Energy Efficiency in the New Generation of IRP Modeling

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ABSTRACT

In the 1980s and early 1990s, utilities utilized integrated resource planning (IRP) to make informed, cost-effective, long-term resource decisions. As utility restructuring proceeded over the last decade, the role of IRP was diminished as market forces were expected to create the most efficient resource portfolio. Recent energy shortages, and gas and electric market price volatility, have spawned renewed interest in IRP, especially in the West.

In the "new" generation of IRP, we have the ability to reflect on some of the first generation's limitations, particularly in terms of quantifying the energy efficiency resource. Other benefits of energy efficiency such as reduced emissions, local employment increases, and risk mitigation were generally ignored. Moreover, energy-efficiency impacts were often just "subtracted" from the load forecast based upon marginal or avoided costs, and many industry professionals did not view this approach as truly "integrated."

This paper discusses these key energy efficiency issues as they relate to new IRP methods and models. In particular, we focus on model simplicity and multiple decision-making criteria to develop a multi-dimensional approach to resource portfolio selection.

Introduction

Prior to the energy shortages of the 1970s, traditional electric resource planning consisted of meeting projected demands through the acquisition of supply resources at least cost. With the development of renewable and demand-side management (DSM) resources, the traditional approach was transformed in the 1980s into integrated resource planning (IRP), where the idea was to meet projected demands through a least-cost mix of supply, renewable, and DSM resources.

Both traditional and IRP methods relied upon generation expansion or production-cost modeling to determine the least cost mix as reflected by revenue requirements. IRP often went a step further by including environmental and social costs along with generation, transmission, and distribution costs. IRP models traditionally "solved" for this least-cost generation expansion plan through the use of optimization algorithms. In recent years, IRP tools have been expanded to address competitive power market issues including real-time dispatch, hour- and day-ahead bidding, uncertain commodity prices, emission credits, congestion and locational pricing, maintenance and scheduling, and merchant plant construction and operation.

The analysis of DSM resources has also evolved considerably since the advent of simple engineering/end-use accounting models of the 1970s. In most IRP processes, DSM resources were screened on the basis of economic considerations. Benefit-cost analyses compared the costs of purchasing the DSM resource to the lifetime benefits derived from "avoided" capacity and energy costs. The cost-effective resource was generally subtracted from the load forecast to estimate net demands, and then a production-costing model was used to optimize future supply mix (Barakat & Chamberlin, 1993).

Recent evaluations and analyses have brought DSM resources closer to supply-side counterparts by focusing on issues such as savings/performance uncertainty and the hedge value of DSM investments. Indeed, the evolution of sophisticated risk management practices has now moved directly into IRP processes (CPUC, 2003).

Optimization Models

The First Generation

IRP was first brought about by the realization that least-cost resource planning must incorporate both supply- and demand-side resources. A meta-study by Stone and Webster (1989) provides clear examples of the market and regulatory paradigm for the optimization of resources based on least cost. The issues at the forefront were incorporating the customer (or demand) perspective, the rising costs of power plants, integrating efficiency resources, and assessing environmental impacts.

The models were extremely complex, typically using a 50-year study period. Particular importance was placed on the maintenance of equal reliability between portfolios, maintaining "the same reserve margin, loss of load probability or the same unserved energy" (Stone, 1-3). In these models, the reserve margin was defined as the available amount of unused generation capacity relative to total system capacity at the time of the system peak. Loss of load probability (LOLP) is the probability that resources will be insufficient to meet demand over a certain time horizon (e.g., winter or summer peak periods). Unserved energy represents the resulting energy volumes to be served by market purchases, demand curtailments, or other means when resources are insufficient. The use of these measures to maintain equal reliability between portfolios was necessary to ensure that all portfolios are effectively solving the same resource problem.

One example is MAPPS, a generation planning model developed by General Electric. It has been widely used for generation planning, and its current version models Independent System Operators (ISOs). Another example is WASP, a dynamic programming model developed by TVA, that was widely used in the '70s and '80s for generation planning. Additionally, PROMOD was developed by Energy Management Associates (now NewEnergy Associates), and its recent versions (PROMOD III and IV) are still widely used for planning and production costing/dispatch simulation.

In terms of DSM programs, most models at the time utilized a pre-screening process to find the most cost-effective programs. After this, the amount of expected load change was subtracted out of the load forecast. DSM resources were modeled at the end-use level. The model utilized hourly load impacts, market penetration, customer-behavior characteristics, and potential restoration energy.

