Resource Planning: The Need

New market risks have called on utilities to evaluate an expanding array of new resource options—with antiquated tools to evaluate them.

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REGULATORS, WHO HAD BEEN FOCUSED ALMOST entirely on establishing stranded cost values and overseeing the breakup of electric utilities, are now faced with an industry that is far more complex. Of the traditional oversight activities, the task of ensuring sufficient generation to meet insatiable electric demands—broadly, resource planning—presents today fundamentally different challenges than as little as five years ago.

Resource planning must also adapt to this new market environment.

Today, there are probably few utilities devoting much effort to these sorts of resource planning exercises. Not only have many utilities long exorcised their resource planning staffs, but regulators have been far too mired in restructuring to care. Yet, the need for careful planning has not gone away. The choices faced by utilities in meeting still-present demand obligations have exploded, while the capability needed to evaluate those choices has shrunk.

These new choices for resource planning attempt to take advantage of the uncertainty in the wholesale generation markets. Most utilities now purchase short-term contracts to supply some of their peaking capacity to cover the uncertainty in their peak summer loads. Similarly, utilities receive both solicited and unsolicited offers for baseload generation. Most of these offers are in the form of purchase-power agreements (PPAs) with considerable flexibility in the amount of generation offered, pricing, and the terms of contract renewal. The actual value of these flexible contracts can be assessed only by taking into account the uncertainty now established in the market.

The explosion in resource supply choices is the direct result of deregulated wholesale markets and rapid advances in risk management. As years' worth of excess generating supply were steadily absorbed by unexpectedly large increases in demand, prices in expanding wholesale markets became more volatile. Historic spikes in oil prices and rapid increases in the demand for natural gas exacerbated electric price volatility. As a result, utilities and regulators have become more focused on ways to stabilize costs and prices. For utilities, volatile costs could increase risk and adversely affect shareholder returns. Regulators worry that volatile prices

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could increase ratepayer anger and political disapproval. Lastly, the pace of technological change continues to increase. New resource options are providing greater flexibility for utilities and their customers, but also further complicating the decision process.

Enter risk management, offering utilities ever more exotic financial instruments to hedge their risks and reduce the impacts of volatile markets—but at a price. That price has included the obvious effects of insurance, including raising costs to a higher average level than benefits received and, rarely, catastrophic impacts of utility traders who speculated in generating markets, rather than hedged risks. It also has included new regulatory scrutiny. After all, insurance is truly valuable only when the unexpected happens, providing regulators a potential avenue for deeming insurance costs as imprudent or, if the insurance is used, damning a utility for poor planning.

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In this new era, uncertainty about the future has become a looming issue. Markets have become more volatile, restructuring plans have changed radically, and utilities have changed themselves. Traditional planning tools do not address the opportunities and risks with stochastic markets and new options whose values are inexorably linked to those markets. Resource planning must also adapt to this new market environment.

A New Market-Based Approach: A Case Study

So if the old approach to resource planning cannot address the new era, what can? To answer that question, consider the following actual problem, which we recently addressed for an electric utility in the Southeast. This utility's loads have grown steadily over the years and it needs to acquire new generation. It faced making a decision about a PPA offered to it by a large wholesale generating company. The PPA was structured like a financial call option. The utility could purchase the option for an agreed price. The utility could choose also the duration of the PPA (one year, three years, etc.) as well as the magnitude of the purchase (100 MW, 500 MW, etc.). The "strike" price for the option, in this case, the price at which energy would be provided, would be a weighted average of the then prevailing prices of natural gas and fuel oil at the beginning of the year. If the utility purchased the option, it would be able to determine how much power, up to the agreed maximum, it wished to take. We were asked to advise the utility as to whether this PPA option was a good deal.

The traditional production-cost model evaluation approach (this was the approach the utility expected to use before asking for our help) would have evaluated the PPA as follows:

1. Run a production cost model, assuming some level of load growth and a forecast of electric and fuel prices, without the PPA.
2. Run the same model with the PPA.
3. Compare the present value costs to the utility with and without the PPA, and determine whether or not inclusion of the PPA reduces present value costs.

