Evaluating the Merits of Coal Projects in a Competitive Electric Market

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Abstract

Coal-fired generation produces more than 55 percent of America's electricity, yet much of that generating capacity is over forty years old. Most new electric generation projects have either been natural gas-fueled gas turbines or combined cycles. The recent preference for these natural gas projects has largely been driven by low gas prices that existed in the past, and the acceptable environmental performance of these units. These natural gas units have also been selected due to their lower risk and smaller size increments as the U.S. power market adjusted to new competitive market approaches in some regions.

Still, some significant changes have occurred that might affect future plant decisions. Difficulties in California's competitive market caused some states to pause in their plans to move to a competitive market structure, while other regions, such as the Pennsylvania New Jersey Maryland Interconnect LLC. (PJM), apparently are coping well with competition. Environmental laws lead to uncertainties, and in the past year, natural gas prices have recently risen. New generations of coal and natural gas technologies are or will soon be available to begin commercial service demonstrations.

All this means that there is a significant burden on planners to assess the merits of fossil power generation units, to establish their prospects for competitive electric sales. This paper summarizes an approach being used and developed by the National Energy Technology Laboratory for evaluating the merits of coal- and gas-fired power projects in those areas of the country that have gone to a competitive market. These procedures use a number of different evaluation modules, which collectively have been named "GEMSET," an acronym for "government energy market segment evaluation tool."

The GEMSET product promotes the reasoned evaluation of the economic and environmental prospects of fossil electric power generation technologies in the competitive market regions of the United States. The evaluations and tools in the GEMSET product allow assessment of the existing plant investment and financial return conditions throughout the U.S. These tools and assessments allow the investigation of different environmental, demand, and fuel price scenarios that might exist in the various regions, and gives reasoned projections of where these circumstances might be in the future up to year 2020.

Elements of a GEMSET Evaluation
GEMSET evaluations include the following elements:

- A view of historical electric demand in each region.
- Projections of demand under differing circumstances in the future.
- A view of historical and projected fuel prices to generating company owners.
- An assessment of the expected revenue prospects of a generating company owner in the various regions of the U.S.
- Assessments of how the revenue prospects might change under differing fuel price scenarios.
- Assessments of how the revenue prospects change under different environmental regulation scenarios.

This paper describes the various elements of the GEMSET market modeling approach that has already been developed. It also shows examples of results from these elements where possible power unit additions are evaluated in the PJM and New York (NYISO, New York independent system operator) regions, and gives a summary of where the modeling will proceed.

The GEMSET Modeling System
Generating company owners take significant risk when they invest their money in new electric generation equipment. Several important factors affect the ability of the owner to make a profit on a new electric generating unit. These include the following:

- How well the owner anticipates how much demand there will be for the sale of electricity from the new generation unit,
- How well the owner is able to estimate the price received for that electricity, and
- How well the owner can anticipate how much it will cost to operate the unit.

Of necessity, addressing these also requires close attention to factors that include at least the following:

- Understanding the region's operating rules and regulations.
- Understanding the way units are planned and permitted to add new generation in a region.
- Anticipating retirements of existing units.
- Understanding the present and historical fuel costs, and anticipating how these might change in the future.
- Understanding present environmental regulation, and anticipating how these regulations might change and affect the cost of operating the owner's unit and competing units in the future.

- Understanding how to operate in a market – significantly different if that market is regulated or competitive, anticipating how other owners will operate their units, and the costs to which these competing units might be subject.

In order to better plan, research, and develop practical solutions for America's power future, the U.S. Department of Energy's National Energy Technology Laboratory (NETL) has many of the same needs as power plant owners to evaluate how new electric generating technologies might be received, and how their prospects might change under different future economic and regulatory circumstances.

NETL embarked on a program to develop power market information. A series of program elements are under development to support NETL's internal technology economic evaluation and assessment needs. For convenience this collection of tools is referred to as the "*government energy modeling system evaluation tool*," or "GEMSET." This collection of GEMSET model elements allows the NETL to assess the economic prospects for a new fossil generating unit over a range of different fuel, environmental, demand, and price situations. NETL evaluators can select from well-researched historical regional load demand/ price scenarios, and capacity factor information in a region, or on reasoned extrapolations to possible future price circumstances for a range of reasonable different circumstances. The collection of models assesses the capacity factor expected in that region under the user's input circumstances for his or her study unit, and assesses the financial return expected under that scenario of circumstances. The GEMSET system allows evaluation under both historical and forecast events up to year 2020.