Although the environmental impacts were mentioned, they rarely turned up as decision-criteria. Instead, the standard outputs of these models were deterministic discounted costs. Finally, the modelers assumed that individual utilities were "islands" in the sense that their plans were generally designed to meet reserve margin requirements through their own procurement processes without relying on market purchases.

The Second Generation

Over the last decade, the electric utility industry has built upon the lessons learned from the first generation to create extremely complex, state-of-the-art resource planning/optimization models that recognize the importance of industry restructuring and the development of Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

The new generation of optimization models has a strong focus on risk-management and the impact of the market on the planning process. That is, along with the financial and technical indicators used with the first generation, the second generation has focused on indicators such as volatility, confidence, and hedge value. The new generation realizes the impact of volatility and probability distribution on many fundamental drivers, such as fuel prices, hydrological conditions, electricity demand, new generators, transmission upgrades, and other critical variables.[1]

Most utilities are also concerned with the "robustness" of a given strategy. It is (usually) not enough that a given option is "least cost" given the base case load forecast, fuel and market prices, and other primary variables which affect the strategy. Often, the least-cost option performs much worse than others with changes in load or fuel forecasts. Monte Carlo simulation has become the method of choice for conducting risk assessments. In this probabilistic approach, the uncertainty associated with key portfolio drivers is tackled head-on by specifying their underlying probability distributions and covariances. The Monte Carlo method uses random sampling to "draw" from these distributions, and after hundreds (thousands) of iterations one can glean the impacts of the underlying uncertainty on key results.[2] These ranges are viewed as essential to developing risk-management strategies and assessing various options.

MIDAS is one second generation model example, and Henwood associates and Northbridge have also developed models. MIDAS (originally developed by Gerber Associates) has evolved significantly and now includes price forecasting, production analysis, acquisition analysis, asset valuation, power plant dispatch, financial analysis and forecasting, and portfolio risk management. Recently, Gerber Associates merged with Henwood Associates, which has a "suite of models" that represents current state-of-the-art methods for complicated market optimization and planning. Northbridge developed a Monte Carlo-type model used by New York Power Authority to analyze the NYISO. These models have been able to successfully integrate many portions of the ISO and RTO business into a single model, including short-term dispatch, long-term resource expansion, trading and scheduling operations, load forecasting, power market analysis, and generation operation.

[1] See, for example, information on UPLAN-E at http://www.energyonline.com/products/uplane.as

[2] In the 1940s, scientists at Los Alamos National Laboratory created a computer program to create random combinations of known, uncertain variables to simulate the range of possible nuclear-explosion results. They nicknamed the program *Monte Carlo*, after that city's famous casinos. For more information on this history, see the "Real Options in Petroleum" website: http://www.puc-rio.br/marco.ind/monte-carlo.html#bib-MC.

The Utility IRP Evolution Continues

Portfolio Scenario Models

While the abilities and complexities of the new generation of optimization models are impressive, they are too complex for certain applications. Specifically, smaller utilities require higher-level decision-making without the data and staff requirements necessary for optimization models. These utilities are "price-takers" and must rely on the *outputs* of regional optimization models to determine their best long-term resource strategy.

Two model examples are Navigant's Portfolio Screening Model (PSM) and Quantec's Portfolio Strategist. PSM and Portfolio Strategist are similar because they both assess portfolios of generation assets, power purchase agreements, and demand-side resources. They address the limitations of the new generation of optimization models as they apply to individual utilities by providing:

- Straightforward calculations that can be easily explained to board members and other decision makers
- Calculations and links that are auditable and viewable for review by utility planners
- Outputs that help decision-makers compare different strategies against various indices or measures of performance (e.g., costs, diversity, emissions, local economic development, etc.)
- Estimates of the risk and uncertainty of key portfolio attributes (e.g., VAR, CVAR, Tail VAR, defined below)

To remove complexity and attempt to move away from concerns about a "black box," these models do not use optimization algorithms. They require that users develop scenarios, or multiple possible "portfolios." This enables the planner to determine the relative merits of different policy options (e.g., fossil fuel portfolio, existing mix, renewable and conservation portfolio, reliance on market purchases, etc.). Simplifying the analysis allows the incorporation of additional resource dimensions, which ultimately affect the solution as much as costs. For example, most resource choices differ in various dimensions of risk, including price risk, performance risk, and counter-party credit risk[3]. In today's markets, these additional dimensions of risk often are more important than price. The following sections describe some of the strengths of portfolio scenario modeling.

Model simplicity. To provide straight-forward, auditable model calculations, one easy option is to use Excel as the software platform. Incorporating Visual Basic for Applications (VBA) with Excel enables the modeler to leverage input and output databases to create a clean, flexible model with regards to populating input assumptions and handling calculations.

