TAB H

Affidavit of Professor Benjamin F. Hobbs

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. Docket No. ER05-____-000

AFFIDAVIT OF BENJAMIN F. HOBBS
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. BIOGRAPHICAL INFORMATION

My name is Benjamin F. Hobbs, and I am a Professor in the Department of Geography & Environmental Engineering of the Whiting School of Engineering, The Johns Hopkins University, located in Baltimore, MD. I also hold a joint appointment in the Department of Applied Mathematics and Statistics in that institution. Previously, I was an Economics Associate at the National Center for Analysis of Energy Systems, Brookhaven National Laboratory, Upton, NY (1977-1979). From 1982-1984, I was a Wigner Fellow at the Energy Division of Oak Ridge National Laboratory. Between 1984 and 1995, I was on the faculty of the departments of Systems Engineering and Civil Engineering at Case Western Reserve University, Cleveland, OH. I have also been a visiting scientist or visiting professor at the Department of Civil Engineering at the University of Washington (1991-1992), the Systems Analysis Laboratory of the Helsinki University of Technology (2000), and the Policy Studies Unit of the Energy Center of the Netherlands (ECN (2001-2002). In the last ten years, I have been a consultant to the Maryland Power Plant Research Program (MPPRP); Planit Management, Ltd.; the Office of the Economic Advisor of the Federal Energy Regulatory Commission; the Energy Information Agency of the U.S. Dept. of Energy; The Analysis Group/Economics; Gas Research Institute; U.S. Army Corps of Engineers, Institute of Water Resources; Commonwealth Energy; the Electric Power Research Institute; Edison Source; Northeast Ohio Sewer District; BC Gas, Ltd.; Ontario Hydro; and BC Hydro. I presently serve as Scientific Advisor to ECN, as well as a member of the Public Interest Advisory Committee of the Gas Technology Institute. I am a member of the Market Surveillance Committee of the California Independent System Operator.

My Ph.D. was awarded in 1983 in environmental systems engineering from Cornell University, with minors in resource economics and operations research. I earned a B.S. from South Dakota State University in 1976, and a M.S. from the College of Environmental Science & Forestry of the State University of New York in 1978. I have published widely on electric utility regulation, economics, and systems analysis; and on environmental and water resources systems. These publications include over 80 refereed journal articles, and three books. A particular focus of my research is the use of engineering economy models to simulate electricity and emissions allowances markets, recognizing transmission and other technical constraints and imperfectly competitive behavior by market participants. My present research focuses on power market modeling, capacity market design, analysis of pollution policies under uncertainty and climate change, and decision analysis applications in ecological management. For example, I completed a comprehensive survey and simulation analysis of capacity market mechanisms for MPPRP in 2002. Current project sponsors include the U.S. Environmental Protection Agency, the National Science Foundation (NSF), MPPRP, and the PJM Interconnection.

Among my professional activities, I serve on the editorial boards of *Energy, The International Journal; IEEE Transactions on Power Systems; The Electricity Journal;* and the *Journal of Infrastructure Systems. I am* also Area Editor for Energy, Natural Resources, and the Environment for *Operations Research,* the premier journal in that field I am former chairman of the Executive Committee of the Energy Division of the American Society of Civil Engineers (ASCE), and serve on the Systems Economics Committee and Working Group of the IEEE Power Engineering Society. I am a member of the National Research Council Committee on Changes in

New Source Review Programs for Stationary Sources of Air Pollutants. Among the honors I have earned are a NSF Presidential Young Investigator award (1986-1992), and best publication awards from the Decision Analysis Society (Institute for Operations Research and Management Science) and the Water Resources Planning & Management Division of ASCE.

2. PURPOSE AND SCOPE OF AFFIDAVIT

The PJM Interconnection has proposed a new mechanism to define the capacity obligations of Load Serving Entities (LSEs) and to clear the market for capacity needed to meet the obligations within PJM's territory. The proposed Reliability Pricing Model (RPM) will continue to use a target reserve margin designed to assure resource adequacy for the region as a whole, together with reliability requirements for sub-regions of PJM based on transmission constraints. Unlike the previous mechanism in which the reliability requirement is fixed, RPM considers the reliability requirement as a variable. It will do so by constructing demand curves that define higher capacity prices when the resources offered are less than the requirement, while gradually dropping capacity prices as resources increase beyond the requirement. I was hired by PJM to analyze the demand curve approach and to determine what shape of demand curve, and which parameters, would best achieve PJM's goals of continued future resource adequacy at a moderate cost for electricity customers with limited risk for generators.

Based on the analysis that follows, I conclude that there is a sloping demand curve that can be used to clear the PJM capacity market. This curve, the "Curve 4" described in Section 4, should set relatively stable capacity prices that will attract sufficient new capacity investment to meet PJM's target reserve margins. If its parameters are set appropriately, this curve will balance several related factors effectively – because the curve sets predictable prices for new capacity, it will lower prospective generators' risks enough so that the generators will accept lower prices and profits for their new generation; because enough new generation is built to meet reserve margin targets, energy and capacity prices to consumers will be lower because they pay a lower scarcity premium; and because more generation will he built, expected variability in actual reserve margins relative to uncertain future loads will be reduced and reliability will be improved. Under a wide variety of sensitivity analyses, the recommended curve produced a superior result – in terms of increased new generation investment, lower costs to consumers, and decreased variability in future reserve margins – compared to PJM's current ICAP method, which I characterize as a "no demand curve" or "vertical demand curve" method.

The purpose of this affidavit is to describe the assumptions, procedures, and results of a dynamic analysis of alternative demand curves (or "variable resource requirement", VRR) for the proposed reliability pricing model (RPM) system for the PJM market. In this affidavit, I will use the terms RPM, capacity market, and ICAP market interchangeably. A demand curve for installed capacity has the basic form shown in Figure 1(b): the market operator makes a capacity payment to generators that is a flat or decreasing function of the amount of capacity. The operator then collects those payments from load. (As I portray the curve here, capacity is measured as "unforced reserve margin", defined as the actual capacity less expected forced outages, then divided by the weather-normalized peak load.) In contrast, the present PJM system is equivalent to the vertical demand curve shown in Figure 1(a). The maximum payment results from deficiency charges applied to LSEs who are short of capacity credits (thus, those charges represent their maximum willingness to pay for capacity). But if there is more than enough capacity in the market to meet the target reserve, no one should be willing to pay anything for capacity, which is reflected in a zero price.

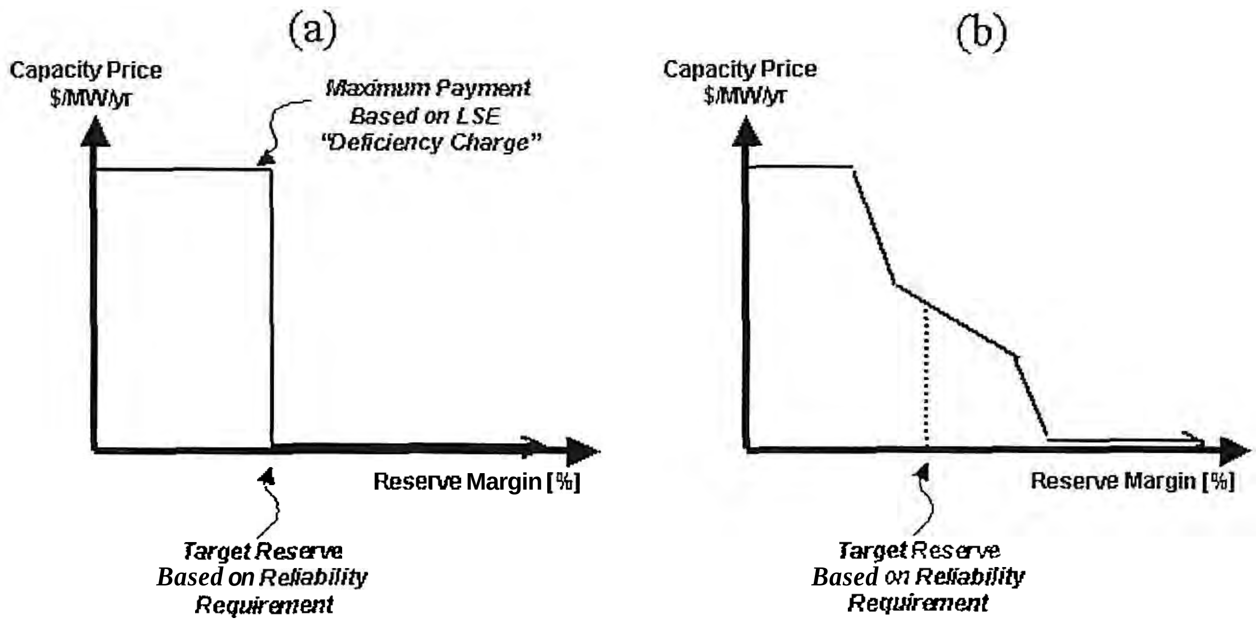

Figure 1. Demand Curves (Capacity Payments Expressed as a Function of Reserve Margin): (a) "Vertical" Case (Implicit in Present PJM System); (b) Downward Sloping Case (VRR)

The dynamic analysis addresses the following general questions:

1. How do different proposed demand curves (including the present vertical or "no demand" curve case) for the proposed four-year ahead auction compare in terms of average profits, capacity payments, energy and ancillary services revenues, reserve margins, and costs to consumers?
2. How do different curves compare in terms of the year-to-year variation in those indices?
3. How robust are those conclusions to changes in the shapes of the demand curve proposals, and to assumptions concerning the behavior and risk attitudes of investors in new generation?
4. How does changing from the present same-year auction system to a four-ahead system alter risks faced by generators?

The dynamic analysis considers the dynamic response of the market to incentives for construction of new generation. Further, it assesses how alternative assumptions concerning the risk attitudes and behaviors of builders of new generation could affect the performance of alternative demand curves under consideration for the RPM system. I have created a dynamic model that simulates generator investment over time in response to incentives in the energy, ancillary services, and capacity markets. Performance of different curves is gauged by three sets of indices: forecast reserve margin; generator revenues and profits; and consumer payments for capacity and scarcity rents. Average values for the simulated time periods are reported for these indices, as well as standard deviations that reflect variability over time in performance.

In the next section of the affidavit (Section **3),** I provide background on the desirability of capacity market mechanisms and the general advantages of a demand curve approach. The advantages include the following: it is broadly reflective of the reality of an increasing social value of capacity as reserve margins shrink; it creates a stable investment environment — which reduces the cost of capital and saves consumers money; and it lessens incentives for exercise of market power in capacity markets. In Section 4, I summarize the assumptions and calculation procedures of the model. The detailed equations underlying the model are presented in the Appendix to this affidavit.

In Section 5 of the affidavit, I first compare five different demand curves for the four-year ahead auction (Section 5.1). These include a vertical demand curve in which there is a fixed \$/unforced megawatt/year (\$/unforced MW/yr) payment if capacity is below a target value, and zero payment if it is above that level (Figure 1(a)). (Below, I use the terms "vertical demand curve" and "no demand curve" interchangeably for this case.) Alternative curves are instead downward sloping (as in Figure 1(b)), and vary in terms of their slope and location relative to the PJM target reserve margin at which loss-of-load-probability equals 1 day in 10 years (the target reserve in the figure). I conclude that downward sloping curves result in more favorable performance in terms of average reserve margins, consumer costs, and year-to-year variations in these indices. Section 5.2 is devoted to an example that explains why boom-bust cycles can occur in capacity markets. In

Section 5.3, I describe a set of sensitivity analyses of these results. The selected curve should be robust relative to assumptions about the investors' degree of risk aversion, and their willingness to invest as a function of expected profits, because such behavioral characteristics are uncertain and subject to change.

I conclude that the advantages of the downward sloping demand curve recommended by PJM relative to the vertical demand curve prevail for wide variations in these and other model assumptions. The vertical demand curve (the present ICAP system) produces higher long-run consumer costs than the demand curve that PJM recommends for every set assumptions tested. That is, adding a slope to the demand curve, in the manner proposed by PJM, does not worsen costs to power consumers in the simulations and, under most assumptions, significantly decreases those costs.

In Section 5.4, I compare the effects of a four year-ahead auction with a same year auction. The primary difference between the two is that capacity prices are more uncertain in the latter case; as a result, if investors are risk averse, higher average returns may be required in order to induce investment. As a result, the dynamic analysis finds that for the case of no demand curve (the present PJM capacity market) and for the proposed PJM sloped demand curve, a same year auction yields lower average reserve margins and higher costs to consumers.

3. BACKGROUND

In normal commodity markets, the consumer buys just the commodity. For example, a car owner does not pay Exxon for gasoline, and in addition pay for "ancillary services" (e.g., separate charges for delivery trucks or gas pipeline maintenance) or capacity of refineries or oil wells. The gasoline buyer pays a per gallon charge, and the gasoline supplier then figures out how to arrange and pay for production, processing, and delivery. Even though gasoline consumers do not pay separately for, say, gas tanker trucks, this has not resulted in shortages. In normal commodity markets, much or all of the funding for capacity and storage required to meet peak demands is provided by higher than normal prices during those times. Why then are there repeated calls for separate capacity markets for electricity or other mechanisms to ensure that "enough" generation capacity is built?

There are several reasons why power markets do not conform to the assumptions of the perfect competition ideal. One reason is specific to electricity itself—because power is very capital-intensive to produce, yet cannot be produced at one time and stored for future use at another, it is very expensive to meet peaks demands that only occur a few hours per year. For instance, in PJM, the highest hourly load in most years is over 8% greater than the loads served in 99% of the hours (i.e., higher than the 1% exceedence level for loads). The marginal cost per MWh of building enough generation capacity to meet that highest load is several tens of thousands of dollars, compared to an average price that is three orders of magnitude smaller. This is based on the annualized capital cost of a combustion turbine, which is $61,000/installed MW/year (in annualized real dollars), as discussed later in this affidavit. The marginal cost during the peak hour is so high because the incremental capacity would be idle the other 8759 hours per year, making no contribution to capital costs. In other industries, this swing of marginal cost from off-peak to peak periods is less extreme for three reasons: some are less capital intensive, they have more ability to store and transfer commodities from one period to another, and finally they can often charge high prices to dampen demand during peak periods,

High peak marginal costs do not by themselves explain the need for capacity markets. The other consideration is the absent demand-side of the market. One failure of the demand-side is the presence of price caps or other sources of price rigidity that prevent prices from climbing anywhere near that high during peak periods. To pay for the carrying cost of a combustion turbine that operates only eight hours per year, prices must approach $10,000/MWh for those hours. In a competitive bulk power market, this would only happen if there is a capacity shortage such that operators had to curtail load in order to maintain sufficient operating reserves. However, in the PJM and other eastern US ISO markets, prices are capped at $1000/MWh. So when shortages loom, prices approach and can bump into the price cap, and generators fail to receive the high revenues that unrestrained price spikes would bring. When prices cannot spike to uncapped levels that reflect the true value of peak electricity consumption to customers, load cuts and near-shortages must occur several dozens of hours per year with prices approaching the cap of $1000/hr in order to justify constructing a combustion turbine. (This assumes (1) there is no capacity market and (2) energy prices otherwise do not exceed the running cost of turbines.) Market participants would view a system with such frequent shortages as unacceptably unreliable.

In current retail electric markets, price fluctuations in the bulk power market are not communicated to most retail customers, who pay a rate that is either constant or just seasonally adjusted. Those consumers then do not notice whether the price of bulk power is $10/MWh or $1000/MWh during a particular hour. Their consumption decisions would be unaffected by price spikes, unless they hear public conservation requests or they are among the minority that participate in utility interruptible rate or load control programs. In contrast, when consumers are subject to prices that fluctuate in real time, they can often respond by decreasing loads in peak periods, or shifting uses to off-peak periods. This reduces the need for expensive capacity. Economic theory shows that when real-time prices are faced by all market participants in a competitive market, the optimal amount of generation reserves can result. This is because market prices will express the consumers' willingness to pay for power during peak times—just as in other commodity markets. But price regulation and lack of hourly meters for most customers mean that this ideal is unattainable, at least in the near future.

The absence of demand response to real-time prices also means that consumers are vulnerable to the exercise of market power. If a generation market is concentrated, generation will benefit from tight supply conditions because suppliers can more easily raise price above marginal cost. This dampens the incentive for capacity construction by incumbent generators. In contrast, higher reserve margins benefit consumers by making the exercise of market power less likely.

As a result of these demand-side failures, generation capacity becomes a public good. That is, every electricity user in the market benefits from the addition of new capacity, but the owner of the capacity cannot capture all those benefits through higher revenues. Economic theory says that public goods tend to be undersupplied in markets, so demand-side failures tend to cause capacity under-investment. Recognizing the value of capacity, the North American Electric Reliability Council (NERC) has explicit standards for capacity adequacy that require that certain reserve margins be maintained.

Several alternative mechanisms have been proposed to correct these market failures and to respond to adequacy mandates. One approach is to directly address the market failures by widespread installation of real-time metering and removing the price caps on both electric demand and supply. A second approach is a regulatory requirement that those who sell power to consumers hold long-term contracts or options for energy, perhaps with a stipulation that the options be backed up by physical generation assets. A third approach is a fixed payment (price-based) mechanism, where the ISO provides a set payment per MW for capacity, subject perhaps to performance penalties.

A fourth approach is quantity-based methods, in which a market operator either procures reserve capacity directly or sets up a capacity market. There are several varieties of capacity markets currently implemented. However, each market has most or all of the following basic features:

- a target level of system generating reserves (commonly based on an adequacy criterion of capacity deficits occurring only once every decade);
- an allocation of responsibility for meeting that target by creating an obligation (either on the part of LSEs or the ISO itself) to acquire capacity or capacity credits;
- a system to assign credits to generators, based on their capacity and reliability, and also to load management programs that can diminish the need for capacity;
- a system that allows trading of credits so that those with credits beyond their needs can sell them to those who are short;
- a set of requirements defining how far ahead of time (days, months, or years) those responsible for obtaining capacity must contract for it; and
- a system of incentives to encourage availability of capacity when needed, and for penalizing LSEs who have insufficient credits.

The present PJM capacity market is of this general type, with most of the features mentioned in this paragraph.

