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FAIR + equitable

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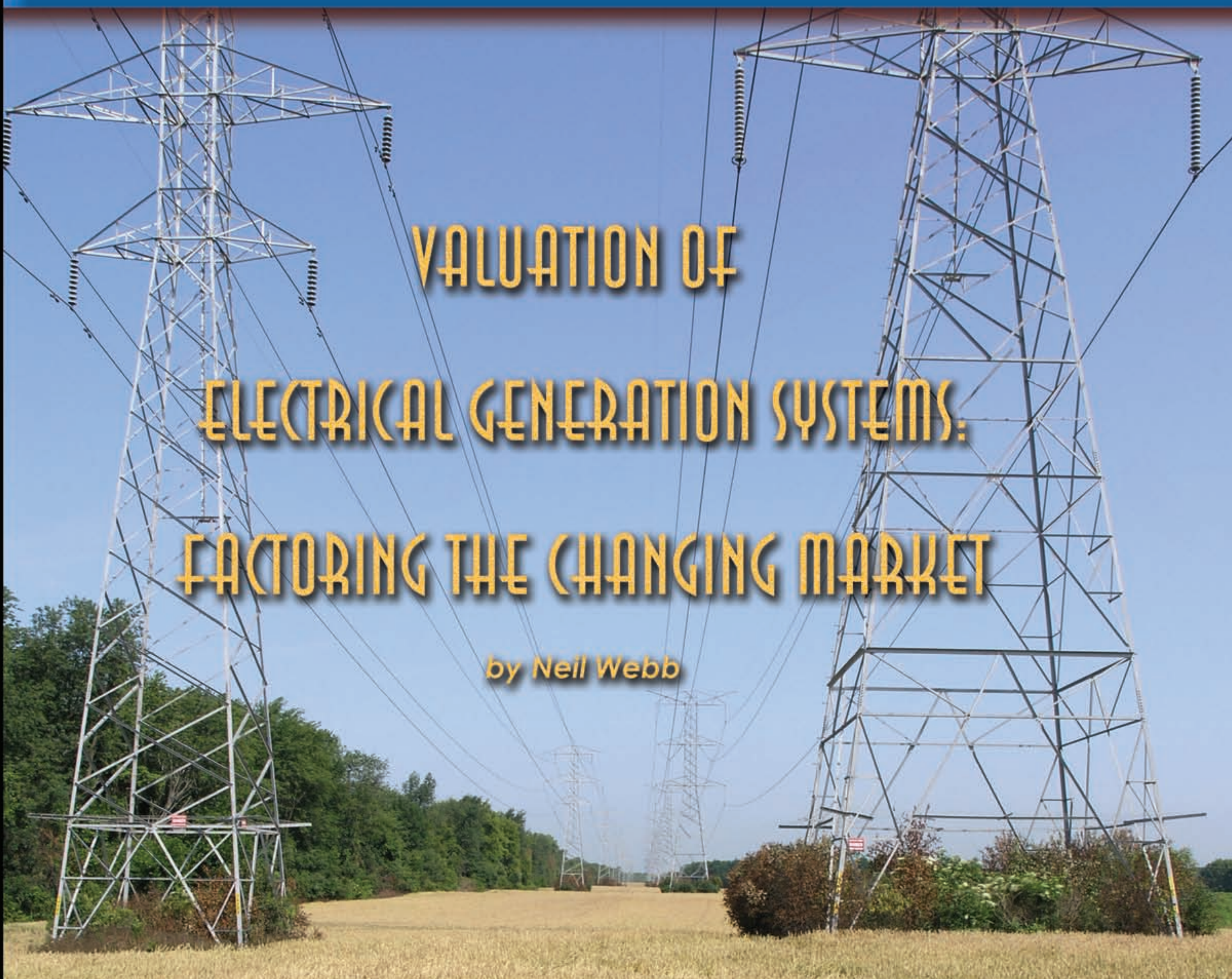


VALUATION OF ELECTRICAL GENERATION SYSTEMS: FACTORING THE CHANGING MARKET

by Neil Webb

Intent Is King

by Richard Norejko, CMS

A part of the Southeast Quarter of Section 23, Township 6 North, Range 1 East, Salt Lake Bas and Meridian, U.S. Survey: Beginning at the SE corner of this Section 23, thence South 89°36' 25" West 1446.81 feet along the quarter ... 51" East 565.86 feet, thence South 4°54'27" West 66.0 feet; thence Easterly ... of 206.57 feet., an arc distance of 110 feet, a chord bearing of N. 79° 39' 08" E and a chord length of 108.70 feet to the True point of Beginning. Thence Easterly along a curve to the left with a radius of 206.57 feet, an arc distance of 50.3 feet, a chord bearing of N. 57° 20' 25" E and a chord length of 50.13 feet; thence Northeasterly along a curve to the left with a radius of 2683.29 feet, an arc distance of 100 feet, a chord bearing of N. 49° 23' 04" E and a chord length of 99.99 feet; thence South 4

