial portfolios are generally managed and, in particular, has brought the notion of diversification (that is, combining assets with different characteristics) to the forefront. The practice of diversification and the mathematics of MPT have been employed extensively within the arena of financial risk management. More recently, their application has been extended to other industries, including electricity, and to the analysis of physical, as opposed to purely financial, assets.

Measuring Return and Risk

MPT is centered on the return and risk characteristics of individual securities and portfolios (that is, combinations) of securities. This section discusses the ways that historical values of the return and risk parameters are measured.

It is important to note that, in evaluating investment prospects—that is, in constructing portfolios of securities to hold—decisions are to be based on expectations of future risk and return values. We focus on measurement issues (of historical values) in this section to ensure that basic valuation and presentational mechanics are clear. Also, as a practical matter, future expectations are often based largely, sometimes exclusively, on historical values. But it is important to remember that, in conducting Portfolio (indeed, any type of investment or financing) Analysis, the fundamental orientation is forward-looking. While beyond the scope of this report, there is a vast literature covering the forecasting of economic and econometric parameters.

Return on investment, or simply return, measures the change in an asset's value over time.[4] This is represented as follows:

$$\text{Return} = (P_t - P_{t-1}) / P_{t-1}$$

where P_t denotes the price of an asset at time t.

[4] Change in value of a financial security can result from a change in the price of the security and/or the generation of income (in the form of, for example, dividends or interest) from the security. For ease of exposition, we will, without loss of generality, assume throughout that all changes in value result exclusively from security price changes.

Returns can be calculated across any time period. If returns of different assets are to be compared, then the time periods should be the same. For purposes of these sorts of comparisons, annual returns are often employed.

Given a set of returns for individual assets within a portfolio, the return for the aggregate portfolio is easily computed as a weighted average of the individual returns, with the weight for each asset reflecting the portion of the overall portfolio value embodied within that security, as follows (for a portfolio comprised of n assets):

$$\text{Portfolio return} = x_{1*}r_1 + x_{2*}r_2 + \ldots + x_{n*}r_n$$

where r_i reflects the return on the i^{th} asset, and x_i reflects the percent of overall portfolio value embodied within the i^{th} asset.

The basic measure of risk associated with holding an asset is the volatility of the return on the asset, where volatility is most often measured as the variance or standard deviation of returns. With a forward-looking (forecasting) orientation, a return statistic is generally understood as reflecting the average (or mean) expected gain from holding an asset. A variance (or standard deviation) statistic characterizes expectations about how close (or far away) any particular future value is likely to be from the specified mean.[5] The risk being measured is, loosely, the likelihood that, and the extent to which, actual events will turn out differently than the average. It is a reflection of uncertainty.

Formally, variance is expressed as the expected value of squared deviations from the expected average return, as follows:

$$\text{Variance (r)} = \text{the expected value of } (r - Er)^2$$

where r is a variable reflecting the return on an asset, and Er is the expected value of that variable (that is, the average expected return on the asset).

Variance is measured with historical data in accordance with the formula below:

$$\text{Variance (r)} = \sum_j (Er - Or_j)^2 / N\text{-}1$$

Where r and Er are as defined above, N is the number of historical return values (i.e., instances of the variable r) observed and incorporated within the computation, and Or_j is the value of the j^{th} (out of a total of N) observations. Standard deviation is the square root of the variance:

$$\text{Standard deviation of r} = \quad r = \sqrt{\text{Variance (r)}}$$

[5] The application of MPT to the analysis of portfolios is sometimes referred to as Mean-Variance Portfolio Analysis.

Historical volatilities (in the form of either variances or standards deviations) can be measured for different units of time. According to the so-called square root of time rule, if fluctuations in a stochastic process (that is, the movement in observed returns) from one period to the next are independent (that is, there are no serial correlations or other temporal dependencies), volatility increases with the square root of the unit of time. As prices (and, by extension, returns) of financial securities are generally thought to follow a random walk, this rule can often be applied in financial analysis.

In practice, volatilities are most often calculated from daily data. Because, for the sake of consistency and comparability, volatilities are usually quoted on an annual basis, daily values are often converted to an annual basis by applying the square root of time rule. This is often done when the required temporal independence condition has not been strictly shown to be satisfied. The resulting values are referred to as annualized (rather than annual) volatilities to signal the lack of statistical rigor.

Options are derivative securities; i.e., their prices are determined by the prices of other securities.
A **call option** is an agreement in which the buyer has the right (but not the obligation) to exercise by **buying an asset** at a set price (strike price) on or before a future date (the exercise date or expiration); the seller is obligated to honor the terms of the contract.
A **put option** is an agreement in which the buyer has the right (but not the obligation) to exercise by selling an asset at the strike price on or before a future date; the seller is obligated to honor the terms of the contract.

It is, in some cases, easy to obtain forward-looking, rather than historically-based, volatility estimates. The approach is based on option pricing. In their landmark 1973 paper,[6] Fischer Black and Myron Scholes derived a formula for pricing a standard put or call option on a non-dividend paying stock.[7] The formula requires the following inputs:

- The stock's current price
- The option's strike price
- The option's time to expiration
- A risk free interest rate
- The stock price's annual volatility (based on log returns)

These parameters, except for the stock price volatility, are typically observable on financial exchanges. While the volatility of the stock can be estimated on a purely historical basis by analyzing movements in historical stock prices, if a call or put option on the stock is actively traded, it is possible to obtain a volatility estimate reflecting the forward-looking assessments of the community of options traders.

[6] "The Pricing of Options and Corporate Liabilities," Black, Fischer and Myron Scholes, *Journal of Political Economy*, 1973, pp. 637-654.
[7] This approach plays an important role in various types of financial engineering, many of which, such as real options analysis, have become popular within the electricity industry.

The Black-Scholes formula for the value of a call option on a stock is as follows:

$$c = s\Phi(d_1) - xe^{-rt}\Phi(d_2)$$

where

$$d_1 = \frac{log(s/x) + (r + \sigma^2/2)t}{\sigma\sqrt{t}}$$

$$d_2 = d_1 - \sigma\sqrt{t}$$

and s is the current price of the stock, x is the option strike price, r is the risk free rate, t the time to expiration,   is the measure of expected future stock price volatility,   is the standard normal cumulative distribution function, and c is the value of the call option.

When we are able to observe the price of a call option (c) and the values of all the input parameters other than expected volatility of the underlying stock, we can work with the above formula to impute investor expectations about future price volatility. This is not a simple arithmetic process because there is no closed-form solution for   within the above formula. But several software programs, including Microsoft Excel™, include or allow for the development of the required algorithms incorporating root finding techniques.

Assume the following values for a call option and related parameters:

- Option value = $4.56
- Current stock price = $56.25
- Option strike price = $55
- Option time to expiration = 0.34 year
- Risk free interest rate (annual) = 2.85 percent

Employing the appropriate algorithms within Excel (created through the programming of macros – that is, add-ins), the imputed estimate of future volatility for the stock price is 28 percent.

This is one way of measuring volatility—its basic appeal is that it allows for a direct estimate of the specific construct of interest—that is, expectations about future volatility. These expectations are imputed based on amount transactions prices for traded options. Such estimates will not always be more accurate than measurements based on historical data (investor perceptions can at any moment be biased), but they always provide useful supplements to otherwise backwards-looking analyses.

Systematic and Unsystematic Asset Risk

The total risk associated with any asset can be systematically broken into two components. Unsystematic (or unique) risk reflects the portion of the asset's overall volatility that is uncorrelated with returns in the overall market, while systematic (or market) risk reflects the portion of the asset's overall volatility that is correlated with returns in the overall market.

In financial, rather then statistical, terms, market risks are driven by broad macroeconomic factors (such as, for example, long-term interest rates) that impact all assets (within whatever geographic regions comprises the "market") in essentially the same way. In contrast, unique risks reflect factors that affect some assets but not all, and affect assets in different ways (for example, if the price of corn goes up, this is good news for a corn farmer, bad news for a ethanol producer, and of no consequence to television manufacturers).

Examples of these two different types of risk factors from the perspective of an oil company are illustrated below.

Sample Unsystematic Risk Factors	Sample Systematic Risk Factors
A wildcat strike is declared	Oil producing countries institute boycott
A lower-cost foreign competitor enters the market	Congress votes for a massive tax cut
Oil is discovered on a firm's property	There is a precipitous rise in long-term interest rates

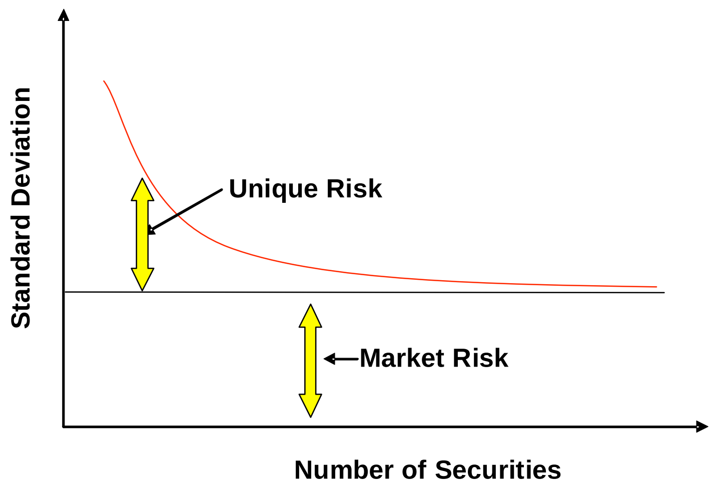
The delineation of risk within these two categories is at the core of the objective of developing portfolios. Indeed, the concept of developing portfolios is primarily rooted in reducing the investor holdings' overall risk by trying to eliminate unsystematic risk. The logic is straightforward. An investor could, for example, avoid risks associated with changes in corn prices by either investing in companies (such as television manufacturers) whose business are not affected by corn prices or by investing in several companies (including for example, corn farming and ethanol producing businesses) that are impacted by movements in corn prices in different ways.

Portfolio Diversification

A portfolio is a combination of assets. The challenge in constructing portfolios is to obtain the highest possible expected return for a given (accepted) level of risk. The central insight of MPT is that, while the market risk component of assets cannot be eliminated, the unique components can be reduced (or eliminated) through diversification—that is, the combination within portfolios of assets whose unsystematic risks are inversely correlated.

Figure 8 below illustrates a process whereby the unique risk within a portfolio is progressively eliminated—through the incremental addition of securities whose unique risks inversely correlate those of securities already in the portfolio—until, in this example, all that remains is market risk. It is a process of subtraction (of unique risk) through addition (of new securities with inversely correlated unique components). Within this context, high volatility of an asset that is driven by unique risk factors is not perceived as problematic; it is perceived as establishing an opportunity to improve portfolio efficiency by counterbalancing the inversely correlated unique risks of a different asset.

Figure 8: Diversification Illustration



Source: London Economics International LLC

Mathematically, the covariance between the returns on two assets is calculated as the product of their correlation coefficient and their two standard deviations, as follows:

$$\text{Covariance of assets A and B} = p_{AB} * {}_{A} * {}_{B}$$

where p is the correlation coefficient and the standard deviation.

Before the development of MPT, portfolio risk was calculated as the weighted average of the (unique and market) risks of individual assets within the portfolio. By incorporating covariance in the measure of portfolio risk, portfolio variance (for a two-asset portfolio) is calculated as follows:

$$\text{Portfolio variance} = x_A{}^2 * {}_A{}^2 + x_B{}^2 * {}_B{}^2 + 2(x_A * x_B * p_{AB} * {}_A\ {}_B)$$

where x reflects the portion of portfolio value embodied within the asset.

When assets are less than perfectly correlated, and particularly when they are weakly or even negatively correlated, the volatility of the two assets is less than the sum of the volatilities of the individual assets, and there will likely be benefits from diversification.

As an example, assume an investor is faced with an opportunity to invest in the stocks of company A and B, with the following characteristics:
Company A stock:

- Expected return = 0.20
- Expected volatility (std deviation) = 0.18

Company B stock:

- Expected return = 0.25
- Expected volatility (std deviation) = 0.27

The correlation coefficient between the two stocks is estimated as 0.2.

For a portfolio consisting with an allocation of 60 percent in company A and 40 percent in company B, expected return is calculated as:

$$0.60 * 0.20 + 0.40 * 0.25 = 0.22$$

The portfolio's expected variance is calculated as:

$$(0.60)^2 * (0.18)^2 + (0.40)^2 * (0.27)^2 + 2(0.60 * 0.40 * 0.2 * 0.18 * 0.27) = 0.028$$

The expected volatility of the portfolio as measured by its standard deviation is computed simply as:

$$\sqrt{0.028} = 0.167$$

This portfolio offers an unambiguously better risk-return proposition than a portfolio consisting only of the stock of company A.

The logic and mechanics outlined above are easily extended for three or more assets.

While it is not always possible to eliminate all unique risk from a portfolio, the basic efficiency goal is to eliminate as much as possible, given the characteristics of available assets. A perfectly diversified portfolio will only include market risk. In this case, the risk of the portfolio will be driven entirely by the strength of the market risks of the individual assets within it. In turn, each asset's market risk is measured relative to the overall market, in particular, as the sensitivity of its returns relative to overall market returns.[8] This measure is called the asset beta, denoted as . Betas

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[8] Within the framework of MPT, the "overall market" is best understood as a construct rather than an empirical specification. It is meant to refer to the entire population of assets competing for investment dollars within a defined geographic region. The defined geographic region is generally a country, but cross-border flows of capital complicate this sort of designation. In practice, an overall market tends to represented by large indices, such as the Standard & Poor's (S&P) 500, that represent fully diversified portfolios for which all unique risks have been eliminated.

greater than one indicate that movements in the asset's returns tend to magnify movements in the overall market; betas between zero and one indicate that asset returns tend to move in same direction as market returns but with reduced magnitude; negative betas indicate that asset returns tend move in the opposite direction as (that is, are inversely correlated with) market returns. A beta equal to one indicates that asset returns tend to move in the same direction and proportion as the overall market.

Mathematically, asset beta is calculated as follows:

Beta = covariance of asset returns with market returns / variance of market returns

Portfolio beta is then calculated as the weighted-average of the individual betas of security within the portfolio, with the weight for each security reflecting the portion of the overall portfolio value embodied within that security, as follows (for a portfolio comprised of n assets):

$$\text{Portfolio beta} = x_{1*}\ {}_{1} + x_{2*}\ {}_{2} + \ldots + x_{n*}\ {}_{n}$$

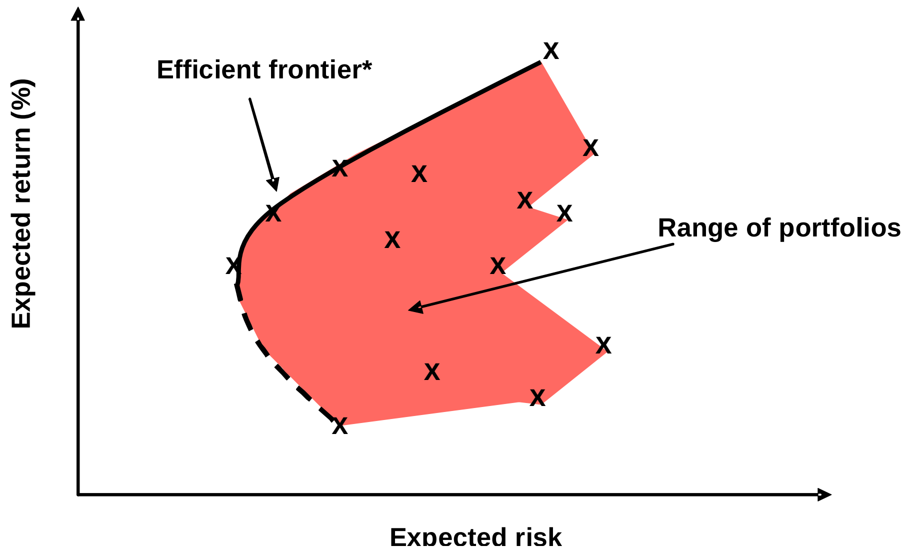
where ${}_{i}$ reflects the beta of the i^{th} asset, and x_i reflects the percent of overall portfolio value embodied within the i^{th} asset.

The Efficient Frontier and Optimal Portfolio Selection

For any set of assets, there are an infinite number of possible portfolio combinations. The challenge of portfolio theory is to identify the relatively small set of portfolios that are efficient—that is, that provide the highest possible return for a specified (investor accepted) level of risk (or, alternatively, the lowest risk for a specified (investor required) level of return. The analysis requires quantitative estimates of future values of, for each individual asset, average return and return volatility, and, for each pair of assets, correlations.

With these inputs, the expected future average return and volatility of every conceivable portfolio can be computed and can be positioned within a two-dimensional space where the horizontal axis embodies a measure of expected portfolio volatility and the vertical axis embodies a measure of expected portfolio average return. The resulting two-dimensional shape reveals the range of risk-reward possibilities from combining available assets into portfolios. A portion of the boundary of this shape is called the "efficient frontier," that is, the set of achievable efficient portfolios. A stylized illustration of an efficient frontier is displayed in Figure 9.

Figure 9. Efficient Frontier



* The efficient frontier is the solid part of the line
Source: London Economics International LLC

Any portfolio that is not part of the frontier is inefficient in the sense that it is possible to adjust that portfolio to achieve either a higher return at the same level of risk or a lower level of risk for the same level of return.

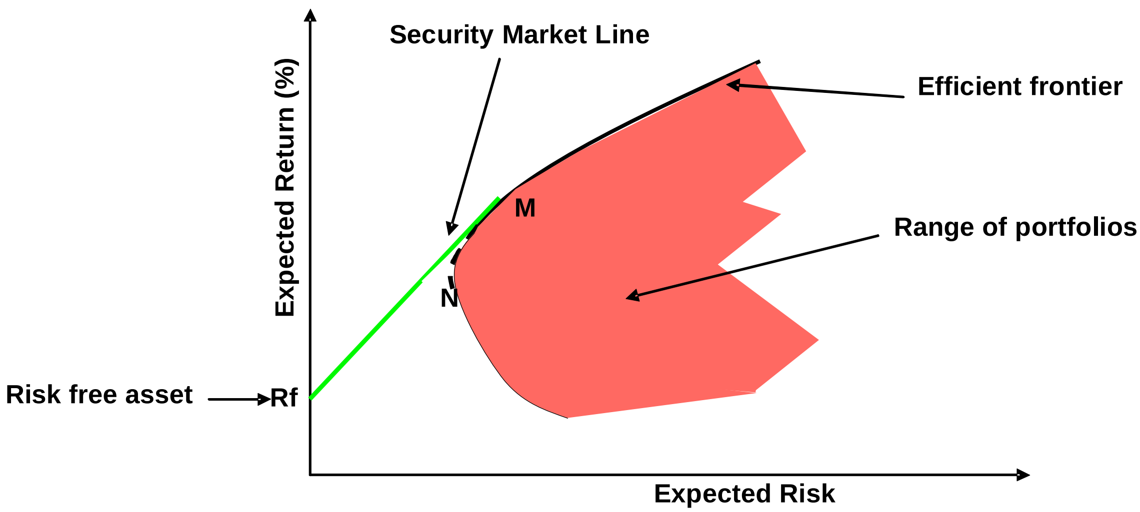
There is no analytical basis for selecting an optimal portfolio from the set of efficient portfolios. This selection is based on the personal (subjective) preference of the owner of the portfolio with respect to risk tolerance and/or return objectives.

The discussion above assumes that all of the individual assets have some level of risk (in the form of expected volatility of future returns). It is sometimes appropriate to identify a riskless asset for (potential) incorporation within portfolios. For example, a short-term U.S. Treasury Bill, backed by the full faith and credit of the U.S. Government, is generally considered, for practical purposes, to be riskless. Introducing a riskless asset into the portfolio mix has the interesting and perhaps surprising effect of establishing a new efficient frontier that increases the range of attainable risk-return profiles and (usually) establishes portfolio opportunities that are unambiguously superior to those of the efficient frontier established without having accounted for the riskless option.

Figure 10 displays the efficient frontier introduced in Figure 9 (that is, all efficient combinations of risky assets) and introduces a green line, called the Security Market Line, that extends from a point on the vertical axis (representing an asset providing a risk-free rate of return, rf, with no expected volatility) to a point, M, on the (old) frontier. The new efficient frontier is represented by the combination of the Security

Market Line and the portion of the old frontier that is solid (that is, non-dashed). For the portion of the new frontier represented by the Security Market Line, any point along the line is attained by constructing a portfolio consisting of the riskless asset and the portfolio of risky securities denoted as M. The weighting of these two entities (the riskless asset and the portfolio M) determines positioning on the Security Market Line.

Figure 10. Security Market Line



Source: London Economics International LLC

Notice that there is a now a set of portfolios, represented by points on the green line to the left of point N's position on the X axis, offering risk-return profiles that were not previously available. Also note that points on the green line to the right of point N's position on the X axis reflect unambiguously improved portfolio choices relative to the portion of the old frontier that is displayed with dashes in Figure 10.

A graphic like Figure 10 is sometimes displayed with the Security Market Line extended beyond point M. Points along this extended portion of line would represent portfolios that are constructed by borrowing at the risk-free rate (that is, being an issuer of rather than an investor in the riskless asset) and using the borrowed proceeds to invest in portfolio M. While conceptually possible, there are few instances where investors can borrow at a risk-free rate.

Modern Portfolio Theory Applied to the Electricity Industry

Introduction

Modern Portfolio Theory, initially developed with a sole focus on financial securities, has since been applied to several types of assets and industries, including the electricity industry. The analysis of return and risk, the principles of diversification and the identification of, and selection among, efficient portfolios all have application to the physical assets, particularly the generating assets, comprising an electricity system. Some modifications to the basic metrics and methodologies outlined in the preceding section have been developed and implemented.

MPT has been applied to electricity sectors within jurisdictions in, for example, the United States, Canada, Europe and South America, among others. Approach and basic objectives have varied depending on circumstance. For instance, an analysis identifying an optimal portfolio for a power producer will need to be different than an analysis identifying an optimal portfolio for consumers. The basic methodology has been primarily applied for four distinct purposes:

1. Determining an optimal portfolio for generators (return)
2. Determining an optimal portfolio for consumers
3. Determining an optimal generation fuel mix
4. Determining an optimal strategy for generators

The first of these has been by far the most common. This type of analysis focuses on identifying efficient sets (frontiers) of generator portfolios, where each of the efficient portfolios optimizes company profitability at a specific level of risk.

This approach can, and has been, shifted to focus on “returns” to consumers rather than generating companies. In this case, an appropriate measure of returns to consumers must be defined. While there are several options, the most common has been kWhs produced per unit cost of generation.

The third type of analysis that is commonly performed maintains focus on returns to generating companies and the construction of efficient and optimal portfolios of generating assets. The distinction relative to the first type of analysis is that one or more constraints on fuel usage are imposed, usually by a regulator. The objective is to find the best ways of complying with regulatory requirements on, for example, fuel diversity or use of renewable fuels. Finally, MPT has been employed by electricity companies (generators and others) to evaluate strategy alternatives with respect to, for example, international expansions and asset divestitures.

For the purposes of this report, we will focus on the second type of analysis—determining an optimal portfolio of generating assets from the consumer’s perspective. This is the appropriate orientation from the perspective of an industry regulator.

Measuring Returns and Risk

When applying MPT to developing an optimal portfolio of generating assets from the perspective of a generator, application of the traditional financial techniques outlined in the preceding section is straightforward. The appropriate measure of return is the (financial) return on the generating company's investment in its generating assets—that is, (electricity price – fuel costs - operating costs) / investment cost. This approach is consistent with the basic profit maximization presumption underlying microeconomic analysis of corporate behavior and decision making. A portfolio analysis exercise in this context aims to identify the most attractive portfolios of generating assets—that is, those that, for any specified level of risk (such as expected volatility of generator returns) —yield the highest expected return. The optimal portfolio of generating assets would then be selected by the generator based on its risk tolerance.[9]

When the analysis is to be performed from the consumer's perspective, it is necessary to change the return measure. As consumers are not investors (in financial securities or physical assets), the standard asset-based measure of financial returns is not applicable. A metric reflecting benefits to, or burden imposed on, consumers must be established.

The most natural metric to employ is the inverse of price/kWh—that is, kWh/price. This transaction-based (rather than asset-based) metric makes intuitive sense as it reflects the benefits (in the form of electricity) delivered (returned) to consumers in exchange for their provision of payment. While this metric is conceptually valid and straightforward, there are two potential empirical difficulties.

First, market prices are difficult to forecast. Such forecasts generally require sophisticated production cost and dispatch models. Second, application of portfolio analysis requires examination of risk-return characteristics at the level of individual assets (such as generators) or collections of assets, but prices paid by customers are determined at the level of the market, not individual assets. Prices are not uniquely associated with assets, and may not be uniquely associated with distinct portfolios. If portfolios being analyzed are not large relative to the overall market—more generally, if the composition of the portfolios being analyzed is not expected to impact market prices, then a price-based return metric, because it would not return different average return and risk values for different portfolios, cannot be employed for a portfolio analysis.

When the requisite price forecasting models, and the budgets required to deploy them, are available for analyzing portfolios whose compositions are likely to directly impact market price, then a price-based return metric is the preferred choice. In other instances, it is appropriate to employ a return metric focused on cost rather than price—that is, kWh / (unit) cost.[10]

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[9] While the theoretical extension of the PA methodology is clear, the focus on portfolios of generating assets rather than, in the traditional PA context, financial securities does introduce empirical challenges. Price—and, by extension, return—data is generally publicly available on a daily basis for financial securities. This allows for robust historical measurement as a basis for establishing future expectation of both average returns and volatility (risk). In contrast, return on invested assets is an accounting construct whose measurement is imprecise.

[10] The unit cost measure in the denominator accounts for all cost components – fuel, operating and capital.

This cost-based metric is, in deregulated markets, an imperfect proxy for the theoretically superior but empirically difficult price-based metric. In markets, such as California's, where generators compete to supply electricity, the connection between generator costs and customer prices is weaker and less direct than in markets where generators (integrated within utilities) serve franchised customers at prices set by regulators. Prices will at times vary for reasons other than underlying costs. The related price volatilities and the risks associated with them (for example, the risk of the exercise of market power driving prices higher than costs) will not be reflected in a cost-based portfolio analysis. Even when markets are functioning as conceived (that is, prices are cost-reflective) the prices realized in competitive markets are expected to reflect the short-term marginal costs of generation rather than the average costs reflected in the kWh/cost metric.

For the above reasons, a cost-based return measure is not a perfect indicator of consumer impact. But over the long-term, that is, the sorts of timeframes over which portfolio analyses are generally conducted, it is expected that when deregulated electricity markets operate efficiently, the revenues received from consumers for generated energy will, over the long-term, be approximately equal to the full cost of owning and operating the generating assets. While this is by no means guaranteed, it is a reasonable approach.

When working with the kWh/cost metric, the unit cost in the denominator is properly composed of three components: fixed (predominantly capital-related), variable operations and maintenance (O&M), and fuel. Changes in the unit costs of each of these three components are the risk factors driving volatility in customer returns.

Some commentators have claimed that renewable generators can be treated as essentially risk-free assets.[11] The argument is that unit fixed and variable O&M costs tend to vary little and, in any case, collectively comprise a relatively small portion of aggregate unit costs and that fuel costs, which generally drive the bulk of the volatility for generating assets, are fixed at zero for renewables. This argument ignores the risk of renewable generators not being able to deliver energy at various times when needed (for example, wind generation may not be available during the hottest part of the day). At these times, the owner / operator of the renewable generator must meet its obligation by securing replacement energy, through either a market purchase or reliance on installed backup generation. In these instances, the unit cost in the denominator of the return metric associated with the renewable asset is equal to the market price (which reflects either the price paid for replacement energy or the revenue foregone by diverting the production of backup generators from market sales). This introduces considerable volatility and, by extension, risk.[12]

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[11] See, for example, *Applying Portfolio Theory to EU Electricity Planning and Policy-Making*, Shimon Awerbuch and Martin Berger, IEA/EET Working Paper, February 2003.

[12] Commentators who introduce renewable generators into portfolio analyses as riskless assets tend to do so as part of, sometimes the foundation for, a presentation displaying the value of renewables within generating portfolios. The comments above do not of course imply that renewables are not an

With the basic return and risk metrics clear, there is one additional consideration in applying MPT to the analysis of the position of electricity consumers—that is, the appropriate scope of the generating portfolios to be analyzed. Although we are focusing on measuring risks and rewards from the perspective of consumers, decision-making about the construction of generating portfolios, which will determine the risks imposed on consumers and the benefits (or equivalently, the returns) realized by them, is performed within competitive (as opposed to regulated monopoly) electricity markets by several different generating companies. While consumer risks and returns will be driven by the overall market's portfolio of generating assets, there is no single decision-making entity that selects the market's portfolio of assets. These decisions are made at the company level.

From the perspective of regulatory policy, there are two ways to proceed with a consumer-focused analysis. The first is for the regulator to conduct or contract for a study analyzing portfolio options at the level of the overall market (for example, the entire Western interconnection) or a specified portion of the overall market (e.g., California or a zone within California). The position of the existing portfolio of assets within the defined geographic area can then be examined relative to the identified efficiency frontier to determine the risk level currently realized by customers (and, to the extent analyses from previous years are available, the way this has changed over time); and the extent of inefficiency, if any, embodied within the current portfolio, as reflected in the distance of the current portfolio from the efficient frontier. Such results can guide a regulatory examination about inappropriate risk levels and/or inefficiencies, and perhaps, ultimately lead to the establishment of incentives or the imposition of directives to collectively drive the industry towards an improved market portfolio of generating assets.

The second approach is for the regulator to mandate that companies conduct a portfolio analysis not only on the basis of corporate financial returns, but also on the basis of customer transactional returns. To the extent the two analyses point towards different portfolios (which could happen when the market price variable is significantly coordinated with one or more of the cost-based risk factors), there could be a requirement for the company to examine and report on the reasons for the discrepancy.

Efficient Frontiers of Generating Portfolios and Optimal Portfolio Selection

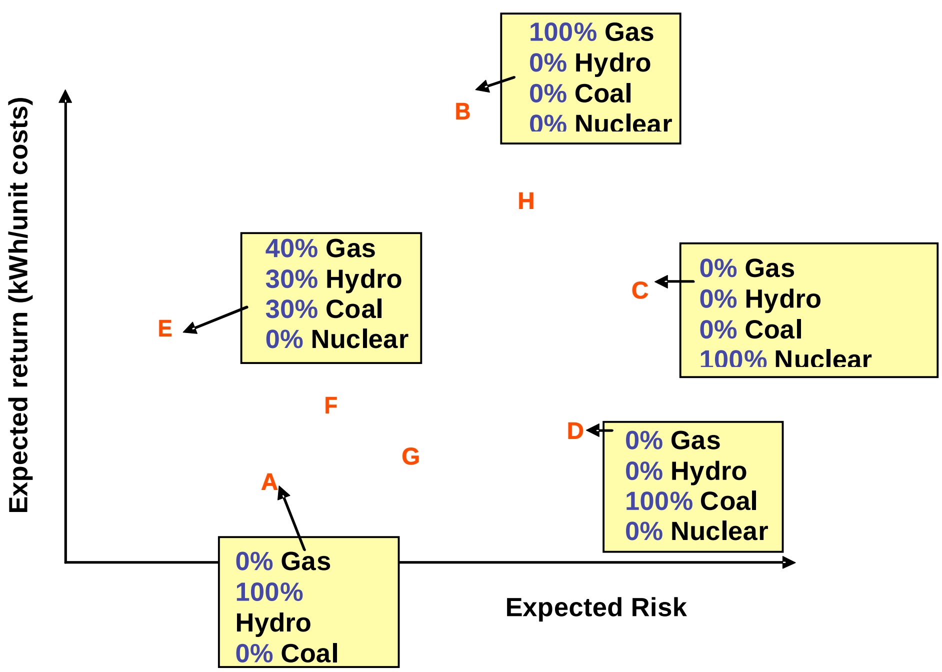
Portfolio assets can be defined at various levels of aggregation: individual generating units, generating plants, or combinations of generating plants sharing the same technology and fuel source. The latter is appropriate to the extent generating plants sharing a common technology / fuel source also share a common cost structure.

effective source of diversification. But, they should not be construed, or treated analytically, as riskless.

Whatever the selected level of aggregation, the identification of efficient frontiers for generating assets proceeds along the same lines as for a portfolio of financial securities. Each asset potentially to be incorporated within the portfolio is assigned, based on appropriate historical analysis, metrics reflecting estimates of expected future average return and expected future volatility of returns. The next step entails arithmetically identifying and graphically displaying the full range of potential portfolio asset combinations.