Evaluating Power Plant Economics

The GEMSET methods evaluate electricity price, revenue, and unit capacity factors to approximate how generating company owners choose to bid their units into competitive and regulated electric markets. The user can review the capacity factor[§] that the GEMSET model estimates would result for operations under a range of regional operational scenarios. The user can specify how a unit might be expected to perform, and what its costs will be, or can select from a library of power generation technologies. The model provides estimates of what results

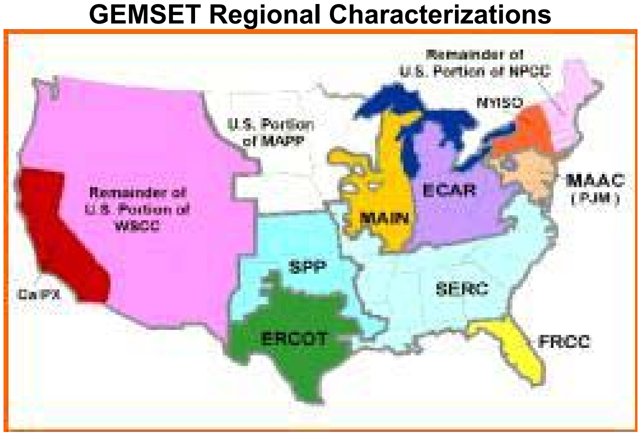
[§] Cf = [actual kWh] / [period hours * rating] might typically be obtained for coal units of different output ratings under the same circumstances, used as benchmarks to compare the merits of the study unit to that of the most likely technologies that would also be considered by the owner before the owner would make an investment decision.

GEMSET Model Features

The GEMSET evaluations cover (or will, when the project is complete) the entire United States. There are dramatically different circumstances in each region: load growth, makeup of the existing fleet of generation, different choices of competitive or regulated power generating entities, etc. To make the assessments more valuable, the GEMSET team chose to break the U.S. into 12 evaluation regions, shown in the graphic below. For each of these regions, assessment begins with a thorough characterization of the region. These characterizations establish the following:

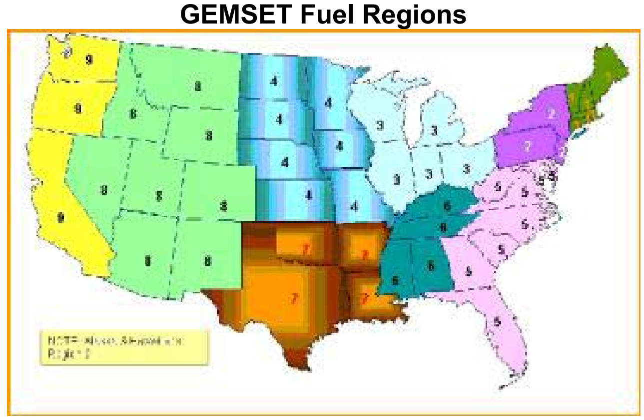
GEMSET Evaluation Breakdown

GEMSET Regional Characterizations



- CALPX - The California Power Exchange, a portion of the NERC's Western Systems Coordinating Council (WSCC)
- East Central - East Central Area Reliability Coordination Agreement (ECAR)
- Florida - Florida Reliability Coordinating Council (FRCC)
- Mid-America - Mid-America Interconnected Network (MAIN)
- Mid-Continent - the US portion of the Mid-Continent Area Power Pool (MAPP)
- Northeast - the U.S. portion of NERC's Northeast Power Coordinating Council (NPCC), excluding New York
- NYISO - The New York ISO, a portion of NERC's Northeast Power Coordinating Council (NPCC)
- PJM - the Pennsylvania, New Jersey, Maryland Interconnect, which comprises the NERC's Mid Atlantic Area Council (MAAC)
- Southeast - Southeast Electric Reliability Council (SERC)
- Southwest - Southwest Power Pool (SPP)
- Texas - Electric Reliability Council of Texas (ERCOT)
- Western - the U.S. portion of the NERC's Western Systems Coordinating Council (WSCC), excluding California

GEMSET Fuel Regions



- GEMSET Fuel Region 1 – New England
- GEMSET Fuel Region 2 – Mid-Atlantic
- GEMSET Fuel Region 3 – East North Central
- GEMSET Fuel Region 4 – West North Central
- GEMSET Fuel Region 5 – South Atlantic
- GEMSET Fuel Region 6 – East South Central
- GEMSET Fuel Region 7 – West South Central
- GEMSET Fuel Region 8 – Mountain
- GEMSET Fuel Region 9 – Pacific

Legend:

- *= Existing characterization complete*
- *= Planned characterization, or characterization underway when this paper was written*