This model simplicity requires that planners sacrifice some of the old paradigms of IRP modeling. For example, due to Excel constraints, it is nearly impossible to calculate the model on an hourly basis while also providing a wide range of resources for consideration in the development of the portfolio. However, we found that long-term resource decisions are unaffected by using costing periods rather than hourly modeling. This is due to the fact that there

[3] Risk that the selling entity bankrupts, and defaults on the sale

is little, if any, hourly variation in long-term price forecasts resulting from the optimization models *within* identified costing periods (on-peak, mid-peak, off-peak). Similarly, monthly dispatch by costing period can adequately represent plant operations that are occurring hourly in the real world over a long run future.[4]

Energy-efficiency resource bundles. Portfolio scenario models treat energy efficiency resources like traditional supply resources. This is achieved by creating "bundles" of energy efficiency resources by key markets (e.g., residential, non-residential; existing, replacement, new construction) and end-use load shape. These, like any diversified portfolio, combine high and low risks, and different availabilities and reliabilities, to create a non-dispatchable, "must run" resource.

The bundling process provides an opportunity for planners to incorporate the potentially hundreds of energy efficiency measure variants contained in supply curves, while also reflecting the resource characteristics of possible energy efficiency programs. A good illustration of this approach can be found in Puget Sound Energy's 2003 IRP. PSE evaluated two primary energy-efficiency scenarios using the bundling approach: (1) a constant rate of acquisition case, which relied on replacement/new construction opportunities and traditional retrofit programs, and (2) an accelerated energy efficiency case that relied on very aggressive retrofit program strategies. PSE's portfolio scenario model was then able to show the cost and risk characteristics of the various conservation portfolio options.

Modeling risk and uncertainty. Without optimization calculations, risk and uncertainty can be easily incorporated using Monte Carlo simulations on multiple series to produce effective risk simulations. Monte Carlo simulation is repeatedly viewed as a valid way to obtain the probability distributions around the change in portfolio value, particularly in situations that exhibit non-normal distributions. For example, one can specify random variables for:

- Load Forecast
- Hydro Availability (Weather)
- Electric Market Prices
- Natural Gas Market Prices
- Coal Market Prices
- Availability/Penetration of Energy Efficiency

Possibly the most important risk analysis issue is the incorporation of simultaneous relationships between some of these variables. For example, in the Northwest the Monte Carlo simulations explicitly recognize the impacts of the load forecast, hydro availability, and natural gas price market on electric spot market prices. Similarly, the load forecast can be correlated with the availability of energy efficiency through the influence of new building starts.

Risk measures. In May of 2002, the California Public Utilities Commission (CPUC) proposed that portfolios should be based on either value-at-risk (VAR) or Cash Flow at Risk (CFAR) (CPUC, 2003).

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[4] Consider, for example a single-cycle combustion turbine that may be used to offset peak market purchases or take advantage of high market prices. If the long-run forecast of peak period market prices doesn't vary by hour *within* the peak period each month, then monthly dispatch will provide results that are identical to hourly dispatch.

CFAR is a measure of uncertainty about future cash flows to a portfolio. It typically provides the maximum shortfall relative to specified target, due to impact of market risk on set of exposures. "Within the context of electric utility procurement, CFAR can be used to gauge expense level at the worst-case scenario given the portfolio's net short position" (Tam, 2003).

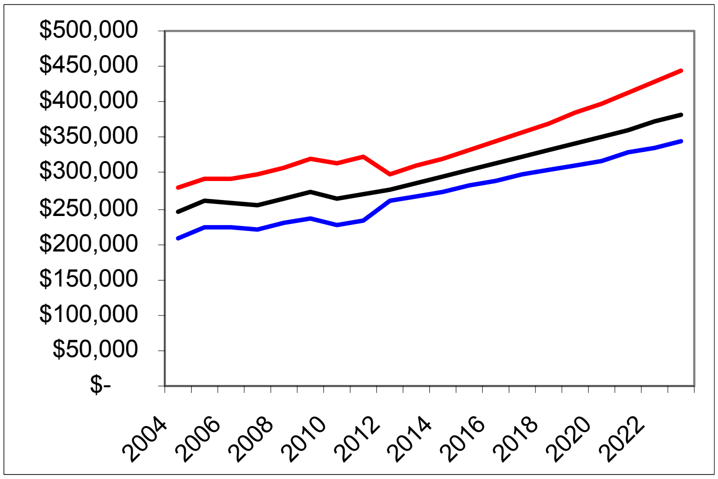
VAR is a measure of uncertainty about the future value of the portfolio. It measures the maximum loss within a specified confidence level if the portfolio is held for a certain length of time. In general, VAR is used for liquid financial assets while CFAR is relevant for assets with physical delivery. Lauckhart (2003) reported that CFAR is the "right measure" for utility risk valuation, given that utilities have generation assets that face illiquid markets, and are associated with significant market volatility. Additionally, weather's impact on generation and retail load are difficult to hedge, consequently utility risk is best measured in cash flow volatility. He finds that Monte Carlo is "needed" to simulate the key risk drivers for utilities.