Figure 11 illustrates this process for the generation asset classes of natural gas, hydro, coal, and nuclear. A small selection of portfolio combinations are displayed, each reflecting a distinct weighting of the four fuel categories. Each portfolio's positioning on the graph reflects its return-risk characteristic.

Figure 11. Plotting a Set of Generation Asset Portfolios



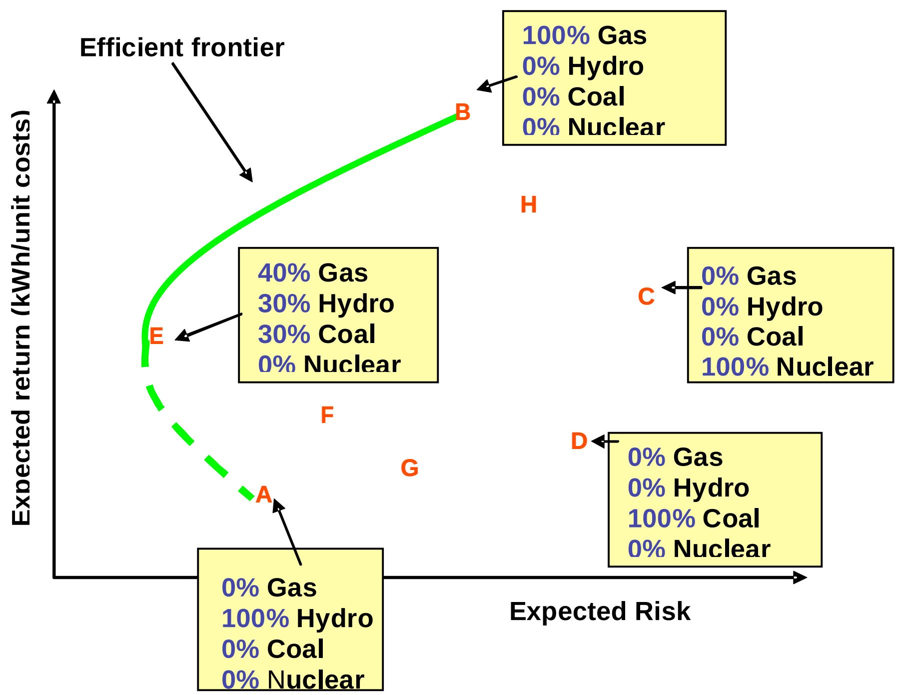
Source: London Economics International LLC

The process of identifying generating asset combinations highlights an assumption of MPT (that assets are completely liquid and infinitely divisible; that is, any quantity can be bought or sold at any time) that clearly does not apply to electricity generating assets. This necessitates minor modifications to the mechanics and solution algorithms, but it does not undermine application of MPT to the electricity industry.

Once all potential portfolio combinations have been plotted, the efficient frontier can be identified and graphically represented, as displayed below in Figure 12.

Portfolios E and B are two examples of efficient portfolios. The choice between these would ideally be based on perceptions about consumer's desired risk tolerance.
In theory, all portfolios not on the frontier should not be considered as viable options. With respect to analysis of financial securities, it is generally accepted that financial return captures everything of interest. In employing MPT or a variant within the electricity industry, the most common application, as mentioned earlier in this section, is for generators to analyze portfolio options, most often with reference to a metric measuring financial returns associated with investment in generating assets. This approach is straightforward when the factors driving average returns and the volatility of returns are narrowly focused and common—for example, fuel costs, operating costs, etc.

Figure 12. Plotting the Efficient Frontier



Source: London Economics International LLC

There are occasions where broader strategic considerations factor into the analysis of generating options. For example, choice of one plant over another might offer the opportunity to strengthen a relationship with a strategic partner; or choice of a particular plant might provide the opportunity to experiment with a new generating technology that, while costly in the short-term, is expected to create substantial commercial opportunities over the longer term.

Conceptually, it is possible, perhaps even desirable, to establish quantitative estimates of exactly these sorts of expected benefits and systematically incorporate them within the analysis by expanding the scope of the return metric. But, as a practical matter, there are limits to what managers will attempt to quantify. The more long-term and broadly strategic are the elements affecting choices among generators, the more likely it is that decision-makers will want to account for them informally within an analysis, relying on intuition-based adjustments to the results of a purely quantitative analysis. In the case of portfolio analysis, portfolios removed from the efficient frontier may well have desirable attributes not reflected in the established return metric. In these instances, it may well be appropriate to select them in favor of those on the frontier.

The same considerations apply to analyses performed from the perspective of consumers rather than the owners of generating assets.

Concerns About the Application of Modern Portfolio Theory to the Electricity Industry

The primary objection to employing Modern Portfolio Theory to the analysis of firm-level investment decisions, within the electricity industry and elsewhere, is that it is an open question whether there is any benefit and, therefore, whether managers should be paying attention to diversification of operating assets.

It is very easy for investors in corporate financial securities (stocks and bonds) to diversify their holdings. This is particularly true today with the wide availability of portfolio-based investments, such as mutual funds and index funds. Therefore, if assets within a firm are not fully diversified, investors will not impose a penalty because they can so easily diversify away firm-level idiosyncratic risk through the construction of extensively diversified financial portfolios.

While the construction of fully diversified portfolios of financial assets is simple and essentially costless, this is not the case for diversification of operating assets (such as electricity generating plants). Different types of operating assets require different types of operational, technical and/or managerial skills within organizations. It is not at all costless for organizations to establish the range of skills required to operate and manage effectively across diverse asset categories.

If diversification of operating assets is costly, and there is no corresponding benefit, then it is of course not something managers should do. This is the essence of the argument against the application of MPT to firm investment decisions.

This is a legitimate argument and deserves consideration by anyone considering employing MPT to analyze and guide managerial decision-making on investments. But, this argument applies with less force to analyses from the perspective of consumers. As electricity is generally considered a necessity with minimal opportunities for substitution, it is very difficult for consumers to effectively mitigate the risks of electricity price volatility through diversification. Therefore, well-diversified generating portfolios, at the level of the market rather than the individual firm, may well provide a significant consumer benefit.

CHAPTER 6: SELECTED PLANNING CASE STUDIES

The Fifth Northwest Electric Power and Conservation Plan

Introduction

The Northwest Power and Conservation Council (the Council) is an “interstate compact” agency comprised of the states of Idaho, Montana, Oregon, and Washington. Under the Pacific Northwest Electric Power Planning and Conservation Act, the Council is required to develop a 20-year power plan to assure the region of an adequate, efficient, economical, and reliable power system, and to update the plan every five years. The May 2005 update, the Fifth Northwest Electric Power and Conservation Plan, was developed from a regional model that tested different resource development plans against various futures. The following section discussing the regional model and Plan is excerpted from Chapters 6 and 7 and Appendix P of the Fifth Northwest Power Plan (NWPCC 2005).

Decision Making Under Uncertainty

Strategic decision-making models use and manage uncertainty differently from many simulation models that incorporate uncertainty. The key difference between the two is the scale of risk and how a decision maker responds to uncertain events. Sensitivity analysis may be appropriate where the scale of the uncertainty and risk is small enough that the decision maker can live with the outcome of a selected plan.

Strategic decision analysis is concerned with catastrophic outcomes. In decision analysis, the tails of the distribution, especially the upper tail of high costs, assumes greater significance than they do in ordinary simulations. Adaptations that improve the outcomes in the worst of circumstances receive emphasis. Decision making under uncertainty has to do with making decisions that, while they may not have been optimal in retrospect, did not lead to a catastrophic outcome.

The regional model implements planning flexibility. Planning flexibility enables the regional model to evaluate contingency plans and implement those plans as circumstances change during each scenario’s study period. Therefore, the regional model performs true strategic decision analysis on a large number of scenarios.

Stochastic Process Uncertainties

The regional model uses a variety of stochastic processes to represent the future behavior of sources of uncertainty and capture both short-term variation and strategic uncertainty. Values for each source of uncertainty in each time period are produced in such a way that the values have the correct correlation with previous and future values of that source of uncertainty and with the previous and future values of all the other sources of uncertainty. Prices are affected by short-term purchases and sales of the commodity in the market. Some commodity prices, instead of drifting away from their starting point, tend to return to some equilibrium level. The long-term equilibrium price represents the level to which prices trend whenever substantial excursions occur. Away from the equilibrium price, long-term supply and demand do not balance, and fundamental economic forces contrive to rebalance them.

Excursions occur in prices and loads for several reasons, including a disequilibrium in long-term supply and demand. Gas and electricity prices can depart significantly from their equilibrium values when capacity shortages occur. Large and sudden changes, which can last a significant time, are key sources of uncertainty and risk. In the regional model, such changes are modeled as jumps, which can begin at random times and have random magnitude and duration. There is logic to model the recovery from excursions and to constrain when jumps can take place. CO_2 and emission taxes exhibit a special kind of jump behavior not shared by loads and prices. There is only one jump, but its value can change in particular periods.

Plan Development

The Council's approach to developing the Plan was to test a wide variety of possible resource development plans, or portfolios, against 750 futures, or scenarios, that describe the behavior of key sources of uncertainty during the planning period. The Council calls this approach to resource planning "risk-constrained least-cost planning." Given any level of risk tolerance, there should be a least-cost way to achieve that level of risk protection.

The following terms are used throughout the power plan:

- Uncertainty - a measurement of the quality of information about an event or outcome
- Futures - uncontrollable events or circumstances
- Plans - future actions that are controllable
- Scenario - a plan considered under a specific future
- Risk - a measure of bad outcomes associated with a given plan

The power plan addresses the following sources of risk:

- Wholesale power prices
- Plant availability
- Load uncertainty
- Aluminum load uncertainty
- Natural gas price trends
- Hydro generation
- Climate change

- Renewable energy production incentives
- Green tags
- Windpower shaping costs
- Other emissions costs
- Distribution uncertainties and modeling errors

Given a particular future, the primary measure of a plan is its net-present value total system costs. The expected net present value is the average of net present value total system costs, where the average is frequency weighted over 750 futures. The expected net present value total system cost captures the central tendency of the distribution, but does not give a picture of the risk associated with the plan. Instead, the Council employs a summary measure of risk called TailVaR90, which is the average value for the worst 10 percent of outcomes.

The portfolio model estimates costs of generation, purchases and sales of wholesale power, and capacity expansion over a 20-year study period. Monte Carlo simulations of the scenarios are performed, with each game corresponding to a future. Since simulating 750 futures for each of 1,400 plans would require that around a million scenarios be examined, algorithms were developed to estimate plant capacity factors, generation, and costs for periods of one to several months. Using these techniques, the 20-year study period is represented by 80 hydro-year quarters on peak and another 80 off peak. For a given level of risk, the model finds the least-cost plan.

When coordinates corresponding to the average cost and risk (TailVaR90) of each plan are plotted, a distribution corresponding to the feasibility space and efficient frontier, as discussed in Chapter 2, is obtained. Each point represents the average cost and risk for a particular plan over all futures. The least-cost outcome for each level of risk falls on the left edge of the distribution. Each outcome on the efficient frontier is preferable to the outcomes to the right of it, since it has the same risk as those outcomes, but lowest cost. Choosing from among the outcomes on the efficient frontier, however, requires accepting more risk in exchange for lower cost, or vice versa. The outcome on the efficient frontier ultimately chosen depends on the risk that can be accepted.

Risk/Cost Trade-off

The Council has extensively discussed the issue of risk/cost trade-off. While it may not be possible to settle on a level of risk tolerance that represents all parties in the region, consideration of risk issues and the efficient frontier can provide insights for the Council and others in the region.

First, the efficient frontier alone can yield significant insights. Attributes that are common or absent from among all the plans on the efficient frontier can help a decision maker to identify robust resource strategies and flag potential strategic blunders.

Second, many plans along the efficient frontier may differ only by commitments that do not need to be made today. If the earliest resource commitments from among all the plans occur at some point in the future, decision makers can and should wait until then to make them. At that future time, the decision makers will have more information and a better choice may be more apparent.

Third, partitioning plans along the frontier into classes of strategy can make planning more manageable. Typically, plans along the efficient frontier do not follow a simple, “more resources mean less risk” pattern. The analyst will observe regimes where different technologies and strategies prevail, or different kinds of risk dominate. Using representative plans from each regime can help simplify subsequent analysis.

Risk Mitigation Actions

Hedging

Hedging is an action that offsets the effects of something else. A utility may add wind generation if it is concerned about risks of natural gas price increases. However, hedges are not free. If natural gas prices decrease, some of the reduction in natural gas costs is offset by the utility’s commitment to the fixed costs of a wind power plant. Thus, hedging not only mitigates the worst outcome, but moderates the best outcome as well.

Flexibility or Optionality

When electricity is expensive relative to natural gas, the owner of a combustion turbine may sell the electricity generated from the gas. If natural gas is expensive relative to electricity, the owner tends to resell the valuable gas or hold it in storage. Demand response represents another form of this flexibility. When electricity is expensive relative to a commodity that a utility customer is producing, the load serving entity and its customer may agree to sell the more expensive electricity and compensate the customer with more money than the customer would have made producing the commodity.

Long-term flexibility includes a decision maker’s ability to cost-effectively cancel or defer a project. The ability to add small increments of capacity, often referred to as modularity, is another form of planning flexibility, as is the ability to construct a plant very rapidly to take advantage of current market conditions.

The treatment of flexibility, and in particular long-term planning flexibility, distinguishes the Council’s study and analytical technique from many of the techniques currently used to evaluate resource plans. This distinguishing feature is critical to the Council’s evaluation of risk.

Resource Additions and Decision Criteria

The value of flexibility stems from the ability to change plans when unforeseen events occur. This implies that a risk model must incorporate at least two special features.

First, a risk model must have the ability to add resource capacity without the benefit of perfect foresight. An iterative process removes or adds resources until all new resources would just cover their risk-adjusted costs. Second, a risk model that incorporates capacity expansion must have a decision rule that determines whether to build or continue building.

The Council evaluated several approaches to decision criteria. For conventional thermal resources and wind generation, the approach that performed best incorporates information about resource-load balance and forward prices for fuel and electricity prices. Specifically, the model uses a three-year average of load growth and any change in resource capability to determine when in the future resource-load balance would cross below a given threshold. The selection of the threshold is itself part of the choice the model makes to minimize cost or risk. In each simulation period and for each resource candidate, the model determines whether the crossover point is less than the construction time required for that resource.

If the model needs a resource to meet anticipated future load, the criterion consults pertinent forward prices for each resource. If the plant would pay for itself, construction proceeds; if not, the model compares the value of the plant to that of alternatives. If the plant cannot pay for itself but is still the least expensive alternative, construction continues. Consequently, the model estimates forward prices using the assumption that futures and forward prices closely track current prices. The average commodity price over the last 18 months is the forecast of forward prices.

Each resource that is a candidate for capacity expansion uses its decision criterion to control progress on construction, depending on where the resource is in its construction cycle.

Portfolio Analysis and Recommended Plan

This section describes the plans that appear on the efficient frontier and outlines how the Council selected a single plan from among them.

Unlike deciding among portfolios consisting solely of simple financial instruments, systems as complex as the Northwest power system require a consideration of a variety of perspectives in addition to examining the feasibility space and its efficient frontier.

Examples of issues not fully represented by the feasibility space include the predictability of cost to ratepayers, environmental impacts, and risks associated with the feasibility of developing the technologies in sufficient quantity to meet uncertain schedules. The risks associated with some of these are monetized, but additional study reveals issues that merit consideration. The feasibility space and efficient frontier are really a means to filter down the number of plans to a handful for more careful study.

Developing the Plan

The Council developed the plan using the following steps:

1. Develop a base case—Characterize the power system, uncertainties, and resource behavior.
2. Examine the efficient frontier and near-frontier—Similarities and differences among the plans provide important insights.
3. Consider alternative perspectives on cost and risk—Although measures of cost and risk are robust, other measures such as power cost volatility, power system reliability, and exposure to market price excursions can provide additional sources of discrimination and may provide a more intuitive indication of risk than TailVaR90.
4. Identify the Action Plan—Several decisions requiring commitment within the next five years are called for in all the plans along the efficient frontier. These actions comprise the Action Plan. Other actions may not require immediate commitment, but their timing provides the region with an idea of how soon re-evaluation is necessary.
5. Create implementation milestones for the Action Plan—Commitments in the Action Plan must be feasible and cost-effective.

Developing a Basecase

In addition to characterizing uncertainties such as gas prices and hydro availability, assumptions are made pertaining to candidate resources for future growth in requirements, including conservation resource potential, the availability and cost of demand response, and generating resource characteristics. Other key assumptions include a wholesale electricity price cap of $250 per megawatt hour on average for a quarter, unavailability of independent power producer plants not currently under contract, declining resource capability of the hydro system, availability of regional coal, and inclusion of resources having a high chance of completion. Although significant transmission constraints exist in the region, these do not appear explicitly in the model, although the analysis and interpretation of any plan incorporates them. The portfolio model considers looking at loads and resources in aggregate.

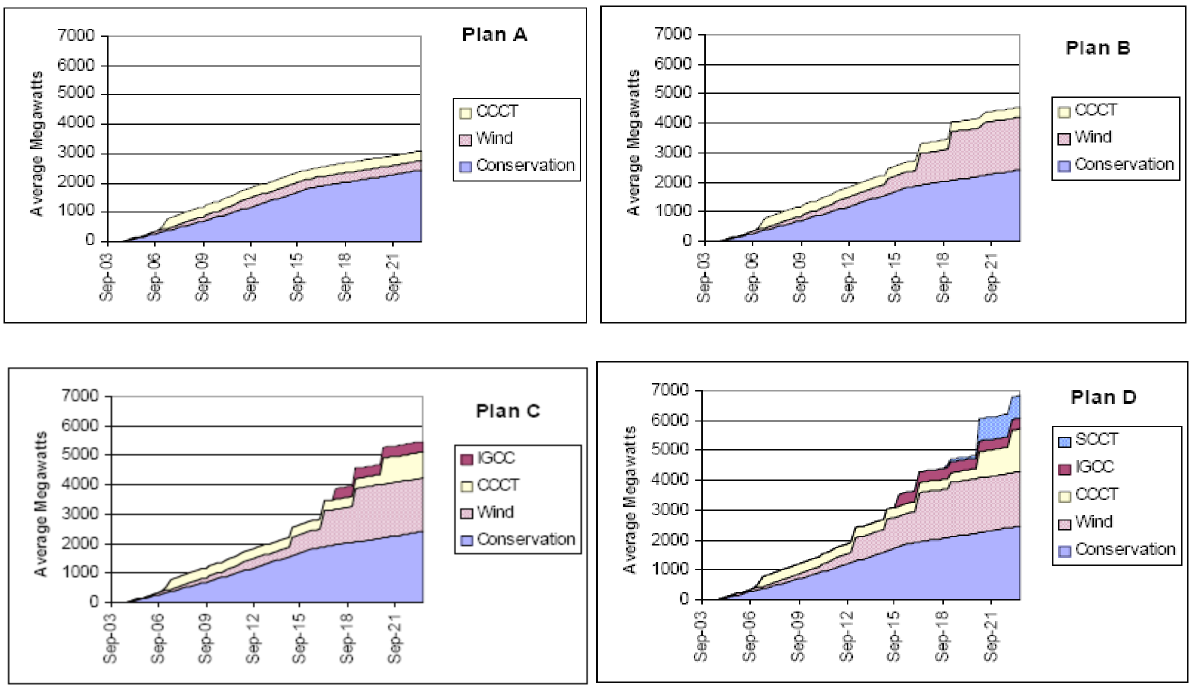
The Efficient Frontier

Each point within the feasibility space and on the efficient frontier line represents the expected (average) cost and risk values for a single plan over 750 futures. Plans near the efficient frontier that differ significantly from those along the frontier would warrant additional exploration. Those plans within a quarter of a billion dollars cost and risk, however, resembled closely those on the efficient frontier. Only those plans well away from the frontier, where typically larger amounts of generation are added, had significantly different schedules.

Four Alternative Plans

Four plans are presented for comparison purposes, including the absolute least-cost plan (A), the absolute least risk plan (D) and two intermediate plans (B and C), all of which are located on the efficient frontier.

Figure 13: Representative Development Schedules for Alternative Plans Along the Efficient Frontier



Source: Fifth Northwest Power Plan, Chapter 7, pp. 7-8.

Plan A (least-cost, highest risk) —In addition to the already committed combined cycle combustion turbine generation (CCCT) and wind, this plan relies on conservation, market purchases and demand response. Demand response is usually dispatched relatively infrequently and the associated energy is small and is not shown. This plan is the plan most exposed to market risk.

Plan B (lower risk, somewhat higher cost) —This plan offsets some market risk by adding the ability to develop additional wind generation in the latter parts of the planning period. Demand response continues to be utilized, although less heavily than in the least-cost case.

Plan C (even lower risk, higher cost) —This plan adds the ability to develop 425 megawatts of gasified coal generation (IGCC) as well as somewhat earlier construction of wind and 1200 megawatts of CCCT capacity late in the planning period. Demand response, though not shown, continues to play a role, albeit at a reduced level.

Plan D (least risk, highest cost) —This plan adds greater diversity with the ability to develop additional CCCT and single cycle gas-fired combustion turbines (SCCT) close to the end of the planning period.

Differences Among the Plans

Plan A (least-cost, highest risk)—In addition to the already committed CCCT and wind, this plan relies on conservation[1], market purchases and demand response. Demand response is usually dispatched relatively infrequently and the associated energy is small and is not shown. This plan is the plan most exposed to market risk.

Plan B (lower risk, somewhat higher cost)—This plan offsets some market risk by adding the ability to develop additional wind generation in the latter parts of the planning period. Demand response continues to be utilized, although less heavily than in the least-cost case.

Plan C (even lower risk, higher cost)—This plan adds the ability to develop 425 megawatts of IGCC as well as somewhat earlier construction of wind and 1200 megawatts of CCCT capacity late in the planning period. Demand response, though not shown, continues to play a role, albeit at a reduced level.

Plan D (least risk, highest cost)—This plan adds greater diversity with the ability to develop additional CCCT and SCCT close to the end of the planning period.

How Much Conservation?

The analysis incorporated estimates of the achievable rates of conservation development that the Council believed to be doable, though aggressive. Three different rates of conservation development were investigated to examine the effects on cost and risk:

- Option 1 (base case)
    - Discretionary[2] (non-lost opportunity) conservation limited to a maximum rate of development representative of the levels the region achieved in the early 1990s and in 2001 and 2002, but not on a sustained basis

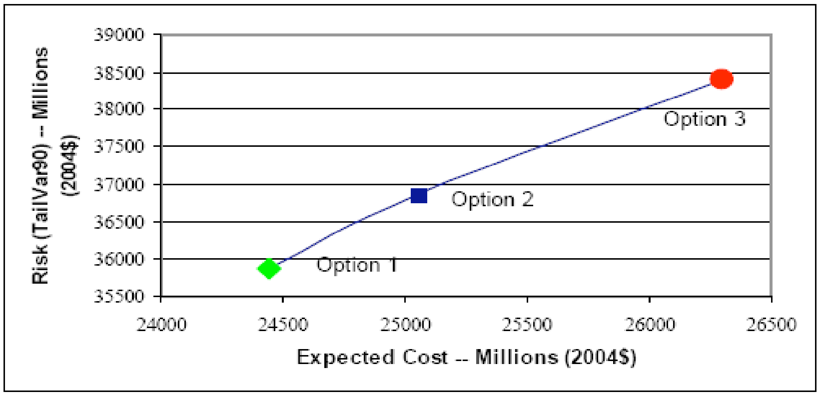
[1] The Council includes energy efficiency measures within the category of conservation.
[2] Discretionary (non-lost opportunity) conservation can be deployed any time within practical limits. Lost-opportunity conservation measures must be captured at the time new buildings are built or new appliances and equipment are purchased.

- Lost opportunity conservation limited by a 12-year phase-in (representative of the time between adoption of the original standards and implementation by state and local governments)

- Option 2
  - Discretionary conservation limited to a maximum rate of development well short of the maximum that has been accomplished
  - Lost opportunity conservation same as Option 1

- Option 3
  - Discretionary conservation limited to a maximum rate of development that is close to the lowest rates of conservation development experienced over the last 20 years
  - Lost opportunity conservation requires a 20-year phase in before the available potential could be developed to its maximum achievable level (85 percent of the cost-effective potential)

Figure 14: Cost and Risk of Least Risk Plans for Alternative Conservation Strategies



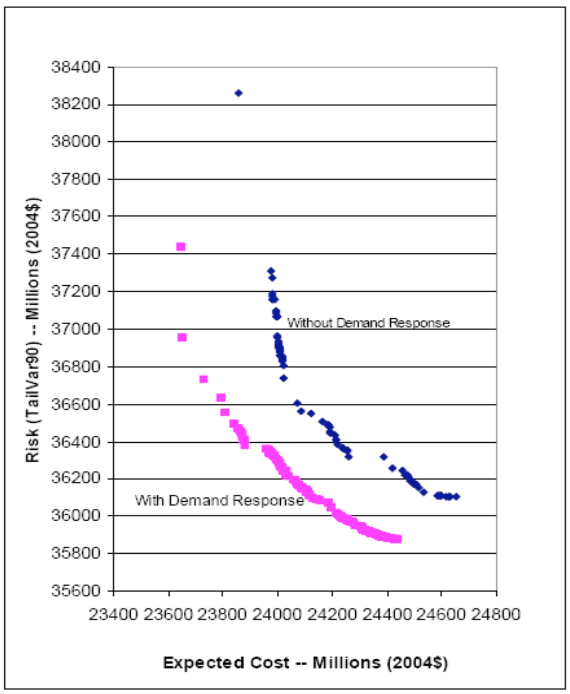
Source: Fifth Northwest Power Plan, Chapter 7, pp. 7-14.

Figure 14 shows the cost and risk values for the lowest risk plans along the efficient frontiers for the three options. The more aggressive level of conservation results in both much lower expected cost and risk. Because the conservation is low cost compared to the alternatives, it has value, even when prices are relatively low. The rate of conservation development also affects the need for other, more expensive resources. A modest reduction in the rate of conservation acquisition over the next few years requires moving development of generation resources forward. Earlier conservation development allows the region to defer decisions on generating resources—decisions that bear relatively greater risks given the uncertainty the region faces. Compared to generating resources, conservation is a low-cost and low risk way to maintain an economic reserve margin.

Value of Demand Response

Demand response develops gradually over the planning period, beginning with 500 megawatts in 2008 and reaching 2,000 megawatts by 2020. Dispatched when market prices exceed $150 per megawatt-hour, demand response is used in 83 percent of all the years examined. In most (85 percent) of those years, it is used the equivalent of less than 89 hours per year. In 95 percent of all years, 8 percent or less of the available demand response capability is used. But in futures with very high prices, it can be dispatched at higher levels to help moderate prices and maintain reliability.

Figure 15: Efficient Frontiers With and Without Demand Response



Source: Fifth Northwest Power Plan, Chapter 7, pp. 7-18.

The Council compared the efficient frontiers for the base case demand response assumptions compared to the assumption of no demand response. Figure 15 demonstrates the effect of demand response along the efficient frontier. The loss of demand response shifts the efficient frontier up and to the right (more expensive and risky outcomes). The increased costs are largely attributable to significantly more gas-fired generation included in the plans without demand response as well as greater exposure to high market prices. The fewer conventional resources, the more valuable demand response becomes.

Cost-Effective Generating Projects May Become Available Prior to 2010

Because of their diversity, small-scale or site-specific nature, projects such as industrial or commercial cogeneration, landfill, animal waste or wastewater treatment plant energy recovery, hydropower renovations, forest residue energy recovery, and photovoltaics were not included in the portfolio analysis. While plan does not call for generation resource development prior to 2010, opportunities for developing these types of projects may occur prior to 2010. The opportunity to economically develop these projects is often created by needs not directly related to electric power production, such as a waste disposal issue, process or equipment upgrading or new commercial and industrial development. These opportunities should be monitored and the projects secured when cost-effective.

Carbon Dioxide Emissions Mitigation

A major uncertainty is the likelihood, timing and magnitude of measures to reduce carbon dioxide emissions. This is important because of the impact that carbon dioxide control costs would have on comparative cost of new generating alternatives. With the exception of wind and coal gasification with carbon sequestration, the costs of power are very sensitive to carbon dioxide control costs.

The Plan treated a wide range of outcomes for climate change policy as equally probable. A tax was assumed for modeling purposes, although the effects of a cap and trade system would be similar. The carbon tax modeled ranges from zero to $15 per ton of carbon dioxide emissions, beginning as early as 2008 with the possibility of change every 4 years. The level can increase to as high as $30 per ton carbon dioxide beginning in 2016. Thus, some futures will have no carbon tax, some will have $15 per ton beginning in 2008, some will have $30 per ton beginning in 2016, and the rest will represent other possibilities between those extremes. By the end of the planning period, roughly two-thirds of the futures have some level of carbon tax.

The probability of a relatively significant carbon control cost increases with time. As a likely consequence, the portfolio model has no coal generation coming into service after 2017 in any future. However, it is likely that more significant carbon control measures implemented earlier in the planning period could have a more significant effect. This makes monitoring the state of climate change science and policy important as future resource decisions are made.

Scenarios

While it is useful to examine a representative resource in-service schedule for the plan, that particular schedule is not likely match what will happen in any particular future that is actually realized. That is why it is also useful to see how the plan would be implemented under different situations. Scenarios describe how the plan will manifest itself for particular futures. Minimizing risk does not mean that the plan protects the region from experiencing a bad outcome, it only minimizes the magnitude of the bad outcomes. The primary measure of a bad outcome is very high cost.

The portfolio model identifies the plan that, over all the futures evaluated, results in the lowest average cost for a given level of risk. If a future unfolds that is significantly different than those anticipated, the current plan may not be able to take advantage of it. The plan must be constantly reviewed and revised as knowledge and perceptions of the possible futures change.

The average cost for the plan is $24.4 billion but depending on the future, the cost could range as high as $50 billion or be as low as about $12 billion. But there is a 10 percent chance that the cost could be $32 billion or higher. Of all the plans considered (over 1,000), the chosen plan had the lowest risk; but even so, the range of possible future costs is still quite large.

In light of this wide range of possibilities, it is important for the region to understand what kinds of future conditions lead to a high cost scenario. Recall that the major uncertain variables modeled include demand, price of electricity, price of gas and a carbon tax. By monitoring these variables over time, the region can best prepare itself to adapt the plan, if necessary, to keep costs as low as possible and maintain a reliable power supply.

Ontario Power: Integrated Resource Planning[1]

Following the deregulation of Ontario's electric and gas markets in 1998, the Ontario government introduced an electricity price cap in 2002 that led to reduced investments in electricity generation. The resulting capacity shortage was exacerbated by the need to replace aging plants and the government's decision to phase out all coal-fired generation. Estimating that it would need 25,000 MW of new generation capacity by 2020, the Ontario government created the Ontario Power Authority (OPA) in 2004 to help ensure adequate electricity supply and stable prices within the province of Ontario.

The OPA's mandate is as follows:

1. Forecast electricity demand and the adequacy and reliability of electricity resources for Ontario for the medium and long-term.
2. Conduct independent planning for electricity generation, demand management, conservation, and transmission and develop integrated power system plans for Ontario.
3. Engage in activities to facilitate the diversification of sources of electricity supply by promoting the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources.
4. Engage in activities that facilitate load management and promote electricity conservation and the efficient use of electricity.

[1] This section was prepared by London Economics International LLC.

OPA's position within the overall Ontario electricity industry is overviewed in Figure 16.

Figure 16: OPA's Role in the Ontario Electricity Market

A core responsibility for OPA is to develop an Integrated Power System Plan (IPSP) outlining approaches for ensuring the ongoing supply-demand balance within the Ontario electricity sector through generation procurement and conservation. The first step in developing the IPSP is to conduct a "supply mix assessment," leading to a recommendation for the Ontario Energy Board (OEB) on what the supply mix (including conservation) should look like throughout the following 20 years.

This case study reviews the 2005 analysis conducted by the OPA. IPSP employed the results of the analysis as a basis for future RFPs and RFOs issued by the Ontario Energy Board.[2]

Portfolio Development

To develop its supply mix assessment, the OPA constructed several portfolios that balanced supply and demand subject to specified constraints and defined socio-political objectives. Such socio-political objectives included, for example, that customer demand management was to be employed as a resource before supply-side resources, and renewables were to be prioritized over conventional resources. The defined portfolios were then evaluated in relation to defined criteria, including cost, risk, environmental attributes, adequacy and reliability.