COVER STORY

Valuation of Electrical Generation Systems: Factoring the Changing Market

by Neil Webb

The statements made or opinions expressed by authors in Fair & Equitable *do not necessarily represent a policy position of the International Association of Assessing Officers.*

Electrical generation plants are not conventional static assets. Rather, they are a dynamic part of a community that is strongly influenced by local, national, and international issues. Keeping pace with the factors that drive fluctuations in value of electrical generation plants can be a challenge for the professional focused solely on the energy sector, let alone for a municipality with limited resources. In the past 15 years, valuation methodologies, which support valuation from a fully integrated utility perspective, have not been adjusted to contend with deregulation.

The basic production, transmission, and delivery structures of the electrical generation system have changed little over the years. Early in the development of electrical supply and production systems, it became clear that vertical integration was necessary and ownership would need to be centralized and regulated. This was largely a function of the prevailing technology and large capital investment required to build these systems. Construction costs were so large it was necessary to amortize assets over longer periods, and cash flow could be ensured only through monopolies protected and monitored by the government.

Today, vertical integration of this industry has given way to specialization. This transformation has been driven by the search for an efficient competitive market in electricity. For many, the promises of efficiency and subsequent cost savings that justified the movement towards deregulation are difficult to measure, and the lingering question is, "Was it worth it?" Asymmetry is rampant region to region, state to state, and asset to asset, and it has yet to be determined whether deregulation has been a success.

Nevertheless, the energy value chain (Fuel ➡ Generation ➡ Transmission ➡ Distribution ➡ Services ➡ Customer) has become segmented and in some cases can be divided even further. Electrical generation has witnessed the largest transition, with most assets being acquired post-divestiture by holding companies, banks, private equity, and hedge funds, in almost the same order of declining aversion to risk. Trading also is being flooded with professional risk management firms, while the transmission and distribution segments of the chain have remained with the old definition of utility. Each entity or interest is looking for its piece of the energy pie.

How Did We Get Here?

In the 1980s many traditional utilities were beset with federal and state mandates that changed the course of events for years. These policies were in response to fears of the cost and environmental impact of nuclear power and new discoveries of clean cheap natural gas in the Gulf of Mexico. Major deregulation of standards in gas and then electricity also allowed the proliferation of non-utility generation.

By the mid-1990s a construction boom was well under way. There was a proliferation of natural-gas-fired power generation plants, which provided the hope of environmentally friendly low-cost-power production. These units were assisted by federal and state regulations that guaranteed cash flows for developers through purchased power agreements (PPAs). Consequently, many projects were highly leveraged due to the lucrative front loading of PPAs to spur development. Ultimately, this led to an oversupply of power in many parts of the country, which are just now reaching economic equilibrium.

Gas-fired units had several other advantages: They were relatively easy to site because of their small footprint (significantly smaller than that of nuclear plants), physical appearance (absence of coal piles), incentives (competing Payment in Lieu of Tax deals), quick use, and useful capability. Figure 1 shows the changes in net electrical generation in the United States from 1999 to 2005 by energy source.