A fifth approach is a hybrid of the third (price-based) and fourth (quantity-based) approaches. It involves the market operator creating a downward sloping demand curve that pays more for capacity if reserves are short, while providing smaller but nonzero payments for some capacity levels that exceed the nominal reliability target. (In a sense, the present PJM system can also be viewed as a hybrid, as the deficiency payment paid by LSEs who are short of capacity credits puts a cap on how much they are willing to pay for capacity. This translates into an effective demand curve with a horizontal segment equal to the deficiency payment to the left of the target reserve margin, a vertical segment at the target, and no payment to the right of the target. Because there is no slope to this "curve", I term this the "vertical demand curve" approach below.)

There are several general advantages of a sloped demand curve-based capacity mechanism relative to fixed payment and quantity-based systems. Compared to fixed payment systems, the downward sloping demand curve will signal a higher value for capacity if reserves are short, and a lower value if reserves are ample. On the other hand, compared to a pure quantity-based system, where prices for capacity are zero if there is 1 more MW than needed but are very high if there is 1 MW less than required (Figure 1(a), ***supra)***, a demand curve will reflect the reality that additional capacity over and above a target reserve margin nevertheless has value. Additional capacity has value for two reasons. One is that in the face of varying load growth, weather, and capacity availability, the probability of available capacity being less than what is required to meet load and operating reserves never reaches zero, even for large reserve margins. Thus, reserves beyond the target are valuable for reducing the risk of capacity shortfalls. The second source of value is that reserves beyond the target lessen the risk of large suppliers being pivotal or otherwise able to exercise market power. Conversely, if reserves are below the target, a downward sloping demand curve provides increasing incentives for new capacity to the extent that the system is short, reflecting in a general way the greater risks of shortages and market power.

Another major advantage of a demand curve-based capacity market compared to the pure quantity-based system is that the stream of capacity payments received by generators will be more stable. In contrast, a capacity market with a fixed capacity requirement (no demand curve) can bounce between two extremes, depending on whether there is too little capacity or too much relative to the target. The resulting large swings in generator net revenues can exaggerate boom-bust behavior. Boom-bust cycles occur when a market adds too much capacity after a period of high prices, which results in a period of low or no capacity payments, which then dries up capacity additions until reserves are again short of target levels. Volatile revenues that cannot be hedged because of incomplete forward markets for energy and capacity increase risks to investors. Because investors in capital markets dislike risk, more volatile profits mean that higher rates of retum will be required for new generation investments. In order to obtain the higher returns required by risk averse investors, shortages of capacity would have to happen more frequently, resulting in higher costs and risks to consumers. In comparison, as I show later in this affidavit, a demand curve-based system will lower the variation in generator revenues, especially for peak capacity. Further reductions of risk to investors result if capacity commitments are made years in advance, as opposed to the present PJM system. With advance capacity commitments, my market simulations show that if investors are risk averse, they will accept lower rates of retum and be more willing to construct new capacity, ultimately decreasing costs and risks to consumers.

A third potential advantage of a downward sloping demand curve for capacity relative to a pure quantity-based capacity market (or vertical demand curve) is that the incentive to engage in either economic or physical withholding of capacity from the capacity market is reduced. This is because the slope of the demand curve causes a given reduction in capacity or increase in the capacity bid to have considerably less effect on the price of capacity than when the curve is vertical. as it effectively is for a quantity-based system. However, the presence of a "must-offer" requirement, backed by effective penalties, can also mitigate market power under either vertical or sloped curves.

4. DYNAMIC MODELING METHODOLOGY

4.1 Overview.

The purpose of the dynamic modeling methodology is to assess how the location and shape of the demand curve for capacity affect investments in generation adequacy. Because I focus on general adequacy issues, I do not represent capacity markets or payments for capacity differentiated by operating flexibility or location.

The fundamental idea of the methodology is that construction of generation capacity in a restructured electricity market represents a dynamic process with lags (due to construction lead times), short-sightedness (additions are based on recent energy and ancillary service market behavior, rather than perfect forecasts of future prices), and uncertain load growth. Thus, for instance, if it takes four years to bring a combustion turbine on-line in year y, the amount of turbine capacity installed in year y might be assumed to be some function of profits that such a turbine would have earned in, say, years y-4 and y-5. Profits, of course, are based on gross margins (revenues minus variable costs) earned in the energy and ancillary services (E/AS) markets, and any capacity payments. Investors may make construction decisions based on forecast profits, but since forecasts are generally based on past experience, construction decisions can therefore be represented as ultimately depending on the recent history of profits.

Investments based on recent profit histories can result in an unstable system exhibiting overshoot-type behavior. This behavior could result from an overreaction of merchant generation to high profit opportunities, resulting in a glut of capacity that then depresses prices, which then throttles capacity construction, leading subsequently to a shortage of capacity, and so forth. Instabilities can be exacerbated by load uncertainties. Because of variable economic growth, the growth in peak load (weather-normalized) can deviate from the expected value (that value being 1.7% per year for PJM), implying that realized reserve margins (with respect to weather-normalized peaks) will likely diverge from those forecasted in an advance ICAP auction. Further, variable weather adds volatility to E/AS gross margins. The resulting unstable profits lessen generators' willingness to invest. This is because investors are likely to be risk averse, in part because the market structure is new and changing, and in part because markets for financial hedges are inadequate for PJM E/AS and capacity markets.

Capacity markets should be designed to dampen boom-bust cycles, improve the stability and predictability of system adequacy, and minimize costs to consumers. It is reasonable to expect that the slope and location of a demand curve will affect the stability of the capacity market and, ultimately, prices and reliability. **A** good capacity market will also create some predictability and stability of generator profits, which is desirable to facilitate continued capital investment. My analysis focuses on those objectives.

There are tradeoffs between different market design objectives, so some judgment is needed.. On one hand, it is possible to essentially guarantee that the target capacity would be hit if **a** vertical demand curve (with an extremely high price to the left) was set at the target reserve level. But such a demand curve might result in more variation in consumer costs and profits and perhaps more market power than a sloped curve. So a choice requires consideration of those tradeoffs, and I use a dynamic model of capacity additions to quantify them.

Investment decisions are complex, and it is not possible to know or represent the precise decision processes of each potential generation investor. Therefore, my simulation modeling approach is intended to be a simple, reasonable, and transparent representation of the fundamental considerations that are affected by the demand curve and that contribute to stability or instability in the capacity market. These considerations include:

- uncertain load growth and E/AS revenues,
- generator risk aversion,
- forecasts of generator profits that depend on past profits, and
- willingness to invest in generation that increases as a function of forecast profit.

The models represent these considerations using simple functional forms with a minimum of parameters in order to facilitate alternative assumptions and improved understanding of the relationship of those assumptions to the results. A general principle of good modeling is Occam's razor: no more complex relationships should be used in a model than is necessary unless the additional complexity demonstrably increases the model's realism. Therefore, in the absence of evidence of more complex relationships or data to support their modeling, I have chosen to use simple functional forms in the models.

Because any model is necessarily a simplification of reality, and because many of the parameters of the model cannot be known with certainty, no single set of outputs should be treated as being definitive statements of the performance of a demand curve. Instead, I test several forms of the demand curve and conduct numerous sensitivity analyses around key parameters to determine the patterns of their influence on the model results, and the robustness of any conclusions about the relative performance of different curves. While the model necessarily simplifies capacity market decisions and impacts, the model is useful for the purpose of understanding qualitative dynamic effects such as whether a long-term capacity market is less likely to induce boom-bust cycles than a short-term capacity market, and whether the relative ranking of different alternatives is robust under a wide range of assumptions. The model is not accurate enough to make precise quantitative predictions, but its intent is to illuminate several qualitative decisions that must be made at the outset of the RPM.

Since no particular set of assumptions can be the "right" ones, sensitivity analyses are essential to assess the robustness of the comparisons. The model is designed to clearly show the implications of alternative assumptions concerning generator investment behavior and market conditions for the comparison of demand curves. A simple, transparent model that captures the basic features of the capacity market — uncertain loads, the dependency of forecast profits on past profits, generator risk aversion, increased investment in response to increased profits, and the effects of reserves upon energy and ancillary service market revenues and system reliability — is most likely to lead to useful insights and conclusions about the relative performance of different demand curves.

Models should produce sensible and consistent results. In particular, in the case of no uncertainty and risk neutral investors, the model should yield the expected equilibrium solution of enough capacity being added in each year to meet load growth, and generator revenues equaling costs, including a normal return to capital. Under these assumptions, a constant reserve margin—in an amount that depends on the location of the demand curve—should result. The model described below satisfies this consistency condition.

4.2. **Model Assumptions**

4.2.1. Flow of Model Execution

The dynamic model is a discrete time simulation, with an annual time step. Uncertainty is introduced in the form of both variations in economic growth and weather, which both affect the growth rate for the peak load. The model is implemented in EXCEL®.

Figure 2 summarizes the basic logic of the model for the case of the four-year ahead auction. An auction for ICAP in year y must take place at y-4, four years before that time. The following steps are executed in each year:

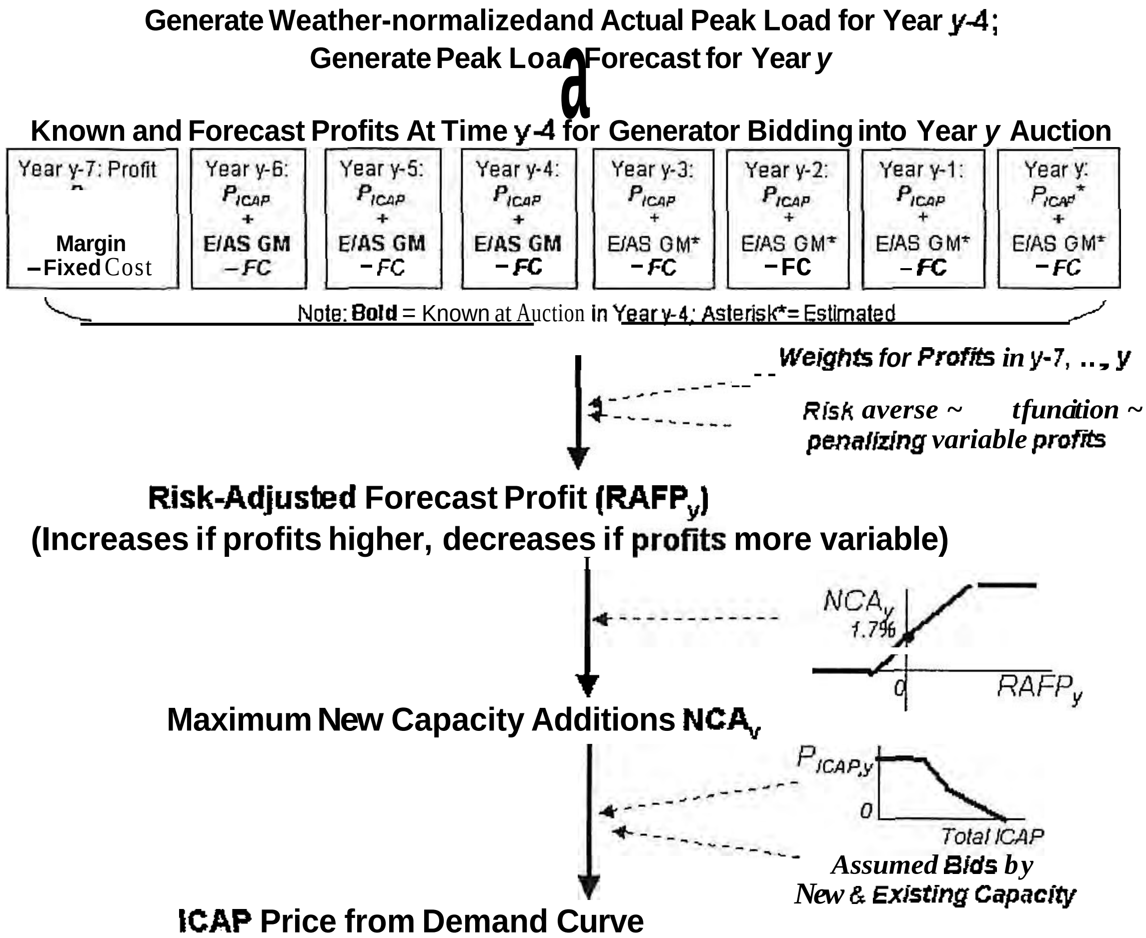

Figure 2. Flow Chart Showing Steps of Simulation

- Given the previous year y-5's weather-normalized peak load, and assuming random economic growth, the simulation model first generates a random weather-normalized peak for year y-4. The simulation then generates an actual peak load, accounting for random weather. EIAS gross margin, defined as E/AS revenue minus variable costs, is then calculated for a benchmark combustion turbine (having fixed annual cost *FC*) for year y-4. This margin is a function of the actual peak load and reserve margin in that year. Based on PJM experience, as I discuss below, tighter actual margins are associated with higher EIAS earnings. The ElAS gross margin plus the RPM revenues (determined in a previous auction) minus FC define the turbine's profit in that year. Then a forecast is made of the weather-normalized peak four years in the future (year y); this forecast is the basis of the demand curve in the auction held in yeary-4.

- In the next step, companies who might build new generation assess profits for a combustion turbine in years y-7 toy. (Fewer or greater numbers of years could be chosen, but the relative performance of different demand curves would not be greatly affected.) Profits for some of those years (*y*-7 to y-4) are assumed to be already known, since those years have already passed (*y*-7 to y-5) or are in process (*y*-4) and can be fairly accurately projected. Profits for future years (*y*-3 to y) are not known, since E/AS revenues depend on loads, which in turn are unknown because of uncertain economic growth and variable weather. The ICAP price is known for y-3 to *y*-1 (thanks to prior auctions), but has to be estimated for this year's auction (*y*), which has not yet occurred.
- Then, given those profits, a risk-adjusted forecast profit $RAFP_y$ is calculated, which requires two inputs. One is a set of weights to be attached to the profits in years y-7 toy; for example, more weight might be given to recent profits. The other is a risk-preference function (called a "utility function" in decision theory) that incorporates attitudes towards risk. Basically, such a function penalizes bad outcomes in such a way that if there are two distributions of profits with the same average value, the more variable profit stream will be less attractive.
- In the next step, the risk-adjusted forecast profit is translated into a maximum amount of new capacity NCA_y that generators are willing to construct; it is assumed that higher risk-adjusted profits will increase the amount of capacity that generators are willing to build. The function shown embodies an assumption of 1.7%/year average load growth, and a maximum amount of capacity additions; I discuss these specific assumptions in more detail later in this affidavit.
- Then a supply curve for capacity is constructed, based on the amounts of existing and po-

tential new capacity and the assumed prices that each would bid. This supply curve is then combined with the demand curve to yield an ICAP price and committed amount of new capacity for year y. This committed amount might be less than the maximum amount if new capacity is assumed to bid a positive price.

After these steps are executed, the simulation then moves to the next year, and the process is repeated.

Because the model randomly samples economic growth and weather, good modeling practice requires that a large sample of years be simulated in order to obtain reliable estimates of the average long-run performance that are unaffected by sample error. In such so-called "Monte Carlo" simulations, it is typical to repeat the random draws many thousands or more times. I follow this standard practice by repeating the above process for 100 years, and then a new simulation is started. It is important to note that a particular simulation does not represent a prediction of the market's development over the next 100 years; rather it is one sample path which, when repeated a number of times, allows for a statistically precise estimate of the average long-run performance of a particular curve and set of assumptions. Altogether, twenty five simulations of 100 years apiece are run for each demand curve and set of assumptions tested. This results in a sample size of 2500 years that allows the long-run average and standard deviation of each of the four sets of performance indices to be calculated.

4.2.2. Specific Model Assumptions: Four-Year Ahead Auction Model

The model requires a number of parameters that characterize the market design, load, system reliability, E/AS gross margins, and generator responses to incentives. I summarize these below.

Inflation. All calculations are made in real (uninflated) dollars. All capital and operating costs are assumed to inflate at the general rate of inflation (no differential escalation). Prices defined by the demand curve are also assumed to be adjusted upwards by PJM at the rate of inflation.

Market design parameters. The model's simple characterization of the demand function for capacity includes maximum payment (the flat left portion of the curve in Figure 1) and location and slopes of the downward portions of the demand function. To focus on general resource adequacy issues, I do not consider the following complications: capacity payments differentiated by operating flexibility or location; possible backstop mechanisms if reserve margins are lower than acceptable for several years; and possible administrative adjustments to demand curves that are made in response to new information about capacity costs and revenues from energy and ancillary services revenues

I do not consider how changes to an ICAP mechanism might affect administrative and transaction costs incurred by generators and load serving entities participating in the market. I also do not consider imports of capacity from outside PJM, or other seams issues.

Load parameters. Load is summarized by the annual peak load in each year. Three separate types of loads are considered: actual peak load, weather-normalized peak load (actual peak load adjusted for normal weather conditions), and forecast peak load (assuming normal weather conditions) for a future year. The growth in forecast peak load is assumed to be 1.7%/yr, consistent with the current official PJM forecast (see the February 2005 PJM Load Forecast Report), but below the PJM experience of 2.2% annual growth in weather-normalized peak load in the last decade. Year-to-year variations in the growth of weather normalized load are greatly influenced by economic growth in the PJM region; recent experience indicates that the growth rate has a standard deviation of 1%/year.[1] I model this variation in weather-normalized load growth by adding a normally distributed random component in each year to the 1.7%/yr expected growth,

[1] This 1% value is derived by comparing PJM four-year ahead forecasts with the experienced weather-normalized peaks over the 1995-2003 period. The standard deviation of the ratio of those two is 1.8%, which is consistent with the following set of assumptions: (1) a 0.9% random year-to-year error in weather-normalized growth, which I round off to 1%; (2) uncorrelated errors (from year to year) in that growth; and (3) an assumption that in the future, forecast load

Meanwhile, the actual peak load in a given year equals the weather-normalized peak plus an error reflecting year-to-year weather variations. Analysis of annual peaks from 1995-2003 for PJM and ISO-New England show that the ratio of actual to weather-normalized annual peaks has a standard deviation of about 4%, and I assume this value here.

Reserve Margins. Random economic growth and weather variability result in considerable instability in installed reserve margins, as well as in gross margins from EIAS sales which depend on those margins. Two different reserve margins are considered by the model: the forecast reserve margin, which is the basis of the capacity payment (Figure 1) and is based on forecast peak loads; and the actual reserve margin which depends on the actual load, including variation due to weather.