Notice that this approach deviates from the comprehensive portfolio analyses described in Chapter 5. The OPA did not systematically identify, through the use of

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[2] This approach is similar to the Energy Commission's *IEPR* and CPUC's long-term procurement process.

algorithms, all possible portfolios and then identify a smaller set (i.e., a frontier) of efficient portfolios. Its approach was more ad hoc, centered on the construction of a small number of portfolios in accordance with specified standards.

The OPA defined five scenarios representing plausible future market outcomes, as follows:

- Scenario 1: all expected procurements, new renewable and conservation resources, and out-of-province purchases materialize
- Scenario 2: fewer resources materialize, including procurements, new renewable and conservation resources, and out-of province-purchases
- Scenario 3: the full replacement of a small number of coal-fired units is delayed
- Scenario 4: demand growth is higher than expected, but the contribution of conservation and efficiency is higher
- Scenario 5: greater achievement in terms of conservation and efficiency potential

For each of these scenarios, the OPA developed 2 portfolios capable of meeting Ontario's supply needs through 2025. The resulting 10 distinct portfolios, each developed through in-depth analysis of the potential of each resource type relative to the conditions defined in the associated scenario, mostly shared the following common elements:

- 1,800 MW of conservation & demand management (CDM)
- 5,000 MW of wind power
- 1,500 MW of hydro
- 1,250 MW of firm renewable purchases
- 500 MW of biomass generation
- 40 MW of photovoltaic generation
- 500 MW of fuel cell generation
- 250 MW of gasification generation
- The assumption that all hydro and natural gas/oil fired resources remain in service throughout the study period
- All capacities derated to reflect each technology's contribution to meeting peak load
- A base demand forecast of 0.9 percent and peak demand forecast of 1.3 percent/ year

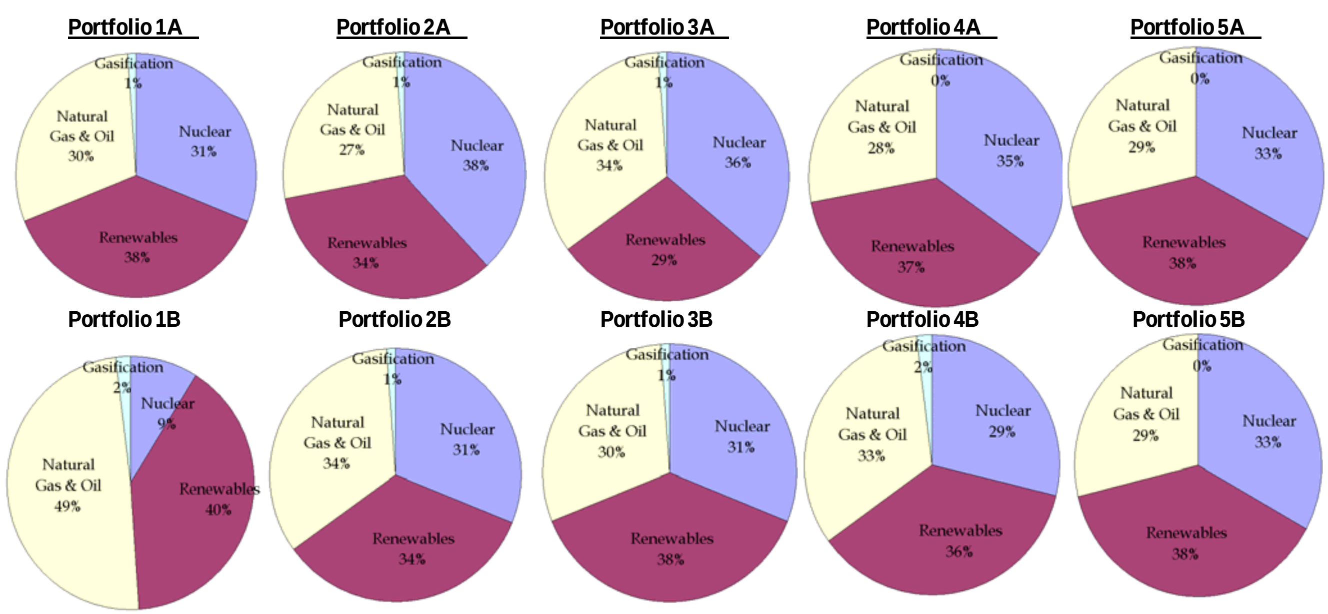
The distinguishing characteristics of the 10 portfolios are summarized in Figure 17 and Figure 18, and their detailed resource mixes are illustrated in Figures 19 through 28.

Figure 17: OPA Portfolio Comparison

	PORTFOLIO (All Numbers in Nominal MW)									
	1A	1B	2A	2B	3A	3B	4A	4B	5A	5B
Contains all Common Elements	Yes	Yes	Less 1,200 firm purchase, half of expected new hydro, biomass, fuel cell	Less 1,200 firm purchase, half of expected new hydro, biomass, fuel cell	Nanticoke retirement delayed	Nanticoke retirement delayed	Higher load growth, more CDM, No gasification	Higher load growth, more CDM	More CDM, less 1,200 firm purchase, No gasification	More CDM, less 1,200 firm purchase, No gasification
All Procurements & on Time	Yes	Yes	Less 1,000 gas procurement	Delay 1,000 gas procurement	Less 2,000 gas procurements, 600 gas procurements deferred	Yes	Yes	Yes	Less 200 gas procurements, 1,400 gas procurements deferred	Yes
Nuclear Refurbishment /Replacement	Yes	Only Bruce A	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Additional Nuclear	No	No	3,000	No	2,000	No	3,000	No	No	No
Other New Resources	1,000 natural gas	9,300 natural gas, 750 gasification	1,300MW natural gas	3,100 natural gas	750 natural gas	1,000 natural gas	1,200 natural gas	2,400 natural gas, 1,000 gasification	No	No
Total Natural Gas/Oil Capacity by 2025	12,500	20,762	11,500	14,300	10,200	12,500	12,700	14,800	11,300	11,500
Total Nuclear Capacity by 2025	12,900	3,555	15,900	12,900	14,900	12,900	15,900	12,900	12,900	12,900
Total Renewable Capacity by 2025	16,500	14,347	14,200	14,200	16,500	16,500	16,500	16,500	15,200	15,200

Source: Ontario Power Authority 2005 Analysis

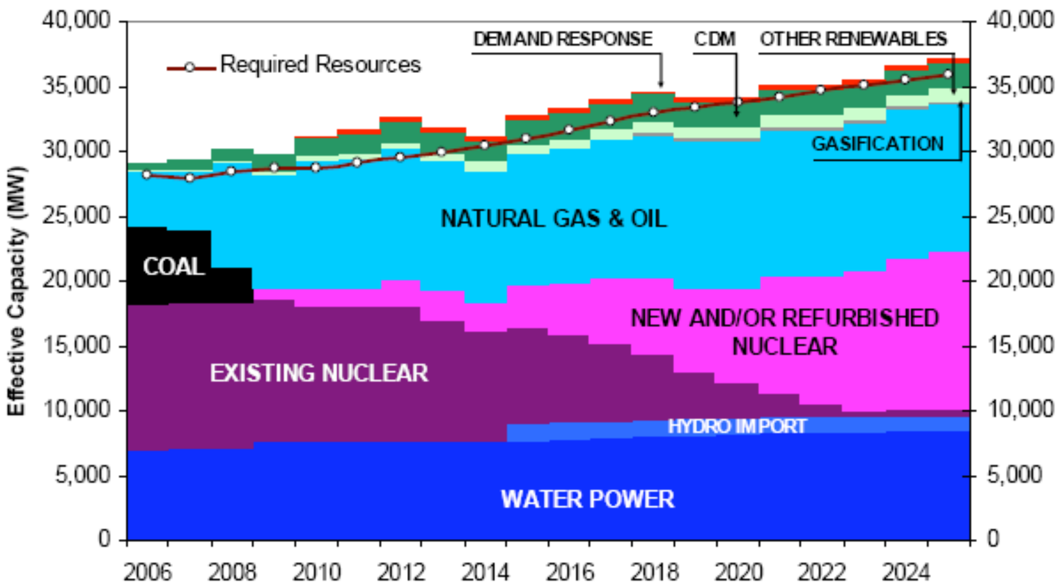
Figure 18: OPA Portfolio Comparison (Installed Capacity 2025)



Source: Ontario Power Authority 2005 Analysis

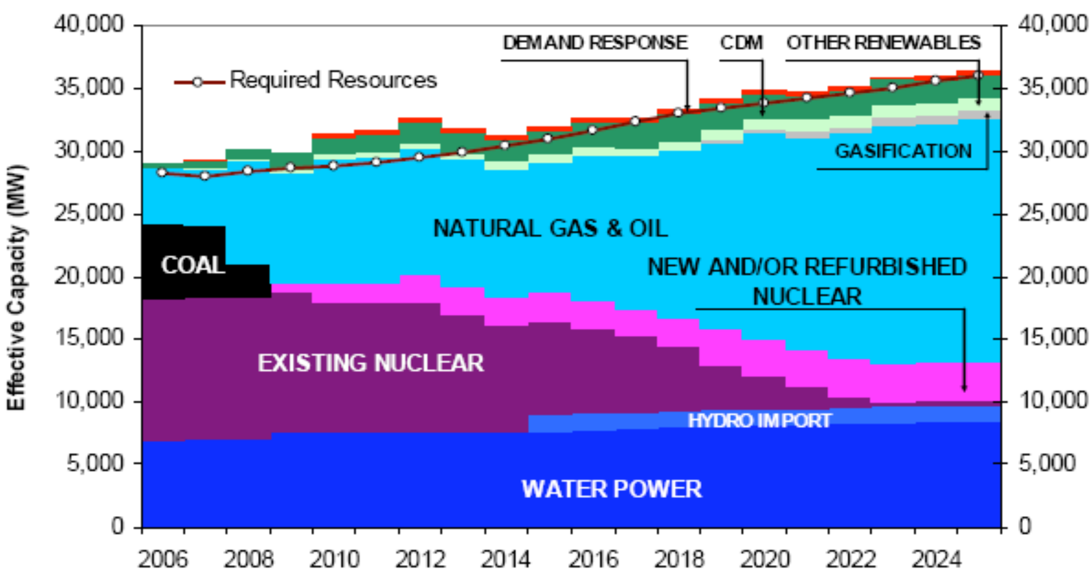
Portfolio 1A (Figure 19) assumes that that most of Ontario's nuclear units are refurbished or replaced as they reach the end of their estimated lives, and that all coal-fired units are removed from service by 2009. Portfolio 1B (Figure 20) differs from 1A in that more nuclear units are retired and replaced by gas & oil-fired generation.

Figure 19: OPA Portfolio 1A



Source: Ontario Power Authority 2005 Analysis

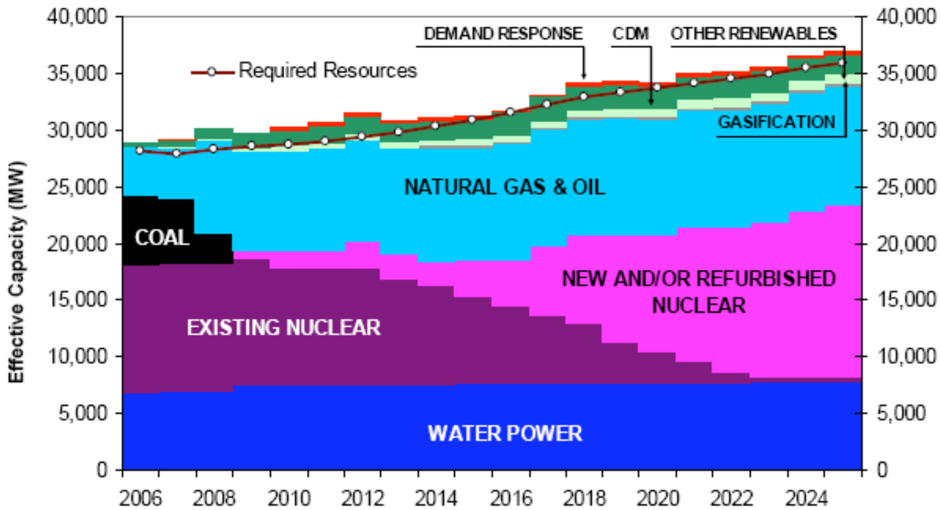
Figure 20: OPA Portfolio 1B



Source: Ontario Power Authority 2005 Analysis

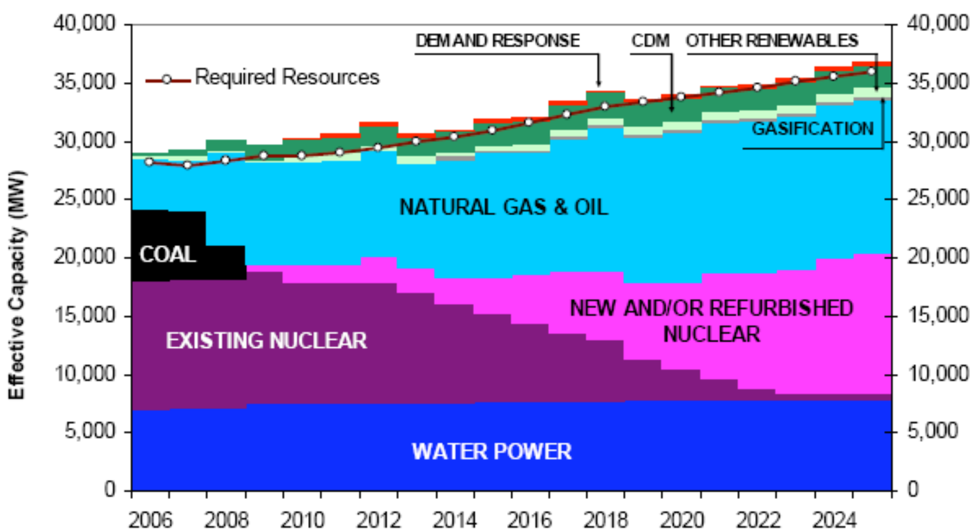
Portfolio 2A (Figure 21) also assumes that most of Ontario's nuclear units are refurbished or replaced and that the coal fired units are replaced. But relative to portfolios 1A and 1B, portfolio 2A assumes fewer imports occur; that generation planned under government procurements do not materialize; and that fewer hydro, biomass and fuel cell resources come online. As a result, additional gas-fired and nuclear generation is added to compensate for the generation shortfall. Portfolio 2B (Figure 22) is identical to 2A except that no new nuclear generation is added, replaced in 2B by gas-fired generation.

Figure 21: OPA Portfolio 2A



Source: Ontario Power Authority 2005 Analysis

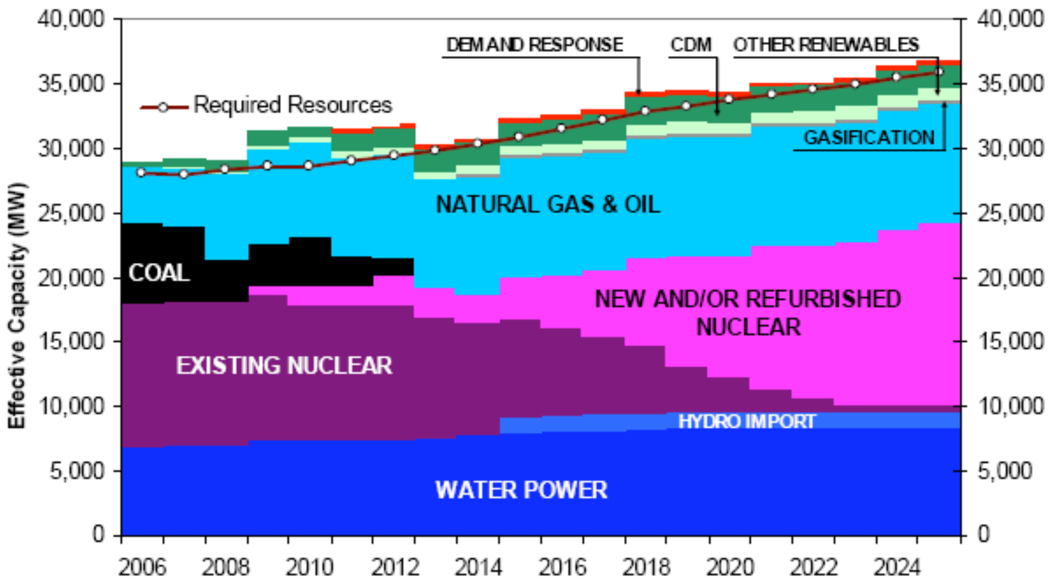
Figure 22: OPA Portfolio 2B



Source: Ontario Power Authority 2005 Analysis

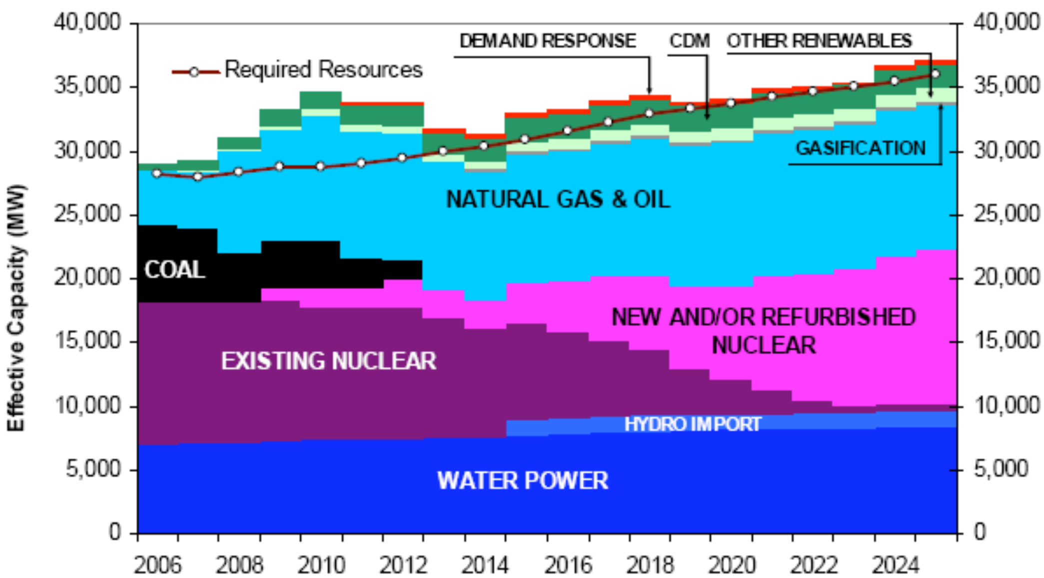
Portfolio 3A (Figure 23) assumes that the retirement of certain coal-fired units is delayed and that the delay has been fully anticipated and planned for; and that existing nuclear units are refurbished or replaced in parallel with new nuclear units coming online. Portfolio 3B (Figure 24) differs from 3A only in that the retirement of the coal plants is not anticipated and planned for.

Figure 23: OPA Portfolio 3A



Source: Ontario Power Authority 2005 Analysis

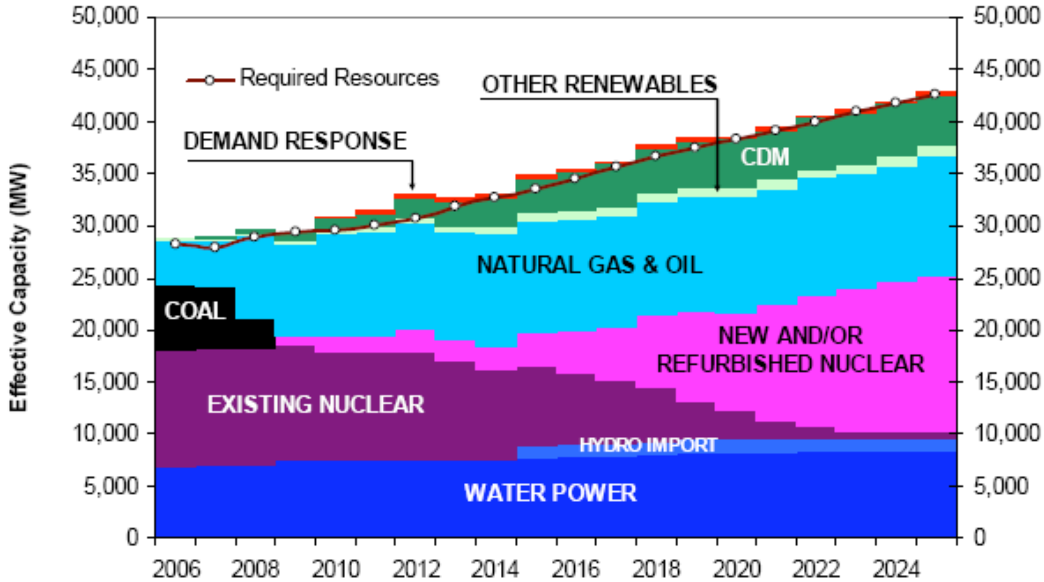
Figure 24: OPA Portfolio 3B



Source: Ontario Power Authority 2005 Analysis

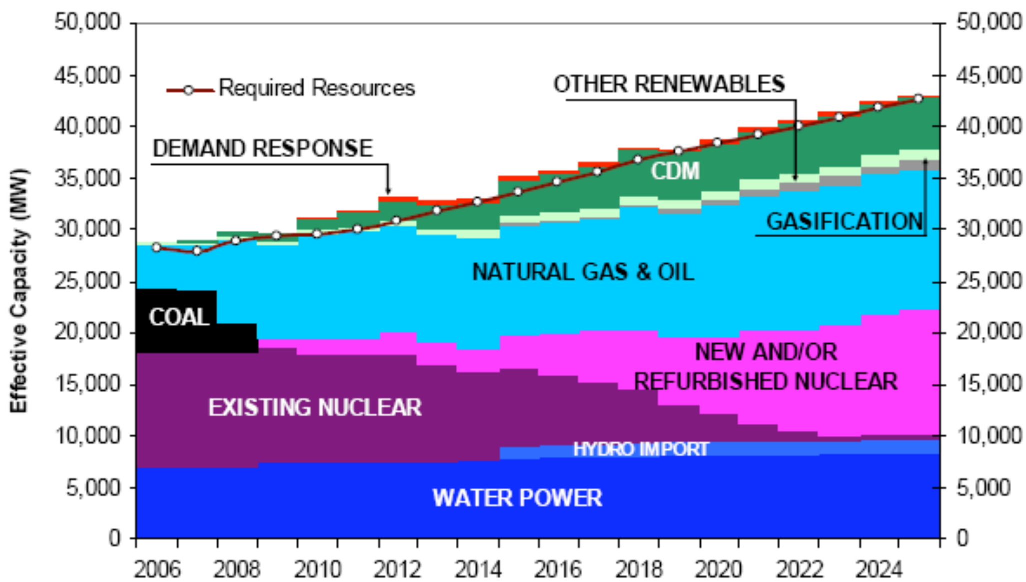
Portfolio 4A (Figure 25) assumes a different load growth scenario than the preceding portfolios. The higher load growth is met principally through the addition of new nuclear and gas-fired units and also through additional conservation and demand management. Portfolio 4B (Figure 26) differs only in that it does not include any new nuclear generation, replaced in 4B by gas-fired units.

Figure 25: OPA Portfolio 4A



Source: Ontario Power Authority 2005 Analysis

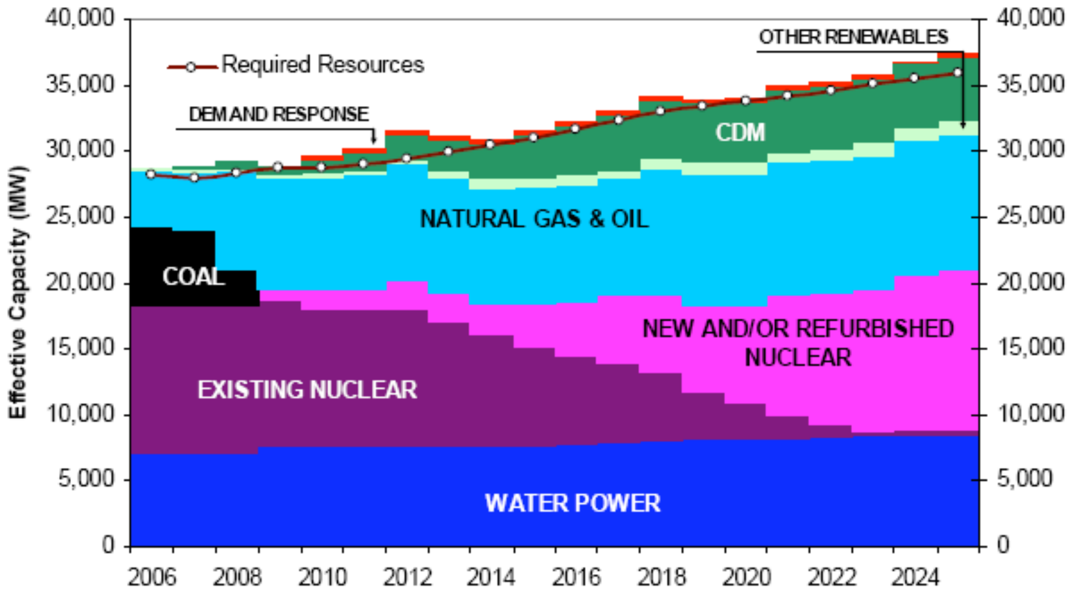
Figure 26: OPA Portfolio 4B



Source: Ontario Power Authority 2005 Analysis

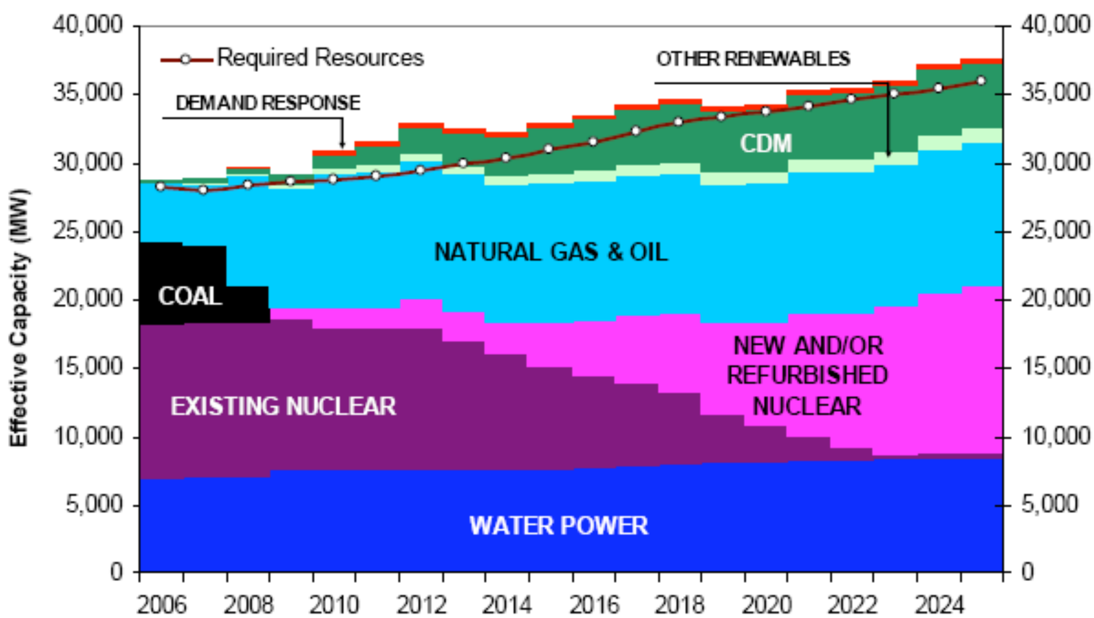
Portfolio 5A (Figure 27) assumes a higher success rate in developing conservation and demand management than preceding portfolios, resulting in reduced imports and gas-fired generation and delays in bringing online substantial amounts of gas-fired procurement. Portfolio 5B (Figure 28) differs only in the assumption that conservation and demand management potential is first realized in 2008/2009 rather than immediately.

Figure 27: OPA Portfolio 5A



Source: Ontario Power Authority 2005 Analysis

Figure 28: OPA Portfolio 5B



Source: Ontario Power Authority 2005 Analysis

Measuring Returns

The OPA did not incorporate a ratio-based return metric within its analysis. Instead, it focused on minimizing the total costs associated with each portfolio, where total cost was measured as the present value of a 20-year stream of estimated annual "revenue requirements" for the generators comprising the portfolio.

Annual revenue requirements for each generator were calculated using what the OPA refers to as a "Portfolio Screening Model" (PSM), essentially a least-cost dispatch model bundled with a financial model. The return of each portfolio was calculated as the net present value (NPV) of the portfolio's revenue stream up to 2020.

For each portfolio, based on the characteristics of the portfolio and its associated scenario, the dispatch model was used to build a supply stack and identify a market clearing price for each hour throughout the 20-year forecast horizon. "Must run" resources – which include conservation and demand management, intermittent resources (run of river hydro and wind), zero variable cost resources (dispatchable hydro), cogeneration and non-utility generation (NUG) facilities – were dispatched first; all other generating units were then dispatched based on their variable costs.

The dispatch model output the following key data that was used to develop an overall revenue requirement for each portfolio:

- Total annual energy produced by fuel type in each year
- Forecast annual average marginal energy cost
- Total annual carbon produced
- Annual capacity factors for all generating units

These dispatch model outputs were input to the financial component of the PSM, which estimated the portfolio's annual revenue requirements for each year of the forecast horizon.

As overviewed in Figure 29, the annual revenue requirement was calculated based on a return on and of capital employed, income taxes, and fixed and variable operating costs.

Figure 29: Revenue Requirement Calculation

Revenue		
Revenue Requirement	$9,071,962	Total of all costs from below
Operating Expenses - Variable		
Dispatch Expense	$3,931,218	Variable O&M & fuel costs for those units dispatching during the year
Operating Expenses - Fixed		
Fixed O&M	$1,475,722	Based on assumptions for new and existing assets
EBITDA	$3,665,022	
Book Depreciation	$1,090,022	Calculated from book life of asset
Interest Expense	$700,000	Average capital in year financed by debt multiplied by the cost of debt
Earnings Before Tax	$1,875,000	
Current Income Tax	$675,000	Reflects cash taxes (book income tax less deferred tax)
Net Income	$1,200,000	Average capital in year financed by equity multiplied by the expected ROE

Source: Ontario Power Authority 2005 Analysis

The OPA assumed, for all generators, a capital structure of 50 percent debt and 50 percent equity, a cost of debt of 7 percent and a cost of equity of 12 percent (resulting in a weighted-average cost of capital of 9.5 percent). Net income after tax (NIAT) was calculated as follows:

$$\text{NIAT} = \text{Average capital employed} * \text{\% financed by equity} * \text{expected ROE}$$

Interest expense was calculated as:

$$\text{Interest expense} = \text{Average capital employed} * \text{\% financed by debt} * \text{cost of debt}$$

To properly account for the impact of taxes on the revenue requirements, the tax computations factored in various tax incentives available for efficient and renewable technologies, displayed below in Figure 30.

Figure 30: Capital Cost Allowance by Technology Type

Technology	Capital Cost Allowance
CCGT	15%
SCGT	8%
Biogas	50%
Cogen	40%
Hydro	40%
Nuclear	8%
Wind	50%
IGCC	8%
Fuel Cell	50%

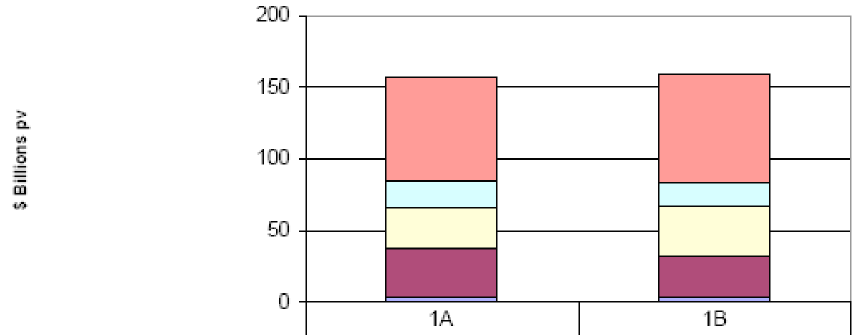
Source: Ontario Power Authority 2005 Analysis

The depreciation and operation and maintenance (O&M) cost components of the revenue requirement were computed based on characteristics of the generating units comprising the portfolio and outputs from the dispatch model. The O&M computations accounted for the financial impacts associated with renewable energy incentive credits – including, for example, the Wind Power Production Incentive and the Renewable Power Production Incentive - and carbon emissions taxes that were assumed to be $15 per ton based on intensity targets for coal and natural gas-fired plants.