Applying this traditional approach to valuing the PPA would have ignored the market and demand uncertainties that give the option its value, but would have been quite irrelevant to the valuation exercise. The PPA's value is entirely predicated on future uncertainty, not only of the prices of fuel oil and gas that determine the strike price, but also on uncertainty about load growth (would the utility need the power?) and the market price of electricity.

Instead, to directly incorporate future uncertainty, we developed a unique Monte Carlo model to evaluate the PPA option. But why not use the Nobel Prize–winning financial models used for pricing stock options? The main reason for not using these convenient financial models is they generally consider only one uncertainty and assume that uncertainty acts like share prices traded over the world stock exchanges. For resource planning, as with the PPA example, there are a number of uncertainties. For example, the exercise prices may not be known in advance, and the price of the PPA, without the flexibility of its options is not known from active trading on a market exchange. As a consequence, we often need to build a Monte Carlo model to value generation options.

PPAs with options are useful as hedging tools because their downside risk is limited. A utility that previously purchased the PPA option can, if it chooses, elect not to exercise that option. Thus, once having purchased the option, the utility has no additional downside risk. This makes sense, since having an option to decide later whether to take power or not cannot possibly be less valuable than not having that option whatsoever.

Of course, the option could have lots of value if the market price of electricity were higher than the strike price of the PPA agreement. In that case, the per-MWh value of the option would equal the difference between the market price and the option price, times the size of the PPA. Therefore, to determine the expected value of the option, our Monte-Carlo model evaluated whether it would make sense for the utility to exercise the option under thousands of different scenarios, each with its own probability.

While that equation may look formidable, it just says that the value of the option at any time depends on the difference between the prevailing market price and the purchase price, times the amount purchased. However, if the prevailing market price is less than the purchase price, the utility could choose not to take the energy from the PPA, and hence wouldn't lose any money. Thus, the PPA option was a type of insurance, with the purchase price the insurance "premium." If market prices remained low, then the utility could buy from the market and wouldn't need the PPA; if prices were high, the PPA would be there to reduce the utility's costs.

In our PPA example, the option value had a probability distribution as shown in Figure 1, which shows a large spike at a $0 value. In fact, it shows that in 45 percent of the cases, there would be no option value whatsoever. In the remaining 55 percent of the cases, the option would have positive value. Our analysis showed that the mean value would be about $15 million, but that the median value was only $3.5 million.

Figure 2 presents an alternative way of looking at the option value. This figure shows the option's overall cumulative probability distribution, which is often called a "risk profile." Figure 2 shows a risk profile