Generation Costs and Revenues. In the model, the focus is on combustion turbine additions, and investment decisions concerning baseload and cycling capacity are not modeled. More sophisticated assumptions about entry of other types of capacity can be made, but to simplify the simulations, we assume that incremental capacity is provided by benchmark combustion turbine (CT) capacity. This is based on the assumption that the price of capacity will be driven by the cost of turbines, net of their gross margins in the EIAS market, while other types of capacity receive most of their gross margins from the E/AS market. I have also conducted simulations of long-run equilibrium entry of coal plants, combined cycle facilities, and peaking plants for the PJM system.[2] Justifying my present focus on turbine investments, it turns out that those simulations show that the amount and mix of non-peaking capacity is not affected by the required reserve margin or the price of ICAP. Only the amount of peaking capacity is affected. However, all generating units are assumed to receive capacity payments, and consumer costs are calculated on that basis.

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growth rates (1.7%) are not biased up or down— that is, on average, the 4 year ahead forecast of the W/N peak will be correct.

[2]For a summary of the long run simulation approach and results, see B.F. Hobbs, J. Inon, and S. Stoft, "Installed Capacity Requirements and Price Caps: Oil on the Water, or Fuel on the Fire?", Electricity Journal, 14(6), August/Sept. 2001, 23-34. Since then I have updated the load duration curves and cost assumptions of the analysis, but the same basic result holds: capacity market mechanisms do not affect the quantity or mix of nonpeaking capacity added.

In reality, it is possible that in some years capacity additions for other types of plant will be undertaken while no turbines are being added. For example, if there are large shifts in relative fuel prices, as in the 1970s, generation additions beyond what is needed to meet reserve margin requirements might be justified in order to displace uneconomic fuels in the existing generation mix. For simplicity, I assume that these conditions are relatively infrequent, and that if capacity is being added, at least some of it will be in the form of combustion turbines, for which ICAP revenues will constitute a major part of their forecast profits

All CT units are assumed to have the same marginal operating and capital costs (in real terms) in all years of the simulations, so technological progress and fuel price changes are not represented. I disregard real (after-inflation) changes in technology and costs in order to avoid having to make assumptions about escalation rates. The annualized capital and fixed operations cost is assumed to be $61,000/installed MW/yr in annualized real dollars.[3] Accordingly, my model implicitly assumes that the second-year annualized capital cost will be higher than the first by a factor equal to the inflation rate, and the third-year figure will be higher than the second, and so on. It is my understanding that PJM is proposing a fixed CONE figure stated in its tariff that cannot be changed without a stakeholder process and regulatory approval, but that the proposed fixed CONE value also takes future inflation into account using a nominal levelized financial model, as explained by Joseph E. Bowring in his affidavit as witness for PJM.

With an assumed forced outage rate of 7%,[4] this translates into a cost of $65,600/unforced MW/yr for a new turbine, again in real dollar terms. I assume that the marginal operating cost is $79/MWh. I also assume that the lead time for CT construction is four years, including time re-

[3] See affidavit of Mr. Raymond M. Pasteris, witness for PJM. The difference between an annualized real dollar figure and an annualized nominal dollar figure is that a time series that is constant in real terms will escalate in nominal dollars at the rate of inflation, while a time series that is constant in nominal terms will have no inflation, i.e., the same "dollars of the day" in every year. See also the affidavit of Joseph E. Bowring for further explanation of the difference.

[4] The 7% forced outage rate is based on the latest NERC 5 year (1999-2003) class average (6.93%) for industrial type simple cycle combustion turbines over 50 MW in size, which is the closest publicly available fit for a GE Frame 7 machine. The corresponding value for the large aircraft-derivative units is almost identical at 6.91%.

quired for necessary regulatory approvals.[5] The willingness of investors to build new turbine capacity is assumed to depend on future profit forecasts, which in turn are assumed to depend on profits that would have been earned by such a CT in previous years, equal to the sum of ICAP revenues and EIAS gross margin, minus the annualized cost of CT capacity. Profits in previous years are important to consider because they provide a basis for forecasting the level and volatility of profits in the future.

The E/AS gross margin that a turbine would earn in each year is critical to its profitability, and therefore to investors' willingness to build capacity. Furthermore, as I document below, this gross margin varies greatly from year-to-year, depending strongly on the amount of capacity relative to the actual peak loads. The model therefore includes a relationship between market conditions (reserve margin) in a year, and the EIAS gross margin earned by a new turbine. This gross margin consists of two portions: a scarcity portion, which arises when price exceeds the marginal cost of the last generating unit (due either to a genuine shortage, or to exercise of market power), plus an assumed $10,000/MW/yr that is earned in ancillary service markets that I do not model or which results from margins earned when more expensive plants are on the margin.[6] Figure 3 shows the resulting total EIAS gross margin for a hypothetical new turbine (solid line), as well as the actual values that would have been experienced for such a turbine in years 1999-2004 (triangles), under the assumption that the turbine could operate in any hour in which price exceeded its

[5] This estimate is based on a typical time of up to two years to acquire necessary permits, in addition to an actual construction time of hvo years. The precise lead time required depends on location and the presence of complicating issues (such as non-attainment status for criterion air pollutants or land use restrictions).

[6] Within the model, this function could be calculated by an appropriately calibrated production costing submodel that represents all operating constraints. Instead, we estimate this function using the results of a simplifiedprobabilistic production costing model for PJM in which the energy price paid to the generator is assumed to equal the marginal cost of generation unless load is within 8.5% ofavailable capacity, at which point scarcity pricing is assumed to take place and the price of energy hits the cap ($1000/MWh). The simplified model bas a capacity mix of baseload coal and gas-fired combined cycle and combustion turbine capacity, and a load distribution reflecting the combined PJM-East and PJM-West load shape. Subtracting the assumed marginal running cost of the CT yields the estimated scarcity rent. The scarcity rent is then added to an assumed minimum E/AS gross margin of $10,000/unforced MW/year. Although the particular assumptions of the production costing model are somewhat uncertain, Figure 3 shows that the resulting E/AS gross margin function is a reasonable approximation to actual PJM market conditions in the 19992004 period.

marginal running cost ("Perfect Economic Dispatch").[7] The actual data confirms the reasonableness of the EIAS function used. The figure shows that when the actual reserve margin equals the target installed reserve margin (IRM) (indicated by a ratio of 1 on the X axis), the EIAS gross margin is about $28,000/unforced MW/yr. This margin is generally consistent with the average EIAS margin for a new turbine for the period 1999-2004 under perfect dispatch assumptions, as reported in PJM's 2004 State of the Market Report.

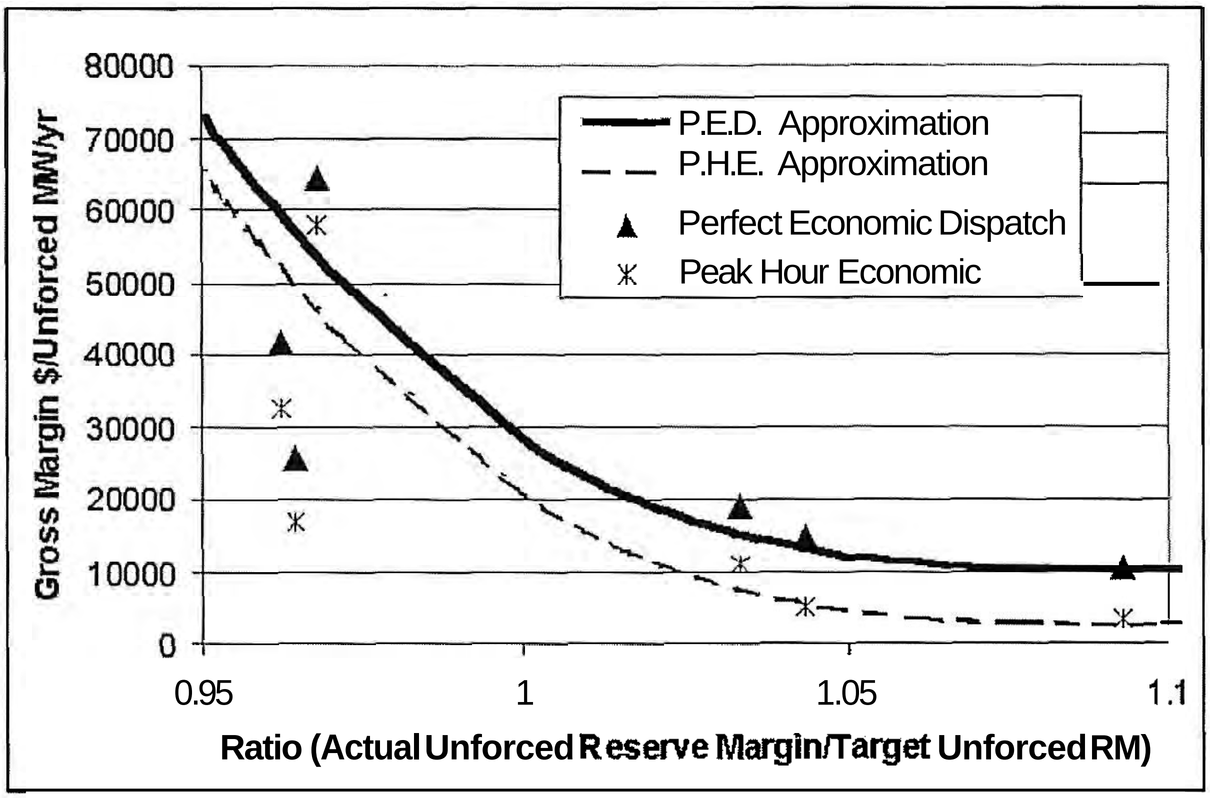

Figure 3. Relationship of EIAS Gross Margin to Unforced Reserve Margin Under Alternative Turbine Dispatch Assumptions, expressed as a Ratio With Respect to the Target Installed Reserve Margin for PJM

An alternative cost function results if a more conservative assumption is made about when the benchmark turbine could be operated. If its operation is limited to peak hours, thus omitting off-peak hours when prices exceed the turbine's running cost, E/AS revenues fall. For 1999-2004,

[7]Source: Table 2-34,2004 PJM State of the Market Report. Values reported in that Table are adjusted upwards, accounting for forced outages, so that die values are expressed as $/unforced MW/yr.

the average EIAS revenue for the baseline turbine would then be about $21,000/MW/yr (ibid.); year-by-year results are shown in Figure 3 (asterisks, "Peak Hour Economic"). The cost curve in Figure 3 can be adjusted to fit those results by lowering the minimum EIAS gross margin from $10,000/MW/yr to $2400/MW/yr (see the dashed line in the figure). Later in this affidavit, I present the results of a set of sensitivity analyses based on this alternative cost function.

Since EIAS gross margins for years y-3 to y depend on actual peak loads which are not known in year y-4 (the year in which a commitment is made to constructing a turbine to be on-line in year y), these margins must be forecast. This is done in a simple fashion in the model by simply calculating the EIAS gross margin under the forecast loads for those years. Alternative, more sophisticated analyses are possible, such as considering a probability distribution of EIAS in each future year, but are unlikely to change the general results of the analysis.

Investment Behavioral Characteristics. As Figure 2 (on page 18) shows, there are four major sets of behavioral characteristics that are modeled: two sets are used to calculated risk-adjusted forecast profit (forecasting and risk aversion assumptions); another set is used to determine the maximum amount of new entry; and a fourth set includes the bid prices that capacity suppliers provide to the ICAP market. Since each set of characteristics is uncertain, I report a set of sensitivity analyses in Section 5.3, *infra*, that summarize the robustness of the model results to those assumptions.

The risk-adjusted forecast profit (RAFP) is defined as a certain profit that is viewed by investors in generation as being just as desirable as the actual stream of observed and estimated profits (the eight profits shown at the top of Figure 2). "Profit" is defined in the sense meant by economists: as profit over and above the cost of capital; so a zero profit signifies that capital costs are just being covered. The generator calculates a risk-adjusted profit for an investment in a combustion turbine by multiplying each profit (adjusted to account for risk aversion) by the probability of receiving that profit, accounting for the range and variability of observed and estimated profits. Generally speaking, if two endeavors offer the average profit, the riskier option is less desirable (has a lower risk-adjusted profit), and the options with the highest risk-adjusted profit will be most desirable. The adjustment for risk aversion is accomplished using a standard representation of risk preferences called a utility function, which I will call a risk-preference function in the remainder of this section. (Appendix A.2 below provides details.) The first step in calculating RAFP is to calculate the value of the risk-preference function for each year's profit.

Different degrees of willingness to take risks are captured by a single risk-aversion parameter in the risk-preference function. As I explain in Appendix A.2, *infra.*, a risk-aversion parameter value of 0.5 signals complete risk-neutrality—any investment with the same average return is valued the same, no matter how variable or risky the profits. Values of this parameter greater than 0.5 signal an increasing distaste for risky investments; a base-case value of 0.7, representing an intermediate degree of risk aversion, is assumed here. Because this behavioral characteristic cannot be known, I undertake a wide range of sensitivity analyses to see if the relative performance of the demand curves depends on the degree of investor risk aversion.

The second step in obtaining the RAFP is to calculate a weighted average of the eight years of risk-adjusted observed and estimated profits (Figure 2, page 18). The sum of the weights is 1. A simple form of such weights is the lagged formulation in which risk-adjusted profit in any year y-1 is a given fraction a of the weight assigned to the next year y's profits. The weights reflect the degree to which the history of profits is relevant to the generator forecasting profits; the greater the weight placed on previous years' profits (y-1, y-2, etc.), the less relative weight is placed on the ICAP price in the particular year y's auction. As a base case, we assume that the weight given profit in year y-1 is a = 80% of the weight assigned the next year's profit. I subject this assumption to sensitivity analysis later in this affidavit.

The third step calculates the RAFP itself, defined as the single profit value whose perceived value to the investor is the same as the weighted average of the risk-adjusted observed and estimated profits.

The second set of behavioral characteristics concerns how investors in generation might react to different levels of RAFP. The maximum amount of new capacity additions (NCA) is calculated using a simple function with the following properties:

- If *RAFP* is zero (that is, capital costs are just covered), then the amount of capacity added is sufficient just to meet expected load growth (1.7%/yr, calculated as a fraction of existing capacity; see Figure 4). This is consistent with the assumption that in a growing market in which investors receive "normal" (zero economic) profit, adequate investment will occur.
- If *RAFP* equals the fixed cost of a combustion turbine (in annualized real terms), then entry of new capacity is highly profitable (not only is the cost of capital covered, but extra profits equal to the capital cost are also earned). I then assume that the amount of entry equals 7% of existing capacity (Figure 4). This value is based broadly on recent experience in the PJM market with capacity additions. In particular, the maximum capacity additions in the MAAC region since 2000 amounted to 3800 MW, equaling 6.3% of the 60,015 MW of capacity existing at that time.
- Capacity additions at other *RAFP* levels are an increasing function of RAFP, and follow a curve that is the same shape as the assumed risk-preference function (the upward sloped portion of Figure 4), with two exceptions. First, additions cannot be negative; retirements are not considered in this analysis. Second, additions are subject to a cap so that implausibly high levels of investment cannot occur in a single year. As a result, the RAFP function has the S-shape shown in Figure 2 (page 18), and reproduced in Figure 4.

Because this function cannot be known with any certainty, I report the results of sensitivity analyses of these assumptions

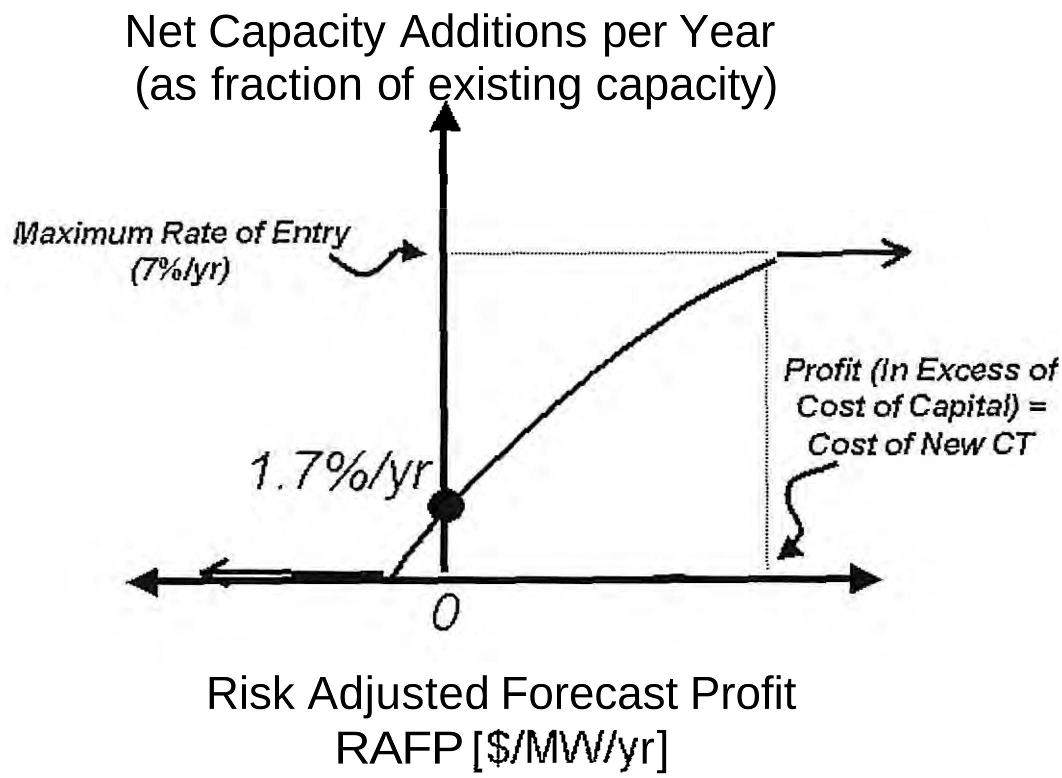

Figure 4. Relationship of Rate of New Capacity Construction (As Fraction of Existing Capacity) to Risk Adjusted Forecast Profit of New Combustion Turbine

The third set of behavioral characteristics in the model involves the assumed prices at which existing capacity and new capacity are bid into the ICAP auction. For simplicity, no retirements of existing capacity are considered. For the base cases, it is assumed that all capacity is bid in at $0/MW/yr; that is, generators are assumed to commit to maintaining or building certain quantities of capacity, and then bid in a vertical supply curve, which makes them price takers for the price of ICAP. Alternative assumptions are considered in our sensitivity analyses; the highest bid cases can be interpreted as an attempt to exercise market power. In all simulations, the bid

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. Docket No. ER05-____-000

AFFIDAVIT OF BENJAMIN F. HOBBS
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. BIOGRAPHICAL INFORMATION

My name is Benjamin F. Hobbs, and I am a Professor in the Department of Geography & Environmental Engineering of the Whiting School of Engineering, The Johns Hopkins University, located in Baltimore, MD. I also hold a joint appointment in the Department of Applied Mathematics and Statistics in that institution. Previously, I was an Economics Associate at the National Center for Analysis of Energy Systems, Brookhaven National Laboratory, Upton, NY (1977-1979). From 1982-1984, I was a Wigner Fellow at the Energy Division of Oak Ridge National Laboratory. Between 1984 and 1995, I was on the faculty of the departments of Systems Engineering and Civil Engineering at Case Western Reserve University, Cleveland, OH. I have also been a visiting scientist or visiting professor at the Department of Civil Engineering at the University of Washington (1991-1992), the Systems Analysis Laboratory of the Helsinki University of Technology (2000), and the Policy Studies Unit of the Energy Center of the Netherlands (ECN (2001-2002). In the last ten years, I have been a consultant to the Maryland Power Plant Research Program (MPPRP); Planit Management, Ltd.; the Office of the Economic Advisor of the Federal Energy Regulatory Commission; the Energy Information Agency of the U.S. Dept. of Energy; The Analysis Group/Economics; Gas Research Institute; U.S. Army Corps of Engineers, Institute of Water Resources; Commonwealth Energy; the Electric Power Research Institute; Edison Source; Northeast Ohio Sewer District; BC Gas, Ltd.; Ontario Hydro; and BC Hydro. I price for existing capacity is assumed to be no more than for new capacity. Figure 5 shows how the resulting market clearing price and quantity of capacity are calculated. The new capacity that is offered but not accepted (the portion of the second step to the right of the point where the curves cross) is assumed to not be built.