The annual revenue requirement for the overall portfolio was computed as the sum of the corresponding annual revenue requirements across all the generators comprising the portfolio. The 20-year stream of portfolio annual revenue requirements, plus an estimated terminal value reflecting value beyond 2025, was then reduced to a single NPV metric through a standard discounting computation. A discount rate of five percent was employed, reflecting the long-term cost of public debt—the OPA referred to this as a “social discount rate.” A constant discount rate based on the treasury bill interest rate might have established a bias in the analysis towards resources yielding primarily short term benefits.

Reduction of 20-year portfolio costs to a single NPV metric allowed for portfolio comparisons, as illustrated in Figure 31.

Figure 31: Portfolios 1A and 1B Return Comparison



	1A	1B
Total	157	159
Long Term (Post 2025)	71	75
Capital Charged to Study Period	20	18
Fuel & Variable OM&A	28	35
Fixed OM&A	34	29
CDM	3	3

Source: Ontario Power Authority 2005 Analysis

Measuring and Accounting for Risk

Risk was defined as the volatility of the chosen “return” metric (i.e., NPV of portfolio annual revenue requirements). Portfolio volatility was in turn assumed to be driven by several risk factors, including the following:

- Fuel: variability of fuel prices and the uncertainty of long-term supply availability
- Technology: uncertainty surrounding the cost and performance of various technologies now and in the future
- Generator availability: uncertainty about whether generating plants will be available to produce energy when called upon to do so
- Load: uncertainty associated with load growth over time caused by population growth and growth in the economy and changes in electricity usage
- Weather: including the impact on water flows for hydroelectric generation and electricity demand

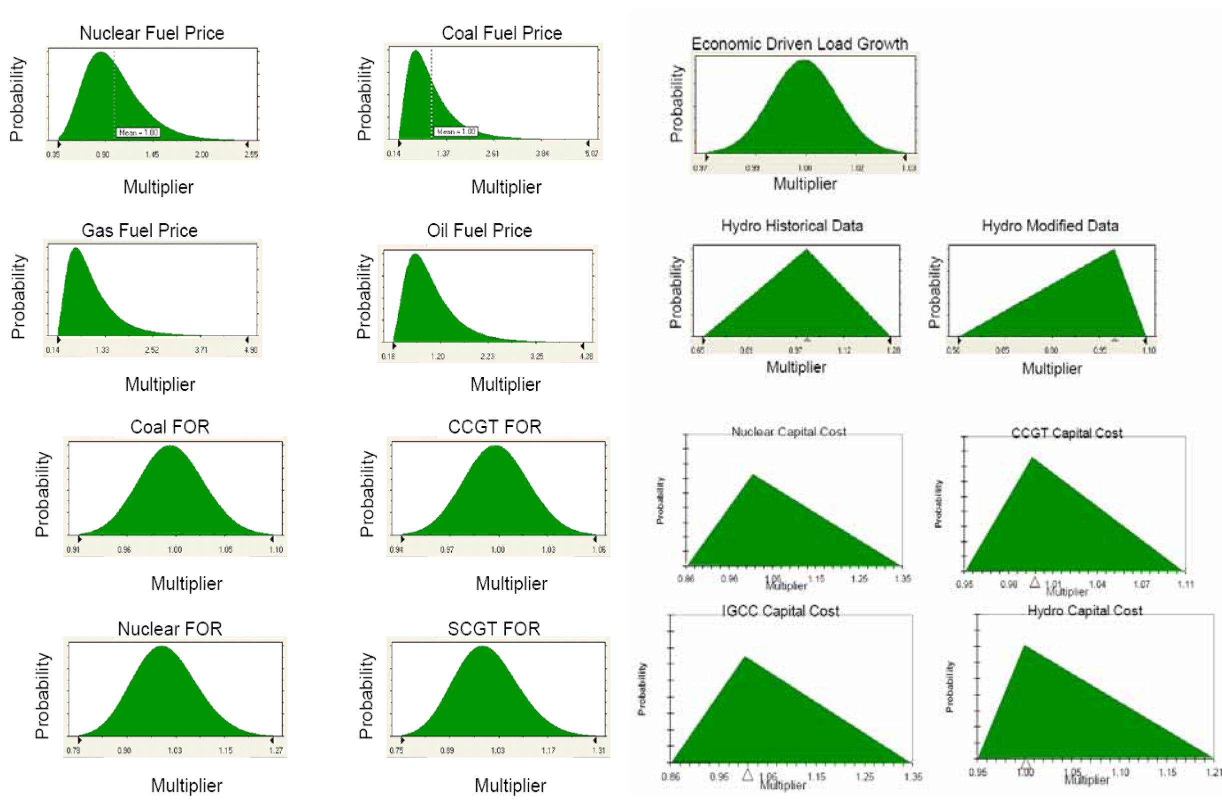
To quantify the impact of these risk factors on portfolio costs, the OPA employed the Monte Carlo simulation technique. Monte Carlo simulation is used to imitate the behavior of real-life systems, often in situations where a complicated system is subject to the effects of significant uncertainty in many inputs. The basic assumption underlying this type of simulation is that the behavior of the system can be well represented by functions and variables that, once defined, establish statistical distributions that can be sampled from randomly.

The Monte Carlo simulation employed by the OPA assumed the following with respect to the various simulation variables:

- Time horizon: an annual time horizon was assumed for each variable in the simulation process
- Distribution type: commodity prices are assumed to follow lognormal distributions, load growth is assumed to follow a normal distribution pattern, and capital costs are assumed to follow a triangle distribution pattern
- Variance parameters: load growth and interest rates are modeled with constant variance applications, and commodity prices are assumed to follow a random walk with mean reversion
- Correlation: the simulation incorporates cross-correlations between variables, notably commodity prices based on their historical interactions

Distributions for several risk factors are displayed in Figure 32.

Figure 32: Risk Factor Distributions

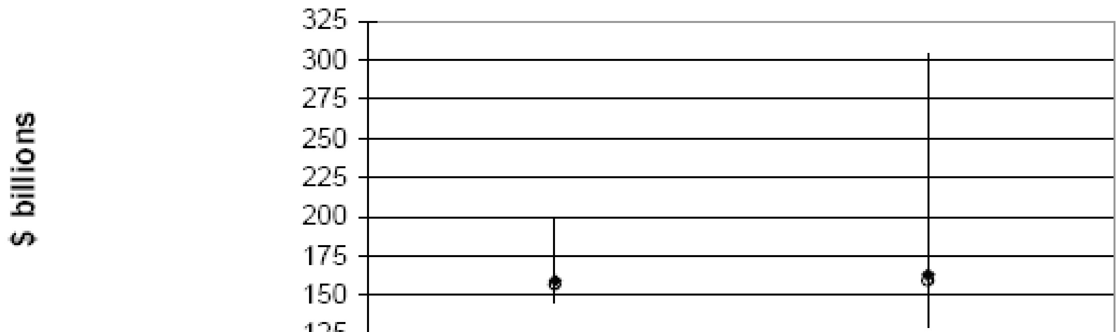


Source: Ontario Power Authority 2005 Analysis

For each portfolio, each iteration of the Monte Carlo simulation proceeded by randomly drawing values for each of the risk factor variables from defined distributions, and using these values to compute the portfolio's revenue requirement

NPV. This process was repeated 250 times to obtain a distribution for the portfolio's revenue requirement NPV.
The resulting distributions for each of the 10 portfolios were then compared. Figure 33 displays, for example, the range of portfolio costs, and maximum and minimum values, from the distributions derived for portfolios 1A and 1B.

Figure 33: Portfolios 1A and 1B Cost Comparison

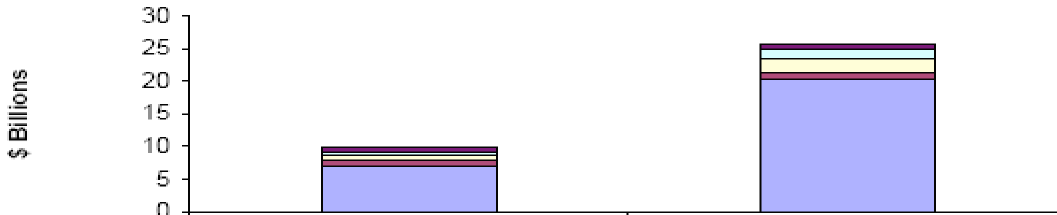


	Portfolio 1a	Portfolio 1b
Maximum	198.90	304.73
Minimum	145.33	130.26
◆ Stochastic Average	159.53	163.20
○ Deterministic Average	156.59	159.01

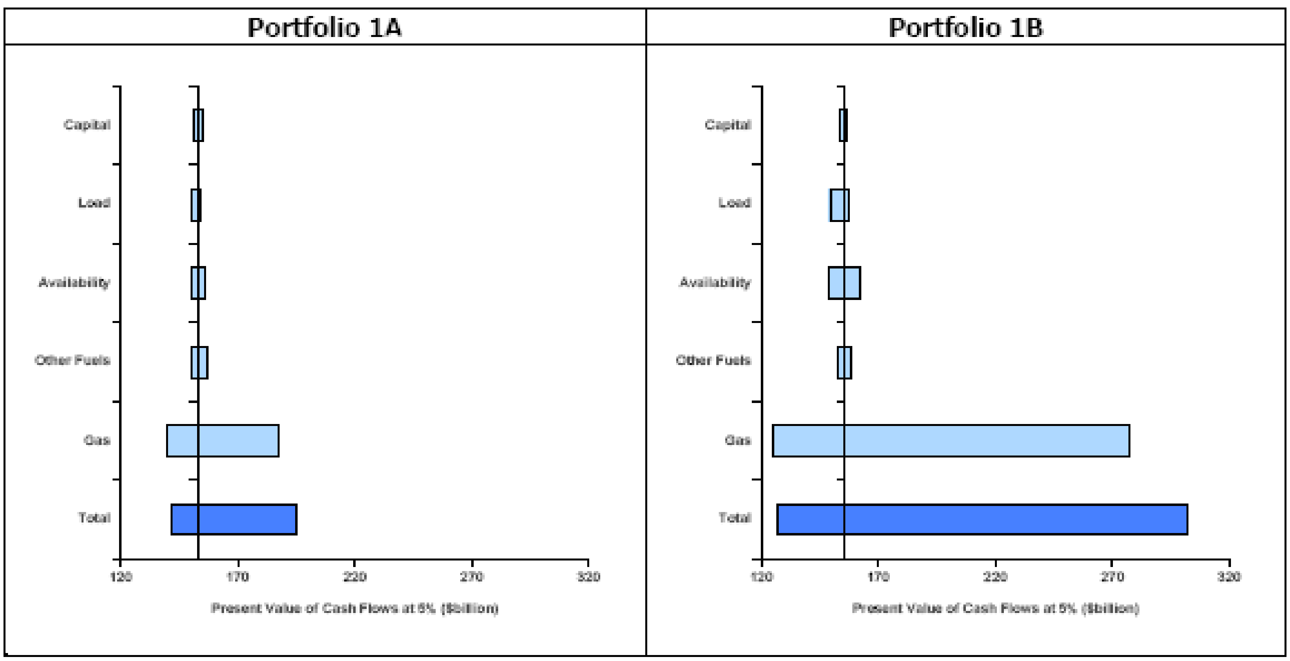
Source: Ontario Power Authority 2005 Analysis

The simulation results also allowed for identification of each individual risk factor's contribution to the portfolio's overall volatility. The top portion of Figure 34 displays not only that portfolio 1B is clearly more risky than 1A, with a much higher standard deviation of expected cost, but also that this difference is due predominantly to volatility associated with natural gas price. This is not surprising, since gas-fired generation comprises 51 percent of portfolio 1B and only 31 percent of portfolio 1A. The bottom portion of Figure 34 illustrates the impact of several risk factors on portfolio volatility.

Figure 34: Portfolios 1A and 1B Risk Analysis



	1a	1b
Capital	0.490236177	0.544455825
Load	0.53	1.55
Availability	0.85	2.21
Other Fuel	0.90	0.92
Natural Gas	6.97	20.30



Source: Ontario Power Authority 2005 Analysis

Portfolio Evaluation

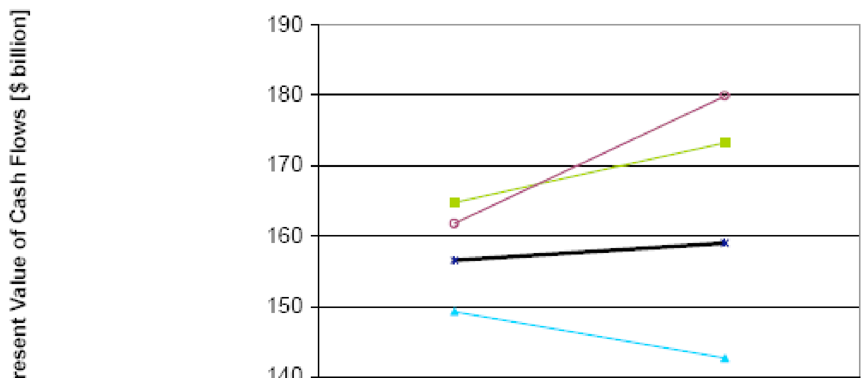
Within each of the five scenarios, OPA examined which of the two portfolios was preferable based on expected portfolio cost and the sensitivity of the portfolios to risk factors. Portfolio sensitivity was quantified by systematizing and extending the risk analyses described in the preceding section.

Changes to portfolio costs in response to one or more of the following changes to key parameters were determined:

- Climate change: results in low hydro availability, broader application of carbon mitigation costs, high wind incentives and low capital costs
- Low gas price
- Technology improvement: high gas price, low capital costs for fuel cells and wind power

Portfolio costs were determined for different scenarios defined by varying values and combinations of these three parameters. Figure 35 illustrates the results of such a sensitivity analysis for the Scenario 1 portfolios. The results indicate that Portfolio 1A is clearly more robust than 1B, which is more expensive under all scenarios except those assuming low gas prices.

Figure 35: Portfolios 1A and 1B Sensitivity Analysis

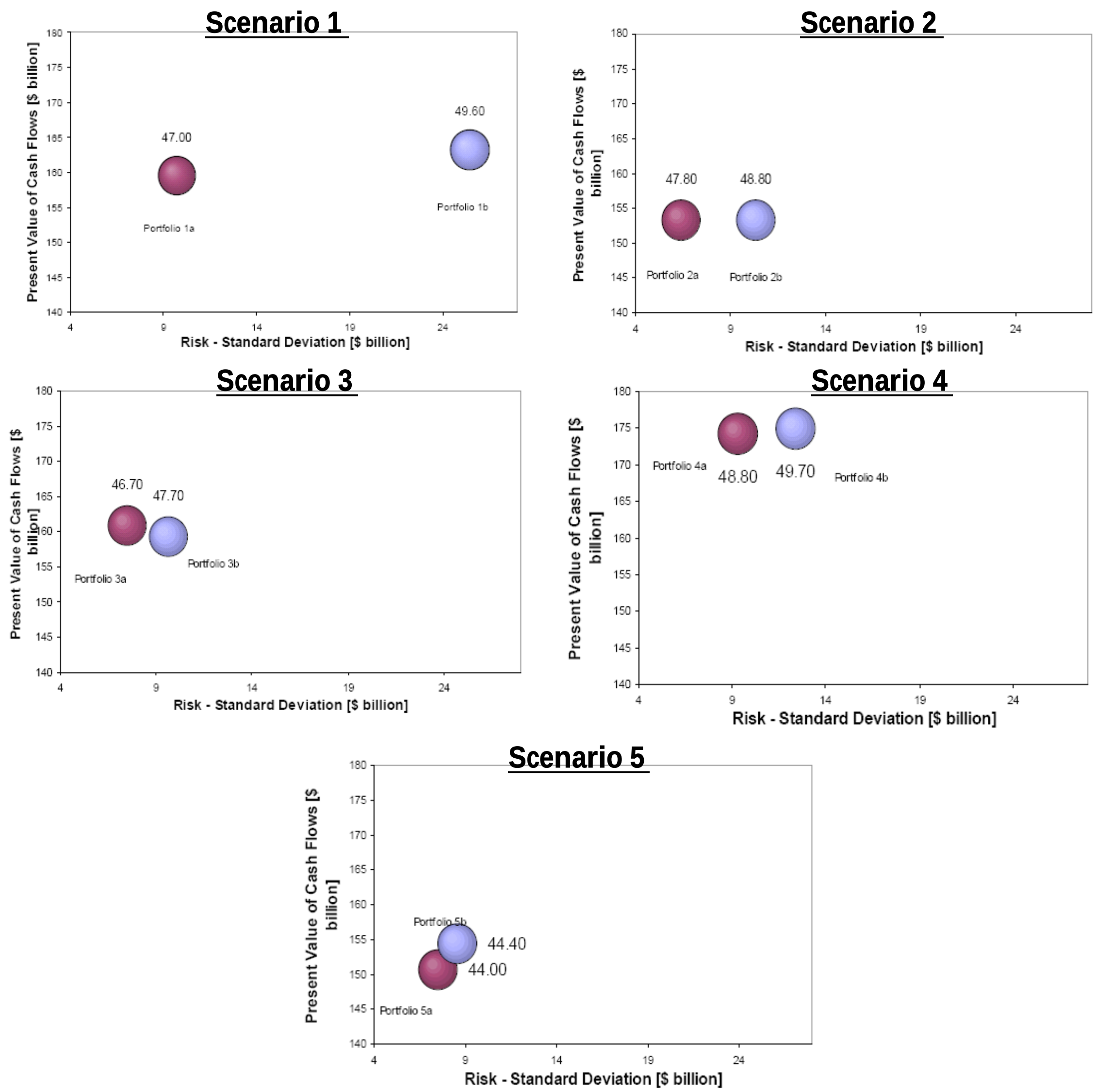


	Portfolio 1a	Portfolio 1b
Deterministic Average	156.59	159.01
Climate change	164.75	173.26
Low Gas Price	149.26	142.66
Technology Improvement	161.77	179.87

Source: Ontario Power Authority 2005 Analysis

The return/risk profiles of the two portfolios associated with each of the five scenarios are plotted within two-dimensional graphs in Figure 36.

Figure 36: OPA Portfolio Analysis Results



Source: Ontario Power Authority 2005 Analysis

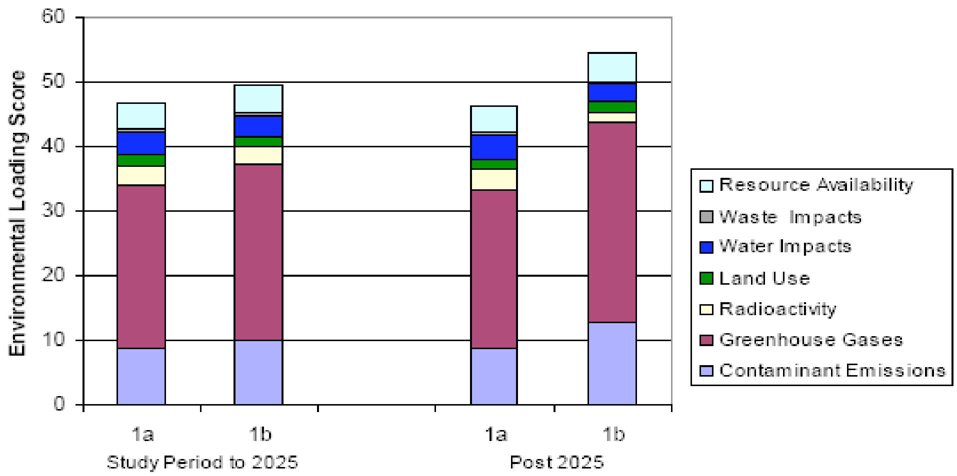
In addition to financial return and risk, the OPA also assessed environmental impact by assigning each portfolio an environmental load score based on the following parameters:

- Resource availability
- Waste impacts
- Water impacts
- Land use
- Radioactivity
- Greenhouse gases

• Contaminant emissions

Environmental scores were computed for two periods, one corresponding to the 20-year forecast period and the other for the years following the end of the forecast period. As the scores indicate amounts of negative environmental impact imposed by portfolios within specified timeframes, lower scores are preferred. Figure 37 presents environmental scores for the two Scenario 1 portfolios.

Figure 37: Environmental Load Scores for Scenario 1



Source: Ontario Power Authority 2005 Analysis

Based on the return/risk and environmental analyses, the OPA characterized the analytical results as follows:

- For scenario 1, portfolio 1B is more risky than portfolio 1A, as it is more reliant on gas-fired generation. It also has a greater environmental impact than portfolio 1A.
- For scenario 2, portfolio 2B is less expensive but more risky than portfolio 2A, as it is more reliant on gas-fired generation. It also has a greater environmental impact than portfolio 2A.
- For scenario 3, portfolio 3B is less expensive but more risky than portfolio 3A, as it is more reliant on gas-fired generation. It also has a greater environmental impact than portfolio 3A. Portfolio 3A is slightly more expensive than 3B due to higher investments in nuclear generation.
- For scenario 4, portfolio 4B is more expensive and risky than portfolio 4A, as it is more reliant on gas-fired generation. It also has a greater environmental impact than portfolio 4A.
- For scenario 5, portfolio 5B is more expensive and more risky than portfolio 5A, as it is more reliant on gas-fired generation. The difference in cost is attributed to

the fact that in portfolio 5B the conservation and demand management potential is recognized three years later than under portfolio 5A.

Based on these results, the OPA made the following observations and recommendations with respect to future technology choices:

- Conservation and demand management must be a major part of any IPSP
  - A level of 5 percent of total demand (1,800 MW) is recommended as appropriate
- Renewables offer considerable potential in the long term
  - Conservation and renewables (mostly hydro) could suffice to meet demand growth by 2025, but would not suffice in replacing retired capacity
- Gas-fired generation will be used in a targeted (limited) fashion
  - Not recommended for baseload operations, solely peaking
- Nuclear generation will continue to serve as baseload generation
  - Expected to continue contributing 50 percent of energy in Ontario
- Gasification with containment of carbon dioxide could possibly be included in the mix if the technology matures

Critique of Analysis

The OPA analysis is a truncated version of the more comprehensive form of portfolio analysis described in earlier chapters. Rather than employing algorithms to identify all possible portfolios and identify an efficient subset (i.e., frontier) within this population, the OPA constructed a small set of 10 possible portfolios and then analyzed those in detail.

The appropriateness of this approach must be evaluated in context. The objective of the OPA's analysis was to establish broad parameters for generation fuel mix within the IPSP, not to identify an optimal portfolio. The analysis is best understood as a step in a broader process rather than an endpoint—an attempt to identify generation technology mixes worth exploring further during Ontario's integrated power system planning process.

That said, it is worth noting that the process by which the OPA selected its 10 portfolios was informal and also politicized. The portfolios were constructed in accordance with various socio-political objectives defined by the Ontario Government. Issues that have been highly volatile politically in Ontario, such as the retirement of coal-fired units and the development of new nuclear facilities, were incorporated within the analysis in ways that were less than analytically rigorous. This approach runs the risk of excluding from consideration economically efficient portfolio combinations that would have been identified by a more automated and systematic portfolio construction and filtering process.

The return metric employed by the OPA, focused on minimizing the collective revenue requirements of generators within the portfolios, even when hourly market price forecasts were available from the running of a dispatch model, reflects the trade-off between price- and cost-based return metrics discussed in an earlier section of this report. The ideal measure of customer burden in a deregulated energy market is based on market prices. In this instance, because the analysis was conducted at the overall industry level, the compositions of the analyzed portfolios would impact (in fact, directly determine) market prices. Because market prices were forecast through the running of a dispatch model, the data was available, at least for computation of average expected prices associated with the portfolios. Despite this, the OPA still relied on the cost-based revenue requirement as the return metric. This was likely due to concerns over the intensive computational requirements for running the number of simulation iterations required to generate robust volatility estimates for each of the portfolios, combined with comfort in the assumption that, over the long-term, prices will be cost-reflective.

With respect to the mechanics for computing revenue requirement, the net present value computation includes a component reflecting portfolio costs beyond the 20-year forecast horizon. This is estimated by discounting a perpetuity value based on portfolio costs forecast for the last few years of the study period. This might not be a good estimate because portfolio composition can change dramatically over time periods for several reasons – e.g., units will be retired, heat-rates of existing units will deteriorate, new technologies might replace older ones, and costs for currently expensive technologies could decline.

While the OPA employed a conventional risk measure—i.e., one based on the volatility of the return metric—its treatment was unconventional in one respect. Each of the 10 constructed portfolios was defined with respect to a specific scenario. The five distinct scenarios incorporated different assumptions about future states of the world. A more traditional approach would have defined a single base case scenario and then incorporated all uncertainty associated with future states of the word within the estimation of the risk metric. Representing all aspects of uncertainty quantitatively—rather than partly through textual descriptions of scenarios—would have allowed for direct comparisons of each of the 10 portfolios rather than, as had been the case, only pairs of portfolios within each of the five scenarios.

An interesting and important aspect of the OPA's analysis was the manner in which it essentially added a third dimension—in addition to return and risk—to the portfolio comparisons. Environmental impacts were systematically quantified, albeit in non-financial terms. This is a very natural and logical extension of the standard portfolio analysis approach.

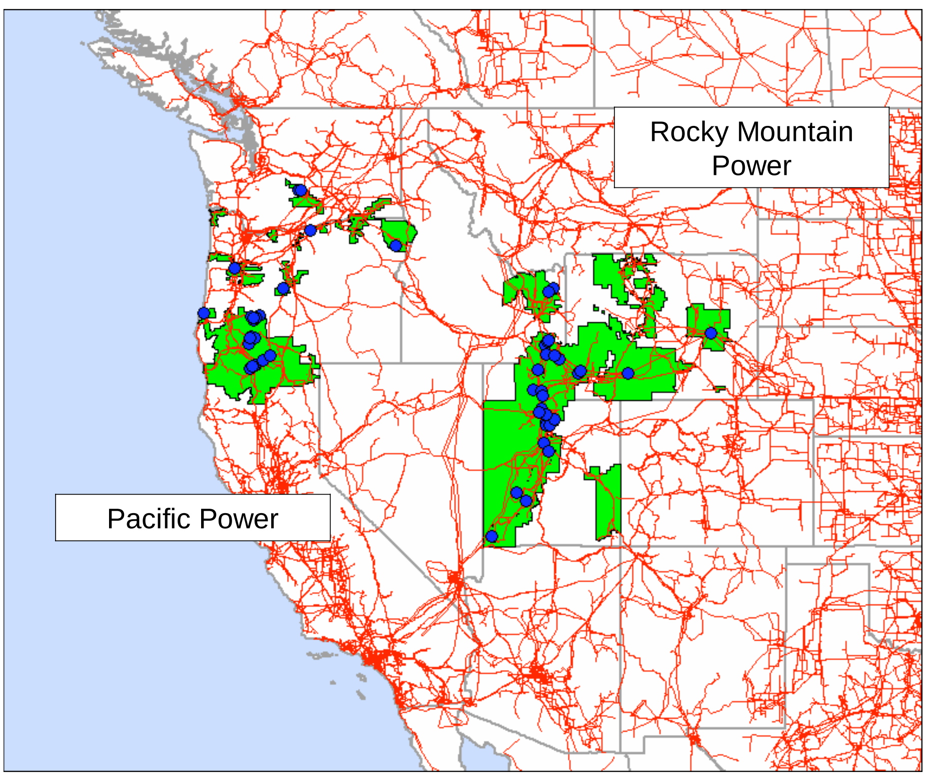
Pacificorp: Long-Term Procurement[3]

PacifiCorp is a vertically integrated, regulated utility operating in portions of the Western and Northwestern states of Oregon, Washington, California, Utah, Idaho and Wyoming. Its electricity delivery subsidiaries operate as Pacific Power in Oregon, Washington and California; and as Rocky Mountain Power in Utah, Wyoming and Idaho. Its generation, trading and coal mining businesses operate as PacifiCorp Energy. The company is headquartered in Oregon and was acquired by MidAmerican Energy Holdings Company in 2006.

PacifiCorp satisfies its load obligation through a combination of owned generation and (short-term and long-term) purchased power. Its mix of resources includes transmission, coal, gas, hydroelectric, renewables and demand side management programs. The firm attempts to maximize the value of its resource portfolio by selling excess power on the wholesale market when the economics of those transactions are favorable.

The largest portions of PacifiCorp's customer base reside in Oregon and Utah. A map of the firm's service area is displayed in Figure 38.

Figure 38: Service Areas of PacifiCorp (Including Major Transmission Lines and Generating Units)



Source: PacifiCorp

[3] This section was prepared by London Economics International LLC.

Every two years, PacifiCorp develops a long-range, 20-year plan identifying the least-cost alternatives for satisfying future electric demand in its service territories and maintaining reliability while not exposing ratepayers to undue levels of risk. The integrated resource plan seeks to integrate the overall resource needs of Pacific Power and Rocky Mountain Power across its different regulatory jurisdictions, spanning six states. This naturally exposes tensions between jurisdictions as none want to bear a greater cost burden than necessary to directly serve their constituents. Planning efforts have therefore played out to some extent as multi-state efforts to coordinate and determine cost sharing among the different states.

PacifiCorp begins by developing a base case based on extensive modeling, technical workshops, public input and business planning analysis, and then prepares a business plan. The business plan then forms the basis for request for proposal (RFP) solicitations for the resources identified in the IRP. The base case functions as a least-cost solution to anticipated resource needs based on a single-system modeling assumption, but it does not account for specific legislative and regulatory requirements within the states served by PacifiCorp. California and Washington, for example, have Renewable Portfolio Standard requirements. California restricts the use of coal plants to serve its load, and Oregon and Washington may in the future do the same. An RFP that solicits a large amount of coal-fired generation to serve its western system may therefore be met with resistance from western system stakeholders.

Specific state energy policies are addressed, as necessary, within the RFP approval process. Washington, Oregon, and Utah require RFP approval, whereas Wyoming, Idaho and California do not. When state level policies cause the business plan to deviate from the unconstrained least-cost solution, the firm seeks to recover additional costs from the states responsible.

This case study examines PacifiCorp's most recent long-term planning process, relying heavily on its 2004 Integrated Resource Plan, particularly Chapters 4, 5, 7, and 8.

Portfolio Development

PacifiCorp constructs its portfolios using supply side resources, demand side resources and market transactions.

Supply side resources include traditional generating options such as gas-fired generation (simple cycle or combined cycle); coal-fired generation; traditional pulverized coal or IGCC; internal combustion generation; renewable resources (wind, biomass, or geothermal); and hydro generation (pumped storage or conventional). Supply side resources also include distributed generation, which may be comprised of a number of technologies (i.e. microturbines, fuel cells, photovoltaic or PV, and wind turbines) and may be used in a number of applications such as stand-by power, peak shaving, combined heat and power, continuous-use power, and system reliability. These distributed resources carry unique risks to PacifiCorp since it may not be the entity responsible for maintaining or operating them.

Demand side resource options consist of Class 1, 2, and 3 resources. Class 1 resources are fully dispatchable by PacifiCorp; Class 2 are demand reduction; and Class 3 resources result from financial incentives offered to customers to shift load from peak to off-peak periods.

PacifiCorp also includes market transactions in its portfolios. All portfolio combinations explicitly account for transmission constraints between the eastern and western systems.

Measuring Returns

The return metric focuses on impacts to ratepayers in the form of present value of revenue requirement (PVRR).

This is, as described in the preceding case study, essentially the same measure employed by the OPA. Because most of PacifiCorp's customers pay regulated prices, revenue requirements provide in this instance a direct measure of customer cost impact associated with alternative portfolio choices.

Measuring and Accounting for Risk

PacifiCorp categorized risk into three categories: stochastic, scenario, and paradigm.

Stochastic risk refers to the uncertainty of different modeling variables and their deviation around their averages. Stochastic risk reflects uncertainty about future values of key parameters such as retail electric loads, natural gas prices, electricity prices, hydroelectric generation, and thermal availability.

Scenario risk applies to situations where there is a "large and consistent departure from the mean value." The change in gas prices from the late 20th to the early 21st century is an example of an element of scenario risk because prices did not merely fluctuate around an expected mean; they took a different path altogether. The key scenario risks identified by PacifiCorp were the possibilities of fundamental shifts in CO_2 emissions targets and gas prices.

Paradigm risk relates to situations that could force the company to fundamentally change the way it does business. The paradigm risks PacifiCorp considered were the formation of a regional transmission organization; federal imposition of renewable portfolio standards and/or multi-pollutant legislation; and deregulation (similar to that in Oregon) occurring in other states where PacifiCorp does business.