Figure 1: Probability Distribution of PPA Option Value

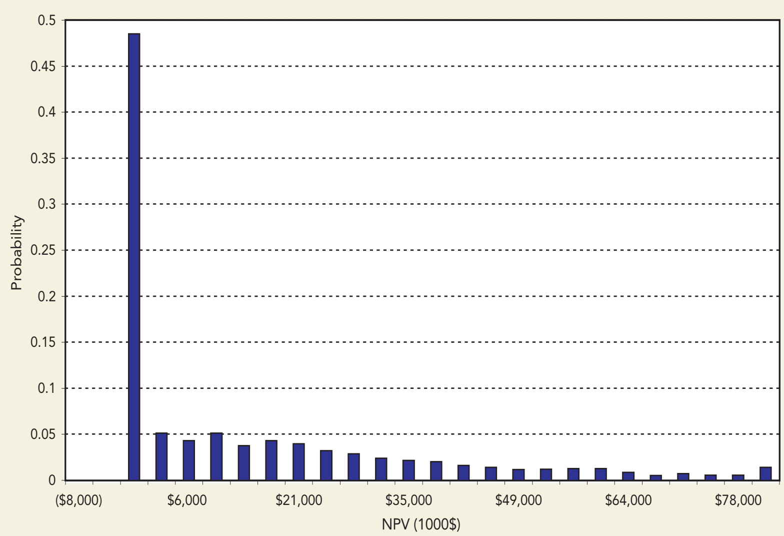
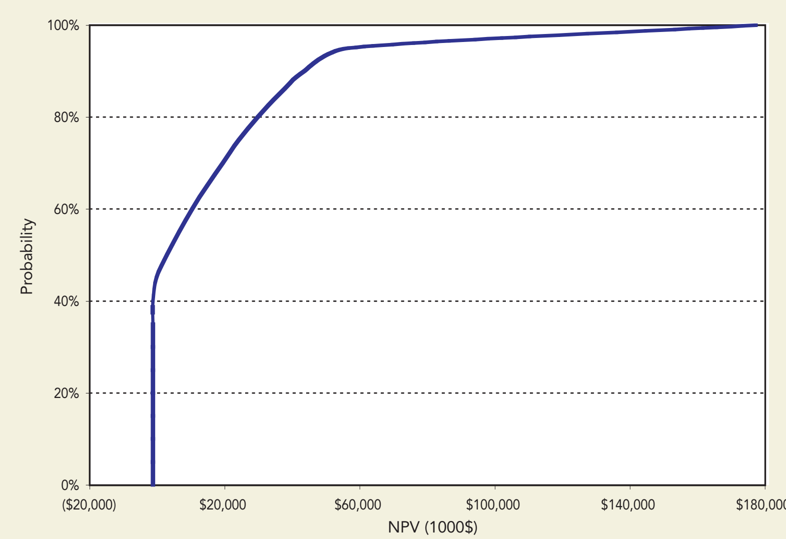


Figure 2: PPA Option Risk Profile



that is just below zero (the option's purchase price) 45 percent of the time. That value then increases rapidly over the remaining cases. The option has the greatest value when fuel prices are comparatively low, electric prices are high, and the utility's loads are low.

Even if it were useful for valuing generation options (it's not), the deterministic, production-cost approach could not provide any of the richness of the Monte-Carlo approach. In this case, one of the most important issues for the utility was the riskiness of signing the option. By developing this Monte-Carlo model, we were able to provide the utility with that information, thus enabling it to make a more informed decision. (The utility decided to go ahead and purchase the option.)

The Role of Regulators

As financial-type instruments become more widely used by utilities to meet their electric power supply obligations, those utilities will not only have to employ sound analytical methodologies with which to choose among competing instruments, they will have to justify those choices to regulators. Unfortunately, the entire concept of risk-management and financial market instruments in the context of regulated utilities is poorly defined. While regulators often discuss requirements that utilities "diversify" away risk, it is not always clear what sort of risk is to be diversified, nor why it should be diversified, nor what is an appropriate method for diversifying. Lastly, arm-chair quarterbacking remains an issue. Regulators, perhaps under pressure from constituents and politicians, can be tempted to revise assessments of utility actions after the fact. Since many market-based financial instruments are insurance vehicles, utilities cannot expect them to reduce average costs. What they can do is reduce the

The Traditional Planning Approach: A Step Back In Time

Before the emergence of wholesale markets and, more recently, the explosion of market-based risk-management instruments, resource planning was a rather plodding exercise. Utilities would examine their existing generating resource portfolios, throw in required demand-side management (DSM) programs, project future load growth, and run gigantic production-cost models. Planners would determine when they would need to add resources, then insert either specific new generation sources, such as plants under construction or dangling purchase-power contracts, for the first few years, and then "generic" plant additions out into the far future.

After months of computation simulations, resource planners would prepare a reverent tome, called an integrated resource plan, for their regulators. The plan would outline all of the steps taken, the new load forecast, the state of existing and new generating resources, the state of the environment, and various "action plans," carefully describing all of the utility's forthcoming decisions for the next 20 years. Regulators would ponder the plan for many months. Hearings would be held, assumptions challenged (especially about the paucity of DSM included), and ultimately, after several years, the plan would be approved. The plan would then proudly take its place on the shelf of other, past resource plans, hopelessly outdated. Then the true battles would begin, with utilities fighting regulators and intervenors in rate cases to establish the prudence and used-and-usefulness of their existing resource portfolios.