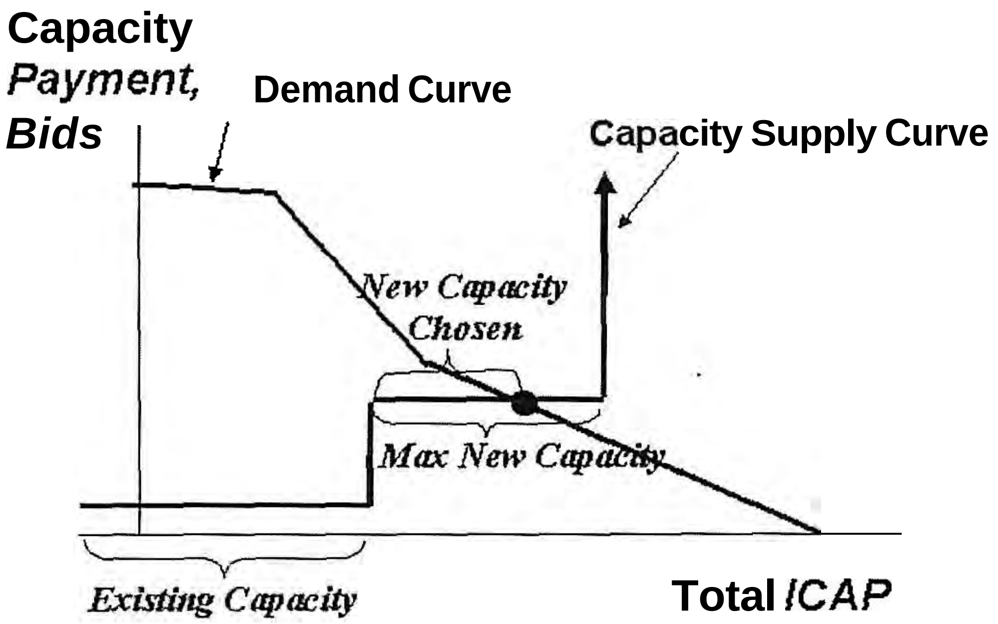

Figure 5. Determination of Price for Capacity Installed in yeary

Performance Indices. The performance of a particular ICAP payment scheme is summarized by three sets of indices:

1. Reserve margin indices. One is forecast reserve margin, including its average and year-to-year standard deviation. Also calculated is the fraction of years in which the forecast margin is at or above the target installed reserve margin.
2. Indices regarding generator costs and profits. These include avcragc values of profit for CTs, the price of ICAP, and E/AS revenues, as well as their year-to-year standard deviations. These are expressed in terms of $/installed MW/yr of capacity for the benchmark CT.

3. An index of consumer cost. We calculate average and standard deviation (year-to-year) of customer payments ($/peak MW/year) for ICAP and for the scarcity rents earned by new turbines. It is assumed that other payments by consumers (including, e.g., energy produced during nonscarcity periods, wires charges, customer charges) are unaffected by the ICAP curve. A higher average cost can occur if chronically low reserve margins result in high ICAP prices and scarcity payments. Such conditions could persist if high market risks make generators reluctant to construct new plants unless average returns are large.

Both averages and standard deviations are reported, because the latter provide indications of the risk in the market for the market participants. For instance, two demand curves might provide the same average forecast reserve margin, but one policy might result in much more variation in that reserve.

5. RESULTS

5.1 Base Case Analyses

Five demand curves are considered in the base case analyses. Each of these curves is displayed in Figure *6*. (The four parts of Figure *6* each show Curve 1, the "no demand curve case", superimposed upon Curves 2 through 5 respectively.) The X axis is expressed as a ratio of the unforced reserve margin to the target unforced reserve margin, so that a value of 1 signifies that the target is just met. Multiplying this ratio by the target and then subtracting 100% converts the X axis into the unforced reserve margin.

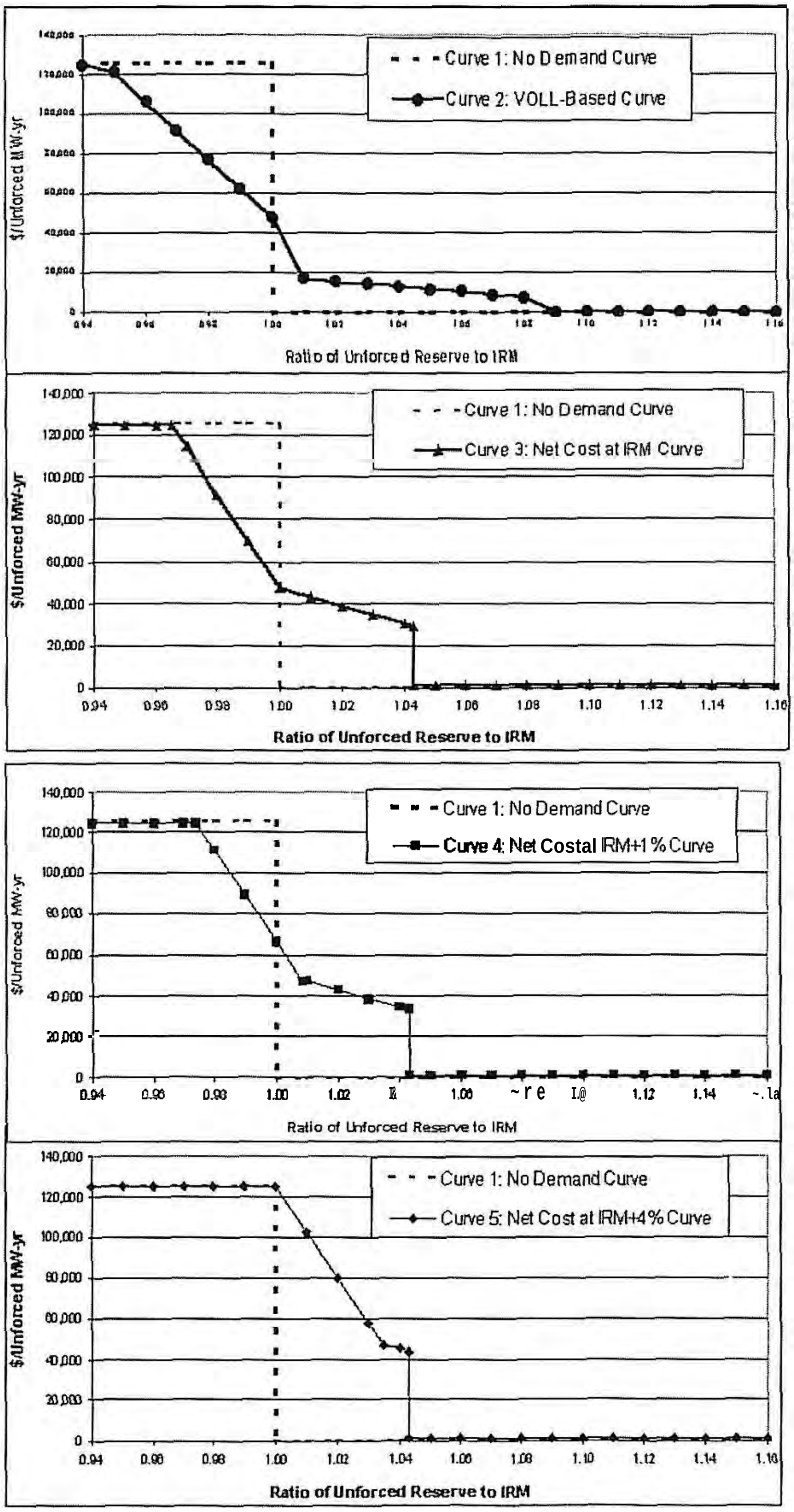

Figure 6. Five Alternative Demand Curves: ICAP Price Paid to Unforced Capacity as Function of Reserve Margin (Expressed as Ratio to Target Unforced Capacity)

The curves are defined as follows:

1. No *Demand Curve*. *A* vertical demand curve (also called the "no demand curve" case) yields an ICAP payment that is two times the fixed cost of a turbine ($144/kW/year, based on an annualized nominal dollar cost of $72/kW/yr) minus the average EIAS gross margin ($28/kW/yr) for values of forecast reserves that are less than the target installed reserve margin (IRM).[8] (The nominal dollar annualized cost is consistent with a $61/kW/yr real annualized cost and a 2.5% inflation rate.) (The capacity payment is expressed in terms of $/unforced MW/year. Therefore, the highest payment is actually (2*72-28) divided by 0.93 (1 minus the assumed 7% forced outage rate), or $124.7/unforced kW/yr.) The target reserve margin (shown as a ratio of 1 on the X axis of Figure 6) corresponds to a loss of load probability of 1 day in 10 years. If reserves exceed that level, then no capacity payment is made. This is analogous to the present PJM system in which load serving entities (LSEs) are willing to pay up to but no more than their deficiency payment for ICAP credits if they are short of credits, while if credits are in surplus, LSEs are assumed to be unwilling to pay for any more than their total ICAP obligation. As I noted *supra*, the average E/AS gross margin of $28,000/installed MW/yr is an average for the 1999-2004 period for the benchmark CT, as reported in PJM's 2004 State of the Market Report.
2. *VOLL-Based* **Curve.** A demand curve originally proposed by PJM in August, 2004 that is based upon an approximation of how the expected value of lost load VOLL (also called unserved demand) changes when average reserve margins diverge from PJM's target reserve margin (installed reserve margin IRM = 1.15). PJM's existing ICAP model, the capacity markets used by other northeastern ISOs, and the other curves evaluated in this affidavit, all are based on the fixed costs of a marginal capacity unit. Instead of looking at

[8] As I discuss later in this affidavit, sensitivity analyses using lower multipliers (i.e., 1.2 and 1.5) of a turbine's fixed costs, did not change the general result.

the cost of an increment of additional capacity, this VOLL-based curve attempts to approximate the value to the consumer of an increment of unserved load.

3. *"Alternative Curve with New Entry Net Cost at IRM" Curve.* As shown in the second part of Figure 6, this is a sloped demand curve with four segments: (a) a horizontal segment with an ICAP price equal to two times the fixed cost of a turbine if the reserves are less than 96% of the target reserves, minus the average E/AS gross margin, divided by one minus the forced outage rate ($124.7/unforced kW/yr); (b) another horizontal segment with a zero price if the installed capacity exceeds the target installed reserve margin of 15% by 5% or more (shown as occurring at 1.043 on the X axis in Figure 6, which is the ratio of 1.2 to the target installed reserve of 1.15); and (c) two linear downward sloping segment located between the other two, with the righthand one having a shallower slope.[9] The location where the slope changes is at a reserve margin equal to the IRM, and a price equal to the levelized nominal cost of the turbine ($72/kW/yr) minus the mean E/AS gross margin ($28/kW/yr, for the period 1999-2004), divided by 0.93, or $47.3/kW/yr. As a result, if capacity hits the IRM exactly, then the payment will equal the difference between the benchmark turbine's fixed cost and the average EIAS gross margin.

4. *"Alternative Curve with New Entry Net Cost at IRM +1% " Curve.* As seen in the third part of Figure 6, this curve is a version of Curve 3, except moved 1% to the right in installed capacity terms, but with the zero price still occurring at an installed reserve margin of 20%. (That is, if the X axis in Figure 6 was installed capacity rather than the ratio of installed capacity to the target IRM, the curve would be shifted 1%. In terms of the X axis of Figure

[9] Note that the capacity payment is expressed in terms of $/unforced MW/year. Therefore, as in the vertical curve, the highest payment is actually (2*72-28) divided by 0.93 (1 minus the assumed 7% forced outage rate), or $124.7/unforced kW/yr. Note also that the adjustment for E/AS gross margin is not adjusted year-to-year in the simulation, but reflects the 1999-2004 experience in PJM. The slope of the right hand sloped segment is defined by running a line from the inflection point (at the target IRM) to zero (at the target IRM plus 14% installed margin). That segment is then cutoff at IRM plus a 5% installed reserve margin, which is 1.043 times the IRM, as shown in Figure 6.

6, this shift is instead 1%/1.15.) Thus, at a given reserve margin, capacity will receive a higher ICAP payment than in Curve 3. As shown by the simulations summarized *infra*, this will tend to give additional incentive to invest in generation, and actual reserve margins will tend to be higher.

5. *"Alternative **Curve** with **New Entry Net Cost at IRM** +4%"* ***Curve.*** This is a version of Curve **3,** except moved 4% to the right, and is shown in the last part of Figure 6. As in Curves 3 And 4, the capacity price falls to zero at an installed reserve margin of 20%, which is a factor of 1.043 higher than the target IRM.

In addition to this set of five curves, a second set of curves is also considered based upon an average E/AS gross margin of $21,100/MW/yr. As I noted earlier, and as explained in the 2004 State of the Market Report, this lower value results from an assumption that a benchmark turbine will only operate during peak hours. This assumption results in an upward shift in the left hand part of the curves, because the height of the curve in that region is based on the capital cost of a benchmark turbine minus this margin. In particular, the maximum capacity price increases by about $7400 (= $28,000-$21,100/MW/year, divided by 0.93), as does the location of the kink in the "Net Cost at IRM" curves.

A range of alternative assumptions is considered in the sensitivity analyses described in Section 5.3. I present my conclusions about the relative performance of the curves later in this section, but first some general observations are helpful in understanding the performance indices.

- The more capacity you get, the more likely you will exceed your IRM target, with less variability.
- The more capacity you get, the less scarcity there will be, so scarcity payments in the enrgy market will be lower.

- The sloped demand curves that PJM has proposed yield consistently higher capacity investment with consistently lower consumer costs than the other curves investigated. The vertical demand curve (Curve 1) pays the most for new capacity, but because it creates volatile and fast-changing signals to generators, it hits or exceeds the reserve margin target the least often.

Table 1 summarizes the averages and standard deviations of the performance indices for reserves, generation cost and profit, and consumer payments for the five demand curves summarized above. These results assume zero bids by existing and new capacity, moderate risk aversion (risk-preference function parameter of 0.7, see Appendix A.2), and moderately declining weights for profits in the RAFP calculation ($a = 80\%$).

Table 1. Summary of Results Under Base Case Assumptions (All Curves under Four-Year Ahead Auction)

Curve	Forecast Reserve Indices		Generation	Components of Generation Revenue			Consumer Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
	% Years Forecast Reserve Meets or Exceeds IRM	Average % Forecast Reserve over IRM (Standard Deviation)	Profit, $/kW/yr (standard deviation [s.d.]) /IRR	Scarcity Revenue $/kW/yr (s.d.)	E/AS Fixed Revenue $/kW/yr	ICAP Payment $/kW/yr (s.d.)	
1. No Demand Curve	39	-0.44 (1.92)	66135.3% (113)	47 (85)	10	70 (57)	129 (121)
2. Original PJM Curve, Based on VOLL	54	-0.06 (0.74)	25121.2% (73)	37 (70)	10	39 (14)	84 (78)
3. Alternative Curve with New Entry Net Cost at IRM	92	1.23 (0.87)	15117.5% (53)	26 (52)	10	40 (4)	74 (55)
4. Alternate Curve with New Enhy Net Cost at IRM+1%	98	1.79 (0.90)	12/16.6% (46)	21 (44)	10	42 (7)	71 (48)
5. Alternate Curve with New Entry Net Cost at IRM+4%	98	3.40 (1.05)	13117.0% (41)	14 (31)	10	50 (20)	74 (43)

Some broad conclusions about Table 1's comparisons of the different demand curves are noted here, with further detail below.

1. The percentage of years that forecast reserves meet or exceed the IRM is related to the average reserve margin and its variability. For instance, Curve 4 exceeds the IRM in 98% of the years simulated.
2. Resource adequacy is also indicated by the average percent by which the forecast reserve exceeds the IRM, providing a safety margin. This is expressed in terms of unforced capacity. The standard deviation of this value indicates how much the forecast reserve varies from year to year.[10] Figure 7 provides an illustration of how the reserve margins vary over time, using data from sample 100-year simulations for two of the curves. Further explanation of the reasons for such variations is provided in Section 5.2. Under a given variability of the reserve margin (as measured by the year to year standard deviation), higher average reserve margins result in the IRM being achieved a greater percentage of the time. Comparing Curves 3 and 4, for example, Curve 4 has a higher average reserve margin (1.79% higher than the IRM, versus 1.23% for Curve 3), and therefore a higher percentage of years in which the IRM is met or exceeded (98% versus 92%).