The firm's modeling tools included the firm's own spreadsheet model (used to measure supply, demand and reserve margins) and Henwood's MarketSym multi-area production cost model.

To perform its stochastic risk analysis, PacifiCorp developed distributions of future outcome values by varying key inputs and using deterministic and stochastic modeling techniques. It employed the Monte Carlo functionality of MarketSym to produce deterministic operational simulations and to randomly vary modeling inputs to introduce stochastic (probabilistic) elements to the key input variables: gas prices, electricity market prices, loads, hydro availability and thermal outages. Cross-correlations between these input variables were modeled into the simulations. The firm ran "all-in analysis" by altering all key input variables at once, and "spark spread analysis" by varying only gas and electricity prices.

To perform its scenario risk analysis, PacifiCorp tested the impact of different future operating environments such as those with high gas prices or high CO_2 emission compliance costs. It also incorporated a risk assessment from "non-modeling considerations" including factors such as technology risk and PacifiCorp's experience in operating different generation technologies.

Portfolio Evaluation

All portfolios were designed to maintain a 15 percent reserve margin for reliability. A key metric employed throughout the portfolio development process is the supply gap – i.e., the difference between projected load plus the 15 percent reserve margin and the projected supply. Portfolios were constructed based on the experience of PacifiCorp personnel in selecting resource types deemed to be best suited for filling the supply gap.

PacifiCorp began its analysis by identifying a "Reference Portfolio" that served as the benchmark against which all other portfolio combinations would be measured.[4]

Construction of the Reference Portfolio proceeded by focusing first on only supply-side options, screening all portfolios using a "Portfolio Scorecard" that measures and compares portfolios along the following metrics:

- PVRR
- Capital costs
- Emissions
- Market purchases
- Market sales
- Unit capacity factors
- Transfers

The end result of this assessment was selection of one supply side portfolio that included coal-fired, gas-fired, renewable, and hydro generation.

[4] The Reference Portfolio was also used for PacifiCorp as benchmark for RFP bid appraisal.

Following identification of the preferred supply side portfolio, PacifiCorp incorporated Class 1 DSM and simulated the resulting cost impacts. The introduction of Class 1 DSM that produced the largest reduction in the Reference Portfolio's expected PVRR, by allowing deferment of some supply side investments, was chosen. Class 2 DSM was considered next. Whereas Class 1, being fully dispatchable, can be modeled in much the same way as supply side resources, Class 2 was modeled as decrements to load and was evaluated on the basis of its ability to reduce system operating costs. Class 3 demand side resources and market transactions were incorporated next.

Given a defined Reference Portfolio, the company next developed a range of alternatives. Alternatives were developed by varying the components of the Reference Portfolio with respect to fuel type, technology, project start dates and location. Figure 39 presents examples.

Figure 39: Sample of Portfolio Development Process

Portfolio A: Reference Portfolio

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Utah-S						575					575
	Greenfiled IGCC	WY										368	368
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Wet Cool CCCT w/ DF	Utah-N									560		560
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

Portfolio B: Remove Utah PC, Replace with Gas

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Greenfiled IGCC	WY										368	368
	Dry Cool CCCT w/ DF	Utah-S				525		525					1050
	Wet Cool CCCT w/ DF	Utah-N									560		560
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

Portfolio C: Remove 2009 CCCT with IC Aero

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Utah-S						575					575
	Greenfiled IGCC	WY										368	368
	IC Aero SCCT	Utah-S				525							525
	Wet Cool CCCT w/ DF	Utah-N									560		560
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

Portfolio D: Defer Utah PC, Replace w/ Wet Cooled-CCCT

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Utah-S									575		575
	Greenfiled IGCC	WY										368	368
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Wet Cool CCCT w/ DF	Utah-N						560					560
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

Source: PacifiCorp 2004 Integrated Resource Plan

Portfolio A is the Reference Portfolio. It consists of two coal plants (a brownfield pulverized coal plant in Southern Utah and a greenfield IGCC (gasified coal) plant in Wyoming); three combined cycle gas plants (one in the west and two in the east); and a simple cycle gas plant in the west.

This benchmark was altered by changing the portfolio mix. Portfolio B replaced the pulverized coal plant in Utah with a gas-fired combined cycle. While this change increased fuel costs, it took advantage of the lower capital costs of gas combined cycle compared to coal, and also served to test the impact of greater emission cost credits due to the use of gas.

Portfolio C was designed to test how multiple simple cycle aero units would perform compared to one combined cycle plant. The total capacity size was held roughly the same as the Reference Portfolio, but the technologies were varied.

Portfolio D tested the impact of changing the sequencing of projects. Moving up the investment in gas combined cycle and delaying the pulverized coal plant allowed for analysis of the effects of increasing variable costs early while being able defer the larger capital investment required by the pulverized coal plant.

In addition to the portfolios displayed in Figure 39, PacifiCorp also created portfolios to test the affects of changing plant locations (to take advantage of different infrastructure) and using energy storage technologies. For each of these types of portfolio alterations, it performed a number of variations. In all, it defined and evaluated 23 distinct portfolios.

Evaluation of the portfolios proceeded by computing the cost (PVRR) and risk of each. MarketSym was employed to conduct Monte Carlo simulations. Probability distributions for key risk factors were fed as inputs to the Monte Carlo analyses, which produced, for each portfolio, an expected value and probability distribution for the PVRR metric.

PacifiCorp stress tested the candidate portfolios in several ways to evaluate changes to base assumptions or alternate supply options. One such test was, for example, changing the planning reserve margin. It was not expected that stress testing would be a significant factor in choosing an optimal portfolio; its purpose was to generate insights that could contribute to the development of the Action Plan used to implement the long-term strategy.

Critique of Analysis

This is a fairly standard application of portfolio analysis. Because the bulk of PacifiCorp customers pay regulated prices based on revenue requirements, the selected return metric – present value of portfolio revenue requirements – provides a good measure of customer burden. It appears that the firm was thorough in its analysis - it performed 100 simulations on each of 23 portfolios, generating robust measures of PVRR averages and volatilities across a range of portfolio combinations. While a more detailed simulation method, perhaps combined with an hourly dispatch model, would haven yielded more robust results, this would have come at the cost of additional time and effort required to compile the necessary date and establish the required detailed assumptions.

There are two ways in which the analytical approach might be improved. First, since Class 1 DSM is fully dispatchable and Class 2 DSM can be netted directly from load, additional emphasis might usefully be placed on incorporating these directly into the initial Reference Portfolio construction. There are complimentary benefits that can be derived from combining demand side and supply side resources within the same portfolio beyond the sole benefit recognized by PacifiCorp of reducing costs by deferring investments. Rather than employing deterministic scenarios to capture values of deferment, the analysis itself can be made more robust by using real options techniques to capture the value of delay across a number of different parameters. If incorporated earlier into the system operation and portfolio construction, DSM might reveal reliability benefits in the form of, for example, operating reserves (this is currently being tested in New England through a pilot program). Also, real option values can provide valuable insight into the optimal timing of renewables and DSM investment decisions.

Second, PacifiCorp unnecessarily incorporated a number of non-modeling risks in its assessment. These included its experience with operating different generation technologies and the ability of a new technology to 'live up to' the expectations set by the manufacturer. These non-modeling risks rely heavily on the institutional knowledge and biases of its planners and system operators. PacifiCorp and its customers may be well served to have this knowledge base tested and rigorously challenged. This could be accomplished by external consultants or trainers, and/or by participation in outside forums where utilities and independent power producers share their experiences.

Canadian Energy Company: Corporate Strategy Development[5]

A Canadian-based multinational energy company (Company) employed MPT to help develop its long-term corporate strategy. Scenarios considered included retaining its existing portfolio of primarily North American assets; transforming itself into a global energy company; and returning to its roots as a vertically integrated, regulated electricity or gas utility. This case study reviews this analysis.

While this case study is not directly related to procurement or integrated resource planning, it highlights an application by an energy company of the basic MPT techniques in a broader context.

Portfolio Development

The Company's analysis evaluated five asset allocation bundles (each with a market value approximately equal to the Company's current market value at the time of the analysis) as follows:

1. Minimum Disturbance portfolio, which relies on the Company's current allocation;

[5] This section was prepared by London Economics International LLC.

2. Western Electric Hybrid, which combines the Company's current allocation with selected regulated electricity companies;
3. Western Gas Hybrid, which combines the Company's current allocation with selected regulated gas companies;
4. Continental Genco, which combines the Company's Canadian assets with a mix of generation plants in the U.S.; and
5. Global Genco, which combines the Company's Canadian assets with assets in the U.S., Australia, and Gulf Cooperation Council (GCC) countries[6].

These portfolios are summarized In Figure 40.

Figure 40: The Model Portfolios

Portfolio	Description
Minimum Disturbance	Replacement of the Company's exhausted assets with new assets of the same type with regards to country allocations, fuel, and source of revenues.
Western Electric Hybrid	Consists of 50% of the Minimum Disturbance portion and the 50% from selected electric utility companies in the Western Interconnection.
Western Gas Hybrid	Comprises of 50% of the Minimum Disturbance portion and the 50% from selected gas utility companies in the Western Interconnection.
Continental Genco	Includes 40% of the Minimum Disturbance portion and 60% of other US assets. These assets are 65% in MISO (coal), 15% in New York (hydro), 20% in ERCOT (15% gas and 5% wind).
Global Genco	Consists of 40% of the Canadian portion of the Minimum Disturbance and 20% in New York, 20% in GCC, and 20% in Australia.

Source: London Economics International LLC

The portfolios were developed using both quantitative and qualitative techniques to demonstrate different risk–return possibilities for the Company. The Western Electric Hybrid and Western Gas Hybrid portfolios, which assume that the Company will replace half of its assets with electric or gas utility assets in the Western Interconnection, embody a shift in the Company's overall strategy towards becoming a regulated utility. Continental Genco, on the other hand, emphasizes the generation business by replacing 60 percent of the Company's existing portfolio with generating assets from different U.S. markets. Global Genco also emphasizes generation, but with a broader, international, focus, combining assets within Canada, the U.S. (New York), Australia, and the Gulf.

[6] Gulf Cooperation Council consists of Bahrain, Kuwait, Oman, Qatar, Saudi Arabia and United Arab Emirates.

Scenario Definition

The five candidate portfolios were evaluated under three different scenarios: Global Economic Moderate, Global Economic Weakness, and Global Economic Strength. The characteristics of these scenarios are summarized in Figure 41.

Figure 41: Characteristics of the Three Evaluation Scenarios

	Global Economic Weakness	Global Economic Moderate	Global Economic Strength
fuel price volatility	low	medium	high
gas prices	low	base	high
coal prices [relative to gas]	plateau	gradually rising	rise due to switching
emissions regime	less cap & trade, earlier CO_2	current, cap & trade, gradual CO_2	no CO_2
treatment of renewables	early phase in of mandatory RPS	voluntary, compliance, long lead time	voluntary only
technological improvements in IGCC technology	1% in every 3 years	3% in every 3 years	5% in every 3 years
load growth	lowest observed 10 years	as projected	2nd highest observed five years
siting flexibility	high	current	NIMBY-plants far from load
Province-specific ties	increase tie within Canada	reduction in internal constraints	increase MT frontier tie
increased nuclear capacity	unexpected early closures	no new nuclear capacity in 10 years	3000 MW online within 7 years

Source: London Economics International LLC

The Global Economic Weakness scenario assumes that: future gas prices and fuel price volatility will be low, the government will tighten the emission regime, there will be an early phase in the mandatory RPS, IGCC technological improvements will move at a relatively fast pace, there will more flexibility in siting, and more imports from other Canadian provinces.

The Global Economic Moderate scenario assumes that: the existing cap and trade for emissions will still hold in the coming years, there will be a gradual implementation of the emissions regime, the use of renewables will be on a voluntary basis, and no new nuclear power plants will be built in the next ten years.

The Global Economic Strength scenario assumes that: load growth will be high; prices for fuel, gas, and coal will be high throughout the long-term; there will be no substantial increase in prices if there is no CO_2 emissions regime; compliance with the RPS is voluntary; development of IGCC technology will be relatively slow; and new nuclear power plants in specific markets underlying the portfolios will be online in seven years.[7]

[7] New nuclear capacity was incorporated only in markets with existing nuclear capacity.

Portfolio Evaluation

The portfolios were evaluated by, first, forecasting Company financial results with respect to earnings before interest, tax, depreciation and amortization (EBITDA) under each of the three scenarios; and then employing multivariate regression analysis to relate the forecasted EBITDA values to key drivers.

The specific steps are as follows:

1. Forecast EBITDAs for 2006 to 2016.
2. Run the regression model using the load and price data averaged across regions and technologies.
3. Bootstrap[8] the regression equation to get upper and lower estimates of parameter coefficients.
4. Determine the key drivers' and scenario parameters' effects on the regression's explanatory variables.
5. Using the explanatory variables adjusted for the Global Economic Strength and Weakness scenarios, and upper and lower estimates of the coefficients, calculate the estimated values for Weakness and Strength EBITDAs.

Several econometric models with EBITDA as the dependent variable were developed and tested with factors such as load growth, energy prices, fuel costs and macroeconomic parameters employed as explanatory variables. Because the primary purpose of the analysis was to compare portfolios, the same structural model was employed for all portfolios[9]. The best performing model, displayed below, was a log-linear[10] equation regressing the natural logarithm of forecasted EBITDAs on natural logarithms of peak load, average (yearly) energy price and average fuel costs.

$$\ln(\text{EBITA}) = \quad + \quad {}_1 \ln(\text{load}) + \quad {}_2 \ln(\text{energy price}) + \quad {}_3 \ln(\text{fuel price}) +$$

where load is the weighted average of the peak loads; energy price is the weighted average of annual energy prices; fuel price is the weighted average of gas and coal prices in relevant regions; each represents the impact of changes to the associated variable on EBITDA; and and are artifacts of the statistical technique with no economic interpretation.

8 Bootstrapping is a standard resampling method for obtaining standard errors, confidence intervals and p-values for test statistics. It is essentially a Monte Carlo simulation where the observed sample (the values from 2001 to 2016, in this instance) is treated as the population. Each bootstrap iteration is a random sample drawn from this population by using several probability distribution functions.

9 Each individual portfolio was fit best by a distinct equation. The one displayed above provided the best overall fit across all five portfolios.

10 The log-linear form—that is, the natural logarithm of a variable—is widely used in econometrics, particularly when variables are measured at different units.

Energy and fuel prices were based on the Company's estimates, when available, or Independent System Operator (ISO) reports. Load data was derived from the ISO reports. Weights were based on generation capacity in each geographic market as well as production technologies.[11]

The regression was run using estimated annual observations (e.g., estimated value of EBITDA and explanatory effects of load growth and prices). A bootstrapping method was then employed to get higher and lower bounds for the estimates of the regression coefficients. Bootstrapping was used to capture the effects of variables not included in the regression equation on the global economic Weakness and Strength scenarios.[12]

Finally, the effects on the chosen explanatory variables of some of the scenario parameters that were easily quantified were determined. Reflecting the unique characteristics of the different portfolios, distinct parameter values were estimated for each of the portfolios.

Analytical Results

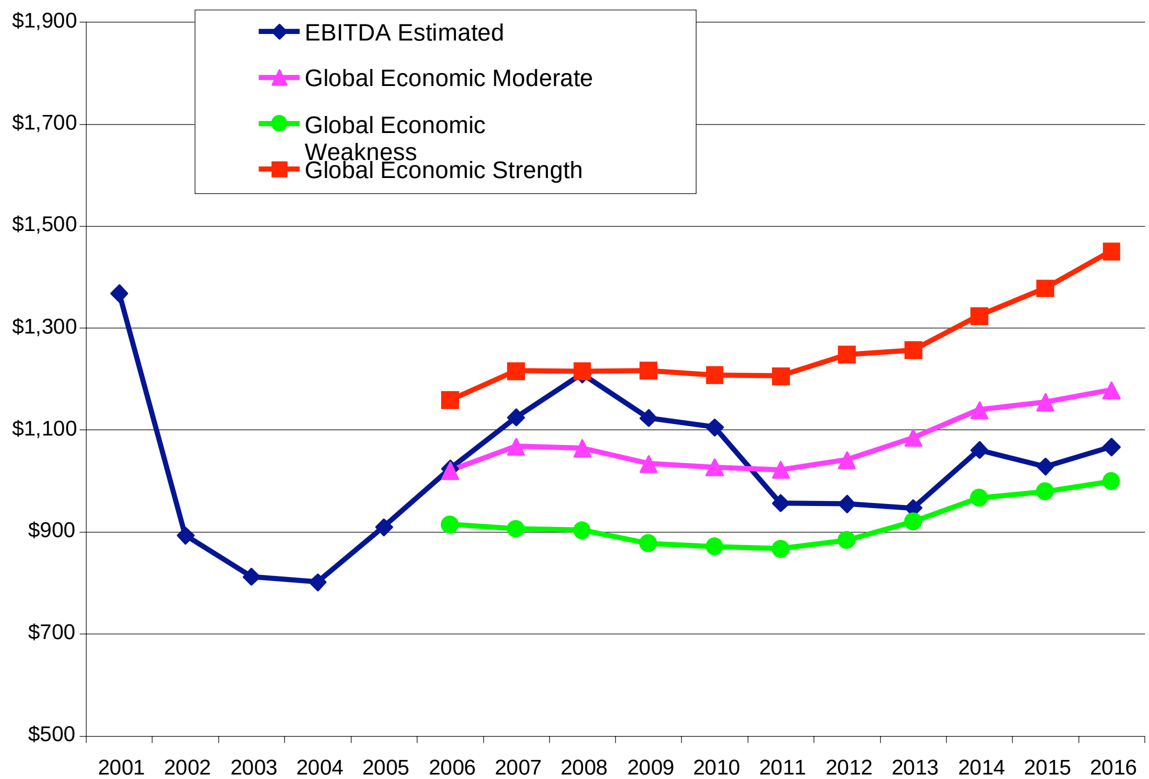
Four forecasts were developed for each of the five portfolios. The first is a base case reflecting the estimation of future EBITDAs, assuming the company keeps its investment structure unchanged, that is, replacing expiring contracts and retiring units with similar assets along the way. The other three forecasts assume three different investment strategies that the company is considering. All four of the forecasts were applied across the three defined scenarios: Global Economic Moderate, Weakness, and Strength.

Minimum Disturbance Portfolio

Results are summarized in Figure 42. The EBITDA of the portfolio was estimated as the sum of the Company's plant-by-plant EBITDA estimates. The CE Generation portion, which is contracted, is estimated by using the historical data as well as the Company's estimates on energy and fuel prices. Fluctuations in the estimated EBITDA are due mostly to the Company's plant-by-plant estimates and are clearly reflected in the Moderate results displaying annual EBITDAs fluctuating between $1 million and $1.2 million.[13]

[11] Analysis of the regression results confirmed that they were robust to the selection of different weighting criteria, such as, for example, weights determined by EBITDA contributions.
[12] The coefficients of explanatory variables included in the equation will likely inadvertently capture some of the effects of variables not included in the equation.
[13] The dollar figures are in real terms, independent of inflationary trends.

Figure 42: Minimum Disturbance Forecasts

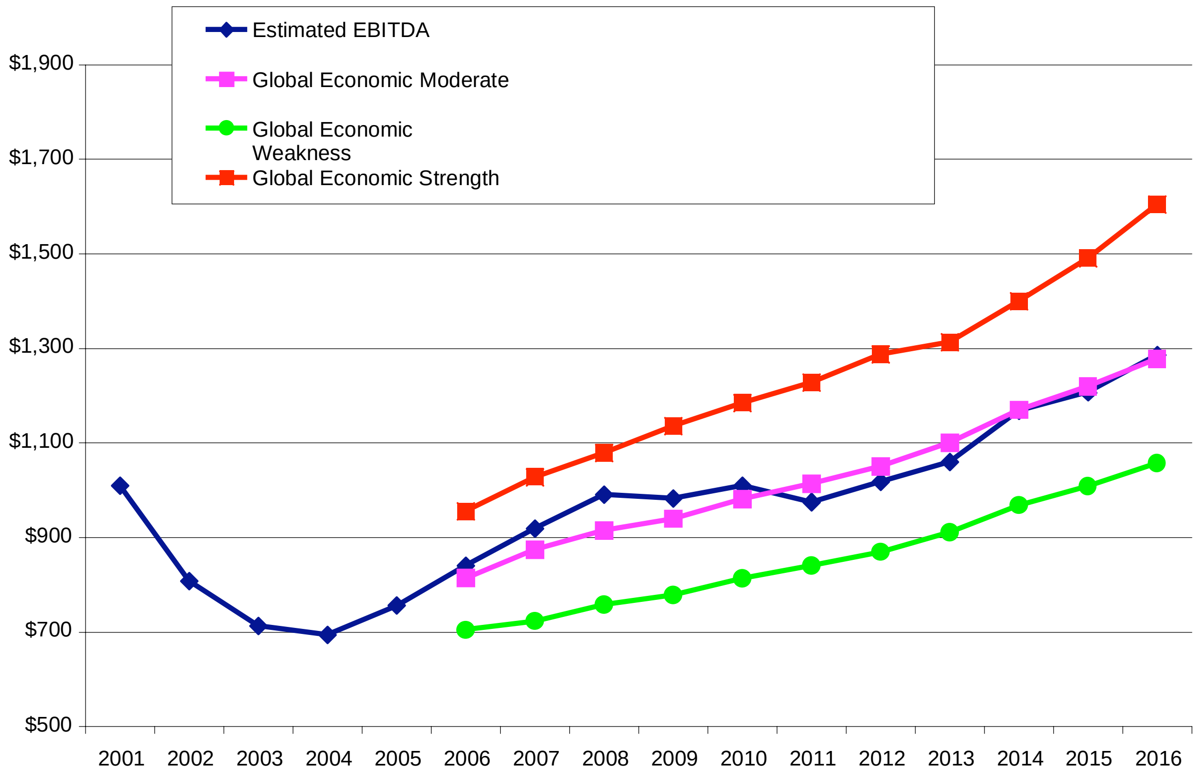


Source: London Economics International LLC

Western Gas Hybrid Portfolio

Results are summarized in Figure 43. EBITDA is estimated as the sum of the Company's Minimum Disturbance EBITDA and previously selected gas utilities' EBITDAs. Since each portion comprises half of the portfolio in market capitalization, the EBITDA values are adjusted accordingly using 2005 values. The future EBITDAs for the selected companies are based on averages of financial analysts' growth forecasts reported by Bloomberg. This EBITDA forecasting approach creates smooth trajectories that reduce the annual fluctuations of the generation component in the Minimum Disturbance. Therefore, the EBITDAs are forecast to gradually rise from $0.8 million to $ 1.3 million under the Moderate scenario.

Figure 43: Western Gas Hybrid Forecasts

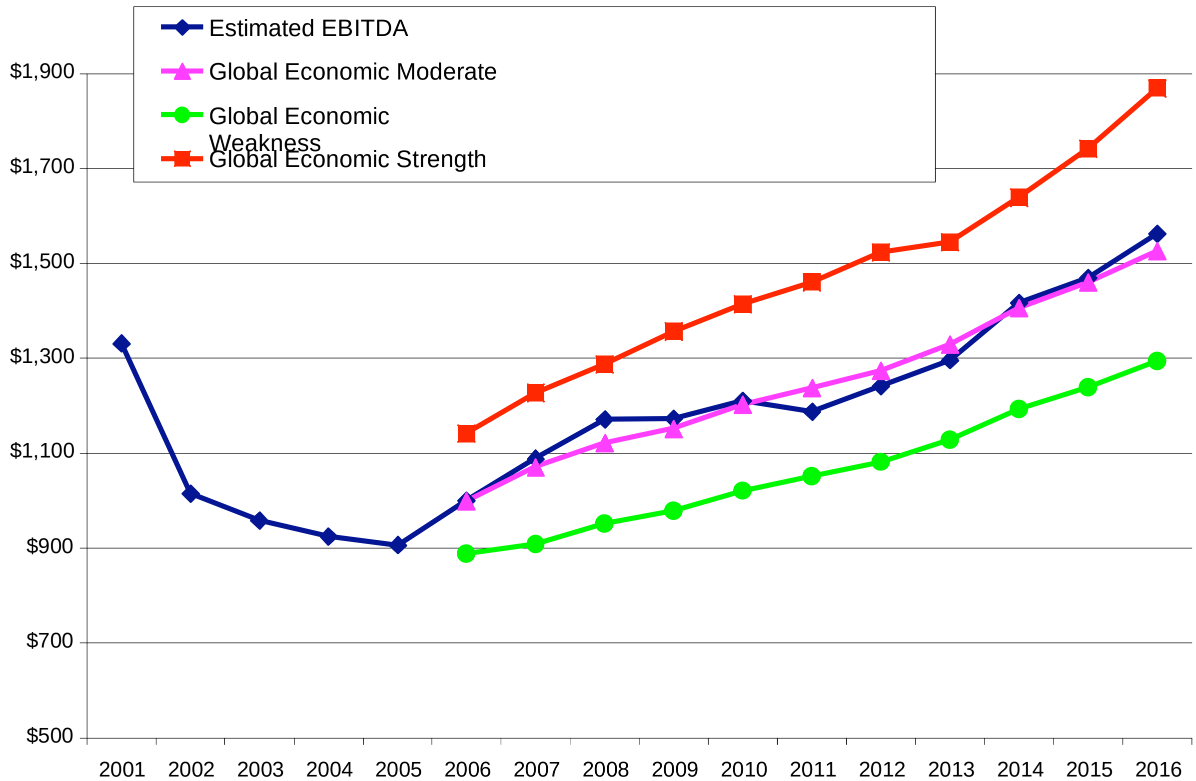


Source: London Economics International LLC

Western Electric Hybrid

Results are summarized in Figure 44. Similar to the Western Gas Hybrid portfolio, averages of financial analysts' growth forecasts were used for the electric companies and again had the effect of smoothing the trend lines. The estimated EBITDAs are higher than for the Gas Hybrid portfolio, rising from $1 million to over $1.5 million. This reflects the fact that analysts expect sharp increases in energy prices.

Figure 44: Western Electric Hybrid Forecasts

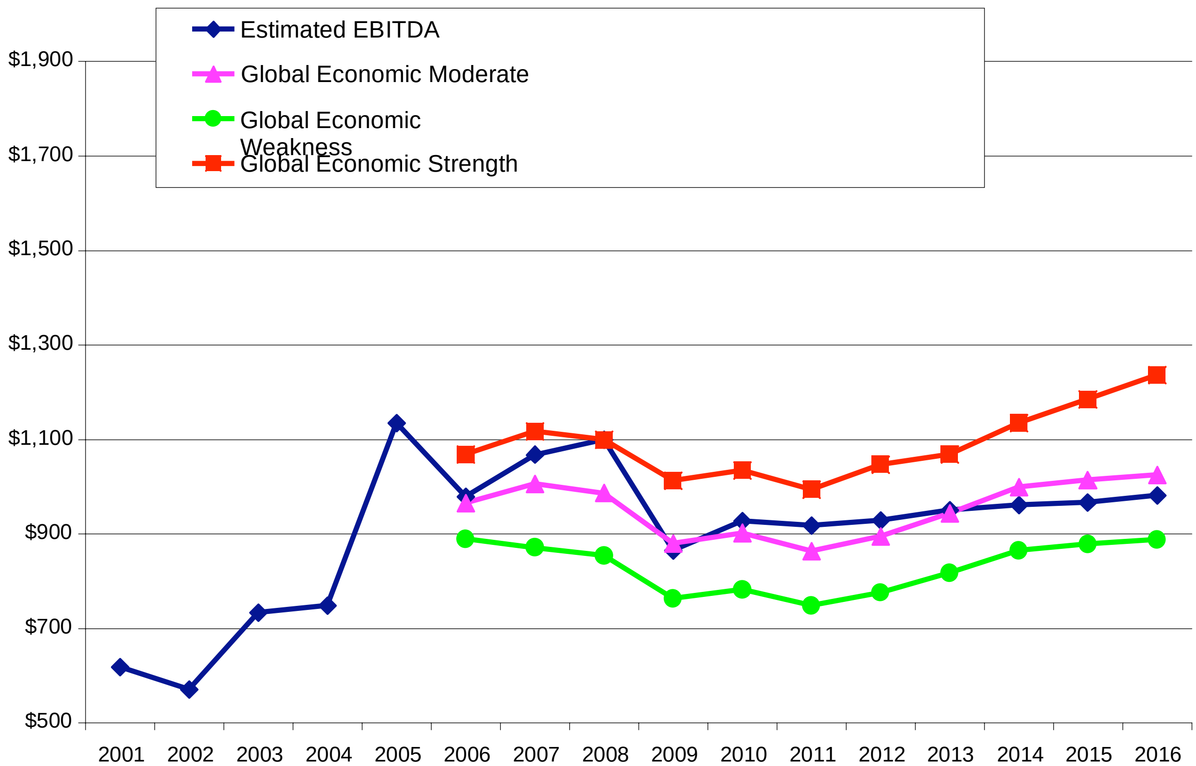


Source: London Economics International LLC

Continental Genco

Results are summarized in Figure 45. The Continental Genco EBITDA estimates are based on the Company's Alberta estimates as well as estimates of representative coal, hydro, gas and wind powered plants in the MISO, NY and ERCOT markets. As in the historical case, the growth prospects are not very high for a continental generation portfolio. Estimated EBITDAs range between $0.85 million and $1.1 million under the Moderate scenario.

Figure 45: Continental Genco Forecasts

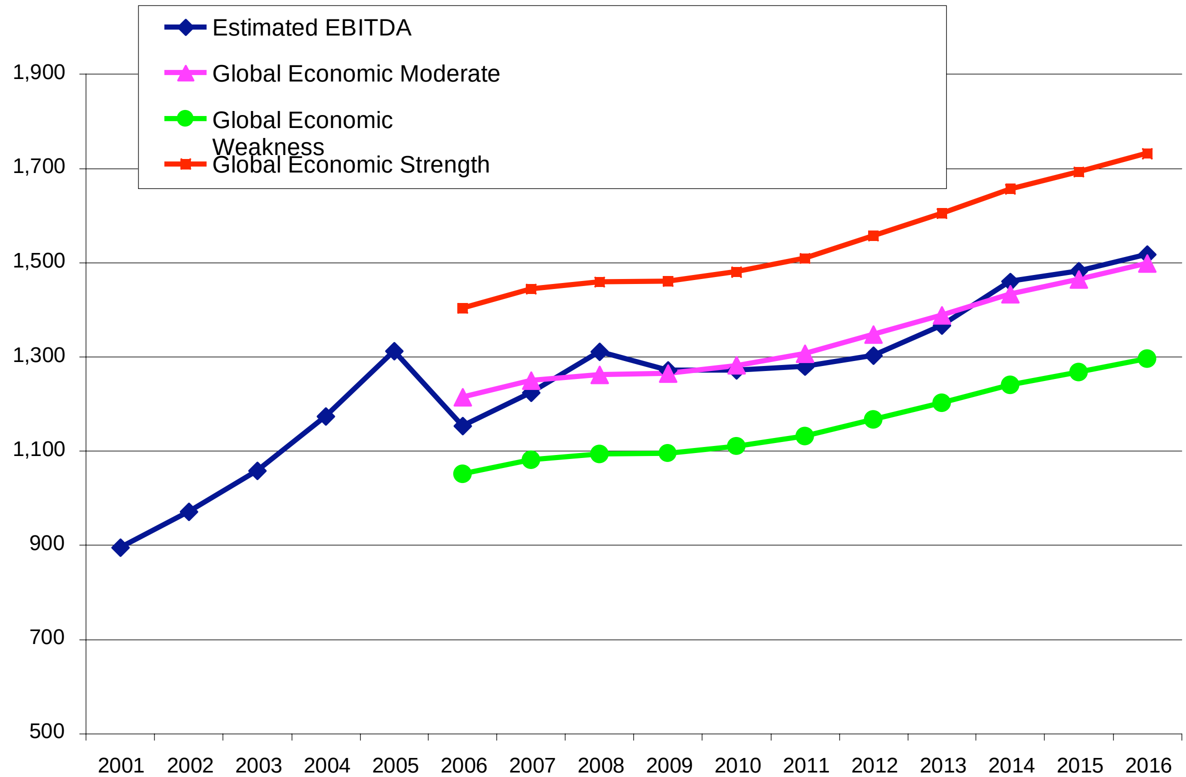


Source: London Economics International LLC

Global Genco

Results are summarized in Figure 46. As for the Continental Genco portfolio, the EBITDA estimates of the non-Canada portion of the Global Genco portfolio were based on estimates of representative plants in N.Y., Australia, and GCC. Data availability, especially the futures of selected parameters for the GCC plants, was a major issue. Also, the overseas comparisons of basic macroeconomic parameters oversimplified the interactions. While the regression results were strongly significant, the Global Genco estimation performed poorly compared to the other portfolios. Estimated annual EBITDAs are estimated to rise gradually from $1.2 million to $1.5 million.