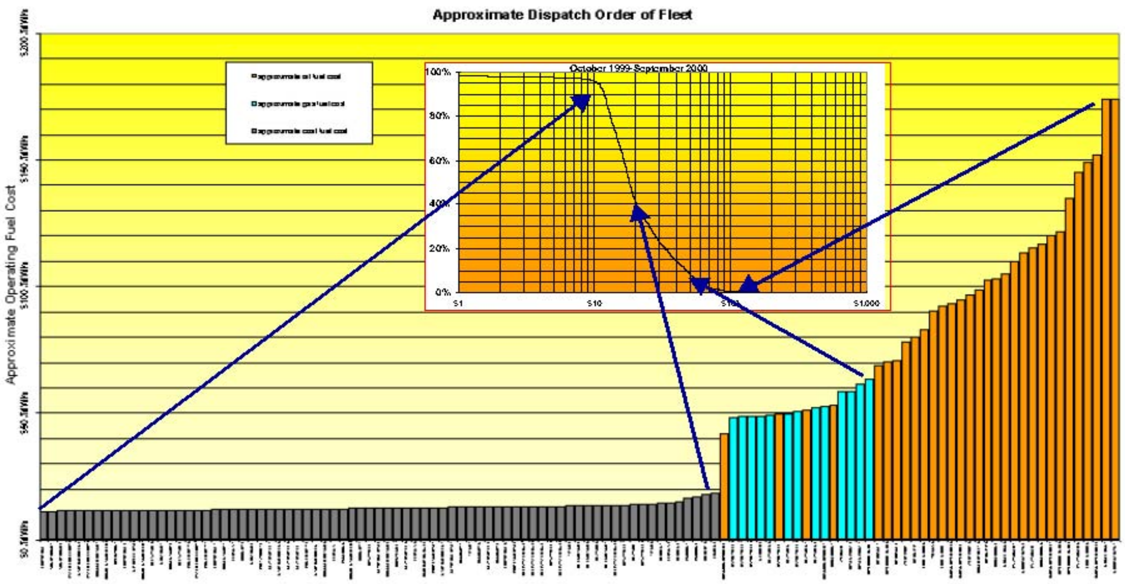
- Characterize the hour-by-hour load demand for each of the power companies, and summarize for the entire the region.

- Develop a database that characterizes an estimate of the regional cost of generation for each level of load demand that depends on assessments of the heat rate of each unit, presumptions of operating costs, and assessment of the expected fuel costs in the region.
- Identify the rack-up of the dispatch order expected for units operating in the region at each load level. If at a condition different from the historical record, re-estimate the new dispatch order under the study's demand profile unit makeup, and fuel price scenario under investigation.
- Assess fuel prices for the GEMSET fuel evaluation regions (right-hand column in the graphic above on the right-hand side), and project fuel price for future evaluations. In GEMSET, averages of the actual delivered price of the various fuels are used as the historical basis, commodity market closings for near-term history and forecasts, and EIA fuel price projections for long-term fuel cost trends.
- Assess expectations of the production cost (in regulated regions), or the threshold bid price strategy (in competitive regions), for each unit.
- Estimate the expected unit dispatch for each hour of the year, and develop capacity factor estimate profiles.
- If the region is competitive, develop an hour-by-hour assessment of return; if regulated, the rate base return expected. This allows ease of evaluation of the potential return to units having different production costs.
- Estimate expected future return, based on reasonable projections of how the price structure might alter depending on the forecast future circumstances. In competitive regions, predict future bid strategies based on historical bids.
- Establish a reasonable future expectation of the region's demand growth, and the list of planned units that might meet that demand growth.
- Identify potential unit retirements in each region.
- Estimate production costs, threshold bid price, revenue and levelized busbar cost of electricity (COE) that might occur under this scenario. This plot indicates the COE (cost of electricity) and breakeven amount of the study case versus those of the GEMSET technologies under the PJM competitive market.

Stacking the Existing Fleet and Projecting the Stack in the Future

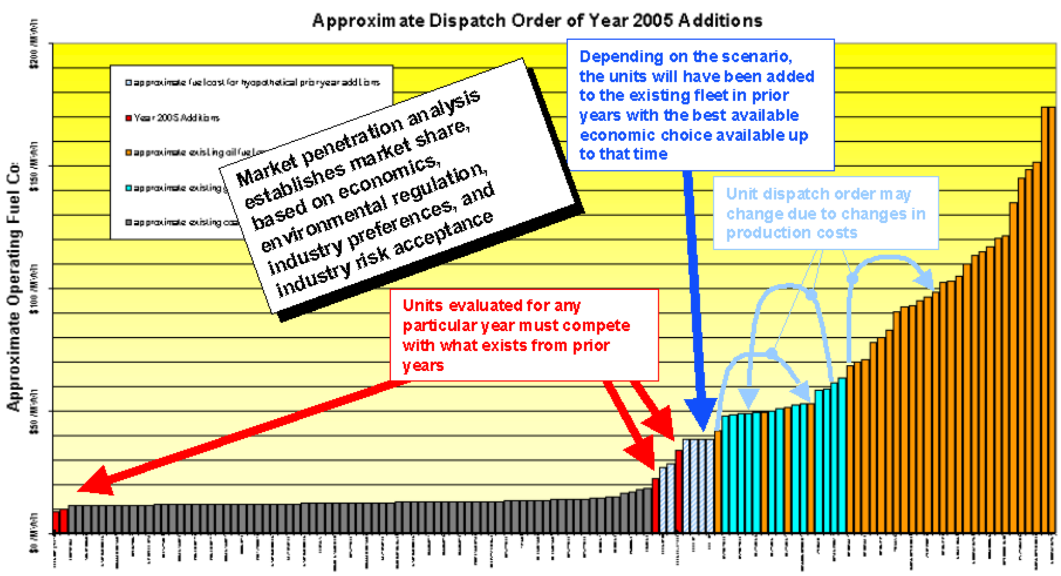
The model stacks the existing fleet of generation on the basis of the estimated threshold for bidding in a competitive market. Each unit within a geographical region is stacked with the lowest production cost units presumed dispatched first, in higher and higher order, until all existing units in the region are sequenced. This process is illustrated in the graphic at the top of the next page.