[10] Note that the actual reserve margin will vary a good deal more, based as it is upon actual weather-influenced peak load. The forecast reserve, in contrast, is based on weather normalized load, growing smoothly at an expected rather than random growth rate.

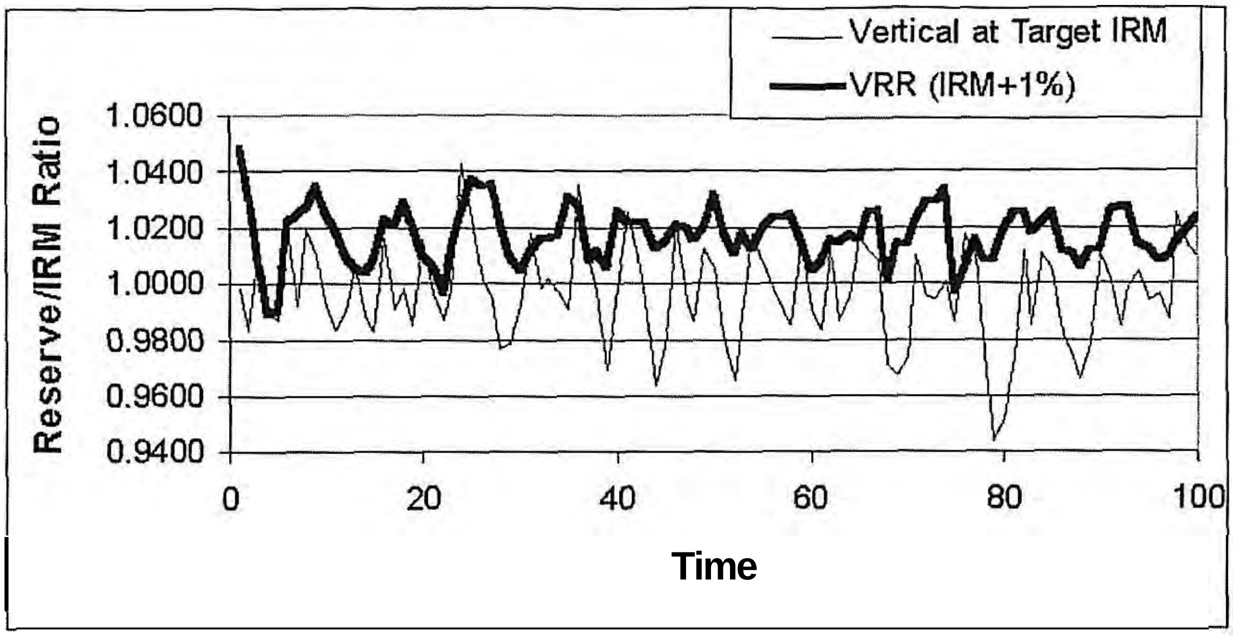

Figure 7. Time Series from Single Simulations of Ratios of Forecast Unforced Reserve Margin to Target Unforced Reserve, Curve 1 (No Demand Curve) and Curve 4 (Alternate Curve IRM+1%)

3. Generation profit is the net revenue that a potential entrant (baseline turbine) would earn over and above the assumed annualized fixed cost of construction. Larger values for this performance figure imply that investors are demanding a risk premium in exchange for higher levels of risks in ICAP revenues and E/AS gross margins. If there was no risk aversion and no risk in the market (from variations in load growth and weather), generators would, in theory, require zero profit, and the model gives this result. In general, lower reserve margins are associated with higher levels of risk and, therefore, higher required profits, because volatile E/AS revenues make up a higher portion of the revenues. This trend is clearly seen in comparing Curves 2 through 4; higher reserve margins are associated with lower average profits. (Curve 5 is an exception to this trend, because it is more vertical than Curves 3 and 4, as Figure 6 shows; this results in more volatile capacity revenues, which increases the profit that risk averse investors require in order to construct capacity.)

Profit is also expressed in terms of average internal rate of return (IRR) earned by owner's equity in combustion turbine capacity. Because the 61 $/installed kW/yr levelized real cost of a new turbine is based on a nominal IRR of 12% (reflecting the after tax cost of equity capital in arelatively stable regulated rate-of-return environment), then an economic profit of $0/kW-yr in the table would translate into an IRR of 12%. The modeling of risk aversion in this analysis reflects the general risk-return tradeoff apparent in capital markets in which higher risks are accepted by investors only if accompanied by higher average profits and IRR. Thus, simulations with higher investor risk result in higher costs of capital, as reflected in higher IRRs. Note, however, that these IRRs are aresult of the risk aversion assumptions of the model which, when changed, yield different IRRs (see Section 5.3). The model is neither defining nor using a target IRR to drive investment; rather, the model merely calculates the IRR implied by particular levels of profits resulting from the risk aversion and other assumptions made.

4. The three components of baseline CT revenues include gross margins from the E/AS market (divided into scarcity revenues and the assumed fixed component, see Figure 2) and ICAP revenues, all expressed in [$/installed MW/yr]. Subtracting the fixed cost of the CT ($61/installed kW/yr in real dollar terms) yields profit. For instance, in the No Demand Curve case, revenues equal 47+10+70 = 127. Subtracting 61 for the real annualized fixed cost yields 66 for profit, as shown in the table. (Because of rounding, the profit may not precisely equal revenues minus cost for all curves.) Generally, the table shows that scarcity revenues are more important when the average reserve margin shrinks, because shortage conditions are more likely.

5. The consumer cost shown here includes only scarcity payments in the energy market along with ICAP payments, assuming that all other electricity costs paid by consumers are not

affected by the demand curve. The consumer cost equals the sum of total payments for energy scarcity and capacity, and is expressed in Table 1 as a ratio of the total ICAP and scarcity payments made by consumers divided by the peak load.[11] In general, consumer cost varies with generator profits; if investors require higher returns because of higher risks, then consumer costs will also be higher, as those higher profits result from higher ICAP prices and E/AS gross margins. However, the table shows that the relationship is not one-to-one (a $1 increase in profit does not translate into a $1 increase in consumer costs) in part because the profit is expressed on a $/installed MW/yr basis for a potential new turbine, while consumer costs have a different denominator (peak load).

From the table, the following conclusions concerning the relative performance of the different curves are apparent. First, the "no demand curve" case (Curve 1) has an average reserve margin that is less than the IRM (-0.39% less, to be exact), even though the vertical portion of the curve is located precisely at the IRM. Also, the variation in the reserve margin is higher (1.92% standard deviation, with the other curves having about half that variation or less). This comparison is illustrated in Figure 7. That figure shows a time series of forecast reserves for one of the sample 100 year simulations for Curve 1, as well as for one of the 100-year simulations for Curve 4 (Alternate Curve IRM+1%).[12] The curve shows that forecast reserve margins for the "No Demand Curve" fluctuate between 94% and 104% of the IRM, while those for Curve 4 not only meet or exceed the target more often, but also fluctuate in a tighter range, i.e., between 99% and 105% of the IRM.

Furthermore, average profits and consumer payments are higher for Curve 1 (no demand curve) than for the other curves. Profits are higher because the risks to investors are greater; by

[11] This can be expressed in other ways, also; for example, if the annual load factor is 60%, then a $80/peak kW/yr consumer cost would be equivalent to $15.2/MWh (= 80*1000/(0.6*8760)).

[12] As explained earlier, I performed hventy-five 100-year simulations for each combination of a curve and set of assumptions.

assumption, risk averse investors in generation require higher average returns in order to compensate them for higher risks, and so, on average, generators must earn higher profits if they are to invest. Therefore, generators who are in the market are earning higher average profits. This higher profit does not mean that generators are better off; rather, the higher profits are needed to offset the greater risks, which will be reflected in a higher cost of capital. The greater risk is indicated by the standard deviation of profits (113 $/Peak kW/yr), which for Curve 1 (vertical) is considerably larger than for the other curves. This greater variation occurs in part because the vertical curve results in more variation in ICAP costs from year to year; in essence, ICAP prices bounce between zero and the maximum level on the curve ($124.7/kW/yr, Figure 6) depending on whether existing capacity plus new additions is greater or less than the IRM. Figure 8 shows an example of the wide variation in capacity payments from a 100 year simulation of Curve 1 (no demand curve). This variation is reflected in that curve's relatively high standard deviation for ICAP revenues (57 $/kW/yr, much higher than for the other curves, as shown in Table 1). In contrast, Figure 7 shows that the variation in capacity payments is much more stable for Curve 4 (Alternate Curve IRM+1%).

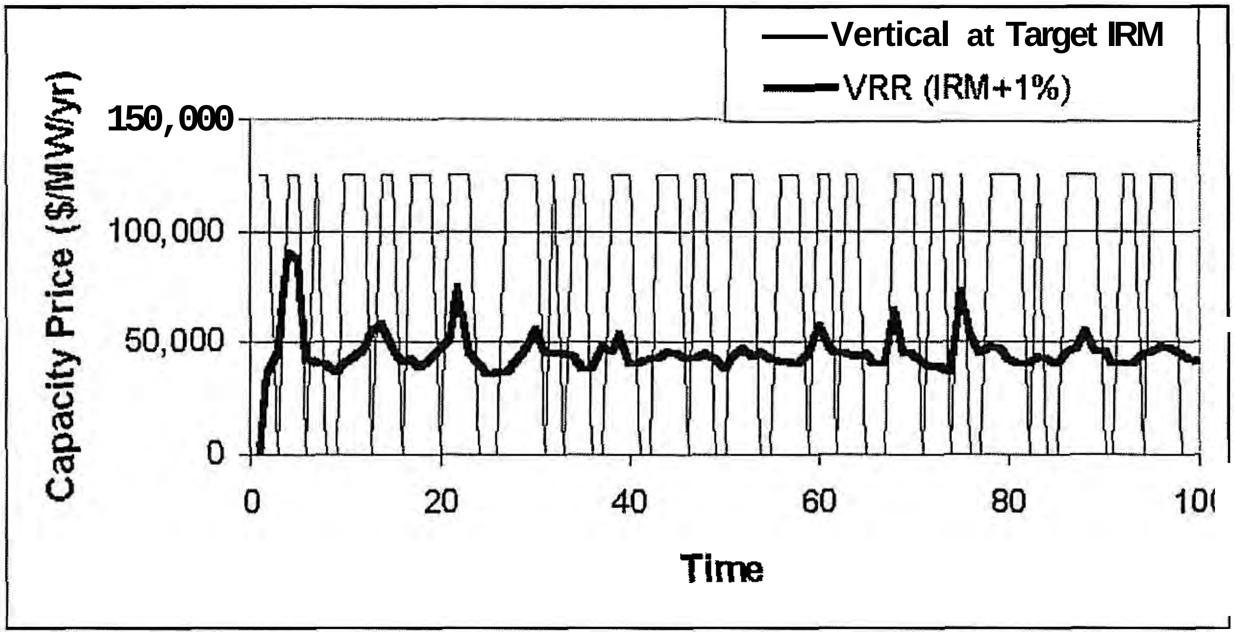

Figure 8. Time Series of Capacity Prices from Single Simulations, Curve 1 (No Demand Curve) and Curve 4 (Alternate Curve IRM+1%)

However, fluctuating ICAP prices are not the only cause of highly variable profits in Curve 1. Energy and ancillary service gross margins also vary more for Curve 1 than for the other curves (with a standard deviation of 85 in Curve 1, and smaller values for the other curves, as seen in Table 1). The reason is that the fluctuating forecast reserves mean that there are a number of years of low reserves; if such years also correspond to hot weather and/or higher than anticipated economic growth, actual reserves are pushed even lower. At such times, E/AS gross margins can be high (see Figure 3).

Because Curve 1 (no demand curve) results in high consumer costs and relatively low reserve margins, the other curves appear more attractive by these metrics. Improved performance of the "no curve" case occurs if it is shifted to the right, which increases reserve margins and somewhat lowers risks to investors and costs to consumers, or if it is assumed that new generation submits a nonzero bid. These and other sensitivity analyses are discussed in more detail in Section 5.3, *infra*. However, the lack of a slope for Curve 1 means that relatively high variations in ICAP prices and, thus, profits persist under alternative assumptions. As a result, required profits remain higher than for the other curves and so do consumer costs. Therefore, I conclude that the sloped curves are more desirable from a consumer perspective.

Comparing the sloped curves (Curves 2 through 5 in Figure 6, page 32), they differ in their reserve margins, generator profits, and consumer costs. Curves 2 and 3 result in lower probabilities of meeting or exceeding the IRM, as well as higher consumer costs than Curve 4, which represents a variant of Curve 3 in which the curve has been shifted to the right. These low probabilities and high consumer costs mean than Curve 4 is more desirable from those perspectives. Curve 5 represents a further shift, although the truncation to zero price occurs at the same location as Curves 3 and 4. The result is a higher average reserve margin, but Curve 5's more vertical characteristics result in more variation in revenues, profits, and reserves than Curve 4. As a result, required profits and thus consumer costs are higher than in Curve 4, and the probability of reaching the target IRM is the same for those two curves.

As the curves are shifted further to the right, a greater proportion of the gross margin for generators comes from the ICAP market, and less from E/AS scarcity revenues. (For example, generators in Curve 3 gain 26 \$/kW/yr from scarcity revenues, on average, and about 50% more from ICAP. However, in Curve 5, where the curve has been shifted to the right by 4%, scarcity revenues are approximately 70% smaller than ICAP revenues.) The standard deviations in Table 1 indicate that ICAP revenues tend to be less volatile (varying by only a few tens of dollars per kW per year) relative to E/AS revenues (which can vary tenfold or more, depending on weather and other variations). As a result, risks are less for generators, and the profit required to justify investment is smaller; this is reflected in the lower equilibrium profit for Curve 4 compared to Curves 2 and 3. The lower required profit translates directly into lower consumer payments. (Curve 5 has slightly higher profit requirements than Curve 4, however, because Curve 5 is closer to vertical, so that revenues are more volatile and the required internal rate of return is higher.)

I should caution, however, that this dynamic analysis is better suited to comparing the relative performance of curves than it is to fine-tuning the "optimal" location of the demand curve. Although Curve 4 has lower average consumer costs than curves to its left (Curve **3)** or right (Curve 5), under other possible assumptions, this might not be so. However, as the sensitivity analyses in Section 5.3 show, the general conclusion that Curve 4 is preferable in terms of reserve margin, lower variance of generation profits, and lower consumer payments compared to Curves 1-3 is robust with respect to a wide range of assumptions concerning behavior of generators. In contrast, the precise location of the demand curve that minimizes consumer payments is more sensitive to these assumptions.

5.2 **Example of Cycles in Reserve Margins**

In Figure 8, the forecast reserve margin exhibits cyclical behavior in which reserves periodically fall below the target (IRM) level. The swings in reserve margins are larger under some curves and assumptions than under others, but are always present in the simulations. In this section, I give some reasons for this behavior with the help of an example. The example is a fourteen year excerpt of a simulation of Curve 1 (no demand curve), and illustrates how random fluctuations in load growth and weather can cause variations in forecast reserve margins. The example represents a situation in which low load growth dampens profits and investment, which then results in shortages of capacity, which in turn increases profits and, after a lag, investment. **As** a result, a period of low forecast reserve margins is followed by one of high margins.

Figure 9 shows the sequence of weather-normalized and actual peaks for years 12-25 from one simulation. The peaks are expressed as a multiple of the four-year ahead forecast peaks for those years. Early on, the weather-normalized peaks around year 16 are several percentage points below the forecast peaks. Furthermore, cool weather in some years depresses actual peaks even further. Turning to Figure 10, we see that those low loads translate into higher than normal actual reserve margins in those years, relative to the reserves that were forecast four years before. The bottom of that figure shows that those higher reserves depress gross margins through year 18, mainly by lowering E/AS revenues (as actually occurred in PJM in 2003 and 2004). This series of depressed profits, in turn, translates into forecasts of low profits, which in turn depresses investment. By years 18 and 19, Figure 11 shows that investment in new capacity bas dried up completely.