Figure 46: Global Genco Forecasts



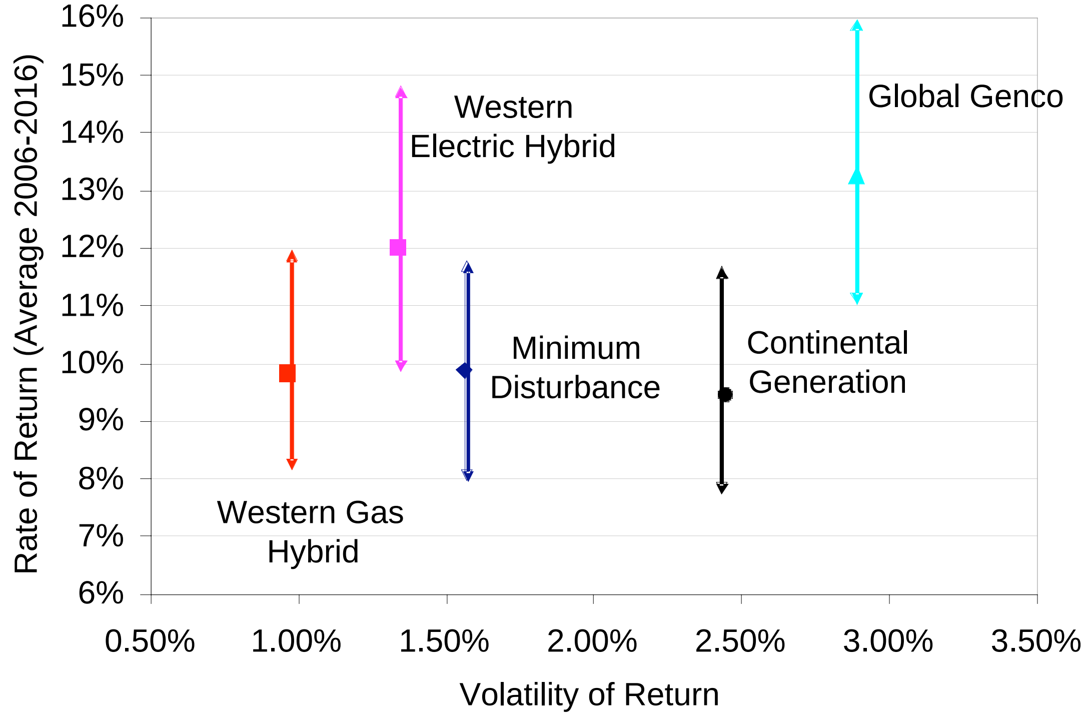
Source: London Economics International LLC

Risk – Return Analysis

For each of the portfolios, the EBITDA parameter was converted into a return metric by dividing the EBITDA value by the market value of the associated portfolio. The estimated rates of return for the five portfolios between 2006 and 2016 were plotted against volatility estimates. As there was a concern about developing forward-looking volatility estimates, volatility was estimated entirely on a historical basis, employing data between 2001 and 2005. Because EBITDA forecasts for several of the portfolios were developed using smoothed annual projections - which highlight secular trends by eliminating short-term fluctuations - estimates of volatility based on the observed standard deviation of these forecast values would likely have underestimated the true volatility of the EBITDA variable.

The resulting return/risk graph, displayed in Figure 47, demonstrates the expected average rate of return versus historical volatility of return for all five portfolios. The ranges around the expected values represent the confidence intervals derived from the simulation analysis.

Figure 47: Risk – Return/Risk Analysis



Source: London Economics International LLC

Figure 47 identifies an efficient frontier composed of Global Genco and the Western Electric and Gas Hybrids. The other two portfolios—Continental Genco and Minimum Disturbance—are inferior options.

The company is currently in the process of evaluating alternatives for its restructuring. One consideration is to simultaneously purchase more international generation assets and one or more electricity and/or gas utilities. The target for an optimal portfolio may be a hybrid of the Global Genco and Western Electric and Gas Hybrid Portfolios.

Critique of Analysis

The analysis was carried out to help determine the medium- to long-term investment strategy for the company. Given this broad focus, it was decided to create a small set of portfolios, each reflecting a specific strategic focus. These informally constructed portfolios were then evaluated rigorously and quantitatively, and the results of these analyses were used not only to choose among the competing portfolios (that is, investment strategies), but also to more precisely define specific strategic and tactical choices within the portfolios. For example, the geographic placement of generating assets across different regions within the Global Genco Portfolio was analyzed with standard risk-return analysis. As with OPA, the analysis was conducted within a broader context, as an input to a broader decision-making process.

Data unavailability and incompatibility complicated the analysis. Each portfolio choice covered a wide range of generating assets, fuel types and technologies. For example, natural gas price forwards and coal price forwards were reported for different timeframes and were not consistent geographically. The analysis relied on market forward prices whenever possible, and employed internal forecasts as necessary. This introduced inconsistencies because some assets' EBITDA estimations were based predominantly or entirely on forward prices, while others were based mostly or entirely on forecast data potentially embodying very different assumptions about future price trends.

Finally, as mentioned above, estimation of the risk metric was based entirely on historical data. While a technical aspect of this analysis did make it difficult to establish forward-looking volatility estimates, this does not change the fact that use of purely historical data implicitly relies on the assumption that the future will, with respect to the structural character of the key risk factors, be like the past. It is not clear how carefully the Company examined the basis for this assumption.

CROSS CUTTING ISSUES AND IMPLICATIONS FOR CALIFORNIA[14]

A few basic challenges reveal themselves in the Ontario Power Authority (OPA), PacifiCorp, and Canadian Energy Company case studies reviewed above. This section identifies and discusses these issues, with emphasis on the way they impact challenges facing California. For some, the experiences of other entities point toward recommendations for how California should proceed. In other instances, the case studies raise questions that remain to be answered.

The common issues and lessons learned can be organized within the following three categories:

- Determining the objective and scope of the analysis
- Distinguishing stochastic from scenario risk
- Employing the efficient frontier, once identified, as an input to an analysis that is less quantitative and automated than the process of constructing the frontier

These issues are discussed below.

Analytical Objective and Scope

Any analysis must, of course, begin with a clear and clearly articulated understanding of its basic nature and central purpose. There are four key questions

[14] This section was prepared by London Economics International LLC.

that need to be answered in preparation for conducting a portfolio analysis, as follows:

1. From whose perspective is the analysis to be conducted?
2. What is the appropriate objective function (that is, return metric)?
3. What is the appropriate geographic scope of the analysis?
4. Who should conduct the analysis?

For an analysis of optimal generating portfolios, an analysis can be conducted from the perspective of a generating company or from the perspective of consumers within a defined market.

Our recommendation is that California adopt a consumer perspective. The reasoning is partly philosophical—that is, the industry, and the firms within the industry, ultimately exist for the purpose of serving consumers—but also primarily mechanical. As discussed in an earlier section of this report, it is not clear that a company should be expected to want to diversify its operating assets along the lines prescribed by Modern Portfolio Theory (MPT). The essential logic of MPT is that investors can and should diversify their financial holdings (their holdings of stock in various companies). To the extent this is true—and there is substantial evidence that investors can and in fact do diversify their financial portfolios—it is not clear what benefit any individual firm provides by diversifying its operating assets (because if they don't diversify, so that significant idiosyncratic risk remains at the level of the firm, stockholders can easily diversify this away by investing in other companies). By this logic, attempts to diversify may not be worth the corresponding costs in terms of shifting organizational core competencies and distracting managerial attention.

In contrast, most consumers have no way, or at least no easy way, of diversifying the risks of volatile electricity prices. They would therefore benefit from steps taken to ensure that the portfolio of industry assets providing service to them is diversified in ways that reduce price volatility.

While an analysis focused on the firm would, consistent with the basic organizational goal of maximizing profits, naturally employ an objective function in the form of a financial return, a customer-focused analysis should aim to minimize customer burden. Most of the time, the objectives of either maximizing firm financial returns or minimizing costs are perfectly consistent. For example, in deregulated markets, firm profits, all else equal, are increased and consumer burden is decreased when fuel, operations & maintenance and capital costs are reduced.

But there are instances where the different objective functions will produce meaningfully different results. Consider, for example, a regulatory policy that allows generators to directly pass through the costs of natural gas to consumers. The justification for this policy is that, since generators have little control over the costs of gas, it is appropriate to protect them from the risk of gas price volatility. But within the context of a portfolio analysis, a policy that strongly connects prices to costs will reduce the volatility of the financial return metric employed by companies (which takes the form of price minus costs) without any corresponding reduction in a consumer burden measure (which will be based solely on price or cost, not the difference between the two). An analysis conducted from a company's perspective, with a financial return metric, will very likely more strongly favor natural gas generators than an otherwise equivalent analysis performed from the consumer's perspective with a return metric reflecting consumer burden.

A return metric for an analysis from the consumer's perspective would, ideally, incorporate market prices, because when portfolio compositions are expected to impact market price, these provide the most direct measure of the burden imposed on customers. When the appropriate industry models are available, and there is adequate time and budget to run the simulations necessary to generate both average return and also volatility values, this is the preferred approach. A reasonable alternative, when dealing with smaller portfolios (relative to the size of the overall market) or when the requisite computations are unmanageable, is to establish a cost-based return metric to be minimized. This could take the form of cost / kWh or, as employed by both OPA and PacifiCorp, annual revenue requirement.

When generating assets are regulated, as in the case of PacifiCorp, use of a cost- rather than price-based metric does not raise any concerns. Because prices are tied either directly or closely to costs within traditional cost of service based-ratemaking and also, albeit to a lesser extent, various incentive ratemaking schemes, a focus on costs within a portfolio analysis provides a very good proxy for prices to be imposed on consumers. When generating assets are unregulated, as was the case for the OPA's analysis, the connection between costs and prices is weaker, and there is a possibility, particularly within short time periods, that prices will deviate significantly from costs. Within this context, the justification for the cost-based measure is the expectation, rooted in economic theory that over the long-term prices in a well-functioning market will be cost reflective. The logic breaks down when a market is not well-functioning. If, for example, a firm felt it had market power, so that decisions about generating portfolios are expected to impact not just costs but also market price, a focus on price rather than cost would yield different results.

With respect to analytical scope, if a portfolio analysis is to be conducted from the perspective of a company, the appropriate scope of the analysis is the company's assets (which may lie entirely within one geographic electricity market or, as in the case of PacifiCorp, may cut across several markets). If the analysis is to be conducted from the consumer perspective, the appropriate scope is the overall market or a specified portion of the overall market.

For California, the potential geographic markets are the entire Western Electricity Coordinating Council (WECC) area, California Independent System Operator's (California ISO) control area or zones within the California ISO control area. In theory, the market is best defined as the WECC area. However, practical considerations may militate in favor of a narrower, California ISO-centered, market construction.

If an analysis is to be conducted at the level of a market rather than a single company, then difficult questions about how to organize the analysis arise. An entity must be assigned responsibility for conducting, or at least coordinating, the analysis. Particularly if the analysis is to be based on costs, some portion of the data will need to be provided by companies, some of which may have concerns about data confidentiality. The required coordination, difficult under any circumstances, becomes considerably more challenging as the geographic scope expands, particularly when it crosses, as will be the case for the WECC area, several state and other jurisdictional boundaries.

Another important decision to be made is whether an industry-level institution, such as the Energy Commission, or the IOUs themselves, should conduct the analysis. In the current structure, IOUs are required to submit long-term procurement plans, and incorporating a portfolio analysis would be relatively simple. On the other hand, three different analyses will create inconsistencies in the methodologies and computational details, and hence will not be comparable. That said, it is perhaps possible that individual firms can be directed to perform specific components of an analysis that would be directed and coordinated by an industry-level institution.

Stochastic and Scenario Risk

A risk metric associated with a defined variable is generally understood to reflect the volatility of observed values of the variable over time. Within the context of a portfolio analysis, the variable at issue is the return measure, and the volatility measure is forward-looking (i.e., forecasted).

There are various ways to operationalize the concept of risk and to perform the required forecasting exercise. Analysts structure risk analyses in different ways. We believe that the most important distinction for practical (computational) purposes is between what we call stochastic risk and scenario risk.

Stochastic risk reflects variability in accordance with a distribution that has been developed based on an assumption that the underlying variable will behave in a manner similar to the way it has in the recent past. Scenario risk reflects the possibility of a fundamental shift in the distributional characteristics of the variable.

This distinction is not a strict and entirely quantitative one. In formal, quantitative terms, the characteristics of variables that are at issue include mean (first moment), variance (second moment), skewness (third moment), kurtosis (fourth moment) and cross-correlations with other key variables. The general sense is that a risk analysis is stochastic when it is based on future distributional assumptions that are similar to observed historical distribution with respect to the various distributional parameters identified above. In contrast, the purpose of a scenario risk analysis is to leave open the possibility of structural changes in future behavior of a variable relative to what is reflected in historical data. That said, there is no defined standard for what qualifies as “similar” or as a “structural change.” This is determined by the judgment of the analyst.

In quasi-epistemological terms, stochastic analysis is meant to reflect uncertainty related to “what we know we don’t know,” while scenario analysis is meant to reflect uncertainty related to “what we don’t know we don’t know.”

Consider the example of natural gas prices. A stochastic analysis conducted at the end of the previous decade, functioning within defined distributional parameters, would have forecasted future gas prices in the range of $2 to $3 per million cubic feet, with very small likelihood of observing prices at the significantly higher levels that have become common this decade. That sort of structural shift is best understood as entailing what is essentially a distinct scenario, a new and fundamentally unpredictable state of the world.

Having established a conceptual distinction between stochastic and scenario risk, the critical question is how the distinction should be operationalized for computational purposes within a portfolio analysis. The three case studies discussed above provide illustrations of three distinct approaches.

The OPA analysis defined a set of five scenarios and then defined five portfolio pairs, each pair associated with one and only one of the portfolios. The Canadian Energy Company, in conducting its strategy analysis, defined five portfolios and three scenarios, with all scenarios applicable to all portfolios. The portfolio risk analysis was then organized within two components – a stochastic component (running identified risk factors through defined distributions) and a scenario component (integrating the defined distributions for the key risk factors within alternative economic contexts defined by each of the three scenarios). PacifiCorp, while having defined and thought through the issues in terms of both stochastic and computational risk, essentially collapsed the two components into one for computational purposes—that is, all uncertainty was reflected in distributional assumptions. With this approach, the effects of scenario assumptions (recognition of prospects for the world to change significantly) are manifest within variable distributions that are wider (more volatile) than they would have been without consideration of new scenario possibilities.

The approach employed by PacifiCorp has the advantage of quantifying all portfolio risk aspects on comparable terms, thereby facilitating direct quantitative, and seemingly objective, comparisons of portfolios. This advantage comes, as is almost always the case when complicated dynamics are reduced to a small set of (distributional) parameters, at the cost of losing some of the richness of the scenario details.

In contrast, the OPA developed textual and quantitative descriptions of its scenarios, with the scenarios collectively covering such a wide range of future state of the world that each identified portfolio was deemed to be valid within only one scenario. This, for better and for worse, produced a result that allowed for – indeed, demanded - considerable interpretation and debating of appropriate next steps for addressing unresolved issues. While strictly quantitative comparisons of the portfolios were impossible, the study assumptions and results were rich in the sort of detail that, upon examination, often yields great insights. This approach is best applied as an intermediate step within a broader analysis.

The approach of the Canadian Energy Company represents a middle ground between the two extremes. All portfolios are applicable across all scenarios and therefore are comparable quantitatively. But because the stochastic and scenario risk components are quantified separately, risk becomes a multi-dimensional, and therefore less analytically tractable, measure.

Each of these approaches can work well, depending on the basic objectives for the analysis. Without a better understanding of how California intends to apply portfolio analysis, it is not possible to recommend one approach over others. That said, as the Energy Commission is currently in the process of completing an intensive analysis defining a set of nine scenarios for future evolution of the California and broader WECC electricity systems, an approach that maintains and emphasizes the structural integrity of the scenarios (for example, OPA and Canadian Energy Company), rather than collapses scenario volatility within standard stochastic distributions, perhaps seems a preferable path.

In all cases, simulation techniques were employed. As the alternative – analytical specifications of cross-correlations between all identified risk factors – is generally not practical, development and deployment of simulation models may be most suitable for California.

Beyond the Efficient Frontier

As discussed above, depending on how scenario risk is incorporated within a portfolio analysis, the results might yield a single efficient frontier (PacifiCorp), a set of frontiers than can be compared quantitatively (Canadian Energy Company) or a set of frontiers that can be compared only qualitatively (OPA). Even in the case where a single frontier is identified, additional analysis is required for policy making purposes. There are three basic issues.

First, a point on an efficient frontier must be identified for the purpose of defining a target portfolio. If the analysis were performed at the company level, then the correct measure of corporate risk tolerance is the firm's weighted average cost of capital. This figure tends to be readily available.

When the analysis is performed from the consumer perspective, the appropriate figure is less conceptually clear. There are several options. The first is to develop a figure that is comparable to a corporate weighted average cost of capital. This could perhaps be computed as an average (perhaps weighted by some measure of company size) of the weighted average costs of capital of major firms in the industry providing customer service. This approach rationalizes corporate service providers as agents, making investments on behalf of consumers. Another option is to perform econometric analyses to impute estimates of consumer risk tolerances based on various types of consumer behavior such as hedging and demand side management. Such analyses require the availability and collection of significant amounts of data, most likely from several sources, and will likely yield results that are reflective of only a portion of the customer base (more likely the industrial and commercial, rather than residential, sectors). Another approach is to directly engage consumers through meetings and/or formal surveys. While this has the advantage of directly engaging consumers in the process, it is the least quantitatively rigorous.

The second issue is that there may be important issues not fully reflected in the analysis generating the efficient frontier. The two dimensions traditionally employed for portfolio analysis, average return and risk, are denominated in financial terms and generally capture the full range of concerns to both companies and consumers in a narrow commercial sense. But just as this report has argued that it is appropriate to conduct portfolio analyses from a consumer perspective, that is, broader than the perspective of an individual company, it is in some instances appropriate to expand the scope of the analysis even further, to encompass considerations impacting broader social welfare.

The classic example of such considerations is environmental impact—for example, the impact on society of emissions such as CO_2, NOx, and SOx. Ideally, the costs of environmental impacts associated with electricity generation (or, alternatively, the value of avoiding such impacts) would be quantified in financial terms and incorporated within the return and volatility metrics. Then, the narrow commercial and broader societal impacts can be evaluated and compared on a common (financial) basis.

Techniques do exist for estimating the cost associated with environmental impacts in strictly financial terms. For example, where markets exist for trading permits for various types of emissions, market prices can be employed as a measure of the costs associated with emissions. However, such market prices are not a pure, objective reflection of the inherent cost associated with an emission; they are determined, in part, by the institutional characteristics of the market (in particular, the number of allocated permits).

If it is considered difficult or impossible to reduce environmental impacts to dollars, then the alternative is to informally compare the financial results to non-financial (but generally quantitative) measures of environmental impact. The criterion for evaluation should be established at the early stages of the study. Both OPA and PacifiCorp employed a score-card, an analytical device that structures the analysis by assigning scores (what are essentially weights) to various financial and non-financial factors deemed to be important. This approach clearly incorporates considerable elements of subjectivity. Some see this as a weakness in that it does not even attempt to establish a common, and seemingly objective, basis for comparison; others see it as a strength in that invites a richer dialogue on the issues than would likely result from a more reductionist approach.

Finally, once a target portfolio has been identified, a process must be established to move from the current situation to the target. If the analysis were performed by a company with respect to the company's own portfolio, then the adjustment process would be planned and driven by management. But, if the analysis were conducted from a consumer perspective, it is not clear how an adjustment process should be managed and directed. Even if an agency were identified that retained the authority to direct the investment (and divestment) decisions of individual companies, the results of the analysis, while indicating the nature of a required adjustment for the overall industry, would not provide guidance on which specific corporate portfolios should be adjusted.

The question of what can and should be done, from a policy perspective, with a consumer-focused portfolio is a challenging one. The next section on Implementation Issues presents further issues and questions that the Energy Commission staff recommends be considered by the Commission in its deliberations regarding future long-term planning policy.

CHAPTER 7: IMPLEMENTATION ISSUES

This chapter will discuss general issues associated with the implementation of a long-term planning method. There are numerous issues regarding the details of the specific analytical method that could ultimately be implemented, such as the risk and cost parameters to include, discount rates, wholesale gas and electric price projections, etc. Discussion of the precise method as well as the assumptions required for the actual analysis are properly the subject of a series of workshops or hearings that would bring together a broad representation of stakeholders and regulatory agencies. The devil is in the details, however; the substantial uncertainty surrounding future gas prices, emission costs, technological advance, etc., has implications for the efficacy of a process intended to evaluate the risks associated with different utility portfolios *and guide future policy decisions*. Here, staff presents broader, more general issues that must be considered prior to the detailed issues noted above.

Deep Uncertainty and the Resource Planning Process

> [Deep uncertainty exists] where decision makers do not know nor cannot agree upon the system model that relates action to consequences, the prior probabilities on the inputs to the system model(s), or the value function that ranks the desirability of the consequences. (Groves and Lempert, 2007)

Historically, utilities and regulators largely considered cyclical risks in the planning process, focusing on the cost and reliability consequences of plant outages, low hydro years, near-term fluctuations in demand, and increases in the natural gas price that were, if only implicitly, assumed to be transient. A key characteristic of these risks is their being amenable to quantitative evaluation using historical data. This fact allowed parties to reach consensus regarding the modeling of these risks, and thus their perceived magnitude.

The most significant risks associated with utility resource planning today are long-term risks characterized by marked uncertainty. While parties may generally agree as to those variables that determine ratepayer costs and the underlying model which relates them to each other, there is anything but general agreement as to the range of values that these variables may take on during the coming ten to twenty years. The probability distributions that describe potential future values of key drivers not only have “wide tails”, we cannot confidently assign probabilities to “likely” prices, much less more extreme ones:

- Forward prices can be used to forecast near-term natural gas prices; the volatility of the gas price over this period can be estimated using, among other tools, recent data on options prices. But, even though such prices are available six years out, these markets are notoriously illiquid beyond two years or so. Longer term forecasts must be extrapolated from forward prices or make use of fundamentals models, which require assumptions regarding natural gas market conditions over the long term. Historical data provides a very uncomfortable basis for a probability distribution of the long-run natural gas price.

- Estimating carbon risk requires assumptions about future restrictions on carbon emissions and the costs associated with them. These are all the more heroic given uncertainties about the details of the regulatory mechanism to be put in place as a result of AB 32. Even more uncertain are the longer-run costs of meeting emission reduction goals; as newly constructed generation resources have a life of thirty years of more, resource planning decisions made today will influence the ability to meet reductions required well beyond the ten-year planning horizon and the cost of doing so. Historical data, e.g., offset costs in existing markets, provide questionable guidance. Their use in resource planning implicitly places a cap on the future cost of emissions: decisions that are made based on an assumed cost of $10/ton CO2 may prove to be regrettable if and when society comes to place a higher value on their reduction.
- The forecasted cost of energy from many sources depends upon assumptions regarding the rate of technological advance. As cost-competitive generation technologies proliferate, a greater number of assumptions will have to be made regarding the future costs of energy from alternative sources, assumptions for which historical data provides little, if any guidance.

Finally, even the significance of these longer-run uncertainties can be altered by assumptions regarding the value of time. The choice of the rate at which to discount future costs can effectively assume way the impact, good or bad, of decisions that we make today. There are marked differences of opinion regarding the discount rate that is appropriate for resource planning; it is very likely that the value of time for utility shareholders is different than that for ratepayers, indicating that utility assumptions regarding the discount rate may differ from those considered appropriate by other stakeholders.

The potential lack of consensus regarding the extent of the various risks faced by ratepayers has substantial implications for the process used to evaluate them in at least three respects.

First, it raises an issue regarding the use of methodologies which assign distinct probabilities to the future values of key drivers of ratepayer costs. Once these probabilities have been assigned, the trade-offs between ratepayer cost and risk can be evaluated for the set of potential resource portfolios, but it must be kept in mind that these results are likely to be sensitive to the probability distributions used. It is for this reason that the NWPCC runs sensitivity cases: to explore the impact of assumptions about the range and likelihood of future values of key drivers on the resulting cost-risk trade-off. The alternative is an assessment methodology that does not assign probabilities to futures or to values of variables that characterize them, but merely presents ratepayer costs under a variety of scenarios. This has the advantage of not requiring the monetization of environmental costs, for example, CO_2 emissions. Not only are the future values of these costs subject to substantial uncertainty, there can be marked and irreconcilable disagreement as to their appropriate value even if they are administratively set. Whereas fuel costs are a financial outlay, parties may hold environmental costs to be other than those indicated by an accounting entry or opportunity cost.

Second, the uncertainty surrounding long-run values of key variables indicates that, whatever assessment methodology is used, the range of values of these drivers over which portfolios should be evaluated should be larger, rather than smaller. The probability of long-run gas prices being higher or lower than assumed by PG&E in their 2006 LTTP, for example, is certainly non-zero. If the resulting costs of a portfolio are alarmingly high in a very high gas-price future, policymakers can then consider the likelihood of such prices, or the possibility of developing “off ramps” as such a portfolio is developed over time.

Third, likely disagreement regarding the appropriate range of values to assume for key variables indicates that, without guidance, utilities may use dramatically different values for these variables in assessing the costs and risks associated with potential portfolios. Utility assumptions regarding the future cost of renewable energy in their 2006 Long-term Procurement Plans provide an example of this, with SCE assuming higher costs than PG&E and SDG&E. Requiring the use of common planning assumptions by each utility facilitates comparison across utilities of the effects of changes in market conditions and the impact of policy decisions, as well assessing the aggregate impact of each. To the extent that assumptions regarding these drivers are comparable across utilities, the aggregate impacts of portfolio choices and policies which influence or constrain them can be more easily evaluated. The use of common assumptions may also contribute to the transparency of the resource planning process, allowing for a public discussion of assumptions that are now held confidential. For example, short run gas price forecasts are now considered proprietary. If commonly agreed upon price trends and alternative scenarios were to be used (specific prices could vary by service area), there would be no need for confidential treatment of that parameter.

Common Planning Assumptions and the Resource Planning Process

As evidenced by the 2006 Long-Term Procurement Plans filed before the California Public Utilities Commission, the IOUs vary substantially in their planning assumptions. Differences exist in their views about possible future states of the world, price and supply projections, availability of resources, etc. Differences in utility assumptions regarding the future values and ranges of values for such variables as the gas price, and CO2 and renewable energy costs need not solely reflect substantial uncertainty about the future; these risks, in fact, are likely to differ by utility. Depending upon the details of the emission reduction mechanism to be developed pursuant to AB 32, the range of potential CO2 costs may differ substantially depending upon how reduction requirements are allocated and the role played by relatively high-emission resources in the utilities’ existing portfolios. The costs of meeting renewable energy targets will depend upon decisions regarding the use of renewable energy credits (RECs), the supply of renewable resources in the utilities' planning areas, the availability of transmission, and the eligibility of out-of-state resources to meet RPS requirements. Finally, gas prices and their volatility will, albeit only slightly, differ across utilities.

If the underlying probability distributions for key drivers of ratepayer costs vary by utility, and such variations are of meaningful size, these variations can be incorporated into an analysis of a utility's portfolios. While a generally common set of assumptions can be used, an "expected value" that deviates somewhat across utilities can be used as they are suggested and supported. For example, small differences in expected gas prices can be assumed if indicated, but the broader range of gas prices over which portfolios are evaluated should be similar for each utility. This will not only provide policymakers a basis for comparing the performance of each portfolio under a common set of futures, but encourage the development of a wider range of portfolios to subject to analysis. For example, while the resource planning process should provide an opportunity for utilities to present evidence regarding the likely cost of a preferred resource, requiring that a range of costs for that resource be assumed facilitates the development and consideration of portfolios that are suggested over that range.

At some point, however, differences in the underlying distributions of key drivers across utilities, may suggest the use of different assumptions by each utility. The CPUC has acknowledged the differences between utilities and the desire to consider these in the resource planning process. As stated in D.04-01-050 (January 2004):

> *"The federal and state legislatures, the Federal Energy Regulatory Commission, and this Commission have set a number of criteria through which utilities are to meet their obligations to their customers,* [*placing*] *the utilities in the position of having less discretion than in the past in determining the best combination of resources with which to meet the needs of their customers and of the state. Therefore, the work of the utilities in forming long term plans is less a matter of Integrated Resource Planning under generalized criteria using a proverbial "clean sheet of paper" than it is a process of "filling in the boxes" to satisfy requirements that have been set up by others…The integrated resource planning we seek to achieve would provide a comprehensive context for all of a utility's resource decisions and would include the following features…*
>
> *Each utility would develop a base plan that would take into account least-cost resources, reliability needs, fuel diversity, and other risk management concerns. On the local level, the utility would determine the optimal way to meet demand (whether it would be through energy efficiency, demand reduction, transmission or distribution additions, distributed generation, renewables, or fossil generation)"* (pp. 95-97).

If a regulatory planning mechanism is to facilitate achieving state policy goals in a least-cost fashion, the mechanism should take advantages of differences in the relative costs of preferred resources across utilities. Doing so, however, requires confidence on the part of regulators that values reported by the utilities themselves are likely to reflect actual underlying differences in the costs of preferred resources and not other factors, which might include differences in the methodologies and assumptions used in forecasting their future costs.

Resource Planning and Policy Targets

The ideal planning process would begin by considering a wide range of available resource options so that a large number of portfolios designed to meet long-term needs could be constructed and examined. From the most efficient of these, the portfolio that best meets appropriate risk/cost requirements could be chosen. As discussed in previous chapters, however, a number of legal and regulatory constraints and requirements exist that currently either specify resources to include or limit the scope of alternatives that can be considered in constructing long-term plans. These include requirements for minimum amounts of renewables, energy efficiency, and conservation, as well as limitations on the use of technologies based on coal and nuclear power. A central question in resource planning relates to the extent that existing requirements and limitations should influence the construction of future portfolios. As pointed out by SDG&E in various forums for example, their resource planning activities consist to some extent of just "filling in the boxes."

An inherent danger in requiring resource plans to assume that targets for preferred resources are met, especially those for individual classes of preferred resources (energy efficiency, demand response, renewable energy), is that the set of portfolios evaluated is then often limited to those that exactly meet the stated targets. For example, requirements for minimum levels of renewables may serve to limit consideration of higher amounts for planning purposes, as discussed in Chapter 3 of this report. If the targets themselves are developed separately in other forums, the resource planning process can be a forum in which procurement of preferred resources are discussed in an integrated fashion. Utilities can present arguments and evidence for the desirability of "overprocuring" some resources and possibly "under procuring" others, yet still achieving state policy goals related to fuel use, greenhouse gas and criteria pollutant reductions, etc.

If a balance should be struck with respect to common resource planning assumptions, striving to provide a common set of futures over which to develop and evaluate resource portfolios while acknowledging differences across utilities, a similar balance should perhaps be considered with respect to resource planning outcomes. Fixed policy targets may fail to adequately recognize that utilities may face, for example, different costs for classes of preferred resources. But even if the possibility of utility-specific targets is considered, portfolios need to be evaluated over a range of assumptions so as to provide policymakers information regarding the potential costs of meeting underlying policy goals.

Resource Planning, Planners, and Geographic Perspective

The resource planning process ensures that a forum exists in which utility needs for various energy and capacity products are publicly presented and that regulatory approval for procurement of the resources is obtained. Given the highly technical nature of the analysis of individual utility portfolios and increasing market-sensitivity of the input assumptions involved, this forum is the primary source of information for regulators regarding the financial and environmental consequences of utility actions. It is also a key source of information regarding the potential consequences for ratepayers of regulatory policies which influence electricity market conditions. Constraints upon the set of resources to be procured are imposed by regulators so that utility portfolios ultimately reflect the preferences of customers and society with respect to the weighting of ratepayer costs, the stability of these costs, and the environmental consequences of energy consumption.[15] The resource planning process brings utility expertise to bear on questions related to potential policy impacts and whether proposed policies, when implemented, will have the desired effects.