A re-stacking of the dispatch order is the first action needed to build the expectation of a scenario's day-ahead electric price profile under different circumstances. All the units must be re-stacked in the revised threshold bid price order. The threshold bid prices of units will change since fuel price or demand profile, or other factors might change in any scenario, compared to the circumstance that existed in the historical data baseline. In any given scenario individual units will likely have a different production order than in the baseline. For example, suppose gas price were presumed lower in an evaluation scenario below. Here, several natural gas units have been "promoted" in their dispatch order to earlier dispatch, while oil units were "demoted" since their scenario threshold bid price places the lower-priced units ahead of what have now become more costly units.

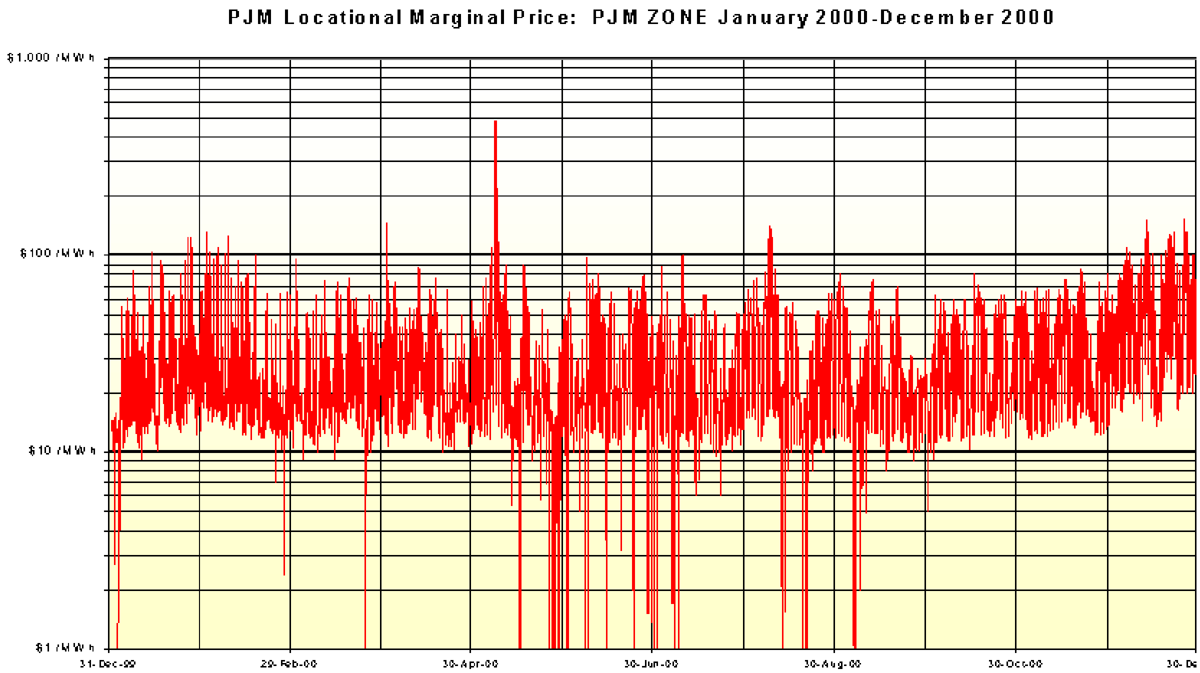


The graphic below is a sketch to give a visual impression to illustrate the concept. The actual GEMSET re-stacking process is more sophisticated.