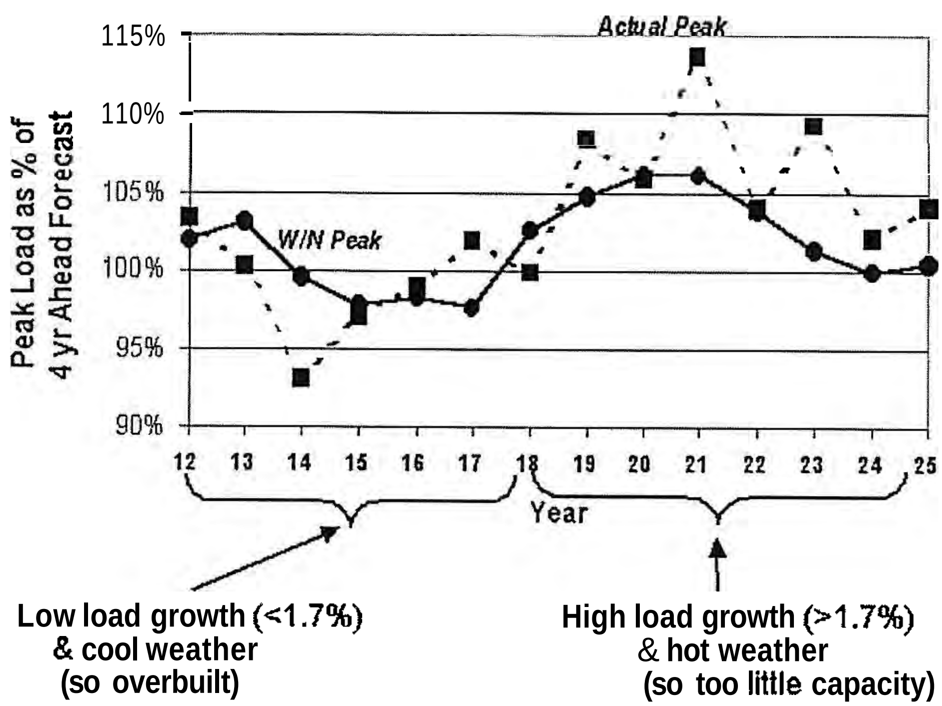

Figure 9. Analysis of Capacity Cycle: Weather-Normalized and Actual Peaks

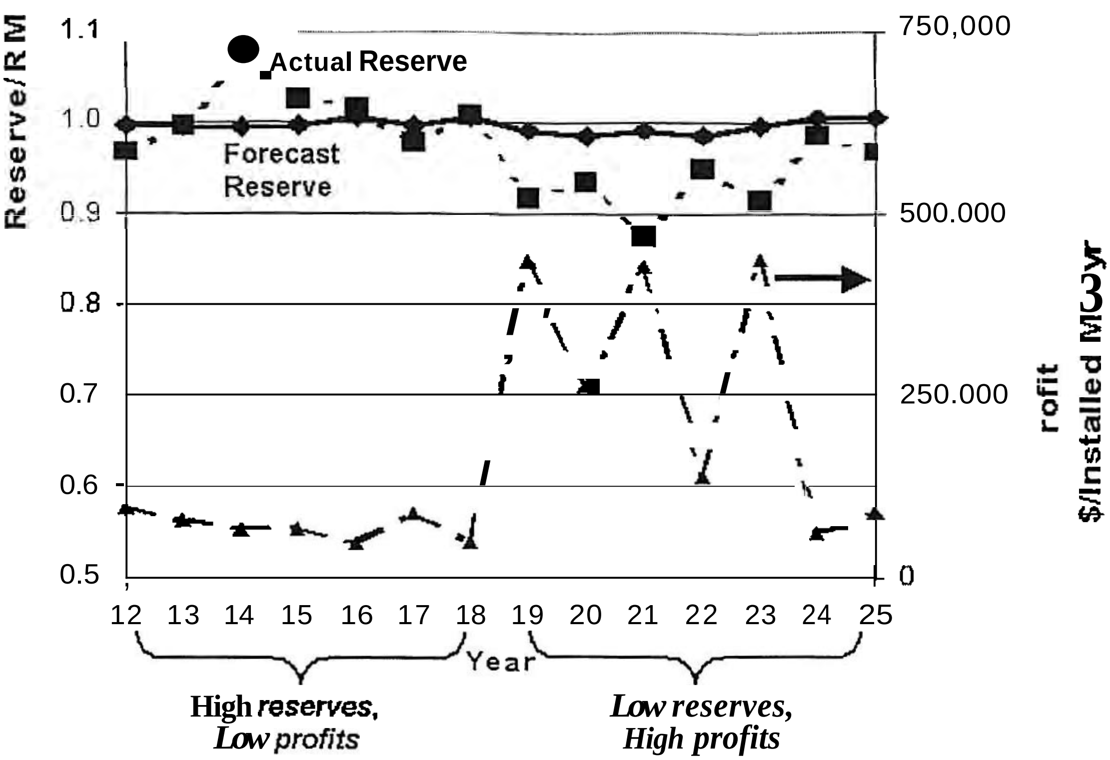

Figure 10. Analysis of Capacity Cycle: Low Profits in Early Years, High Profits Later

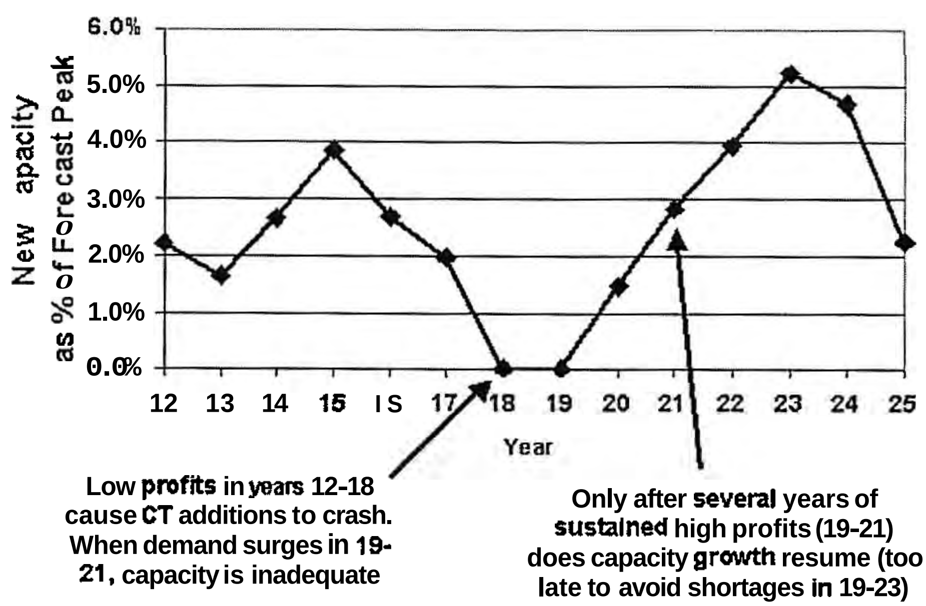

Figure 11. Analysis of Capacity Cycle: Capacity Additions Lag Profitability

The lack of new capacity in years 18 and 19 causes forecast reserve margins to dip below the IRM after year 18 (Figure 10). At the same time, hot weather in years 19 and 21 results in abnormally high actual peak loads (Figure 9) and very low actual reserve margins (Figure 10), causing E/AS revenues to spike (Figure 10). After the generators see some years of high profits, their profit forecasts and subsequent willingness to invest recover, and high investment levels are seen after year 21. Eventually, forecast reserve margins climb back up to the IRM in year 23. This completes the cyclical variation in reserve margins induced by low load growth and cool weather.

5.3 Sensitivity Analyses for the Four-year Ahead Auction

The dynamic model is designed based on simple relationships and a minimal number of parameters that describe the behavior of generators, while still capturing the fundamental phenomena of risk aversion and increased entry in response to increased profits. This is done in order to maximize model transparency and to facilitate sensitivity analyses, since the correct values of the parameters are not known. Hence, it is important that the relative performance of the demand curves not be overly sensitive to these parameters.

In this section, sensitivity analyses are performed relative to my assumptions concerning the four sets of behavioral characteristics. In addition, sensitivity analyses are performed relative to two parameters of the demand curves. Table 2 summarizes those assumptions. The demand curve parameters that I vary and report extensive results for are as follows:

1. The highest ICAP price in the curve. In the base cases, it is assumed to be two times the levelized nominal capital cost of a turbine, minus the expected E/AS gross margin of \$28/kW/yr. Lower values are tested to see if they affect the results significantly (Sensitivity Runs #1,2).
2. The level at which the price of ICAP is assumed to fall to zero. This is done by cutting off the curves entirely at 10% above the IRM (measured in terms of installed capacity), rather than at 5% as in the base case (Sensitivity Run #3). The 10% cutoff affects only Curves 2-5; in Curves 3-5, this assumption has the effect of lengthening the right-hand tail of the curve. This is done by extending the second (rightmost) sloped segment linearly until the

10% cutoff. In Sensitivity Run #4, Curves 3-5 are not chopped off at all; rather, the last (rightmost) downward sloping segment is extended until it hits a zero price. For Curve 3, this occurs at an installed reserve margin of 28% (13% above the IRM target of 15%); for Curves 4 and 5, these points occur at installed reserves of 29% and 32% respectively (14% and 17%, respectively, above the target IRM).

The behavioral assumptions that I change and provide detailed results for include the following:

1. Variations in how much capacity is bid into the market (NCA,) and built when profits (risk-adjusted forecast) are high. Low amounts mean that the market does not respond quickly to profit signals, while higher amounts mean greater responsiveness. In our base case, we assume that if risk-adjusted forecast profit (net of all costs, including annualized capital cost) for a benchmark combustion turbine equal 100% of the cost of the turbine, then capacity amounting to 7% of existing capacity would be added. Alternative assumptions of 5% and 9% are considered (Sensitivity Runs #5 and 6, respectively).
2. Variations in the level of bids ($/unforced MW/year) submitted by existing and potential new capacity. Zero bids were assumed as a base case. This was based upon the assumption that generators would commit to building and maintaining a certain amount of capacity that depends on forecast profits, and would bid that capacity into the ICAP market in a price-taking manner. Various levels of positive bids, up to $44/kW/yr are considered in the sensitivity analyses. The highest bid considered exceeds the net cost of a benchmark turbine (approximately $36/unforced kW/yr, equal to the real levelized capital cost of $61 minus the expected E/AS revenues of $28, divided by one minus the forced outage rate,) (Sensitivity Runs #7-10).
3. Various degrees of risk aversion, ranging from weaker risk neutrality to extreme risk aversion (Sensitivity Runs #11 and 12, respectively). Sensitivity Run #11a is the case of

complete risk neutrality (linear risk-preference function, resulting from a risk-preference parameter of 0.5), in which risk is not penalized at all. Meanwhile, Sensitivity Run #11b is risk averse, but less so than the base case. These sensitivity cases are summarized in terms of the risk-preference parameter explained in Appendix A.2 (see Table 2 and Figure 4).

4. Various relative weightings for recent profits versus profits further in the past in the risk-adjusted forecast profit calculations (Sensitivity Runs #13, 14). In the base case, profit in a given year is assumed to be given only 80% of the weight assigned to profit in the following year.

In addition to those sensitivity analyses of demand curve and behavioral characteristics, I also examine the effect of assuming lower E/AS gross margins (Sensitivity Run #15). As I explained *supra*, confining the baseline turbine's operation to peak hours lowers the average E/AS gross margin to $21/kW/yr (compared to the base case assumption of $28/kW/yr). I simulate this assumption by shifting the demand curve upwards to account for the lower E/AS revenues, and by lowering the E/AS gross margin curve (Figure 3) by the same amount.

Tables 3-12 show the results of Sensitivity Runs #1-15 for all five demand curve cases. Both the average and standard deviations (across the sample of 2500 years) are shown for the performance indices.

Finally, I also briefly report on sensitivity analyses concerning the slope of the demand curves and the assumed year-to-year variation in growth rates for weather-normalized peak loads.

Table 2. Summary of Sensitivity Analysis Assumptions

Sensitivity Run #	Sensitivity Analysis Case	Explanation
1	Max Price = Net Cost multiplied by 1.5	Highest price on demand curve is (1.5*72-28)/(1-.07) [$/kW/yr] = 86 [$/kW/yr] (Base Case = multiplied by 2, 124.7 [$/kW/yr])
2	Max Price = Net Cost multiplied by 1.2	Highest price on demand curve is (1.2*72-28)/(1-.07) [$/kW/yr] = 62.8 [$/kW/yr]
3	Price drops to zero at IRM+10%	Right tail of demand curve is reduced to zero at IRM+10%. Only applicable to Curves 2-5
4	Curves 3-5 long tails; no chopoff	No chopoff of tail; rightmost sloped segment extended linearly to X axis. Only applicable to Curves 3-5
5	Low Percent CT added when profit is equal to cost	If CT profit equals annualized nominal capital cost (72 $/kW/yr), then 5% of existing capacity is added. (Base case = 7%)
6	High Percent CT added when profit is equal to cost	If CT profit equals annualized capital cost, then 9% of existing capacity is added.
7	10,000 bids for new capacity	$10,000/unforced MW/yr is bid submitted for new capacity in four-year ahead auction ("New" includes only capacity for which a commitment is made 4 years ahead of auction). All other capacity bid in at $0. (Base case = $0 bid for both new and old capacity)
8	25,000 bids for new capacity	$25,000/unforced MW/yr is bid submitted for new capacity in four-year ahead auction
9	44,000 bids for new capacity	$44,000/unforced MW/yr is bid submitted for new capacity in four-year ahead auction
10	44,000 bids for new, 20,000 for existing capacity	$44,000/unforced MW/yr is bid submitted for new capacity in four-year ahead auction; $20,000 bid for all other capacity.
11a	Low risk aversion 0.5	Risk neutral (linear risk-preference function for new generation profit); Risk-preference parameter set to 0.5 (Base case = 0.7)
11b	Low risk aversion 0.6	Low risk averse; Risk-preference parameter set to 0.6
12	High risk aversion 0.9	Highly risk averse (strongly concave utility function for new generation profit, see Appendix A.2); Risk-preference parameter set to 0.9
13	High rate of decay in weights	Weight assigned to profit in year *Y*-1 equal to 60% of weight given to profit in year Y in RAFP calculation. This emphasizes more recent profits more than earlier profits. (Base case = 80%)
14	Low decay in weights	Weight assigned to profit in year Y-1 equal to 90% of weight given to profit in year Y in RAFP calculation. This places nearly equal emphasis on profits from all eight years in Figure 2.
15	Lower E/AS margins	Confine turbine operation to peak hours

Table 3. Summary of Sensitivity Analyses of Curve 1 (No Demand Curve), Average Values

Sensitivity Run	Reserve Indices: % Years Meet or Exceed IRM	Reserve Indices: Average % Reserve over IRM	Generation Profit, $/kW/yr /IRR	Components of Generation Revenue: Scarcity Revenue $/kW/yr	Components of Generation Revenue: E/AS Fixed Revenue $/kW/yr	Components of Generation Revenue: ICAP Payment $/kW/yr	Consumer Payments for Scarcity + ICAP $/Peak kW/yr
1. Max Price = Net Cost multiplied by 1.5	35	-0.58	49129.5%	49	10	52	110
2. Max Price = Net Cost multiplied by 1.2	29	-0.91	43127.3%	52	10	41	103
3. Price drops to zero at IRM+10%	not applicable (na)	na	na	na	na	na	Na
4. Price drops to zero at higher IRM	na	na	na	na	na	na	Na
5. Low Percent CT added when profit is equal to cost	36	-0.50	68135.9%	45	10	74	131
6. High Percent CT added when profit is equal to cost	42	-0.32	63134.1%	47	10	67	125
7. 10,000 bids for new capacity	46	-0.59	60133.2%	45	10	66	123
8. 25,000 bids for new capacity	63	-0.31	45128.0%	41	10	55	106
9. 44,000 bids for new capacity	4	-0.13	33123.9%	38	10	46	93
10. 44,000 bids for new, 20,000 for existing capacity	4	-0.07	29122.7%	37	10	43	89
11a. Low risk aversion 0.5	69	1.03	12116.7%	29	10	34	70
11b. Low risk aversion 0.6	53	0.28	39125.9%	37	10	53	99
12. High risk aversion 0.4	21	-3.53	158167.5%	118	10	92	226
13. High rate of decay in weights	49	0.21	44127.9%	38	10	58	106
14. Low decay in weights	36	-0.77	76138.7%	53	10	73	139
15. Lower E/AS margins	39	-0.39	68136.0%	45	10	74	131

Table 4. Sensitivity Analyses of Curve 1 (No Demand Curve), Standard Deviations

Sensitivity Run	Reserve Indices: Average % Reserve over IRM (s.d.)	Generation Profit, $/kW/yr (s.d.)	Components of Generation Revenue: Scarcity Revenue $/kW/yr (s.d.)	Components of Generation Revenue: ICAP Payment $/kW/yr (s.d.)	Consumer Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
1. Max Price = Net Cost multiplied by 1.5	1.84	101	86	38	108
2. Max Price = Net Cost multiplied by 1.2	1.67	98	90	26	105
3. Price drops to zero at IRM+10%	na	na	na	na	na
4. Price drops to zero at higher IRM	na	na	na	na	na
5. Low Percent CT added when profit is equal to cost	1.48	105	79	56	112
6. High Percent CT added when profit is equal to cost	2.25	112	83	57	120
7. 10,000 bids for new capacity	0.81	102	80	53	110
8. 25,000 bids for new capacity	0.64	91	74	45	97
9. 44,000 bids for new capacity	0.43	75	69	22	79
10. 44,000 bids for new, 20,000 for existing capacity	0.29	70	67	15	74
11a. Low risk aversion 0.5	1.74	85	58	53	93
11b. Low risk aversion 0.6	1.42	100	71	57	108
12. High risk aversion 0.9	4.02	166	144	47	174
13. High rate of decay in weights	1.70	100	71	58	108
14. Low decay in weights	2.21	120	92	56	128
15. Lower WAS margins	1.85	111	82	60	120

Table 5. Sensitivity Analyses of Curve 2 (VOLL Curve), Average Values

Sensitivity Run	Reserve Indices: % Years Meet or Exceed IRM	Reserve Indices: Average % Reserve over IRM	Generation Profit, $/kW/yr /IRR	Components of Generation Revenue: Scarcity Revenue $/kW/yr	Components of Generation Revenue: E/AS Fixed Revenue $/kW/yr	Components of Generation Revenue: ICAP Payment $/kW/yr	Consumer Payments for Scarcity + ICAP $/Peak kW/yr
1. Max Price = Net Cost multiplied by 1.5	48	-0.01	25121.0%	37	10	38	84
2. Max Price = Net Cost multiplied by 1.2	47	-0.07	25121.0%	38	10	38	84
3. Price drops to zero at IRM+10%	na	na	na	na	na	na	na
4. Price drops to zero at higher IRM	na	na	na	na	na	na	na
5. Low Percent CT added when profit is equal to cost	56	0.06	25121.1%	36	10	39	84
6. High Percent CT added when profit is equal to cost	51	0.08	24120.9%	36	10	39	83
7. 10,000 bids for new capacity	54	0.06	25121.2%	37	10	39	84
8. 25,000 bids for new capacity	61	0.10	23120.4%	36	10	38	82
9. 44,000 bids for new capacity	95	0.09	25121.2%	35	10	41	84
10. 44.000 bids for new, 20,000 for existing capacity	95	0.09	25121.2%	35	10	41	84
11a. Low risk aversion 0.5	66	0.84	14117.4%	32	10	33	72
11b. Low risk aversion 0.6	63	0.20	21119.7%	35	10	37	79
12. High risk aversion 0.9	30	-1.83	91144.1%	78	10	64	155
13. High rate of decay in weights	55	0.12	21119.9%	35	10	37	80
14. Low decay in weights	50	-0.02	27122.0%	38	10	40	87
15. Lower EIAS margins	58	0.19	25121.3%	36	10	41	85

Table 6. Sensitivity Analyses of Curve 2 (VOLL Curve), Standard Deviations

Sensitivity Run	Reserve Indices	Generation Profit, $/kW/yr (s.d.)	Components of Generation Revenue		Consumer Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
	Average % Reserve over IRM (s.d.)		Scarcity Revenue $/kW/yr (s.d.)	ICAP Payment $/kW/yr (s.d.)	
1. Max Price = Net Cost multiplied by 1.5	0.75	72	69	12	76
2. Max Price = Net Cost multiplied by 1.2	0.81	71	69	11	76
3. Price drops to zero at IRM+10%	na	na	na	na	na
4. Price drops to zero at higher IRM	na	na	na	na	na
5. Low Percent CT added when profit is equal to cost	0.59	70	68	12	74
6. High Percent CT added when profit is equal to cost	0.92	72	68	16	76
7. 10,000 bids for new capacity	0.74	73	70	14	78
8. 25,000 bids for new capacity	0.54	69	67	11	74
9. 44,000 bids for new capacity	0.17	64	64	3	68
10. 44,000 bids for new, 20,000 for existing capacity	0.16	64	64	3	68
11a. Low risk aversion 0.5	1.85	71	65	17	75
11b. Low risk aversion 0.6	0.65	69	66	13	74
12. High risk aversion 0.9	3.13	139	119	36	147
13. High rate of decay in weights	0.84	68	65	16	72
14. Low decay in weights	1.00	76	71	17	80
15. Lower E/AS margins	0.82	72	67	18	77