In this era, there was little or no consideration of market "volatility," because markets were either nonexistent or poorly understood. And, even though many utilities had been burned by erroneous projections of load growth and fuel prices, there was almost no consideration of uncertainty in planning. The best that might be done was construction of hypothetical "scenarios" that could provide information on how the utility's assumed resource plan might change should the world evolve in a different, but still predetermined way. In the end, however, the effect of uncertainty was not borne by the utility. If the investment in a new resource were deemed prudent and used-and-useful, then the ratepayers paid in full.

— JA, SD, WC

volatility of costs. And, other market instruments, such as the PPA option described, must be carefully assessed so as not to increase utility risk.

Defining "prudent" utility resource decisions has always been controversial, as the long and messy legal history of prudence attests. Certainly, in the first half of the 20th century, regulators and the courts did not envision the ever-growing set of complex financial instruments now available to utilities. Fundamental financial models, such as the Capital Asset Pricing Model (CAPM) and the Black-Scholes option pricing formula simply did not exist. Nor was volatility in the electric market envisioned, as there were no competitive wholesale electric markets. As generation supply alternatives take on more characteristics of financial instruments, evaluating their prudence is certain to become more difficult, and thus more controversial, especially in the face of failed industry restructuring efforts.

To prepare themselves, utilities will need to develop much more rigorous analytical tools. First, as we saw in the PPA example, the standard analytical toolbox, relying on deterministic production-cost models, cannot be used to evaluate many of the new supply alternatives. Second, to the extent utilities begin to rely on these supply alternatives, they will need to justify their supply decisions to regulators, even if utilities decide to let third parties completely manage their supply portfolios.

As a first step, utilities and regulators will need to agree to certain guidelines. These include:

1. **Transparency of outcomes and adherence to standard accounting practices.** This means that the results of the utility's power supply and risk management activities must be clear to all parties and follow established accounting guidelines for value at risk (VaR) accounting, which determines the overall volatility of earnings in a specific time period.
2. **Clear incentive structures.** Regulators need to ensure that incentive mechanisms for the utility, in terms of profit-sharing and price caps, are well-defined. The incentive structure cannot be "heads we win, tails you lose." There must be symmetry of risk and reward between the utility shareholders and ratepayers.
3. **Well-defined risk management goals within which a utility may operate.** Because financial distress can have adverse impacts on ratepayers, regulators must also determine maximum acceptable risk exposure levels. If regulators wish utilities to insure against excessive price volatility, for example, they must define acceptable levels of volatility and an acceptable average cost. This will require measurable objectives and attributes that can (and should) be incorporated into a clear incentive structure for the utility. Above all, despite huge temptation, regulators should not "punish" utilities after-the-fact if the utility has been operating under such previously established guidelines. This does not preclude changing existing guidelines, which will probably need to occur as the financial instruments available to utilities continue to evolve, but such changes should not punish a utility for a lack of clairvoyance.

To be useful, resource planning must evolve, since most utilities will continue to retain their obligation to serve in the face of considerable market risks. Utilities will need to evaluate an expanding array of resource options, many of which will have little in common with the traditional resource options that were standard fare for utility planning exercises as little as five years ago. Today, as the planning and regulatory hiatus imposed by restructuring appears to be ending, utilities must gird themselves for new resource decisions in an era of great uncertainty and rapid technological change.

Regulators need to ensure that incentive mechanisms for the utility, in terms of profit-sharing and price caps, are well-defined.

As the supply options available take on more characteristics of financial instruments, traditional deterministic planning tools must be supplanted to provide robust evaluations that specifically incorporate future uncertainty. These tools will also be needed to successfully defend utility decisions that manage the effects of risky markets in a regulatory environment that is likely to remain contentious and politicized. F

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