Re-stacking the Fleet to Establish Threshold Bid Prices vs. Demand Relationship for a Scenario

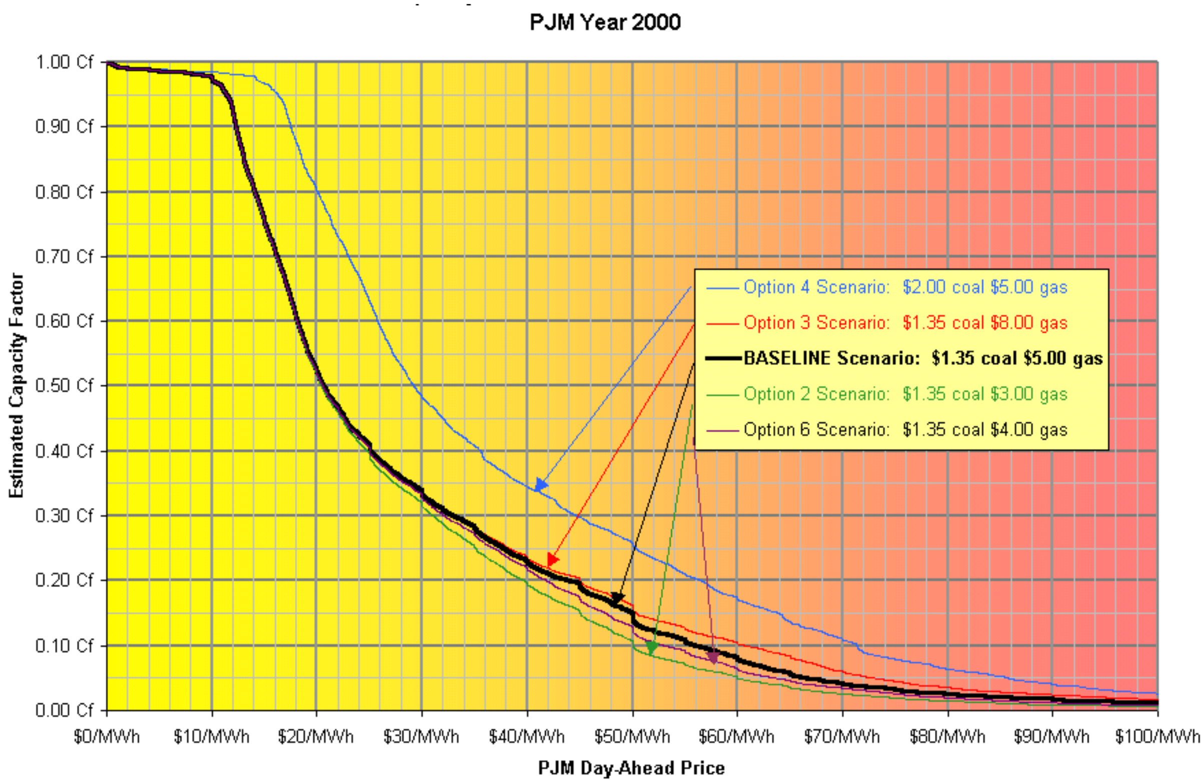


Mapping Price
Competitive prices are obtained for the prior year, and mapped hour by hour. Suitable assumptions are made for the mapping of each unit to this profile, for each hour's demand throughout the year. This is illustrated below for the PJM region beginning in the first hour of 2000 until the last hour of 2000.



Presumed Dispatch
Having calculated a break-even COE for each of the differing units, it is necessary to compare that break-even cost of electricity to the revenue currently in effect in the region. Based on an hour-by-hour accumulation of day-ahead prices, a histogram is developed from the lowest to the highest price experienced in the region. This S-curve is a cumulative distribution function, and is shown graphically on the next page. The baseline (dark line on the illustration) histogram is the basis for the assumed dispatching levels of the new units under current market conditions. Also shown in this illustration are projections under different fuel prices, where the estimated day-ahead price was mapped after re-stacking the units under differing price scenarios. This results in the estimated day-ahead price histograms for each scenario shown. These curves provide the capacity factor information used in the economic studies.