Table 7. Sensitivity Analyses of Curve 3 (New Entry Net Cost at IRM), Averages

Sensitivity Run	Reserve Indices: %Years Meet or Exceed IRM	Reserve Indices: Average % Reserve over IRM	Generation Profit, $/kW/yr /IRR	Components of Generation Revenue: Scarcity Revenue $/kW/yr	Components of Generation Revenue: E/AS Fixed Revenue $/kW/yr	Components of Generation Revenue: ICAP Payment $/kW/yr	Consumer Payments for Scarcity + ICAP $/Peak kW/yr
1. Max Price = Net Cost multiplied by 1.5	90	1.20	15117.6%	26	10	40	74
2. Max Price = Net Cost multiplied by 1.2	88	1.16	15117.7%	26	10	40	74
3. Price drops to zero at IRM+10%	92	1.23	15/17.5%	26	10	40	74
4. Price drops to zero at IRM+13%	92	1.23	15117.5%	26	10	40	74
5. Low Percent CT added when profit is equal to cost	89	1.18	15117.7%	26	10	40	74
6. High Percent CT added when profit is equal to cost	95	1.26	14117.3%	25	10	40	73
7. 10,000 bids for new capacity	92	1.23	15117.5%	26	10	40	74
8. 25,000 bids for new capacity	92	1.23	15117.5%	26	10	40	74
9. 44,000 bids for new capacity	99	0.78	18118.8%	28	10	41	77
10.44.000 bids for new, 20,000 for existing capacity	99	0.78	18118.8%	28	10	41	77
11a. Low risk aversion 0.5	88	1.63	10115.9%	24	10	38	69
I Ib. Low risk aversion 0.6	91	1.35	13117.0%	25	10	39	72
12. High risk aversion 0.9	92	1.02	17118.4%	27	10	41	76
13. High rate of decay in weights	100	1.16	14117.2%	25	10	40	73
14. Low decay in weights	82	1.28	17118.4%	27	10	41	76
15. Lower E/AS margins	99	2.00	11116.4%	20	10	42	71

Table 8. Sensitivity Analyses of Curve 3 (New Entry Net Cost at IRM), Standard Deviations

Sensitivity Run	Reserve Indices	Generation Profit, $/kW/yr (s.d.)	Components of Generation Revenue		Consumer
	Average % Reserve over IRM (s.d.)		Scarcity Revenue $/kW/yr (s.d.)	ICAP Payment $/kW/yr (s.d.)	Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
1. Max Price = Net Cost multiplied by 1.5	0.92	53	53	4	56
2. Max Price = Net Cost multiplied by 1.2	0.98	54	53	4	57
3. Price drops to zero at IRM+10%	0.88	53	52	4	55
4. Price drops to zero at IRM+13%	0.88	53	52	4	55
5. Low Percent CT added when profit is equal to cost	0.94	52	51	5	55
6. High Percent CT added when profit is equal to cost	0.82	52	51	4	55
7. 10,000 bids for new capacity	0.87	53	52	4	55
8. 25,000 bids for new capacity	0.88	53	52	4	55
9. 44,000 bids for new capacity	0.21	53	53	1	56
10. 44,000 bids for new, 20,000 for existing capacity	0.21	53	53	1	56
11a. Low risk aversion 0.5	1.58	51	49	10	54
11b. Low risk aversion 0.6	1.04	51	50	5	54
12. High risk aversion 0.9	0.77	55	54	5	58
13. High rate of decay in weights	0.37	49	49	1	51
14. Low decay in weights	1.40	58	55	11	61
15. Lower E/AS margins	0.89	42	41	4	44

Table 9. Sensitivity Analyses of Curve 4 (New Entry Net Cost at IRM + 1%), Averages

Sensitivity Run	Reserve Indices: %Years Meet or Exceed IRM	Reserve Indices: Average % Reserve over IRM	Generation Profit, $/kW/yr /IRR	Components of Generation Revenue: Scarcity Revenue $/kW/yr	Components of Generation Revenue: E/AS Fixed Revenue $/kW/yr	Components of Generation Revenue: ICAP Payment $/kW/yr	Consumer Payments for Scarcity + ICAP $/Peak kW/yr
1. Max Price = Net Cost multiplied by 1.5	97	1.73	13116.8%	22	10	42	72
2. Max Price = Net Cost multiplied by 1.2	95	1.64	13116.9%	23	10	41	72
3. Price drops to zero at IRM+10%	99	1.82	12116.6%	21	10	42	71
4. Price drops to zero at IRM+14%	99	1.82	12116.6%	21	10	42	71
5. Low Percent CT added when profit is equal to cost	98	1.77	13116.8%	22	10	42	72
6. High Percent CT added when profit is equal to cost	98	1.80	12116.5%	22	10	41	71
7. 10,000 bids for new capacity	99	1.79	12116.6%	21	10	42	71
8. 25,000 bids for new capacity	99	1.80	12116.6%	21	10	42	71
9. 44,000 bids for new capacity	100	1.55	13117.0%	22	10	42	72
10. 44,000 bids for new, 20,000 for existing capacity	100	1.55	13117.0%	22	10	42	72
11a. Low risk aversion 0.5	97	2.12	9/15.3%	20	10	40	67
11b. Low risk aversion 0.6	99	1.90	11116.2%	21	10	41	70
12. High risk aversion 0.9	92	1.31	24120.7%	29	10	46	84
13. High rate of decay in weights	100	1.71	11116.3%	21	10	41	70
14. Low decay in weights	87	1.72	19119.1%	25	10	45	79
15. Lower WAS margins	99	2.50	11116.1%	18	10	44	70

Table 10. Sensitivity Analyses of Curve 4 (New Entry Net Cost at IRM + 1%), Standard Deviations

Sensitivity Run	Reserve Indices: Average % Reserve over IRM (s.d.)	Generation Profit $/kW/yr (s.d.)	Components of Generation Revenue: Scarcity Revenue $/kW/yr (s.d.)	Components of Generation Revenue: ICAP Payment $/kW/yr (s.d.)	Consumer Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
I. Max Price = Net Cost multiplied by 1.5	0.92	47	46	5	49
2. Max Price =Net Cost multiplied by 1.2	0.99	47	47	4	50
3. Price drops to zero at IRM+10%	0.89	45	44	5	47
4. Price drops to zero at IRM+14%	0.89	45	44	5	47
5. Low Percent CT added when profit is equal to cost	0.94	45	44	7	48
6. High Percent CT added when profit is equal to cost	0.87	46	45	7	49
7. 10,000 bids for new capacity	0.88	45	44	6	47
8. 25,000 bids for new capacity	0.88	45	44	6	47
9. 44,000 bids for new capacity	0.36	44	43	2	46
10.44.000 bids for new, 20,000 for existing capacity	0.36	44	43	2	46
11a. Low risk aversion 0.5	1.40	45	42	II	47
11b. Low risk aversion 0.6	0.99	44	43	7	47
12. High risk aversion 0.9	1.54	67	60	15	71
13. High rate of decay in weights	0.39	42	42	1	44
14. Low decay in weights	1.64	60	53	17	64
15. Lower E/AS margins	0.95	40	38	8	42

Table 11. Sensitivity Analyses of Curve 5 (New Entry Net Cost at IRM + 4%), Averages

Sensitivity Run	Reserve Indices: % Years Meet or Exceed IRM	Reserve Indices: Average % Reserve over IRM	Generation Profit, $/kW/yr /IRR	Components of Generation Revenue: Scarcity Revenue $/kW/yr	Components of Generation Revenue: E/AS Fixed Revenue $/kW/yr	Components of Generation Revenue: ICAP Payment $/kW/yr	Consumer Payments for Scarcity + ICAP $/Peak kW/yr
1. Max Price = Net Cost multiplied by 1.5	97	3.13	12116.6%	15	10	48	72
2. Max Price = Net Cost multiplied by 1.2	94	2.75	12116.5%	17	10	46	72
3. Price drops to zero at IRM+10%	100	3.87	7114.8%	11	10	47	67
4. Price drops to zero at IRM+17%	100	3.87	7114.7%	11	10	47	67
5. Low Percent CT added when profit is equal to cost	98	3.32	14117.5%	14	10	52	75
6. High Percent CT added when profit is equal to cost	95	3.16	18118.8%	16	10	53	79
7. 10,000 bids for new capacity	99	3.49	11116.1%	13	10	49	71
8. 25,000 bids for new capacity	100	3.57	9115.5%	12	10	48	69
9. 44,000 bids for new capacity	100	3.72	8115.2%	12	10	47	69
10. 44,000 bids for new, 20,000 for existing capacity	100	3.75	7114.9%	11	10	47	68
11a. Low risk aversion 0.5	100	3.92	5113.9%	12	10	44	65
11b. Low risk aversion 0.6	100	3.60	9115.5%	12	10	48	69
12. High risk aversion 0.9	53	0.12	90143.7%	60	10	81	155
13. High rate of decay in weights	100	3.60	8115.2%	12	10	47	69
14. Low decay in weights	90	2.78	27122.0%	20	10	59	89
15. Lower E/AS *margins*	96	3.26	21119.8%	15	10	57	83

Table 12. Sensitivity Analyses of Curve 5 (New Entry Net Cost at IRM + 4%), Standard Deviations

Sensitivity Run	Resewe Indices: Average % Reserve over IRM (s.d.)	Generation Profit, $/kW/yr (s.d.)	Comoonents of Generation Revenue: Scarcity Revenue $/kW/yr (s.d.)	Comoonents of Generation Revenue: ICAP Payment $/kW/yr (s.d.)	Consumer Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
1. Max Price = Net Cost multiplied by 1.5	1.13	38	32	14	40
2. Max Price = Net Cost multiplied by 1.2	1.35	40	37	10	42
3. Price drops to zero at IRM+10%	0.94	26	23	9	27
4. Price drops to zero at IRM+17%	0.55	26	23	9	27
5. Low Percent CT added when profit is equal to cost	1.04	39	30	19	42
6. High Percent CT added when profit is equal to cost	1.78	53	35	31	57
7. 10,000 bids for new capacity	0.72	33	27	14	35
8. 25,000 bids for new capacity	0.58	29	26	10	30
9. 44,000 bids for new capacity	0.71	29	25	10	30
10. 44.000 bids for new, 20,000 for existing capacity	0.61	26	23	8	27
11a. Low risk aversion 0.5	1.67	34	24	20	37
11b. Low risk aversion 0.6	0.90	33	27	16	35
12. High risk avasion 0.9	4.26	130	107	43	137
13. High rate of decay in weights	0.68	30	25	13	31
14. Low decay in weights	2.09	65	46	34	70
15. Lower E/AS margins	1.58	53	33	33	58

First considering the effects of the demand curve changes, my conclusions about the sensitivity analyses are as follows:

1. Lowering the maximum price in the demand curve from $124.7/kW/yr to $86 or $62.8/kW/yr (Sensitivity Runs #1, 2) improves the performance of the no demand curve case (Curve 1) in terms of consumer payments (from $129/peak kW/yr to $110 or $103), but worsens its average reserve margin. Consumer payments decrease because the lowered maximum ICAP price lowers the variability of total CT revenues, somewhat lowering risk and, thus, the profit required for new entry. However, Curve 1 remains considerably more expensive for consumers than the other curves. For all the other curves, there are no advantages to lowering the maximum price, as the average reserve margins deteriorate slightly and consumer payments stay approximately the same.
2. Dropping the right tail of Curves 3 or 4 to zero at a point further to the right rather than at IRM+5% (Sensitivity Runs #3, 4) has negligible effect on the results, because the forecast reserve margin is rarely in that range for either of those curves. On the other hand, the performance of Curve 5 (IRM+4%) improves (lower consumer cost, higher reserves), because these changes eliminate the vertical character of that curve.

In addition to the above sensitivity analyses concerning the curves, I also examined the effect of alternative slopes of the demand curves by compressing or expanding their range. In general, I find that changing the slopes of the curves makes much less difference in the results than shifting their location left or right. For instance, taking Curve 4 (IRM+1%) in Table 1 and shifting it left by 1% (Curve 3, Table 1) or right by 1% (not shown) changes the percent of years that the IRM is achieved from 98% to 92% and 99%, respectively. (Such a shift is equivalent to changing the target reserve margin you want to achieve and how much you're willing to pay for it.) On the other hand, decreasing the absolute value of the slopes of Curve 4 by 33% (while keeping the kink of the curve centered at IRM+1% and $47/kW/yr) or increasing it by 50% changes that percentage from 98% to 94% and 98%, respectively. This is a smaller effect. The changes in consumer costs show a similar pattern. These left and right shifts of Curve 4 change the consumer costs from the base value of 71 $/peak kW/yr to 74 and 70 $/peak kW/yr, respectively. The decreased and increased slopes, meanwhile cause a somewhat smaller change, from 71 $/peak kW/yr to 73 $/peak kW/yr in both cases. Therefore, the decision about the location of the curve is more important than decisions about its slope.

Turning to the behavioral characteristics, I reach the following basic conclusion: the performance of Curve 1 (no demand curve) is more sensitive to these assumptions than the sloped demand curves, sometimes dramatically so. However, under no assumptions is the "no demand curve" case found to be preferable, in terms of reserve margins or consumer payments. to the sloped curves. Concerning each individual set of behavioral characteristics, my conclusions are as follows:

1. The greater the amount of entry that occurs in response to a given profit, the better the performance of all curves in terms of the reserve indices and consumer payments (Sensitivity Runs #5, *6)*. This is because supply can more quickly adjust to unexpectedly high economic and, thus, demand growth. However, the changes in the performance of the curves as a result of changes in this assumption generally small relative to the effects of changes in some other behavioral assumptions (especially risk aversion and forecast weights).
2. Bidding positive amounts, whether just by new capacity or both new and old capacity (Sensitivity Runs #7-10), stabilizes ICAP prices and thus profits for Curve 1 (no demand curve), while having relatively little or no impact on sloped Curves 2-4. (Curve 5 experiences more impact, because it is more vertical than the other curves.) As a result,

generators face less risk and are more willing to enter the market in Curve 1 (and Curve 5), which yields improved reserve margins and consumer payments. Under the most extreme assumptions (new capacity bids $44/kW/yr, and existing capacity bids $20/kW/yr, Sensitivity Run #10), Curve 1's average reserves improve from 0.44% below IRM on average to 0.07% below IRM, while the standard deviation of reserves falls from 1.92% to 0.29%.[13] The standard deviation of ICAP payments in Curve 1 is more than halved (from $57/kW/yr to $15/kW/yr), because ICAP prices now occur frequently at intermediate values where bids intercept the demand curves rather than just the extremes of $0 and $124.7/kW/yr. The resulting lowered profit risk lowers the required returns, so equilibrium profit falls from $66/kW/yr to $29/kW/yr, with consumer payments for scarcity and capacity correspondingly dropping from $129/peak kW/yr to $89/peak kW/yr. This increases the relative attractiveness of the vertical demand curve, but its performance (in terms of the consumer payments) is still undesirable relative to the sloped demand curves. For example, under Curve 4 (IRM+1%), consumer payments are $71 or $72/peak kW/yr under all bidding assumptions.

3. The degree of risk aversion (Sensitivity Runs #11, 12) has a marked influence on all the results; this is the most important behavioral characteristic, as gauged by the sensitivities shown in Tables 3-12. On one hand, strict risk neutrality causes consumer payments for all curves to fall to the range of 65 to 70 $/peak kW/yr (Sensitivity Run #11), as the risk neutral producers are willing to accept much lower profits. Curves 4 and 5 still have lower consumer costs than the other curves, although not to as a great degree. Required profits are still positive because of nonlinearities elsewhere in the model (in particular, in the response of entry to risk-adjusted forecast profit, see Figure 2). If additional uncertainties

[13] It should be noted that these bidding levels are much higher than daily ICAP prices observed in the PJM market behveen 1999 and 2004; see the PJM State of the Market Report, Figure 4-9.

in load, attributed to economic growth and weather, are eliminated, then the required profits fall to zero or nearly so, as they should in a riskless world with no variations in profits. On the other hand, a high aversion to risk (strongly curved risk-preference function, see Appendix A.2) results in very high profit requirements, particularly for the case with no demand curve, greatly increasing its consumer payments relative to the other curves.

4. The weighting assumptions for profits in different years (Sensitivity Runs #13, 14) in the risk-adjusted forecast profit calculation make some difference in the consumer payments and reserves, but do not change the conclusion that Curve 1 (no demand curve) is inferior.

Finally, in Sensitivity Run 15, I compared the results of the demand curves developed under the assumption that the benchmark turbine earns an average \$21,100/MW/yr E/AS gross margin rather than \$28,000 (see Figure 3 and the associated discussion, supra). This lower value is based on an assumption that the turbine operates only during peak hours, rather than during any hour in which price exceeds its running cost. This assumption means that the E/AS gross margin offset for the curves is smaller, so that the maximum payments defined by the curves are higher by about \$7000 (after adjustments for forced outage rates). The simulations are done using a correspondingly lower curve relating EIAS gross margin to reserve margins (the dashed line in Figure 3). Comparing Sensitivity Run #15 (\$21,100 assumption) with the base case in Table 1 (\$28,000 assumption) shows that under the base case assumptions for other parameters, there is little change in the reserve margins resulting from the curves. However, there are small changes in the profits that investors require and the resulting consumer payments, and these changes are positive for some curves and negative for others. The relative standing of the various curves does not change: the alternative sloped curves (Curves 3-5) still result in lower consumer payments and higher reliability than the no demand curve case (Curve 1).