An individual utility, however, may not be in the best position to evaluate the potential impact of policy choices beyond those on itself and its customers, or even to assess conditions in the broader market and regulatory arena in which they operate. In their 2006 LTPP filings, for example, when asked to evaluate the need for new generation resources in their planning areas, PG&E and SCE both noted that the construction, repowering, and retirement decisions that would ultimately determine the resulting need for new resources were made by other parties whose future actions could not be predicted with any accuracy. The following examples illustrate the need for resource planning assessments by an entity with a statewide, if not regional perspective:

- While an individual utility will likely forecast natural gas prices based on a market-based forward price, it cannot be expected to estimate the change in natural gas prices resulting from the future implementation of state policies. These might include a combination of energy efficiency programs and an RPS requirement that reduces the demand for natural gas to such an extent so as to reduce the market price. Or the siting of an LNG facility could increase the quantity of natural gas.
- Utility assumptions regarding the future cost of renewable energy may frequently be based on observed prices during recent solicitations or the market price referent (MPR). Future policies, however, may allow the use of tradable renewable energy credits or enable contracts with out-of-state, low-cost resources that are not currently eligible for credit toward meeting the RPS.

[15] In theory, they may also be imposed to ensure that, in those instances where shareholder and managerial preferences may conflict with those of ratepayers and society, the latter prevail.

In sum, a resource planning process benefits from being informed by both the analysis by individual utilities of their portfolio choices and of the larger market by other entities. The latter serves to not only inform policymakers of the potential state- and region-wide impacts of their choices, but also to inform input assumptions made by utilities in the assessment of their individual portfolios.

The Resource Planning Horizon

As discussed in Chapters 1 and 4 in this paper, requirements in AB 57 as augmented by CPUC regulations and other requirements of state law specify many aspects of utility planning. Thus, any planning-related changes must take existing requirements into account. Currently, procurement planning is done at the utility level under state-mandated constraints and requirements, as noted. Ten-year procurement plans formulated under such constraints are submitted to the CPUC for approval every two years. The time frame under which individual IOU procurement planning is done may differ substantially from that which might be beneficial for considering longer-term outcomes on a statewide or regional basis. For example, the Northwest Power and Conservation Council planning timeframe is 20 years. Thus, consideration must be given as to the level at which long-term plans are formulated (who does the planning and for what area) and over what time frame.

A 10-year planning horizon can fail to capture longer-run implications of procurement decisions that may be of significant concern. These longer-run impacts are important for several reasons. A power plant constructed today will still be operating 30 years from now and more and, while it may play a different role in meeting energy needs in the distant future (e.g., as steam turbines have moved from being providers of baseload energy to those of seasonal load-following services), can be expected to maintain its place in the dispatch queue for at least 15 to 20 years. Accordingly, the costs of committing to resources today are borne for substantially more than ten years.

These costs are not only the variable cost of plant operation, e.g., fuel costs, but those associated with the environmental impact of operation as well. The constraints on future choices that are embodied in near-term commitments include altering the future costs of meeting long-run greenhouse gas reduction goals. As such goals are expressed in terms of 2020 levels, if not those even farther out in time, resource planning assessments should, at the least, evaluate the implications of commitment to GHG-emitting resources during the near term for the ability to realize reductions over longer periods.

As stated elsewhere in this report, assuming that consensus cannot be reached regarding the appropriate rate at which to discount ratepayer and environmental costs, costs in the outer years of whatever planning horizon is selected should be brought forward under a set of discount rates which reflect the range of perspectives regarding the value of time.

Customer Risk Tolerance and Portfolio Choice

Resource planning methodologies can illustrate the potential trade-offs between cost and risk for a set of portfolios, but do not provide guidance regarding the portfolio that is optimal in that regard. Policy makers must decide for themselves what the appropriate balance is between minimizing ratepayer costs and reducing the risk associated with increases in fuel and emission costs and other determinants of the costs of meeting energy demand.

Customer surveys can be used to evaluate ratepayer risk preferences. These are commonly used to evaluate preferences for rate stability in the shorter term, asking customers to indicate their willingness to pay for stable rates. Customers are also surveyed periodically about their willingness to pay to avoid curtailment of service (that is, blackouts). Such surveys tend to reveal that customer classes have different risk preferences and different opportunities to hedge that risk in the context of a broader set of economic activities. The collective set of risk preferences may indeed vary across utilities, if only because they may differ in their shares of residential, commercial and industrial customers.

While surveys of customer attitudes towards risk are no doubt of great value in informing utilities of the extent to which near- and medium-term fuel and electricity price risk should be hedged, accurate information about customers' willingness to pay to reduce the risk associated with long run price increases may be more difficult to obtain. First, surveys regarding inter-temporal trade-offs are more difficult to construct so as to accurately reveal customer preferences. Second, portfolios that reduce price risk in today's environment, whether it stem from volatile fuel prices or carbon costs, for example, are those that are perceived to have a minimal impact on the environment. Thus, surveys which attempt to isolate intertemporal risk preferences are likely to fail to do so accurately, also capturing consumer attitudes toward other characteristics of the set of resources used to meet energy demand.

In the broadest sense, consumers can reveal their attitudes towards policies in a number of ways. These include not only responses to surveys, which are frequently as much a function of the particulars of the survey as they are of underlying preferences, but through voting and other political activities. In this light, it may not be necessary to poll consumers regarding their willingness to pay for reductions in the risk of long-run price increases, itself uncertain in magnitude, but perhaps only to provide accurate information to policymakers regarding the possible costs of portfolios *cum* policies under different futures.

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APPENDIX 1: USE OF AND EXTENSIONS TO VALUE-AT-RISK AND TO-EXPIRATION-VALUE-AT-RISK FOR ELECTRICITY LONG-TERM PLANNING[1]

Value-at-Risk and Its Use and Limitations in Energy Markets

Value-at-Risk (VaR) analysis, which rapidly spread out from Wall Street as a risk management tool, is now standard in many industries, providing upper bounds on expected potential financial loss due to adverse market fluctuations. Besides its widespread use in financial industries following its adoption by the Basel Committee[2] as a means of setting the standard for the minimum amount of capital to be held by financial institutions as protection against market risks, it has become established as best-practice in the energy industry. The Committee of Chief Risk Officers, a membership organization composed of risk management professionals in the energy industry, produced a white paper advocating the use of VaR or VaR-based metrics, like Earnings-at-Risk or Cash Flow-at-Risk, for energy trading companies.[3]

VaR provides an estimate, at a specified confidence level, of the maximum amount an asset or a portfolio of assets can be expected to lose over a given time horizon. There are many potential applications (and objectives) of VaR models. When calculated at the corporate level, VaR summarizes the overall risk across all practices and/or assets for the company as a whole, helping management to control corporate activities and limit market positions that could result in undue financial stress. VaR can also be used to assess corporate strategy and the extent to which the firm's assets are being optimally utilized.

VaR is often used as a tool by regulators to focus management attention on risk issues.

VaR Basics

Establishing a VaR estimate requires specifying the portfolio in consideration, the confidence level, and the time horizon. Traditional explanations of VaR subsume the volatility and risk drivers of market changes into the considered portfolio which comes with its associated probability distributions of various market risk factors. Assessing those probability distributions constitutes a vital portion of the analysis required.

[1] This appendix was prepared by London Economics International LLC.
[2] The Basel Committee of Bank of International Settlements provides a forum for regular cooperation on banking supervisory matters. Over recent years, it has developed increasingly into a standard-setting body on all aspects of banking supervision, including the Basel II regulatory capital framework. See http://www.bis.org/bcbs/ for more information on the Committee and its adoption of VaR.
[3] "Valuation and Risk Metrics", CCRO White Paper, November 19, 2002. Available at http://www.ccro.org/whitepapers.htm.

The portfolio in consideration is usually pre-determined and is a given to the VaR analysis. It is, of course, possible to analyze different real or hypothetical portfolios and calculate the VaR levels. In doing so, one important point is to carefully determine the risk factors for each portfolio since there will be different components, facing quite different probability distributions. Another issue is to take portfolio sizes into account when making comparisons, since VaR is not normalized and is positively related to the size (i.e., the higher the value of a portfolio, the higher the value-at-risk).

The confidence level is more a matter of choice. In practice, some financial institutions use 95 percent, others 99 percent, and others some other number in the same range. VaR analysis can tell that with 99 percent certainty the portfolio could lose no more than a certain amount, say $10. Or the analysis could say that with 95 percent certainty it could lose no more than, say $5.[4] Both of these statements might be correct; they are simply different readings from the same probability distribution. Neither number is intrinsically more or less correct, or more or less accurate. The question therefore becomes which is more sensible to report.

The time horizon is usually determined by the nature of the industry, considering liquidity of assets in a portfolio. In banking markets, financial instruments are generally quite liquid and looking at a horizon of one day is quite reasonable. Looking further ahead, future prices would generally become less available. Financial institutions still often use a one-day time horizon but this is not always appropriate and longer time horizons can be used. Note, however, that some methods of calculating VaR rely on a short time horizon because some of the assumptions that they make about how the value of instruments change depend on the short time period.

Considering the confidence level and time horizon dimensions together, and trying to find an optimal combination, the choice comes down to ease of backtesting. One of the major questions about VaR is whether it is an accurate prediction of probable profits and losses. One can test this by looking at VaR numbers calculated in the past and comparing these to the actual profits/losses that were realized over the relevant time horizons. With a 95 percent confidence level, for example, one would expect losses greater than the VaR value for one observation in twenty. Over a year, with daily VaR calculations, forecast accuracy can be tested fairly rigorously and systematically. But with a 99 percent confidence level, the expectation to lose more than the VaR value is only one day in a hundred. Many more observations are required for testing.

Calculating VaR

With the Black-Scholes equation and the accompanying assumption that price returns are normally distributed, it is possible to calculate VaR from first principles.

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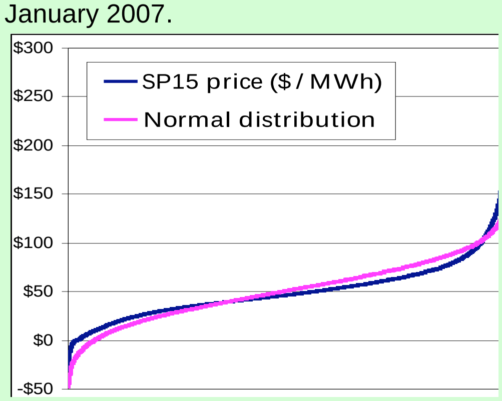
[4] Clearly, with higher confidence levels, the VaR levels go up due to the simple trade off between the level of confidence and the accuracy of the analysis.

Simply, if the probability distributions of all price variables involved in the assets of a portfolio are well understood, and the terms of all of the contracts in the portfolio are known, then it is straightforward to calculate VaR. This is known as the analytic method. The analytic method is very fast, but it is suitable only for instruments that have a constant rate of change in the value of the instrument with the value of the underlying price variable.[5] Even with a simple option, this is only true over short periods of time, since the assumption is that any short section of a curve is approximately straight. For more complex instruments, this assumption cannot automatically be made. And in some markets the assumption of normal distribution of returns breaks down, so new methods of calculating VaR have been devised. These rely on simulating price changes rather than using equations.

The basic idea of simulation VaR is very simple. If we want to know what value our portfolio will have tomorrow we simply generate a lot of potential future prices and value the portfolio using all of them. The end result will be a lot of potential values for the portfolio (one for each set of future prices) which we can plot as a probability distribution. The question is where to get the prices from. One possibility is to simply assume that returns are normally distributed and pick returns at random. This is known as the Monte Carlo method.[6] An alternative is to use a set of actual observed prices from past months, which is known as the historical method. Both of these methods rely on significant assumptions. Monte Carlo VaR assumes that returns are distributed in the way it assumes. Historical VaR assumes that prices in the future will behave in the same way as they did in the past. Neither assumption is necessarily true. Some companies use two or even all three VaR methods in their risk control procedures, and proceed with further examination if and when the results of the methods they use diverge wildly.

Despite its extensive use, assuming a normal price distribution is not suitable for energy markets at all times. Econometric tests for normality often fail in natural gas and power markets. The figure below shows the significant difference between the normal distribution and hourly SP15 prices over a two year period, from January 2005 to January 2007.



A final variation in how VaR is calculated refers to the actual number reported. As noted above, the traditional VaR result is the maximum amount that is expected to be lost at the given confidence level. It is a point on the VaR profit/loss probability distribution. An alternative method is to calculate the probability-weighted average loss for the whole of the curve beyond the confidence level. This is known by a variety of names, including expected shortfall or estimated tail loss. This number is particularly valuable in cases where

[5] In financial engineering, this value is known as the Delta of the instrument.
[6] Some Monte Carlo methods have been developed that use non-normal distributions of returns, but these are rather more complex and are not in general use.

the profit/loss values are not normally distributed but rather have a long and potentially dangerous tail to the loss end distribution.[7]

Limitations of VaR

VaR has limitations that practitioners need to understand. It is calculated assuming typical market conditions, usually assumes normal distributions of risk factors and is dependent on (most often historical-based) estimations of volatilities and cross-correlations of risk factors. It offers little guidance for exploring abnormal events outside the realm of normal statistical variation. Extreme market conditions such as crashes and widespread crises are not normally considered within the VaR framework as they do not fit into the standard probability distributions employed by VaR to make the analysis tractable.[8]

VaR is based on a fairly strict set of methodological assumptions. In the energy industry - where contracts and derivatives in commodities such as oil, coal, gas and electricity are traded – some of the core assumptions are generally not valid. For example:

1. While VaR assumes that markets in the instruments being analyzed are liquid (i.e., sales and purchases can be arranged at executed quickly at transparent prices), energy markets are not always liquid, especially those that are most localized. This makes the assumption of being able to unwind a portfolio in a day, or even a week, suspect. If positions cannot be unwound easily, longer time horizons must be used. The main difference in dealing with liquid and illiquid assets is the need for determining probability distributions and volatilities. Usually there are enough historical data to make assessments for liquid assets since futures markets exist and reveal expectations for the future. For illiquid assets, on the other hand, since there are no or a low number of transactions, determining a market value and/or risk of that market value to go down requires stronger assumptions, making the analysis less robust.

2. While VaR often assumes key variables are normally distributed, price returns in energy markets, and electricity prices in particular, tend to display extreme kurtosis.[9] Even the US natural gas market, which is one of the most liquid energy markets in the world, has revealed price patterns that, under a normal distribution, should occur only once every few million years.[10] On the other hand, VaR methods with non-normal distributions are not well-established and tested. Since the resulting calculations heavily depend on the underlying probability distribution function, it must be chosen carefully, which is not a

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[7] In statistics a distribution where the size of the tail is greater than might be expected from a normal distribution is said to exhibit Kurtosis. More commonly this phenomenon is referred to as a long or fat tail.

[8] Although their probabilities are low - hence the term “extreme”- extreme market conditions inevitably arise occasionally. One recent event was the February 2003 natural gas price jump. Relative to movements of natural gas prices prior to February 2003, the jump in the price was on the order of fourteen (14) standard deviations from expected value.

[9] See the textbox and Footnote 6.

[10] See Footnote 7.

straightforward task.[11] Data series, through time, demonstrate changes and shifts in their behaviors due to structural changes affecting them. A war-like event might affect the behavior of natural gas prices significantly; and using the same probability distribution throughout would not be descriptive of the data before and after the event.

3. Energy companies generally own many physical, as opposed to purely, financial assets. Understanding the risks associated with physical assets requires use of techniques such as real options analysis. Because such assets cannot be easily sold to unwind a portfolio, longer analytical timeframes are required. Assuming that all or most assets of an energy company can be sold would not be realistic. Especially for a utility, since the provided service cannot be intermittent, a shift in the portfolio must be considered rather than a complete liquidation.

From VaR to TeVaR

The California Public Utilities Commission (CPUC) in 2003 ordered the state's three investor-owned utilities (IOU) to resume long-term planning and procurement of generating resources. The order required that, every two years, the utilities submit long-term procurement plans (LTPPs) detailing their ten-year demand projections and their least-cost plans for meeting the demand. The LTPPs are to include analyses of the sensitivity of least-cost plans to variability in load growth, natural gas prices and energy prices.

In a workshop led by the CPUC's Energy Division on April 23, 2003, Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), and Pacific Gas and Electric (PG&E) presented their approaches to meeting the requirements of the order.[12] As part of its presentation, PG&E introduced a modification of VaR that it called To-expiration-Value-at-Risk (TeVaR).

Following the 2003 workshop, the CPUC adopted the TeVaR approach and ordered the three investor-owned utilities to present risk analyses based on TeVaR calculations in their LTTP submissions. In their December 11, 2006 LTPP filings, the three IOUs described their methodologies and provided TeVaR estimates for 30 years (PG&E), 10 years (SDG&E) and 5 years (SCE). Since TeVaR details depend on specific details of confidential portfolios, the values and, in some cases, methods have not been made public.

TeVaR shares the philosophy of VaR, addresses the same basic questions and attempts to deal with the challenges imposed by the assumptions discussed above. An illiquid asset or a contract is considered based on the terms of the contract to its

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[11] For lengthy discussion on its theoretical background and applications, see Darrell Duffie and Jun Pan, "An Overview of Value at Risk", Journal of Derivatives , Spring 1997, 7-49, reprinted in Options Markets, edited by G. Constantinides and A. G. Malliaris, London: Edward Elgar, 2001.

[12] See "Workshop Report on Value at Risk, Cash-flow at Risk, and Other Measures of Portfolio Risk", April 23, 2003, available at http://www.cpuc.ca.gov/published/Report/26947.PDF.

expiration rather than the market conditions. Consider a hypothetical portfolio that consists of two one-year contracts, one purchasing natural gas and the other selling electricity, both at fixed prices. VaR is not applicable in this situation since expected fluctuations of market prices do not affect the portfolio's value or value-at-risk. TeVaR takes the expiration dates into account and, depending on the specified time horizon, looks at probability distributions of market prices beyond the expiration dates. For this simple portfolio, the only risk is spot market price of natural gas going below and/or the spot market price of electricity going above the fixed contract prices.

The three investor-owned utilities employ different implementation procedures. Because long-term results can be very sensitive to small differences in assumptions, chosen probability distributions and related factors, these independent analyses can yield very different results for similar asset portfolios and similar assumptions about future conditions.

PG&E Methodology

PG&E's TeVaR approach is driven by electricity and natural gas prices at different delivery points within California. TeVaR is calculated using a Monte Carlo simulation where, for each iteration of the simulation, daily spot prices are randomly generated for each of the delivery points and for each day of the projection period. The distributions from which simulated prices are drawn are based on market forward prices and historical price volatilities and cross-correlations. The net cost (i.e. the cost of inputs (natural gas) minus the revenues from electricity sales) of every position in the firm's portfolio and by extension, the overall portfolio's net cost, is computed for each day of the simulation period based on that day's simulated prices. The daily net costs are accumulated over the portfolio and over the projection period to produce a single (aggregated) net cost for each iteration. Costs are represented as negative numbers, so the 1st percentile of net cost represents more cost to customers than the 10th percentile of net cost. The difference between the 1st percentile of net cost and the mean net cost is identified as "TeVaR at the 99th percentile," or "TeVaR99." It is important to highlight that, unlike VaR, TeVaR99 does not measure changes in portfolio value. It measures, and develops probability distributions for, cost burdens placed on ratepayers (given the portfolio held by the utility).

For its 2006 analysis, PG&E used broker quotes for forecasts of natural gas prices through 2011 (a five-year horizon) and for forecasts of electricity prices through 2015 (a nine-year horizon). Beyond these periods, PG&E simulated prices on a monthly basis rather than daily.

The methodologies used for extrapolating gas and electricity prices are as follows[13]:

[13] Note that forecasts of volatility are based on historical data throughout the entire 30-year period. The PG&E method implicitly assumes no structural changes in the dynamics impacting price volatility.

- 2012-2015: The PG&E Citygate gas curve is extended through 2015 keeping the implied heat rates based on on-peak implied heat rates of 2011 (by month) constant through 2015. On-peak power prices are divided by these heat rates to get gas prices. The other gas curves are extrapolated such that the growth multiplier (price in current month/price in same month one year before) is same as that of PG&E Citygate prices.
- 2016-2031: Annual Henry Hub Prices are obtained from the Market Price Referant (MPR) forecast. To estimate the PG&E Citygate prices a basis of $0.2566/MMBtu is subtracted from these prices. These annual prices are shaped using the monthly shape seen in the 2011 PG&E Citygate prices. Power prices are calculated using the implied heat rates for on-peak and off-peak by month that are seen in 2011 (by multiplying the on-peak and off-peak heat rates separately). The other gas curves are extrapolated such that the growth multiplier (price in current month/price in same month one year before) is same as that of PG&E Citygate prices.
- 2032-2036: Henry Hub prices are linearly extrapolated (the prices for 2030 and 2031 are used). To get the PG&E Citygate and NP15 on-peak and off-peak prices, the procedure described in the previous paragraph is followed. The other gas curves are extrapolated such that the growth multiplier (price in current month/price in same month one year before) is same as that of PG&E Citygate prices.

Monthly gas and power prices, both on and off-peak, are simulated using the Monte Carlo method. Each Monte Carlo iteration yields a “sample path” (i.e., a time-series of monthly prices for the length of the study period). A large number of Monte Carlo iterations are used to yield an estimated probability distribution of prices. It is important to point out that the resulting probability distribution depends on the price extrapolations upon which the Monte Carlo simulations are based.

For each Monte Carlo simulation path, using the simulation results for three thousand runs, a probability distribution for the 10-year average is developed and the mean (50th percentile), the 90th percentile and the 10th percentile of the ten-year average price are calculated. Each simulation path that is identified to be within a pre-selected small band around the 90th percentile level is put aside to be used for the calculation of a high price forecast for gas and electricity. For those simulation paths that are put aside, average gas, on-peak electricity and off-peak electricity prices are calculated for each month. A price multiplier is calculated by dividing the prices calculated for each month with the corresponding values in the current forecast. A single multiplier for the whole 10-year period is calculated by averaging the monthly multipliers. The current forecast multiplied by this average multiplier gives the high price forecast. For the low price forecast, the same procedure is repeated by selecting a small band around the 10th percentile 10-year-average price distribution and following the same steps.

The volatilities used for the monthly price simulations are monthly volatilities obtained from broker quotes that are based on traded option prices. Beyond the period where option prices are quoted, they are kept constant. The monthly correlations used for simulations are also developed using historical correlations between monthly electricity and gas prices.

SDG&E Methodology

SDG&E calls its metric VaR-to-Expiration (VtE), and establishes its estimates at the 95 percent confidence level for 10-year time periods.

SDG&E begins its process by calculating VaR as follows:

$$VaR = Position\ Value \times Volatility \times Confidence\ Interval \times \sqrt{t_{day}}$$

where Position Value is the current value of the portfolio expressed in dollars;[14] Volatility is the annualized volatility of the portfolio based on historical figures (as in the PG&E methodology); Confidence Interval is the number of standard deviations associated with the chosen confidence level (e.g., 1.645 for 95 percent); and t_{day} is the length of the time period in days for the calculation.

To evaluate a single contract position, the formula for VtE is given by:

$$VtE = 1 - \left(VaR \times \sqrt{t_{year}} \right)$$

where t_{year} is the time in years until expiration of the contract.

For a portfolio of such contracts, the calculation methodology needs to recognize that portions of the portfolio are expiring at different times and the overall computation becomes quite complicated. Daily VaR and time-to-expiration are different for each asset in the portfolio. These are determined separately and added into the VtE formula. The main issue is the time to expiration for some assets might be shorter than the considered time horizon. Such assets would be considered given the market conditions, while others are still under contract.

SDG&E uses a proprietary Excel-based Monte Carlo simulation model,[15] which is a static valuation at-expiration model that accounts for each specific transaction expiration date. The model takes as inputs market information (used to create price simulations that have the appropriate joint distributions), commodity forward curves, forward volatility curves, intra-commodity correlation, inter-commodity correlation, portfolio position information and volume.[16]

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[14] For illiquid assets, position values must be estimated, adding an additional layer to the calculation.
[15] They also use a publicly available model –without reporting its results- VaR Works by Financial Engineering Associates, see http://www.fea.com/products/varworks.asp.
[16] For a detailed explanation of the employed Monte Carlo simulation method see SDG&E 2007 – 2016 LTPP, December 11, 2006, Volume 1, Section III-B, pp. 126–131.

In contrast to the PG&E method (that considers costs to ratepayers), SDG&E's method produces an asset-based measure, considering the position values.

SCE Methodology

To calculate market-specific procurement costs, SCE employs a version of the Monte Carlo method that depends on a direct formula rather than, as for SDG&E, one based on VaR.[17] Calculations are based on the distributions of four variables: power price, gas price, load and supply availability. Stochastic processes are used to represent each of these variables and simulations of the stochastic processes provide sample outcomes of the market-sensitive procurement costs. The sample outcomes are considered discrete probability distributions for the market-sensitive procurement costs.

SCE calculates TeVaR as the difference between the 99th percentile cost outcome and the expected cost.[18] This method is quite similar to PG&E's in its basic objective. It looks at a measure of consumer burden, in contrast to SDG&E's asset value-based calculation.

For each time horizon, the steps SCE takes in determining TeVaR are as follows:

1. Establish a stochastic process for power delivery time, power and gas prices, load, and supply availability.
2. Simulate the stochastic process to provide outcomes which are a series of delivery time power and gas prices, load, and supply availability throughout the reporting time horizon.
3. For each outcome, directly calculate the market sensitive procurement costs.
4. For each outcome, use the power and gas price series to estimate a simulated economic dispatch along with procurement revenues and costs.
5. For each outcome, calculate the procurement revenues and costs for additional portfolio elements.
6. For each outcome, sum the results of steps 4, 5, and 6 and apply the discount rate to determine total present value of procurement costs of that outcome.
7. From the set of all procurement cost outcomes, calculate the various reporting metrics: expected procurement costs, standard deviation of procurement costs, and TeVaR.

Assessment of the Three Methodologies

As described above, the methodologies of the IOUs in calculating TeVaR are quite different than each other, making comparisons almost impossible. Analysis of

[17] For a detailed explanation of the TeVaR formula see SCE 2006 Procurement Plan, December 11, 2006, Volume 1A, Section III-B-6, pp. 106–109.
[18] In Volume II, Section VI-6 of SCE's plan, it is argued that using 95% would be "a meaningful and stable" measure of risk.

PG&E's portfolio using SCE's methodology would result in a different TeVaR value than the one calculated by PG&E. VaR and TeVaR calculations heavily depend on the underlying assumptions and methodologies, and are not robust to even small deviations from these assumptions. The lack of a standard approach by the utilities is an important problem, given the CPUC's 2003 decision.

PG&E and SCE analyze the total costs of providing service, and possible increases in total cost, while SDG&E's methodology, consistent with the original VaR approach employed in financial markets, looks at changes in portfolio values. Even though service costs and portfolio values are related metrics, they are not the same. Analysis of service costs is likely more useful from a regulatory perspective, as this is a customer- rather than shareholder-based metric.

All three methodologies depend on the estimation of a handful of risk factors such as natural gas and power prices. PG&E's methodology, applied across a 30-year time horizon, is based on simple extrapolations of historical and, whenever available, futures markets prices. SCE runs simulations on specified risk factors based on the distributions of historical prices. Both methodologies assume business-as-usual and do not systematically account for the possibility of structural changes in the behaviors of risk factors.

This limitation of VaR-based models, including TeVaR, argues for the use of other methods for comprehensive analysis of different scenarios.

Extensions for Long-Term Planning: Portfolio Analysis and Stress Testing

Long-term forecasts are inherently less accurate than short-term forecasts. A fundamental problem in applying VaR and TeVaR to long-term timeframes is that they do not systematically account for structural changes in the operating environment that, while difficult to predict and anticipate with any specificity, are nonetheless at some point likely to occur within volatile energy markets over long timeframes. Assuming that volatilities of key inputs are constant and based on historical values is inappropriate. For instance, the volatility of natural gas prices may rise dramatically following further political turmoil in the overseas markets. Also, cross-correlations of risk drivers might also change, as demonstrated by the observed convergence between natural gas and electricity prices following the introduction of technology making natural gas a prime input to electricity production.

With long term analysis, with limited availability of market forward data, simulated price forecasts must be employed. Then there are questions to be asked about the actual level of uncertainty in future forecasts. We know they will be uncertain, but can we quantify the uncertainty? And can we adopt different forecasting methodologies that would reduce that uncertainty? The important point is that the validity of the models of risk drivers is itself uncertain. Looking at tomorrow or next week, one can have a certain amount of confidence in the "business as usual" assumption incorporated within VaR and TeVaR. Over longer timeframes, one may be concerned about drift in the mean level of prices.

Extending the basic VaR methodology beyond a 12-month period requires changes to the theoretical basis of the model. Additional risk factors besides the usual gas and power prices should be considered. The distributions and formulations that describe how those risk factors impact the value of the utility portfolio, from the perspective of both ratepayers and shareholders, are very important. Complexities such as the interplay of gas hedging contracts and contracts for gas-fired energy and capacity must be central considerations rather than avoided through adoption of unrealistic assumptions. Some of the issues for consideration may be technical,[19] whereas other issues will require qualitative, policy-level consideration.

The main concern with VaR-based measures is the highly sensitive nature of the measure to small details in the modeling. One has to be sure that the assumptions built into the implementation are consistent with the nature of the assets being modeled. Given the complex nature of calculations, the validity of the assumptions might be overlooked, inadvertently creating an unrealistically elevated sense of trust in the results.

VaR and TeVaR ask a specific question requiring a one-dimensional answer. Long term planning requires a more complete look at the risks associated with the energy industry. Rather than analyzing a static snapshot of a portfolio, its possible evolution must be considered. More detailed analysis, depending on different sets of assumptions and scenarios, is required.

Portfolio Analysis (PA) provides a broad context for understanding portfolio risk and return. The basic objective of the analysis is to identify an acceptable level of risk tolerance and then identify a portfolio with the maximum expected return for that level of risk. For electricity ratepayers, maximum expected return is equivalent to minimum expected cost of service.

An important issue is that, rather than looking at the risk alone, different risk levels and corresponding expected cost levels are considered together, allowing for a choice dependent on the risk tolerance preferences of the public. Another important point is that the mathematics of PA are used extensively in financial risk management and provide a theoretical foundation for VaR-based measures.

Portfolio Analysis has three main advantages over TeVaR:

1. It looks at risk and costs born by ratepayers together and allows for selection of optimal portfolios given preferences and levels of risk tolerance.

[19] Another specific problem in the employed methodologies is due to the fact that the illiquidity of assets in energy industry in longer terms impacts the analysis through the distributions of future prices. Illiquid assets might have significant kurtosis, or distributions skewed towards lower values from seller's point of view. Using the symmetric normal distribution, as the IOUs generally do in their TeVaR calculations, creates a negative bias in value at risk.

2. Since it is more general and starts the analysis at the portfolio selection level, it allows for different scenarios on portfolio choice to be considered.
3. It allows for different scenarios on non-choice variables, or external risk drivers - such as natural gas prices, availability schedules and demand - to be considered.

Also lacking within the existing VaR and TeVaR frameworks are approaches for **stress testing**, to try to estimate the impact of potential shocks to the system, including shocks that are within the course of "business as usual" as well as high-impact, low probability shocks. Stress tests can be implemented simply by, for example, evaluating the impact of a 10 percent rise in natural gas prices; or in more detailed and thoroughgoing ways. For example, through scenario analysis and simulation modeling, it is possible to try to account for market changes that have not been observed historically, such as the impact of the introduction of a carbon tax. This type of analysis allows an entity to measure how well its designated portfolio and investment choices would survive major changes to market conditions. This is an important component of a systematic assessment of long-term procurement planning. Also, mathematical techniques such as Extreme Value Theory can be used to better model the tail of probability distributions where few data points are available.

APPENDIX 2: ADDITIONAL CALIFORNIA IOU PLANNING AND PROCUREMENT INFORMATION

This Appendix presents additional background planning and procurement information for each of the California IOUs, as filed on December 11, 2006 with the CPUC in their respective Long-Term Procurement Plans. The information included in the IOU filings varied in scope and detail, which this section reflects.

Pacific Gas & Electric

Planning

In the planning phase, PG&E identifies the resource needs of its customers and complies with the State Loading Order, Energy Action Plan II (EAP II) and other Commission and legislative directives. To estimate the needed products, PG&E first determines the regional need for new resources. Second, PG&E estimates the capacity and energy open positions of the portfolio. These are determined hourly and aggregated by time of use period (super-peak, shoulder peak, off-peak). In analyzing its needs, PG&E identifies power products that fit the time of use open positions without creating large short or very long open positions under different scenarios. These power products include energy products (baseload, shaping, and peaking), capacity products to meet RA requirements, and various ancillary services products, including spinning, non-spinning, regulation, and black-start capability. After identifying the amount and timing of its need, PG&E then prepares and files a procurement plan with the Commission, seeking authority to procure these products. Once the CPUC approves a procurement plan, the procurement process shifts to the competitive procurement phase.