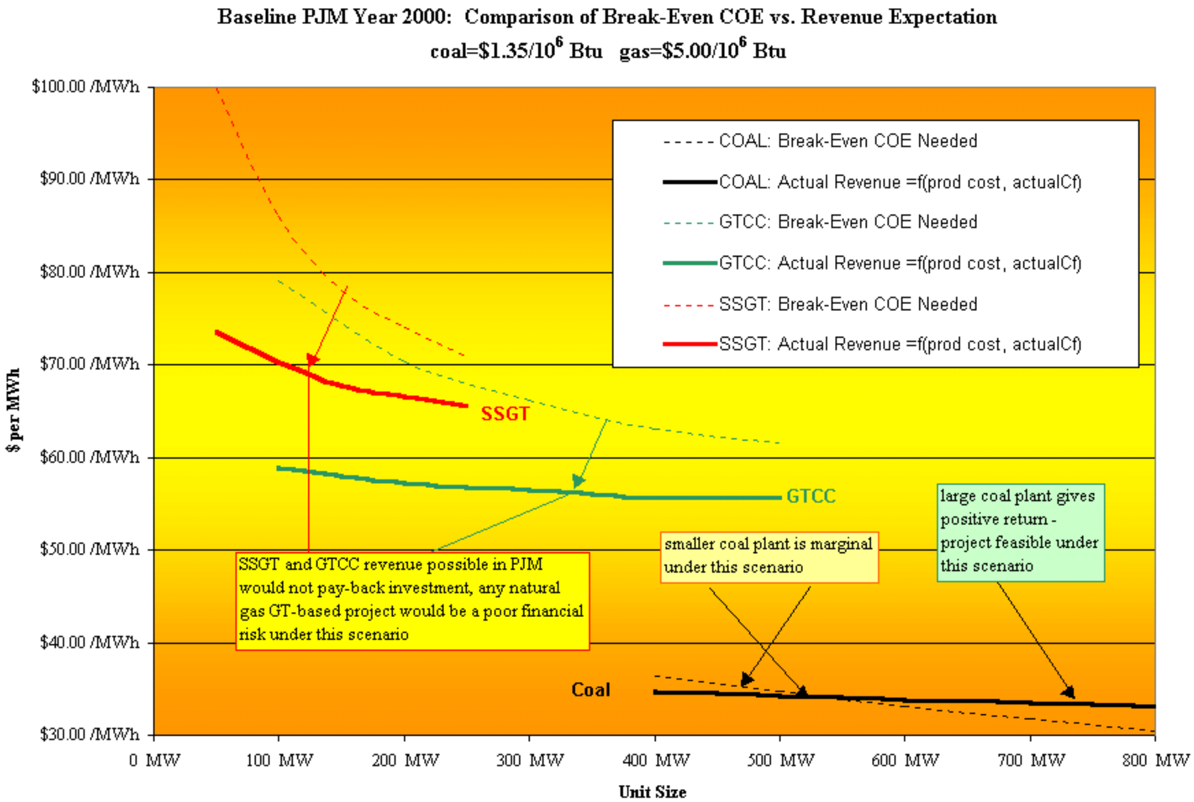
Estimated PJM Day-Ahead Price for Each of the Study Fuel Cost Scenarios



By reading the price on the curve at the level of threshold bid prices for that unit, the number of hours that the unit is likely to be dispatched is calculated. This then gives the estimated dispatch levels and the capacity factor of the unit. With that S-curve is a corresponding calculation of the estimated revenue associated with that number of hours of operation, which can then be compared against the calculated break-even COE to see if the unit can make a positive rate of return for the owner.

Below is a graphical summary of the economic performance of three types of generating technologies used as benchmarks for GEMSET studies, and their expected revenues when compared against the break-even revenue amount from PJM's pricing levels for the year 2000, only one of the price conditions evaluated. Any owner considering buying new generation would likely compare the technical and economic merits of his candidate unit against these three competitors: a simple cycle natural-gas fueled gas turbine, a combined cycle fueled on natural gas, or a coal-fueled pulverized coal steam unit. The graphic is for just one price scenario, here, gas price at $\$1.35/10^6$ Btu and gas price at $\$5.00/10^6$ Btu, prices that existed at the time the evaluation was run. Today, with gas price lower, a different curve would result, obviously lower gas price being more favorable to the gas turbine and combined cycle units at the expense of the coal units.

SSGT, GTCC, and Pulverized Coal Project Break-Even COE versus Potential PJM Revenue with Year 2000 PJM Day-Ahead Electric Price



In this fuel price scenario, only the coal unit achieved some level of return at the larger sizes. If, however, an owner had secured a long-term contract natural gas price at the gas price that existed in the beginning of 2000, then each unit size for the natural gas type units would actually make a positive rate of return. Later, the results of other fuel price scenarios are shown.

Market projections were made at several different natural gas price scenarios. The market projections assume:

- The region's bi-lateral contract price will trend toward the day-ahead free-market price.
- Market price is only loosely linked to threshold bid price; there is a large "random-walk" on any given hour, however, it is presumed that there is a tendency that price is linked to demand in some fashion.
- If a competitor has a lower marginal threshold bid price than another, he can always underbid that other competitor and win, whenever demand is less than the owner's particular marginal price dispatch order.
- On average, the market price will deviate about the price / demand / supply. While an individual hour cannot be accurately predicted, it is presumed here that on average, the deviations about a predicted level will have similar variability to those of the actual market in the prior year. That is, a scenario's variations about price versus threshold

bid price will on average be similar to the variations that actually occurred in the prior year.

- The study presumes that differences in electric price under these several fuel price scenarios are not large enough to substantially alter demand in the region.

Handling the Randomness of Competitive Market Effects in Order to Forecast Alternate Scenarios

While threshold bid price is an important driver for bid price, in a competitive market there are many reasons why bid price varies. It is assumed that these "gamesmanship" effects are random, and driven by competition; however, it is presumed that on average the competitive gamesmanship market variability of cost versus bid price that actually occurred in the prior year will likely be similar to that in any given scenario.