I also examined alternative assumptions concerning the year-to-year variation in growth rates for the weather-normalized peak. Instead of the base case value of 1% for the standard deviation of that growth rate, I also examined 0.5% and 1.5%. These assumptions did have significant impacts on the specific numerical performance of the five curves, but not on their general performance relative to each other. For instance, standard deviations of 0.5% and 1.5% resulted in consumer costs of 121 and 136 $/peak kW/yr, respectively, for Curve 1 (no demand curve), compared to the base case value of 129 (Table 1). More variable load growth results in both greater risks and greater potential rewards for entry; my assumption of risk-aversion then translates into a higher required profit in order for entry to occur. In contrast to Curve 1, for Curve 4 (sloped curve centered at IRM+1%), the 0.5% and 1.5% values yielded consumer costs of 62 and 78, compared to the base case of 71. The sloped curves continue to have relatively lower costs than the vertical curve.

Although the conclusion regarding the desirability of sloped curves (especially Curves 4 and 5) relative to Curve 1 (no demand curve) is robust with respect to these assumptions, the precise financial consequences (ICAP prices, generator profits, and consumer payments) do depend on the assumptions made. Therefore, the conclusion I draw is that there is significant uncertainty regarding the future effects of capacity mechanisms on consumers, but that risks are lower if a sloped demand curve is used.

5.4 Comparison of Pour-Year Ahead with Same-Year Auction

An investor in generation capacity has less information on future capacity prices in the present year-ahead ICAP auction than under the proposed four-year ahead RPM system. Referring to Figure 2, the investor knows at year y-4 the ICAP price in years y-3, y-2, and y-1 in the RPM system, because the auctions for capacity in those years have already been held. As a result, the investor has a firm basis for projecting capacity prices in subsequent years. But in the present

ICAP system, this information is not available. Even though the generation capacity that will be on line in those years might be estimated, based on capacity that already exists or is under construction, the investor does not know the weather-normalized peaks upon which the demand curves for those years will be based. Furthermore, there is also more uncertainty in the ICAP price for year y in the present ICAP system, because the location of the demand curve for that year is not known at the time that the investor commits to construction, unlike the RPM system.

To represent this additional risk, the four year-ahead auction model is modified to consider twelve profits rather than the eight shown in Figure 2. The additional four profit terms enable me to represent uncertainty in the ICAP price in years y-3, y-2, y-1, and y using two possible values for profits for each of these years. The two values, high and low, represent the cases where load growth results in relatively low and high reserve margins, respectively, in those years. This results in greater variation in profits and thus risk for the generator. The values of the low and high reserve margins result from modeling the uncertain evolution of weather-normalized load growth in future years, resulting from variations in economic growth. As I explained earlier in this affidavit, economic growth uncertainties are assumed to result in a 1% (standard deviation) uncertainty in year-to-year growth in the peak load, and, for simplicity, this uncertainty is assumed to be normally distributed and independent from year to year. Based on that assumption, a normal probability distribution for weather-normalized peaks for years y-3, y-2, y-1, and y can be described, conditioned on the peak in year y-4, which is already known; two equally probable values for each year are chosen to approximate the distribution. The two values, low and high, are chosen so that their average is the mean of the distribution and their standard deviation is the same as the actual distribution. Then for each of these weather-normalized peaks, a demand curve is created, resulting in two equally probable demand curves for capacity in each of those years.

These curves, together with the amount of existing and new capacity in each year, determine two capacity prices in each year that, together with E/AS gross margins, determine two profits in each year. For instance, for investment commitments being made in yeary-4, given the weather-normalized peak in that year and investment commitments in previous years, the model might show a 50% probability of an ICAP payment of $80,000/MW/yr and a 50% probability of $30,000/MW/yr in year *y*-1.

In general, this distribution of capacity payments represents greater risk to the generator investor, and can lower the risk-adjusted forecast profit in the simulation model. I focus here on the effect on Curve 1 (no demand curve), since that is the system that is presently in place, while also mentioning results for Curve 4 (the PJM proposal). For Curve 1, the effect of introducing uncertainty into ICAP prices in years y-3, y-2, *y*-1, and y (simulating a same-year auction rather than four years-ahead auction) is to lower the average reserve margin by 0.5%, and to increase the required profit by 9 $/kW/yr and consumer payment by 11 $/peak kW/yr. The target reserve margin is met in 3% fewer of the years. These calculations use the base case assumptions. This result quantifies the effect of subtracting several years from the auction's lead time (from four to same year), assuming no change in the vertical demand curve or in bidding behavior.

For Curve 4, the effect is not as large, but still indicates a positive benefit to suppliers for introducing more certainty to capacity prices. In particular, the impact of a same-year auction rather than a timing of four years-ahead (simulated by introducing uncertainty into ICAP prices in years y-3, y-2, *y*-1, and y) is a decrease in the average reserve margin of 0.2%. Required profit goes up by 5 $/kW/yr, as do consumer payments.

In summary, multiyear lead times for power plants together with risk aversion means that more certain capacity prices are worth something to investors.

APPENDIX: MODEL EQUATIONS

This appendix summarizes the equations and notation used in my dynamic model of the four year-ahead RPM auction.

A.1. Assumptions

Let $P_{ICAP}(r_{F,y})$ be the demand curve for capacity, showing the price [in $/unforced MW/yr] paid for unforced capacity during year y as a function of unforced capacity reserve $r_{F,y}$. The F subscript indicates that the reserve margin is calculated based on the forecast peak load (at the time of the ICAP auction).

Load is summarized by the annual peak load in year y, designated L_y in the model. There are three separate types of loads that are considered: forecast peak load $L_{F,y}$, weather-normalized peak load $L_{WN,y}$, and actual peak load $L_{A,y}$.

The growth in weather-normalized load L_{WN}, is assumed to be 1.7%/yr on average. Uncertain growth in this load is assumed to be independent from year to year (random walk). Thus, the simulation is a Monte Carlo simulation, in which random trajectories of $L_{WN,y}$ are drawn:

$$L_{WN,y+1} = L_{WN,y}\,(1+ERR_{WN}) \qquad (1)$$

where ERR_{WN} is an independently distributed normal random variable with mean zero and standard deviation of 1%, consistent with PJM experience. The forecast peak load in year $y+4$ is related to the actual load in year y by the following forecasting formula:

$$L_{F,y+4} = L_{WN,y}\,(1.017)^4 \qquad (2)$$

This assumes that 4-year ahead forecasts are used in the ICAP auction, and that 1.7%/yr expected load growth is the basis of the forecast.

The actual peak load in year y equals the weather-normalized peak plus an error reflecting year-to-year weather variations. Analysis of annual peaks from 1995-2003 for PJM and ISO-NE show that the ratio of actual to weather-normalized annual peaks has a standard deviation of about

4%. The formula is:

$$L_{A,y} = L_{WN,y}\,(1+ERR_A) \qquad (3)$$

where ERR_A is an independently distributed normal error with mean zero and standard deviation of approximately 4%.

Random economic growth and weather variability results in considerable instability in installed reserve margins and gross margins from E/AS sales. Actual reserve margin $r_{A,y}$ in a particular year is calculated as follows:

$$r_{A,y} = (1\text{-}FOR)X_y/L_{A,y} \qquad (4)$$

where X_y is the installed capacity in the given year, and FOR is its average forced outage rate. Forecast reserve margin is calculated as:

$$r_{F,y} = (1\text{-}FOR)X_y]/L_{F,y} \qquad (5)$$

A.2 Model of Generation Capacity Bidding

Let Y be a particular year, which means that in the four-year ahead design of the PJM auction, the commitment to construct capacity for that year is made in the ICAP auction in year ***Y-4***. The addition of CT capacity in year Y depends not only on the ICAP price $P_{ICAP,Y}$ in the auction held in year Y-4, but also on the anticipated E/AS gross margin in year Y, GM_Y, as well as profits $\pi_y = P_{ICAP,y} + GM_y$ - FC in years y previous to Y. FC is the annualized fixed cost of constructing a new combustion turbine, in real annualized terms. (Note that π_y, $P_{ICAP,y}$, GM_y, and FC are all expressed in compatible units of [$/unforced MW of capacitylyear].)

Profits in previous years provide the basis for forecasting the level and volatility of profits in the future. The E/AS gross margin in each of those years is assumed to be a function of the market conditions in a year, summarized by the actual reserve margin. That is, $GM_y = GM_y(r_{A,y})$, as shown in Figure 2, supra. A function of the form $GM_y(r_{A,y}) = \text{EXP}(a_0 + a_1 r_{A,y} + a_2 r_{A,y}^{2} + a_3 r_{A,y}^{3})$ was found to represent an excellent fit to the output of the production costing model used to estimate gross margins.

An installed capacity bid curve for an auction held in year *Y-4* for capacity to be installed in year Yhas the general shape shown in Figure 1. The simulation model creates such a curve in each year. Existing capacity is assumed to be bid in at price B_E, while the maximum potential incremental capacity NCA_Y is assumed to be bid in at assumed bid of B_N. The ICAP price is then calculated as the intersection of that capacity bid curve with the demand curve. NCA_Y is based on generator's anticipated profits, which reflect both the levels and variability of recent profits, along with an adjustment to account for generator's aversion to risk.

The following are the steps involved in construction of a capacity bid curve in each year.

1. The anticipated or actual profit π_y for a new CT for each of several yearsy = *Y*, *Y*-1, Y-2, ..., *Y-7* is calculated. (Other ranges of years can be considered; a total of eight is considered in these simulations.) Profits in years *Y-4*, *Y-5*, *Y-6*, and *Y-7* are assumed to be known exactly, since ICAP and A/ES prices in those years have been observed or can be fairly well estimated by the time the auction in *Y-4* takes place. Profits in years *Y*-1, Y-2, and *Y-3* can be estimated based on the known $P_{ICAP,y}$ and a projection of gross margin based on the forecast reserve margin $GM_y \cong GM_y(r_{F,y})$. Profit in year *Y* is more difficult to forecast, because $r_{F,Y}$ is not yet known (since the auction has not yet taken place). So an estimate is obtained by assuming that enough capacity would be added in *Y* so that the forecast reserve margin in that year would be the same as in the previous year $r_{F,Y-1}$. The ICAP demand curve in year Y (used in the auction held in *Y-4*) is then used to estimate $P_{ICAP,Y}$ for that year based on that guess of the forecasted reserve, and GM_Y is projected using the same guess.
2. The value of the utility function $U(\pi_y)$ (*i.e.*, the risk-preference function I discuss in the body of this affidavit) of the anticipated or actual profit π_y for y = *Y*, *Y*-1, *Y-2*, ..., *Y-7* is then calculated. $U(\pi_y)$ is a concave nonlinear utility function that represents attitudes towards

risk.[14] The simplest possible risk averse utility function is the negative exponential form $U(\pi_y) = a\text{-}be^{-c\pi y}$, which is standard in decision analysis; the risk attitude can be summarized in one risk aversion parameter c. The constants a, b, and c are calibrated so that zero profit results in zero utility; a utility of 1 results if $\pi_y = FC$ (i.e., a gross margin, including ICAP payments, equal to double the fixed cost); and $\pi_y = 0.5FC$ results in a utility of 0.7 (indicating a somewhat but not extreme risk aversion). Other degrees of risk aversion can be readily simulated. For instance, $U(0.5FC) = 0.5$ defines a linear utility function, which represents risk neutrality; then the generator is assumed to care only about average profits, and not their volatility.

3. A risk-adjusted forecast profit $RAFP_Y$ for capacity added in year Y is calculated. This is accomplished by first obtaining a weighted utility of the observed and estimated profits:

$$WU_Y = \Sigma_{y=Y,\ Y-1,\ \ldots,\ Y-7}\, W_{Y-y}\, U(\pi_y) \qquad (6)$$

where W_{Y-y} is a weight assigned to profits that occur Y-y years before the on-line date for new capacity in that auction. The sum of the weights is 1. A simple form of such weights is the lagged formulation $W_{y-1} = aW_y$, with $\alpha<1$; a value of $\alpha=0.8$ is used in the simulations here. From the weighted utility, $RAFP_Y$ is calculated by inverting the utility function $U(RAFP_Y) = WU_Y$:

$$RAFP_Y = -\ln((a - WU_Y)/b)/c \qquad (7)$$

4. The maximum amount of capacity additions NCA_Y based on $RAFP_Y$ is calculated using a function with the following properties: (a) if $RAFP_Y$ is zero, then the amount of capacity added is 1.7% of the existing capacity (so that if all profits in every year are zero, then capacity growth would be just enough to meet the assumed average load growth of 1.7%);

'' Note that the tern "utility" in "utility function" has nothing to do with the utility in "electric utility"; rather, decision analysis use the tern to refer to a notion of value that is quantified under conditions of uncertainty.

(b) if $RAFP_Y = FC$, then the amount of entry equals $\beta > 1.7\%$ of existing capacity (here, assumed to be 7%); and (c) capacity additions at other risk-adjusted profit levels are an increasing function of $RAFP_Y$, and follow a curve that is the same shape as the utility function. These assumptions yield the following relationship between the maximum additions in Y and the risk-adjusted forecast profit:

$$\text{NCA}_Y = X_{Y-1}*\text{MAX}(0,0.017+\lambda\,(WU_Y-U(0)) \qquad (8)$$

where: $\lambda = (\beta\text{-}0.017)/(U(FC)\text{-}U(0))$, and X_{Y-1} is the installed capacity in the previous year. Because the utility function has a negative exponential form, there is a maximum amount of capacity that can be added in a given year (that is, even if expected profits were extremely high, there is a limited amount of capacity that would be constructed).

Given the existing capacity X_{Y-1} and its bid B_E, and the maximum increment in capacity NCA_Y and the assumed bid B_N associated with it, the resulting ICAP price and quantity for year Y can then be calculated, as shown in Figure 2.

The utility function plays a key role in this analysis, and so I explain it further here. The utility function is an increasing and downward bending (concave) function that reflects an assumed risk averse attitude; this is a standard method used in decision analysis and economics to represent risk acceptance behavior by individuals and companies. The more concave the function, the more risk averse generating companies are assumed to be; i.e., the more that undesired outcomes and profit variations are penalized. A negative exponential form, which is standard in decision analysis, is used so that the risk attitude can be summarized by a single risk aversion parameter. In the base case analyses reported in Table 1, ***supra.***, the constants of the function are calibrated so that zero profit results in zero utility; a utility of 1 results if profit equals the fixed cost FC of the turbine (i.e., gross margin, including ICAP payments, equals double the fixed cost, measured in real annualized terms); and a profit of $0.5FC$ results in a utility of 0.7 (indicating a somewhat but not extreme risk aversion). Other degrees of risk aversion can be readily simulated, and are considered in the sensitivity analyses of Section 5.3. For instance, if a profit of $0.5FC$ is instead assumed to have a utility of 0.5, then a linear utility function results, which represents risk neutrality. In that case, the generator is assumed to care only about average profits, and not their volatility.

Figure 12 illustrates how a risk averse utility function penalizes riskier profit streams. The higher the average utility, the more attractive investors are assumed to view an investment opportunity. Comparing two distributions of profits—distribution A which has \$1 occurring for sure, and distribution B which has a 50:50 chance of \$0.50 and \$1.50—we see that the concave (downward bending) form of the utility function means that the average utility of B is lower than the utility of A. So the riskier investment is less desirable, even though its average profit is the same.

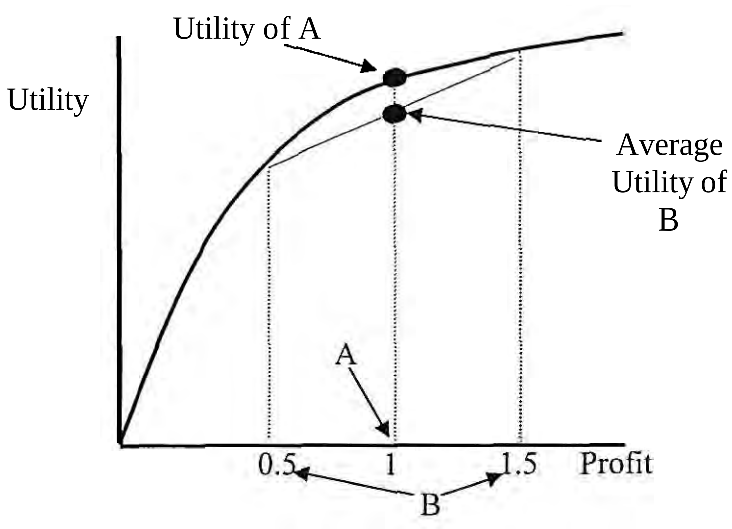

Figure 12. A Risk-Averse Utility Function Results in Lower Average Utility for Riskier Alternatives

Because the utility function is concave, if there is a lot of variation in profits, then RAFP is lower. For example, consider an actual stream of observed and estimated profits that varies over time and has average X. Then RAFP will generally be less than X because the risk averse investor prefers a certain profit to avariable one, and so is willing to give up some average return in order to reduce the risk. The riskier a stream of profits is and the more risk averse (concave) the utility function is, the lower $RAFP$ will be relative to X.

A.3 Model Execution

Each year y of the simulation calculates the following:

1. Random forecast errors (due to economic growth and weather) are drawn, and used to obtain the actual and weather-normalized peak loads (1),(3). The forecast load in y+4 is also calculated (2).
2. The **ICAP** auction is simulated in the manner described in Section A.2, yielding the ICAP price and amount of capacity that will be installed in year y+4.
3. Statistics on the simulation results are compiled for calculating performance indices.

Because the emphasis of the simulation is upon steady-state behavior of the ICAP system, the first 10 years of each simulation are discarded to avoid biases due to starting conditions. One hundred more years are simulated, and then the 110 year simulation is repeated twenty five times, giving 2500 years of output as the basis for the calculation of the performance indices.

This concludes my affidavit

AFFIDAVIT OF BENJAMIN F. HOBBS

Benjamin F. Hobbs, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Benjamin F. Hobbs on behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/______________________________
Benjamin F. Hobbs

Subscribed and sworn to before me this the 5th day of August, 2005.

/s/______________________________
Notary Public

My Commission expires: ____________

AFFIDAVIT OF BENJAMIN F. HOBBS

Benjamin F. Hobbs, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Benjamin F. Hobbs on behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ ______________________
Benjamin F. Hobbs

Subscribed and sworn to before me this the 5th day of August, 2005.

/s/ ______________________
Notary Public

My Commission expires: 1/7/09

ELIZABETH E. WEBER
Notary Public
Baltimore City
MARYLAND
My Commission Expires January 07, 2009