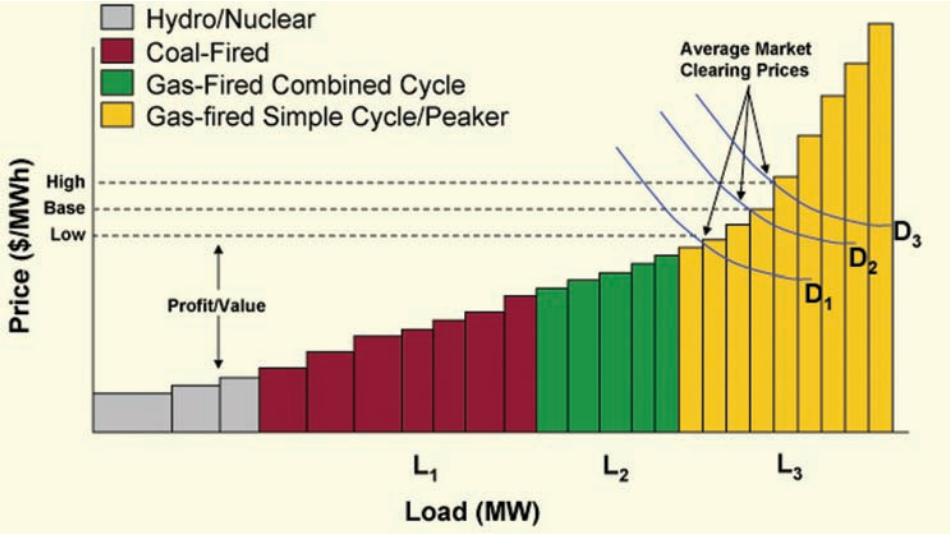
Deregulation

The expansion of new gas-fired generation plants was against a backdrop of the entire electrical generation industry going through the pains of deregulation. In certain jurisdictions, utilities were forced to either divest or spin out generation plants that were part of their vertically integrated history. To level the playing field and create a competitive market, these assets were now expected to participate in markets run by third-party, not-for-profit independent system operators. The assets would then bid into the market at their marginal cost of production and be selected to run by the equilibrium created by the amount of usage in a given system at that point in time.

A simplified view of how a generation plant develops its marginal cost is as follows:

- Fuel cost, $9.00/MM Btu
- Heat rate, 6,900 Btu/kWh
- Variable Operating and Maintenance, $3.00/MWh
- Total = (9.00)(6,900)/1000 + 3.00 = $65.10/MWh

Figure 2. Market clearing prices in relation to megawatts of power produced



This plant then bids $65.10/MWh for power it generates. Barring reliability issues, the plants with the lowest operating costs are dispatched first in what is termed a "merit stack" for generation. If the clearing price for power in this hour is greater than its bid, the unit is selected to run (dispatched). If the clearing price is less than the marginal cost of the unit, it does not run. The last plant selected to operate in any hour sets the clearing price for energy in that hour—all plants dispatched receive that price. If a plant has low operating costs relative to the clearing price, it typically has greater profit margins. Figure 2 helps to demonstrate the theory of Least Cost Dispatch.

Although Figure 2 generalizes much of the discussion, it provides some useful insights into the market forces that can drive the success or failure of generation units. First, fuel is a significant driver in the variables used to develop marginal production costs. It is a relatively small component in the equation for nuclear, wind, and hydro plants, which are selected to run "first." Coal then follows because its unit cost per million Btu's is smaller than that of natural gas (this conversion is often referred to as its heat rate or its measure of efficiency to convert fuel to energy). As usage within an area increases from D2 (base) to D3 (high), more units are dispatched and the increase in price reflects the need to recover greater costs, namely, fuel. Units down the curve that have lower production costs realize greater profitability, especially if their cost structures are unrelated to the price-setter. Because of the large buildout in gas infrastructure and gas generation, the natural-gas-generating unit is the price-setter for most markets in the United States, except where coal deposits are more prevalent.

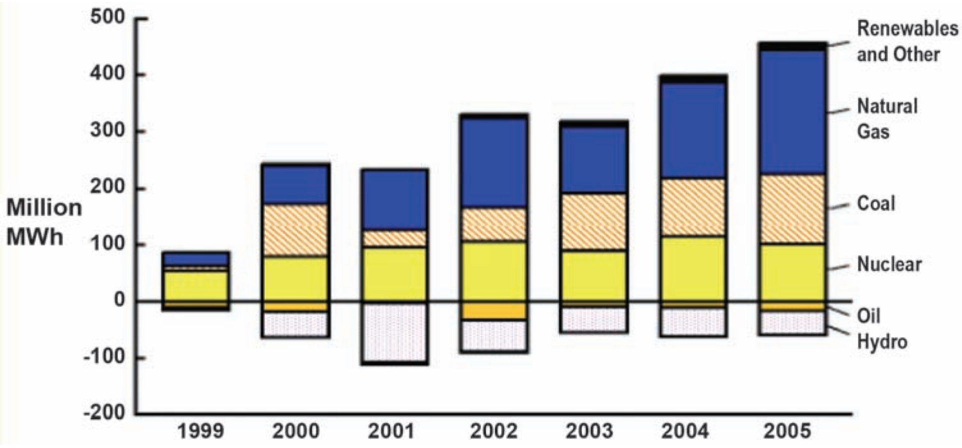
Industry resources show that the role of natural gas is pivotal in domestic energy markets. Katrina has made even the casual observer aware of marketplace volatility. Consequently, income for owners of non-gas generation plants have risen sharply, while many owners of gas-fired plants have had to face tough questions from their creditors.