In GEMSET, an "inferred competition ratio" was established for each hour of the year, and presumed in the aggregate to reasonably approximate competitive variability in other years and scenarios. This ratio maps hour-by-hour the presumed threshold bid price for each hour's demand level and establishes the ratio between cost to the actual day-ahead price in that hour. That hour-by-hour baseline inferred competition ratio is then used to map all future scenarios. It is presumed that while any given hour is random, the aggregate trend of competitive pressures will over a year range through similar variations. That is, while an individual hour's price level cannot be predicted with any accuracy (due to the random nature of competition), still, it is acceptable to presume that over a period of 8,760 hours, the amount of variability between price and demand will likely be similar.

Threshold Bid Price and Price Projections Under the Different Fuel Price Assumptions Scenarios

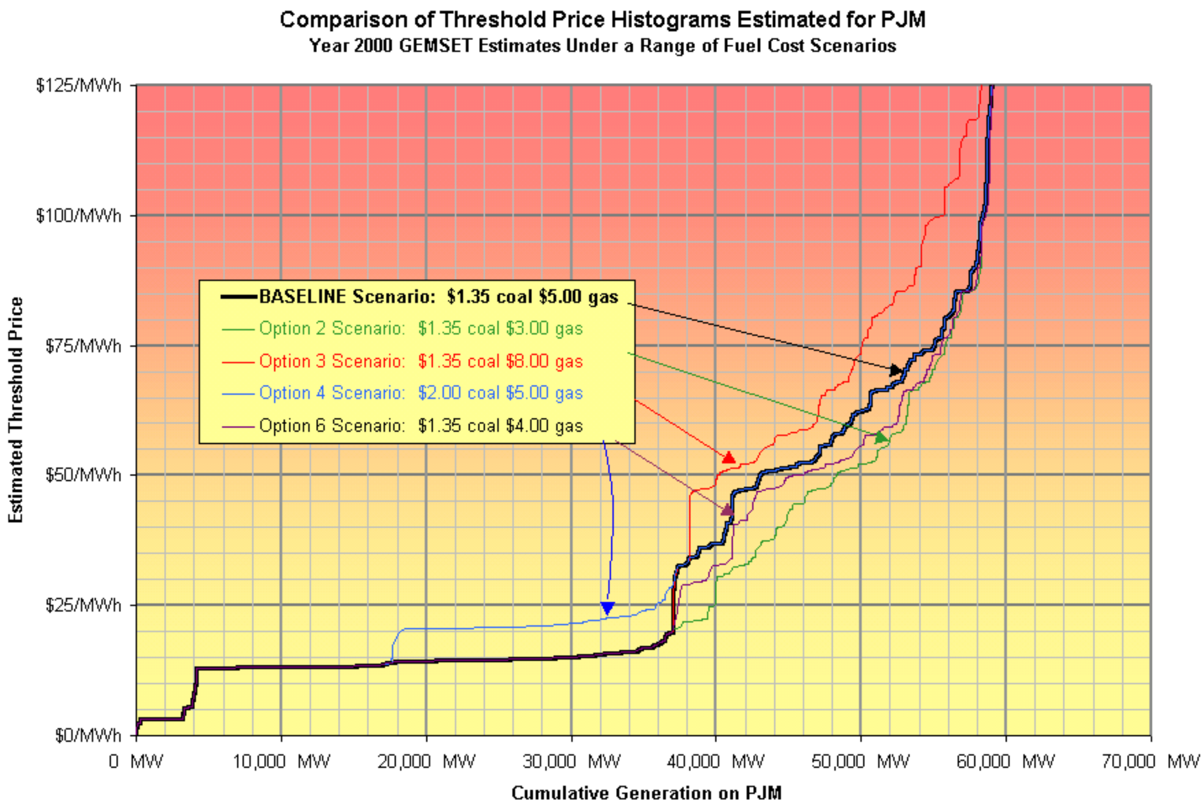
The estimated production units in PJM are evaluated under the several scenarios of fuel price. In each scenario, every unit in PJM is re-stacked according to their expected threshold bid price under that particular scenario. This results in the estimated threshold bid price histograms for each scenario illustrated on the next page.

The estimates of threshold bid prices under the several scenarios of fuel price in PJM were then mapped against hour-by-hour demand for each scenario. This presumed that differences in electric price in each case were not large enough to substantially alter demand in the region. Competitive electric bid price variability versus threshold bid price was assumed to be about the same under each scenario.

Stacking of Existing Units Within a Regional Scenario

The units in the PJM region were characterized using information from a number of databases. As an example, there are 497 units in the GEMSET unit database for the PJM region. The heat rates and the variable operating costs for each of these units was estimated as part of the analysis. Using the fuel costs discussed earlier, threshold bid price can be estimated. The threshold bid price is the point where a power plant owner decides to generate in a competitive region.