Another risk measure utilized in the Northwest is Tail VAR, which is the average of the 1% increment values from 90% to 100% on the distribution.

Multiple decision criteria. Scenario models recognize that there are multiple criteria that decision-making is based upon. They provide detailed information about each portfolio and comparisons between portfolios. Portfolio Strategist outputs will be used as examples below. Each portfolio can be reviewed for the following aspects:

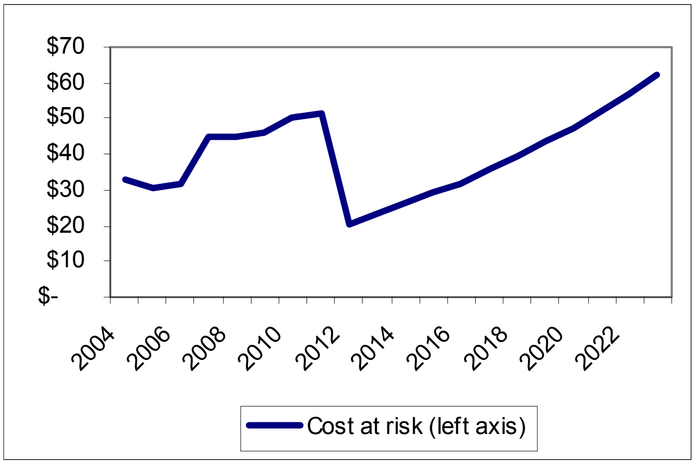
- ***Cost***. Cost can be assessed as discounted total portfolio costs or levelized costs per energy unit. Using the Monte Carlo simulation output, the confidence interval on this series can be provided to decision-makers. Figure 1 below shows the 95% confidence interval surrounding annual total portfolio cost.

Figure 1. Nominal Portfolio Cost: 95% Confidence Interval



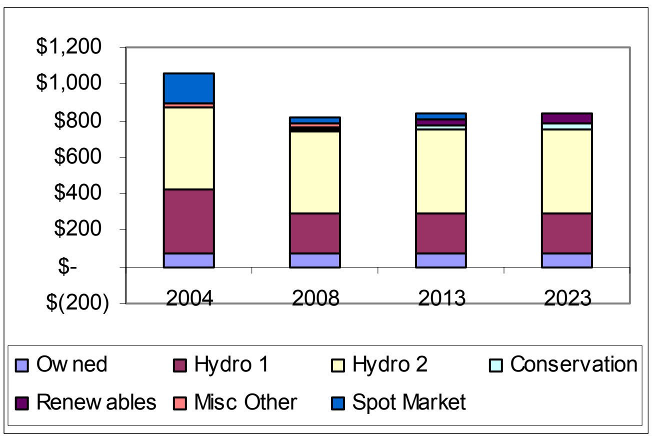
- ***Risk***. Analysts can calculate a variety of risk measures, but, as discussed above, the primary measure used, Cost at Risk, is analogous to the Value at Risk measure used in the risk management community. Cost at Risk measures the difference between the expected cost of a portfolio and a probability level on the tail of the distribution. For example, it is common to view Cost at Risk as the difference in cost between the 95% and 50% probability levels. Figure 2 shows, for a single portfolio the annual cost at risk in millions.

Figure 2. Cost At Risk, Millions



- ***Mix of Resources***. The provision of resources by type is also an important indicator for many decision-makers. Figure 3 shows the mix of resources, by cost, at various points in time.