Production Cost Modeling

In an attempt to keep pace with changing energy markets, energy and financial professionals employ production cost modeling software to perform dispatch simulations. Aurora by EPIS, MAPS by GE, and PROMOD by Siemens are products that synthesize large databases of generation and transmission assets to predict future behavior. They are capable of factoring in changes in regulation, plant construction/retirement, fuel, and other system variables to determine utilization and market-clearing metrics. Because of the interdependent nature of the market, the valid simulation of one asset requires all assets to be factored in. Once deterministic results are established, these models can be used for Monte Carlo analysis to evaluate sensitivities of input variables and their effect on valuation. Compilation of analyses is used to build long-term pro formas of existing and future plants in service. These studies and the resulting financials are used by developers for siting, investors for project financing, traders for risk management, and operators for budgeting

Traditional income techniques require valuation professionals to dissect consolidated income statements for the

Figure 1. Change in U.S. net electrical generation, 1999-2005, by energy source



Source: US Energy Information Administration

**Twelve months ending August 31, 2005*

Figure 5. Valuation of selected types of electrical generation in New England with +/- 20% in Henry Hub

	Value ($millions)		
	Low	Base	High
Gas	$ 326	$ 312	$ 296
Coal	$ 236	$ 148	$ 333
Nuclear	$ 2,179	$ 2,609	$ 3,098
Hydro	$ 19	$ 23	$ 26
Oil	$ (26)	$ (28)	$ (31)

Figure 6. Valuation of selected types of WECC electrical generation with +/- 20% in Henry Hub

	Value ($millions)		
	Low	Base	High
Gas	$ 19	$ 18	$ 19
Coal	$ 658	$ 1,007	$ 1,359
Nuclear	$ 1,683	$ 2,131	$ 2,687
Hydro	$ 102	$ 123	$ 150
Oil	$ (3)	$ (3)	$ (3)

Data in figures 5 and 6 sourced by Webb, Scott & Quinn, Inc. using EPIS' Aurora XMP Electric Market Model.

most recent fiscal year, which is much like driving down a road using the rear-view mirror. In the best case it can arrive at a good estimation of what occurred in the recent past, but it can lead to shortsighted analysis that does not fairly take into account what is potentially "in front of the car." While no technique could precisely foresee the aftereffects of Katrina in electricity markets, traditional income techniques could hardly begin to evaluate the "What if?" scenarios that are possible in production cost modeling.

Similar pitfalls exist when comparables are used for supporting analysis of generation assets. Local and state officials are often challenged to find legitimate comparables under this methodology because of the general lack of similar assets. Even when generation assets are plentiful locally, discrepancies in primary fuel and technology do not serve the apples-to-apples comparison very well. As "identical" or similar assets move further apart, weakness in analysis of comparables grows because the value of electricity also is driven by its proximity to the markets that demand it. These complexities are not lost in production cost modeling, because it can assess market equilibrium through evaluation of system constraints, such as asset availability, transmission limits, or contractual obligations.

To better demonstrate the capabilities of production cost modeling, consider a scenario in which specific generation assets in New England and WECC (Arizona) are affected by Henry Hub gas fluctuations of ±20% (see figures 5 and 6).

In New England, where a high concentration of gas-fired plants sets the market-clearing price 90% of the time, a significant decrease in gas plant value occurs as natural gas prices rise. This decrease corresponds to the increase in coal, hydro, and nuclear plant value under the same circumstance. Most oil assets are maintained for reliability or steam heat capabilities.

In the western United States, the same market fundamentals are at work, although they are less pronounced for these assets largely because gas plants are not as prominent in Arizona and surrounding markets. Natural gas is on the margin 70–90% of the time in this market. While these estimates represent value in absolute terms, it is possible to normalize the valuation of every asset in a region and arrive at a dollars-per-megawatt value of units for comparison.

Production cost modeling has many advantages as a support tool in constructing valuations. Its flexibility in the presence of changing markets can provide necessary insight into the future cash flows of electrical generation assets. With widespread acceptance beyond traditional energy-planning and bank-financing circles, this analytic technique can contribute to the workflow of valuation experts attempting to establish fair and equitable value of electrical generation plants. ■

Neil Webb (neil_webb@wsqi.com) has worked in the energy industry for over 16 years on various issues involving deregulation. He has supported and evaluated market design issues across the United States.