The procurement process is conceptually identical in all time frames insofar as all considered resources are reviewed on an equal basis in determining how to meet PG&E's demand and energy requirements in a least-cost manner. PG&E begins by determining total load requirements, including customer retail demand, wholesale sales, transmission and distribution losses, ancillary services, and all operating constraints. PG&E then determines the quantity of generation from baseload must-run resources such as the Diablo Canyon Power Plant, QFs, and DWR allocated contracts. Finally, PG&E assesses market conditions in order to optimize production from dispatchable resources and market transactions. PG&E's objectives are to meet any remaining load requirements as well as to extract value from resources when it is economic to sell into the market.

Long-Term RFOs

PG&E generally does not negotiate bilateral contracts for long-term procurement (e.g., five years or longer). PG&E's 2004 LTRFO included certain eligibility requirements to ensure a diverse selection of resources, capacity, contract terms and technologies and that the resources would be timely constructed and online in time to meet resource needs in the 2008 through 2010 time frame. The RFO was open to new resources only, with the exception of existing QFs. Eligibility requirements included:

- PPAs: Commercial Operations Date between January 1, 2007 and May 31, 2010; minimum term of 5 years and minimum size of 25 MW; firm physical delivery of generation to the North of Path-15 (NP15) area; unit specific offers only; PG&E given exclusive rights to the unit's capacity, subject to California ISO requirements.
- Facility Ownership: Guaranteed Commercial Availability Date between January 1, 2007 and May 31, 2010; design life of 30 years; minimum 25 MW at any one site; physically interconnect within the NP15 area.
- Humboldt Generation: Guaranteed Commercial Availability Date between January 1, 2007 and August 31, 2009; design life of 30 years; peak capacity of at least 135 MW on a single site; physically interconnected within Humboldt County.
- Qualifying Facilities: Existing QFs in PG&E's service territory as of November 2, 2004, required to meet FERC's QF rules and not have waived these rights to PG&E; option to provide delivery within the ZP26 area; minimum term of five years; minimum of 1 MW or greater.
- Other Eligibility Requirements: Transmission System Impact Study; preliminary application for gas service; deposit requirements; site control.

PG&E's 2004 LTRFO solicitation resulted in a response of over 50 bids for projects totaling in excess of 12,000 MWs including PPA projects, a Purchase and Sale Agreement, and an Engineering, Procurement, and Construction contract, which resulted in winning bidders totaling 2250 MW of peaking and shaping generation.

PG&E will issue a new all-source LTRFO in 2007 to procure 2,300 MW in new dispatchable and operationally flexible generation resources it has identified in the 2004 long-term plan. The 2007 solicitation will seek facilities to meet the identified need for the 2011-2014 time frame. The eligibility requirements, rules, and process are anticipated to closely match those of the 2004 LTRFO and will be designed to ensure a diverse selection of resources, capacity, contract terms and technologies. The LTRFO will consider PPAs as well as utility ownership projects with contract lengths of 10 years or more.

Procurement Methods and Practices for RPS Transactions

PG&E procures RPS resources through competitive solicitations and bilateral negotiations. In bilateral negotiations, PG&E may execute contracts with renewable suppliers for one month up to 20 years or more. For competitive solicitations, PG&E conducts annual RPS solicitations.

PG&E's 2006 RPS Solicitation included the following eligibility requirements:

- Certified by the Energy Commission as eligible renewable resources

- Use one or more of the following renewable resources or fuels
    - Biomass
    - Biodiesel
    - Fuel cells using renewable fuels
    - Digester gas
    - Geothermal
    - Landfill gas
    - Municipal solid waste
    - Ocean wave, ocean thermal, and tidal current
    - Photovoltaic
    - Small hydroelectric (30 MW or less)
    - Solar thermal
    - Wind
- Existing projects are eligible to bid
- The project must either be located in California or demonstrate delivery of energy to an in-state market hub or in-state substation; an out-of-state delivery point may be negotiated as long as the energy is ultimately delivered into the California ISO-controlled grid or a location that satisfies applicable CPUC delivery rules as an RPS eligible resource

PG&E will continue to issue annual Renewable RFOs to pursue RPS targets through procurement alternatives such as PPAs, turnkey utility ownership, and greenfield development.

The Application of Least-Cost, Best-Fit and the Loading Order in PG&E's Procurement Planning and Transactions

Least-cost, best-fit is used to select resource alternatives based on their relative cost-effectiveness and their ability to meet specific portfolio needs. Cost-effectiveness is determined relative to common market benchmarks or market value, while portfolio fit represents how well a resource's energy profile, location, and other operating characteristics meet the needs of the portfolio for a particular product in a given location. PG&E applies least-cost, best-fit principles to supply-side and demand-side alternatives.

Market Valuation and Portfolio Fit Overview

Market value represents a resource's net market value based on its costs and benefits, regardless of its fit with the rest of PG&E's portfolio. The costs that PG&E uses in calculating a resource's net market value include the value that the CPUC has placed on CO_2 emissions.

In valuing demand-side alternatives, PG&E uses the CPUC's Standard Practice Manual's total resource cost (TRC) test. Under that test, the costs that PG&E and its customers are expected to incur in implementing an alternative resource are compared to the expected benefits that would be obtained from that alternative resource. Those benefits include the energy and/or capacity costs that would be avoided by utilizing that alternative resource. As long as PG&E's avoided energy and capacity costs are based on market prices, then PG&E's evaluations of supply-side resources and demand-side resources are consistent.

PG&E considers portfolio fit based on how well a particular resource provides the power products that need to be added to the portfolio. PG&E first identifies the types and amounts of power products that it needs to fill its open position over the planning horizon. Those power products include energy products (baseload, peaking and shaping), capacity or RA products, and ancillary services products (e.g., spinning, non-spinning, regulation, and black-start capacity). Then, PG&E identifies the energy products that each alternative resource can provide (e.g., baseload energy and dispatchable shaping or peaking energy).

RPS Selection and Evaluation Criteria

This section details the criteria used to evaluate RPS offers as described in *PG&E's Report of its RPS Evaluation and Selection Criteria in Compliance with August 21, 2006 Ruling of Assigned Commissioner*, September 29, 2006.

The selection methodology is based upon the mathematics of a strict partial ordering. This is a mathematically rigorous, unbiased ranking approach which makes minimal *a priori* assumptions about the data. The inputs to the partial ordering are the results of offer attributes, which are not weighted in any way to produce a single numerical score.

The following attributes are included:

- Market valuation
- Portfolio fit
- Credit and finance
- Project status
- Technology viability and participant experience
- Renewable Portfolio Standard goals
- Transmission adder

PG&E applies the Partial Ordering method in the following order:

1. Market valuation and portfolio fit are computed for each offer. Then, each of the scores for credit and finance, project status, technology viability and participant experience, and RPS goals are assessed.
2. The values and scores for the above attributes are used to construct a Strict Partial Ordering among the offers. In a Strict Partial Ordering, certain offers will dominate other offers when the dominating offer is better in at least one attribute, but is not worse in any attribute. The offers will then be separated by transmission cluster.
3. Next, the transmission adder is included because the resulting ranking prior to this step determines the allocation of existing transmission and any costs associated with transmission upgrades based on the Transmission Ranking Cost Report (TRCR). Alternatively, if an alternative commercial arrangement has a lower cost than the value from the TRCR, then that value is used instead. Ultimately, the lower of the two values is applied to the market valuation result from before.
4. The values and scores for the attributes above, with market valuation being adjusted for the transmission adder, are used to construct a strict partial ordering among the offers.
5. Offers are then grouped into three categories: superior, inferior, and indeterminate. No inferior offer may dominate any indeterminate or superior offers, and no indeterminate offer may dominate any superior offers. Superior offers are strongly considered for inclusion on the shortlist. Indeterminate offers are further reviewed to determine which offers belong on the shortlist.

If one offer is preferable over another when considering one attribute, but not when a different attribute is considered, the two offers are not well-ordered, so that one offer cannot, on the basis of the attribute scores alone, be determined to be superior. Despite such situations, there is typically enough information in the attribute values to cull out the offers that are not in the top tier. The strict partial ordering concept avoids making arbitrary assumptions about the relative importance of two separate attributes.

Market Valuation

Market valuation is the market benefits of an offer minus its costs. Costs include all anticipated significant relevant fixed and variable costs, including transmission and integration cost adders and debt equivalency. Benefits include energy, capacity, and ancillary services. Costs and benefits are expressed in terms of present value per MWh.

Portfolio Fit

Portfolio fit measures how well an offer’s characteristics, specifically its production profile, match PG&E's portfolio needs. For the evaluation period, hourly net open positions are computed with the existing portfolio. For each offer, the hourly generation of the offer is added to the hourly net open positions, and the measure of portfolio fit is recomputed. The difference between the two measures, one without the offer and one with the offer, is used to estimate a portfolio fit value associated with the offer. The evaluation period—that is, the delivery periods over which this measure is calculated— is for the full term of each offer.

Integration Costs

Integration costs are the costs and values of integrating a generation project into a system-wide electrical supply. The primary categories of integration costs are regulation, load following, and shadow capacity. Pursuant to D. 04-07-029, PG&E assumes that integration costs are zero.

Credit and Finance

PG&E assesses the Participant's ability and willingness to provide collateral to secure its obligations, as well as the overall credit concentration that PG&E has with the Participant and any of its affiliates.

PG&E also assesses the Participant's financial strength and the project's financial wherewithal based on the information, including the Participant's corporate structure, debt ratings, financing plan and commitments, prior project financing experience, and an analysis of pro-forma financials.

Project Status

PG&E assesses the stage of development of each project. Those in operation or advanced development (e.g., permits received, equipment purchased, sites and easements obtained, transmission studies completed, design/construction status) score higher than those in early stages of development.

Each project, including transmission to the point of interconnection, is assessed on the following attributes:

- Land/easements—status of site control and easements
- Permitting/environmental—status and feasibility of applications and permits
- Design/construction - status of feasibility study, design, EPC contractor, construction
- Equipment acquisition—status of ordering and delivery of major components
- Grid Interconnection—status of System Impact Study and/or Facility Study and identification of grid upgrades

Technology Viability and Participant Experience

Each project is scored on the following attributes:

- Resource risk—whether resource availability and sustainability have been proven

- Technology feasibility and commercialization risk—whether in R&D, demonstration, or established commercial use
- Participant experience risk

RPS Goals

Each project is scored based on its support of attributes such as benefits to low income or minority communities, environmental stewardship, local reliability, resource diversity, stable electricity prices, public health, employment opportunities, air quality, reduced reliance on imported fuels, and impact on water quality and use.

Transmission Adder

After the initial ranking of offers on factors other than transmission, PG&E assigns each offer an estimated transmission network upgrade cost, if applicable, using the Transmission Ranking Cost Table in the 2006 RPS Solicitation Protocol. Within each of twenty transmission clusters, PG&E has identified various levels of possible additional transmission capacity and related costs of providing that capacity, divided between Peak & Shoulder and Night periods. Within each of the clusters, and within each period, starting with the highest scoring offer, each offer is be assigned a pro-rata share of the cost.

For projects located outside of the PG&E service area and delivering energy to either the SCE or SDG&E areas of the California ISO grid, PG&E also includes off-system transmission costs based on the Transmission Ranking Cost Reports issued by SCE and SDG&E.

The present value per MWh values for each offer are used to recalculate the Market Valuation described above. In addition to looking at the Transmission Adders, PG&E also evaluates alternative commercial arrangements for integrating the power into its portfolio that would avoid transmission upgrades. PG&E uses the lesser of the Transmission Adders or alternative commercial arrangements in determining the market value of bids and selecting the shortlist.

Fuel Supply Procurement Strategy

PG&E submitted information related to fuel procurement on a confidential basis.

Southern California Edison

Evaluation and Selection of Resources Through the RFO Process

Contract evaluations involve two major steps: (1) the valuation of each offer, and (2) the selection of successful offers through an optimization process.

Least-cost valuation takes into account credit, collateral, debt equivalence, greenhouse gas adders, and transmission adders. SCE's valuation process accounts for improvements in energy and ancillary service valuations, with the ability to value offers simultaneously under 25-85 different pricing scenarios to generate a net present value (NPV) of each contract. The NPV is the factor that is compared to find the Least Cost.

Best Fit is accomplished by specifying, in advance of final offers, a mathematical equation with an objective that maximizes a portfolio selection’s NPV while simultaneously taking into account constraints such as capacity and energy needs as well as qualitative characteristics such as location, product type, procurement limits, and other “fit” criteria. During the selection optimization, SCE can evaluate every combination of offers in SCE’s competitive solicitation (i.e., offer 1 with offer 2, offer 1 with 2 and 3, and so on for thousands of offers concurrently) to find the mathematically optimal outcome for Least Cost/Best Fit.

Valuation Process

SCE first assesses the present value of the energy and ancillary service benefits of each offer. Energy benefits are the difference between projected spot prices and operating costs as calculated by a dispatch simulation that maximizes the benefits. A forecasted discrete spot price power and gas distribution (25 scenarios based on 5 power price and 5 gas price scenarios) is input into the dispatch simulator. The benefits from each forecast scenario are weighted by their respected forecasted probability and discounted back to a present value. Ancillary service benefits reflect the estimated value obtained from participating in Calfiornia ISO’s Ancillary Service Market. Ancillary service revenues are estimated using forecasted ancillary service prices. The simulated dispatch is based on a forecast of power and gas prices, physical constraints of the generating unit, and proposed contractual limitations. SCE’s forecast methodology economically dispatches resources in a least-cost manner.

SCE next assesses the present value of the costs of each offer. Costs include: 1) fixed monthly capacity payments offered by the seller, 2) transmission upgrade costs, and 3) cost adders. Cost adders may include: 1) debt equivalence, 2) collateral cost adder, 3) credit risk cost adder, and 4) greenhouse gas cost adder. Lastly, SCE subtracts the present value of expected costs from the present value of expected benefits to determine the expected net-present value of each offer.

Selection Through an Optimization Process

In order to obtain a best fit selection for SCE’s portfolio, a set of constraints are identified to ensure that contract characteristics that are not explicitly priced, but are of value to SCE, are taken into account. This process involves the selection of a subset of offers that jointly minimizes the procurement costs (the objective function) subject to meeting some procurement goals (constraints). Examples of such constraints include:

- Generation capacity by year
- Generation capacity in a local area
- Quick start capability

- Black start capability
- Wind integration required by the California ISO
- VAR Support
- Minimum Local Capacity Requirements
- Minimum volume needed to meet RA requirements
- Procurement plan volume and transaction rate limits
- Maximum RA tags
- Maximum non-SP-15 RA tags
- Maximum volume of any single product
- Minimum regulation up capacity to be acquired if regulation up capacity is insufficient in current portfolio
- Minimum procurement of resource type (for example, peaking units, intermediate units, baseload units, etc.)

RPS Evaluation Criteria and Selection Process

SCE evaluates and ranks renewable project proposals based on least-cost,,best-fit principles (LCBF) that comply with criteria set forth by the CPUC in D.03-06-071 and D.04-07-029. The LCBF analysis evaluates both quantitative and qualitative aspects of each proposal to evaluate its absolute value to SCE's ratepayers and relative value in comparison to other proposals.

Process Overview

After an initial review, SCE performs the quantitative assessment of each proposal individually. The result of the quantitative analysis is a relative ranking of proposals that helps define the preliminary short list. Qualitative attributes of each proposal are then considered to further screen the short list and determine tie-breakers to arrive at a final short list of proposals.

Quantitative Assessment

SCE evaluates the quantifiable attributes of each proposal individually and subsequently ranks them based on their benefit-to-cost ratio. The benefit-to-cost ratio used in the LCBF evaluation is different than a typical benefit-to-cost ratio, which would usually represent net benefits or value divided by the project cost. In the context of LCBF evaluation, the benefit-to cost ratio measures total benefits divided by total costs because there is no readily cognizable "project cost" for these proposals. Benefits are comprised of separate capacity and energy components, while costs include the contract price, integration costs, transmission cost, and debt equivalence. SCE discounts the annual benefit and cost streams to a common base year prior to calculating the benefit-to-cost ratio for each proposal. The objective of the quantitative assessment and relative ranking is to develop a preliminary short list that is further refined based on the non-quantifiable attributes discussed below.

Capacity Benefit

Each bid is assigned capacity benefits based on SCE's forecast of capacity value and a technology-specific effective load carrying capability (ELCC). SCE's capacity value forecast consists of a market view for the first two years and a combustion turbine (CT) proxy thereafter. ELCC values are established by the Energy Commission's Renewable Generation Integration Cost Analysis (RGICA). Annual capacity benefits are the product of SCE's firm capacity value forecast, the total proposed capacity of the project, and the ELCC.

Energy Benefit

SCE measures the energy benefits of a bid by evaluating its effect on the total production cost of SCE's forecasted resource portfolio to serve its bundled customer load. The evaluation of energy benefits is performed with a portfolio and system that is consistent with SCE's most recently approved long-term procurement plan (LTPP), with some updates to account for fluctuations in gas price, variations in load forecasts, and the results of recent procurement activities.

SCE compares the total production costs of SCE's base resource portfolio (project out) with the total production costs when each bid is individually added to the base portfolio (project in). An hourly, least-cost dispatch is performed with SCE's known resource portfolio and generic generation to meet customer demand. The difference in total production costs between the project in and project out cases is the energy benefit for each bid.

SCE's resource plan and portfolio is generally dispatched against an SP15 power price forecast. For proposals of out-of-area resources, additional congestion charges may be added to the cost of delivering the energy, depending on the power price forecast of the originating area relative to SP15 power prices. The simulation model, and hence the energy benefit calculation, captures additional quantitative effects that the IOUs' have been asked to consider by the Commission, including dispatchability and curtailability. The benefits of these characteristics are rolled into the energy benefit and are not addressed separately.

Payments

The primary costs associated with each bid are the payments that SCE pays to bidders for the expected renewable energy deliveries under the terms of the contracts. Proposals include an all-in price for delivered renewable energy, which is adjusted in each time-of-delivery period by energy payment allocation factors (TOD factors). The total payments are then determined using the generation profile provided in the proposal and adjusted for electric energy loss factors (to calculate the scheduled amount of electric energy).

Integration Costs

The CPUC requires that the cost of integrating renewable resources into the system be assessed. SCE has been ordered to use the results of the Energy Commission's

Renewable Generation Integration Cost Analysis to evaluate the costs of integration. The RGICA provides a technology specific cost adder for additional regulation requirements that SCE incorporates into its evaluation.

Transmission Cost

System transmission upgrades costs are estimated using SCE's TRCR for resources that do not have an existing interconnection to the electric system or a completed Facilities Study. Transmission cost adders for new generation are assigned by cluster, or regions, and are based on standard unit cost guides. Proposals received in a solicitation that do not fit into the clusters defined by the TRCR will have adders developed using the same methodology as was used in the original TRCR.

Debt Equivalence

Debt equivalence describes the fixed financial obligation resulting from long-term purchased power contracts and affects SCE's credit quality and cost of borrowing. Consistent with D.04-12-048, SCE utilizes a methodology that employs a 20 percent risk factor.

Qualitative Considerations

SCE assesses non-quantifiable characteristics of each proposal, which are used to further screen, determine tie-breakers, and make adjustments to the short list of proposals. The attributes that SCE considers include:

- Extent of seller's mark-up of SCE's Pro Forma Agreement, which is provided to bidders with SCE's bid solicitation package
- Project viability
- Seller's capability to perform all of its financial and other obligations under the Pro Forma Agreement, including, without limitation, the seller's ability to provide collateral as described in the Pro Forma Agreement
- Seller experience and technical expertise
- Environmental impacts of seller's proposed project on California's water quality and use, including any particular benefits that will assist in improving water resource management consistent with the Commission Water Action Plan, Energy Action Plan II and environmental stewardship generally
- Resource diversity
- Benefits to minority and low income communities
- Local reliability
- Repowering

Application of Portfolio Risk in Transaction Planning

SCE prepares and submits a confidential monthly risk report to the CPUC indicating the probability that the cost of the SCE portfolio will have a certain value (i.e., SCE will submit a distribution of portfolio costs). The cost components include all SCE and DWR supply resources that have cost structures that are dependent on power and/or gas market prices. The variance of this cost distribution is an indication of the risk of the total portfolio.

TeVaR (to Expiration Value at Risk) is currently used as one benchmark of risk to SCE's customers. For a discussion of TeVaR and how it is used, please see the London Economics discussion in Appendix 1.

Fuel Supply Procurement Strategy

SCE's gas exposure is based on three portfolios: the SCE Non-QF Portfolio, the SCE QF Portfolio, and the DWR Portfolio.

The Non-QF portfolio is made up of the gas requirements related to SCE's utility-owned generation and gas-fired power plants under tolling agreements with SCE. The gas requirements vary based on economic dispatch. Therefore, the type of plants that are contracted for will affect the gas requirements. SCE must manage both the price risk of natural gas procurement (Financial Gas Procurement) and the physical purchase of natural gas (Physical Gas Procurement) for the SCE Non-QF portfolio.

The SCE QF Portfolio represents the financial gas exposure related to SCE's QF contracts. Many of SCE's QF contracts have terms that index the price of power to the price of gas. SCE does not typically purchase the physical gas for QF facilities. Therefore, SCE must undertake Financial Gas Procurement to manage price risk for this portfolio.

The DWR Portfolio represents the gas requirements for the DWR contracts entered into by the State of California during the energy crisis that were allocated to SCE. In this portfolio, as in the Non-QF portfolio, SCE, as agent of DWR, must buy the physical gas and manage the gas price risk. SCE's Gas Supply Plan (GSP) describes how SCE acquires DWR natural gas supplies using the following criteria: (i) reliability, (ii) diversity (price, duration, and suppliers), and (iii) cost-effectiveness. SCE does not have a GSP for non-DWR resources.

The major provisions discussed in SCE's GSPs include:

- Maximum Term: Gas supply, gas hedging transactions and gas transportation and storage agreements will be limited to contract terms not to exceed five years
- Maximum Procurement (Or Hedging) Volume
- Maximum Transaction Rate: Maximum Forward (procurement) Transaction rate limits are determined based on portfolio dispatch against forward prices

- Transaction Selection Criteria: Transactions will be selected in merit order from available market transactions based on their net-present value ranking
- Risk Reporting and Risk Reduction Criteria
- Minimum Forward Transaction Volume

Currently, beyond resources that would be required to satisfy other Commission or State mandates (for example, RPS or EE goals), SCE believes it continues to be likely that natural gas-fired resources would be the least-cost new generation options that competitive solicitations would reveal. SCE believes that excessive reliance on natural gas-fired resources poses growing fuel diversity concerns, due to the increasing risk of high prices and the potential for supply risk. As GHG emissions rules are put in place, the addition of GHG-producing natural gas facilities may be more costly and environmentally risky, compared to other energy sources. SCE may determine that a timely investment in non-gas-fueled technologies may be needed to ensure adequate fuel diversity. These options may be capital intensive (nuclear), may involve emerging or more advanced technologies (for example, IGCC or new solar technologies), and are unlikely to be supplied by the market at the times and locations that are desired.

Energy Action Plan

SCE takes three actions to ensure its procurement decisions are consistent with the EAP. First, prior to every competitive procurement for conventional resources (e.g., fossil fuel sources) SCE updates its procurement needs by first refreshing the latest forecasts for DSM programs, any renewable procurement, and any QF procurement to ensure conventional procurement is last in filling its procurement needs. That is, conventional resources are used for residual procurement. Second, SCE does not close out its energy needs via conventional procurement multiple years forward. Instead, it layers in procurement needs over time (ratably), which ensures that conventional resources do not “crowd out” preferred resources. Finally, SCE applies a greenhouse gas adder to all contracts greater than five years in duration to boost resources that are more environmentally sensitive.

San Diego Gas & Electric

Least-Cost, Best Fit

In using least-cost best fit to find the product from among the candidates that best matches portfolio requirements, SDG&E tailors the analysis to be performed on each potential transaction to the circumstances, with general principles remaining the same.

For long-term RFOs for capacity and energy, SDG&E will tend to rely on models such as PROSYM and the Capacity Expansion Model to perform an analysis of non-standard attributes from differing types of resources and the impacts on the entire portfolio of supply resources. For instance, in an all-source RFO, a LCBF may need to evaluate the trade-offs within the economics of the total portfolio from products that are as different as conventional peaking (capacity with little energy) and wind (as-available renewable energy with discounted RA capacity).

SDG&E evaluates all offers via a three-step process. Passing each level is required in order to advance to the next level, with the eventual Short Listed offers having to pass all levels. The following provides a general description of each evaluation level.

Level I: Check for Conformance

Minimum RFO criteria must be met (conforming or non-conforming) to move to Level II. Not all products in an RFO will have the same conformance requirements and the following list may be expanded to customize evaluation in any given RFO:

- Product type
- Minimum and/or maximum capacity (MW) requirement
- Seasonal requirement (monthly or quarterly)
- Online date requirement andlor seasonal requirements
- Fixed heat rate requirement
- Locational and delivery point requirements
- Grid reliability requirements

Level II: Screening Analysis

SDG&E calculates the total average annual costs in $/MW or $/MWhr for each offer. The following factors may be included in the initial screening analysis:

- Capacity costs as submitted in offer.
- Energy cost/benefit will be calculated based on the energy costs in the offer minus energy benefits. Energy benefits may be determined in a number of ways such as comparing energy costs from the offer vs. forward price curve. Energy costs will be based on data in the offer for energy costs or heat rate, fuel price and variable O&M costs.
- Congestion costs/benefits will be added to/subtracted from offers.
- RA credit value, system and/or local, may be added if needed.

SDG&E then ranks all the offers, either on individual year scores or the net present value, depending on the term of the RFO.

Level III: Modeling Short List Candidates

SDG&E model alls Short List Candidates in its production cost models to determine the portfolio of resources that provides the lowest cost to customers. Ancillary service credit may be added to offers as appropriate. Which ancillary services will be valued and the value for each service will be determined prior to bid evaluation. The GHG cost will be assessed by adding a cost equal to the GHG adder times the change in GHG emissions associated with the entire portfolio's operation with the offer as compared to the portfolio without the offer. The annual cost will be the change in the portfolio's GHG emissions times GHG cost adder.

SDG&E assesses nonquantifiable terms such as:

- Benefits to minority and low income areas
- Resource diversity
- Environmental stewardship
- Corporate capabilities, credit, and proven experience

SDG&E negotiates with those offers that make up the lowest cost portfolios.

VaR-to-Expiration

SDG&E uses VaR-to-Expiration (VtE) to measure portfolio risk. Please see the description of SDG&E's calculation method in Appendix 1.

To calculate portfolio risk, SDG&E utilizes models that take into account market information, commodity forward curves, forward volatility curves, intracommodity correlation, inter-commodity correlation, position information and position volume. The market information is used to create price simulations that have the appropriate joint distributions. SDG&E trends four key metrics:

- Forecast value of remaining CRT at the end of 2006 given each report day forward prices and open portfolio positions that must be purchased at market prices
- VtE at 95 percent confidence interval
- VtE at 99 percent confidence interval
- Remaining CRT minus VtE

Remaining CRT shows what customer costs for 2006 will be if the costs of actual purchases for 2006 are equal to the report day's forward curve. Remaining CRT minus VtE shows worst case end of year customer costs, defined in this instance as a 1-in-20, or 95 percent, adverse price movement. When remaining CRT is very close to baseline, SDG&E will hedge incrementally and over time. When Remaining CRT is approaching zero, SDG&E may undertake more aggressive hedges to close out open positions and thus eliminate the effect of further price increases. VtE tends to be the largest when there are the greatest amount of open positions, such as when SDG&E begins active management of a time period, when time to expiration is longest, thus statistically allowing for large price movements prior to expiration of positions, or when market volatility increases. Volatility is a large driver in the calculation of VtE because statistically prices are likely to make greater changes during periods of high volatility.

SDG&E regularly reports updated measures of risk such as VtE, remaining open positions, forward prices and sensitivities and remaining CRT.

SDG&E currently reports a rolling 60 month VtE to the CPUC. SDG&E proposes that a more appropriate measure for the longer-term horizon is to set a floor on long-term fixed price positions, to at least a small amount, while maintaining a blend of index-based hedges to maintain reliability and contract for environmental concerns. SDG&E believes it is not prudent to either commit too much or too little to fixed-price hedging for the long-term as either of these requires the ability to effectively speculate on both the direction and timing of market price movements.

Hedging Strategies

SDG&E employs hedge strategies for three time periods: short-term (years 1 and 2), intermediate term (years 3 through 5), and long term (years 6 through 10).

For years one and two, SDG&E calculates remaining Customer Risk Tolerance (CRT) and Value at Risk (VaR) as the primary measures to assess the risk of higher costs in fulfilling its load obligation, relative to the baseline cost forecast established in the CRT process. If remaining CRT is greater than VaR, SDG&E will follow an "incremental and over time" hedging program; if remaining CRT is less than VaR, SDG&E will hedge more aggressively to cover its open position and reduce VaR. This hedging strategy is the same as that currently implemented by SDG&E under its approved STPP and Gas Supply Plan.

In the intermediate timeframe, SDG&E undertakes more passive risk management, where it takes positions without regard to market price signals, but with an objective of maintaining a certain percentage of portfolio hedge positions. SDG&E undertakes hedges so that each in each of years 3, 4 and 5, it fixes or caps the price of ratepayer open positions within certain bounds. SDG&E establishes limits for how much of its total portfolio it will hedge in years 3, 4 and 5. Not to do so would preclude ratepayers from realizing the benefit from any future fall in market prices if hedging was accomplished through fixed price instruments. Additionally, high levels of hedging would ignore the risk of load uncertainty created by possible resumption of direct access or community choice aggregation, either of which could lead to potential stranded hedging costs. The intermediate term hedging strategy results in ratepayers acquiring a portfolio that has a weighted blend of market prices transacted at various times, rather than one where all positions are fixed at the same time in the hope that markets will move in their favor.

For years 6–10, hedge levels are already assured through fixed price positions inherent in the portfolio's legacy contracts such as San Onofre Nuclear Generating Station, QFs and renewables. SDG&E views these hedge levels as sufficient, given the long time to delivery, and has no plans to financially hedge a greater percentage. SDG&E proposes to adopt reporting triggers so that if the hedged portion of the portfolio falls below certain levels, SDG&E will notify the CPUC of any planned actions through an update to their LTPP. In addition, the scope of the active hedging horizon has been limited to five years, in part due to reduced liquidity in the market beyond five years (which makes transaction execution more difficult, increases bid/ask spreads and makes prices discovery less robust) and beyond five years, SDG&E relies on some generic, yet to be contracted for resources. The uncertainties surrounding these future resources make calculation of the RNS and gas positions much less certain for these years.

Natural Gas Procurement

The primary physical products that SDG&E trades in procuring gas for electric generation include baseload gas and intra-swing gas. The price for baseload gas will typically be fixed-price or based on index pricing. While SDG&E's practice has been to purchase baseload gas month-to-month, multi-month contracts may also be used to reduce the exposure to bid-week volatility and liquidity constraints. SDG&E expects to procure the balance of its utility-retained generation physical gas requirements (intra-swing gas) throughout the month in the spot market at prevailing prices.

SDG&E considers the various cost recovery mechanisms in its gas procurement strategy. Gas burns may be incurred for a number of reasons, such as dispatch by SDG&E to meet bundled customer load, or dispatch by the IS0 under Must Offer, Reliability Must Run, Reliability Capacity Services Tariff or RA. However, each type of dispatch presents a different gas cost recovery mechanism. Gas for dispatch by SDG&E to serve bundled customer load represents costs that will be recovered from ratepayers through ERRA and thus are part of the CRT risk management strategy. Payment of gas costs for must-offer and RMR energy is based on daily gas indices; therefore, SDG&E buys the gas requirement on a day-to-day basis to match actual gas cost to the payment stream from California ISO, forming a "back-to-back" transaction. Gas costs for supplemental energy dispatch are covered by a California ISO payment to the generator, and SDG&E accounts for the daily gas price in its supplemental energy bids. In contrast to the above revenue-matching strategy for California ISO-reimbursed gas costs, SDG&E procures gas for load-serving generation with the objectives of least-cost dispatch and managing gas costs through its CRT-based risk management strategy.