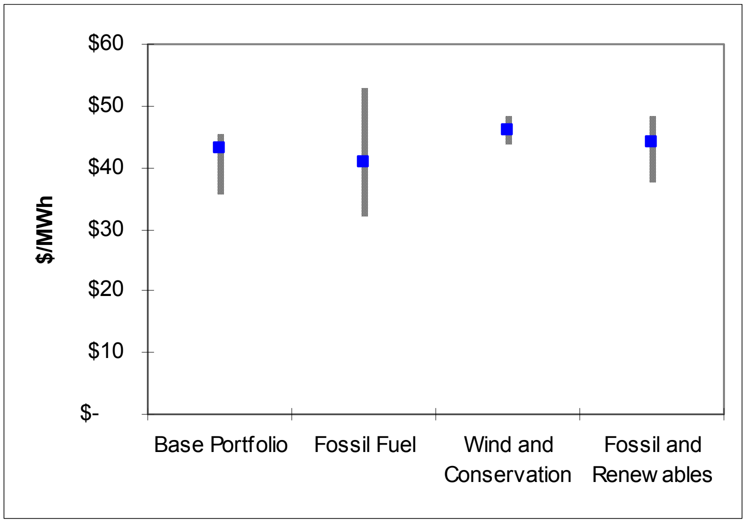
Figure 3. Resource Mix, by Cost



Across portfolios, there are also many indicators of each portfolio:

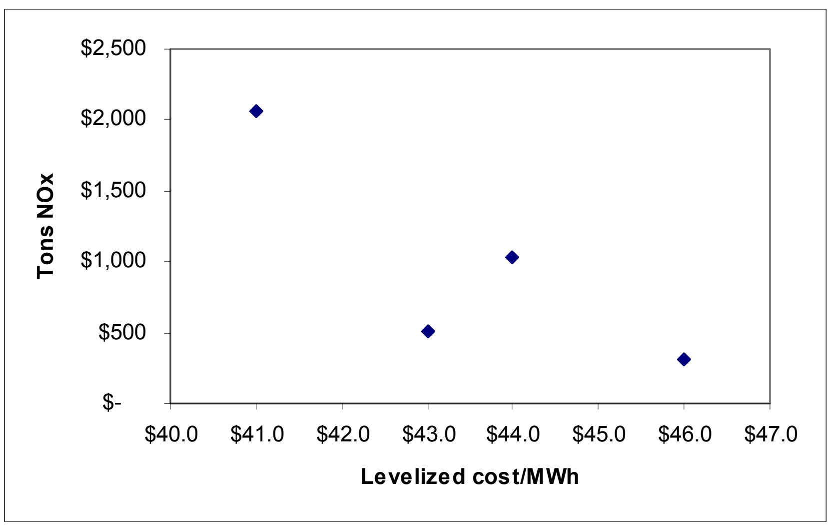
- ***Costs and Range of Costs***. Total costs can be levelized per unit of energy and can be charted showing the distribution. That is, in addition to viewing the average cost, decision-makers can also see the range of potential costs. The figure below shows the median cost per mega-Watt hour (MWh) as well as the distribution around it. Decision-makers can clearly see the trade-offs between cost and volatility. Figure 4 shows, across portfolios, various indicators of cost. The length of the bar indicates the 95% confidence interval for the average cost, which is the center block.

Figure 4. Portfolio Comparison, Levelized Costs and Distribution



- ***Environmental Impacts***. Using environmental impact data for all resources, planners can evaluate the tradeoffs, if any, between emissions and cost. For example, charts can be created to show the relationship between portfolio cost and emissions such as NO_x, SO_x and CO_2. Figure 5 displays the relationship between levelized cost and emissions output.

Figure 5. Portfolio Comparison, Levelized Costs and Distribution



- ***Economic Impacts***. Different resource choices have different impacts on the local community. For example, if a resource is generated far away and transmitted to the utility, its cost is almost fully spent outside of the region. On the other hand, activities such as energy efficiency spend money within the region, resulting in multiplier impacts in the community. For each resource, planners can estimate the portion of costs that are spent within the community and evaluate the tradeoffs, if any, between community impacts and total portfolio cost.

- ***Risk Analysis***. Each resource differs in cost, uncertainty about cost, and in how portfolio risks are combined and managed. The risks of some resources offset one another to act as natural hedges (e.g., cold wet winters increase electric demand, while they also increase hydro availability), while others interact in more negative ways (e.g., hot summer weather increases electric load, while decreasing hydro availability). Risks can be hedged with financial instruments (at a cost) or with physical options.

Conclusions

Spreadsheet-based portfolio scenario models are an important complement to second-generation optimization models in the new generation of IRP. Portfolio scenario models provide straightforward calculations that are auditable, viewable, and easily explainable to board members and other decision makers. They also allow for multi-attribute portfolio evaluation, and an assessment of risk and uncertainty. In practice, the chosen portfolio(s) can be further assessed in one of the optimization models to fine-tune resource levels and the timing of acquisitions. All interested parties can then agree that the final portfolio is truly "best" given the information available during the IRP process.

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