Threshold Bid Price Estimated for Each of the Study Fuel Cost Scenarios

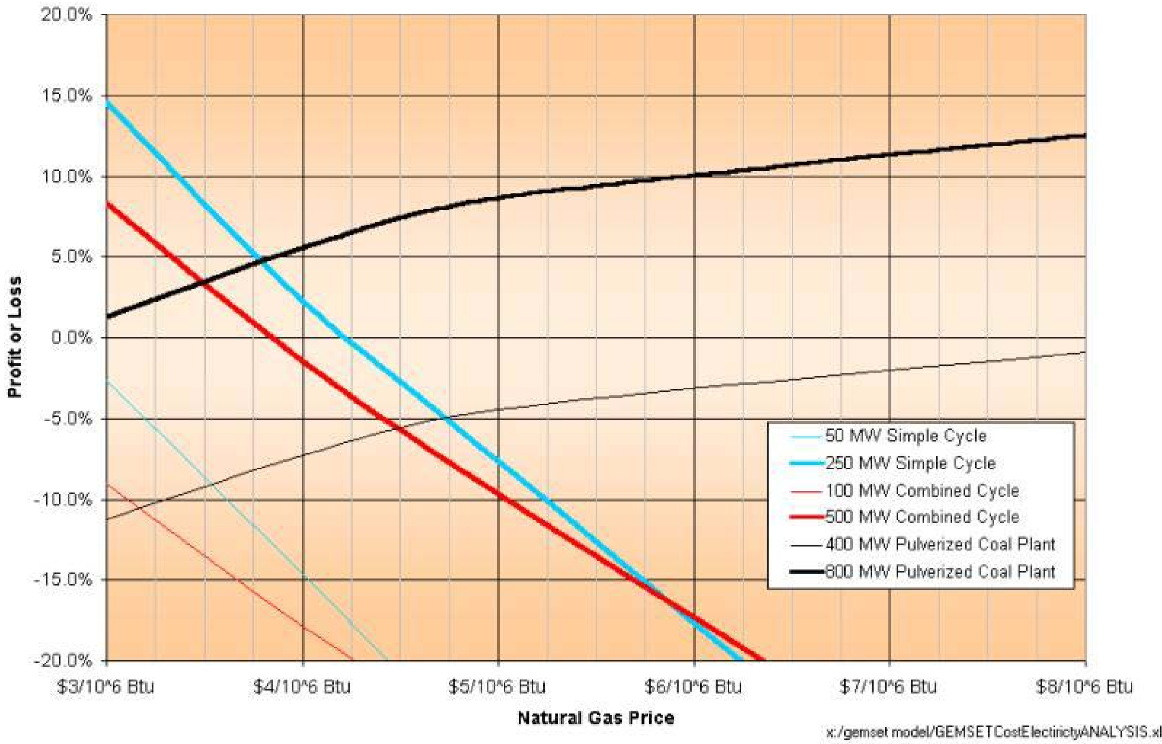


If the revenue from the market were greater than this threshold, the owner would run the unit. If the revenue possible from the operation were lower, the owner would not offer power for sale until the price were higher. Generally, it is expected one would run the unit only when it earns revenue, and not run when it costs more in fuel and operating costs than the market price at the moment. There are times and gamesmanship conditions when it is worthwhile to operate at a loss for short periods, for example, if it avoids a start-stop cycle when the period of low price is expected to be low for only a few hours.

Threshold Bid Price does not include a capital component, since those costs are captured in the capacity obligation prices. It is also important to understand that even though operating costs are met, it does not necessarily mean that adequate return is being received to service the debt.

When Do Coal Projects Make Sense?
With the development of the various scenarios, a price histogram of each of the scenarios is developed, with a much different result depending on which region is chosen. Differing mixes of natural gas and coal units, different fuel prices, and demands mean that in each region of the U.S., different circumstances rule. Since we have chosen in this paper to model gas turbines, combined cycles, and coal units in the PJM region as our example, profit expectation for these projects are shown cross-plotted against natural gas price in the illustration on the next page.

Prices Where Each Type of Unit Makes Sense in PJM



As gas price increases in the PJM region, the gas turbine and combined cycle projects would look less and less attractive. Notice that even though coal price was held fixed, and the capacity factor of the coal units remains baseloaded and essentially fixed, still, at the higher gas price scenarios they would earn more money as gas price went up. This is because of the expected impact of gas price on the peaking tail, the "golden hours." Since this peak generation is nearly all made up of gas turbine units, in the golden hours electric sales prices are expected to rise. All the gas units have higher production costs, so they charge more to supply peaking energy. Coal units, which get the same price as all other units get during peaking, simply become more profitable. Coal unit costs remain the same, but their revenue increases during these peak periods.

At PJM's current mix of generation and supply of generation, combined cycles would prove more profitable than coal projects so long as gas price persists below about $\$3.75/10^6$ Btu. The results would be much different were these evaluations repeated in different regions of the country.