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Can Electricity Markets Work Without Capacity Prices?

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Can Electricity Markets Work Without Capacity Prices?

No, because one-price trading (energy only) forgets that an outage is usually the least-cost option. By Robert McCullough

MANY PLAYERS IN THE ELECTRIC INDUSTRY HAVE COME to believe that energy-only prices will soon replace the hundred-year tradition of pricing both energy and capacity.

This idea, sometimes called "monomic" trading, offers a seductive simplicity. Even so, research indicates that it is unlikely to work well.

First, consider some terminology. Traditional electric markets contain prices for both energy and capacity. Energy prices pertain to the actual kilowatt-hours. Capacity prices pertain to the right to take energy. Purchases from a thermal unit usually include prices that will cover fixed costs (capacity) and payments to cover fuel (energy).

Starting from these definitions, the energy-only pricing school then teaches that the volatility of spot prices is an adequate replacement for capacity. They argue that spot markets will implicitly guarantee capacity in two ways: (1) In the short run, energy prices will climb to the point where users will curtail their needs and release capacity for those customers without the ability to curtail their demand, and (2) In the long run, the probability of high-price periods in the spot markets will create an opportunity for entrepreneurs to build new capacity.

In reality, however, the same simplicity that makes this monomic pricing scheme attractive obscures serious operating and economic issues, which could lead to unnaturally high prices. Commodity markets can prove complex. To say simply that monomic pricing remains untested for electricity is to be conservative, at the very least. More importantly, to those with a more extensive understanding of commodity trading, the monomic formulation hides enormous assumptions. Further, experience implies that any theory based on unstated and untested assumptions may fail entirely.

Curtailment Costs (Seen as a Function of Supply Price)

Modeling of a monomic future critically depends on curtailment charges. These charges reflect the true supply price necessary either to induce a customer to curtail load or to liquidate the damages that the customer would incur from an unexpected outage.

The relationship between frequency of curtailments, curtailment cost and alternative resources is simple. We have reviewed several models that reflect values similar to those in Figure 1. This chart shows that the more an electric supplier has to pay a customer to curtail his load, the less often the supplier will do so. This relationship implies levels of curtailment entirely out of our experience in the electricity industry.

What factors do these curtailment values represent? In the electric utility industry, at least, these factors remain largely hidden.

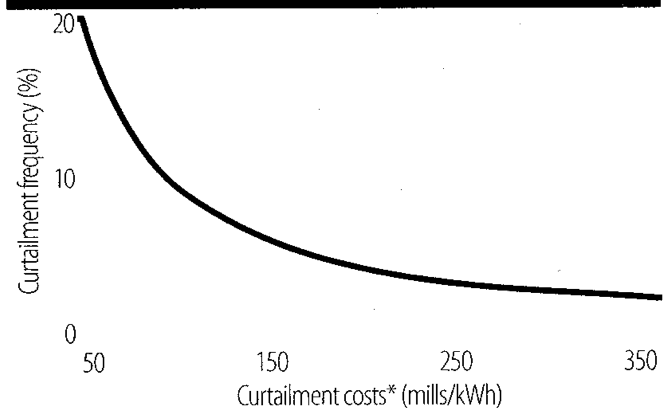
Simple experience with electricity end users indicates that curtailment is seldom considered a very good option. In fact, although many industries have accepted interruptible rates, most don't really expect interruptions. Recent growth of contracts that include interruptibility has coincided with increasing levels of electric capacity surplus in the U.S. and Canada. The only major use of interruptibility in the last five years led to lawsuits and the elimination of the interruptible clauses in subsequent contracts.

In the short run, curtailment costs strongly reflect the share of electricity in total costs.

Figure 2 shows the energy intensity of different major industries. Each industry will have a different cost for curtailment of electric service, based on a variety of factors, including its storage capability and the impact of loss of power on processing. For example, actual curtailment costs for metals can be relatively low at 90 mills per kilowatt-hour. Curtailment costs for food and lumber climb to 1,000 mills. For the vast majority of other industries, curtailment costs range from 3,000 to 5,000 mills per kilowatt-hour.

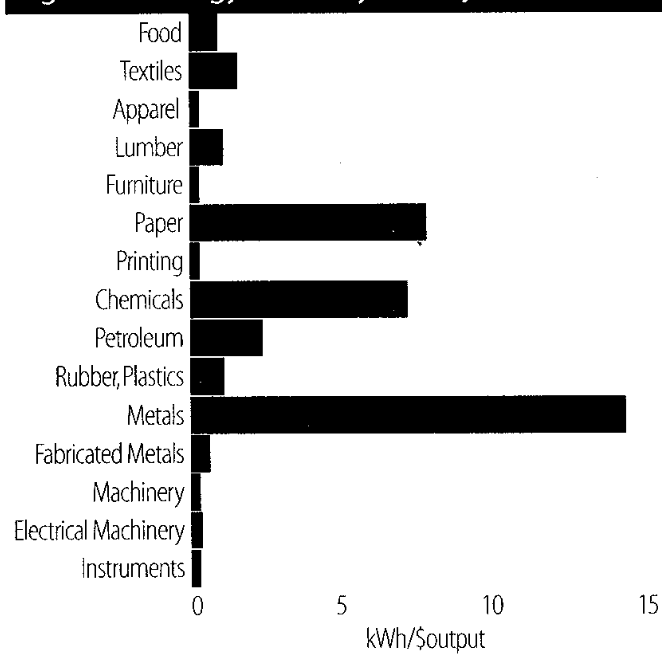
Why are curtailment-based prices so high when other commodity industries do not experience price ranges that vary by a factor of 100? The major reason is the availability of storage and substitutes. One commodity-based industry that is closely linked to electricity is aluminum. Aluminum is a pure commodity where approximately 30 percent of its cost is energy. Aluminum prices range from $0.40 to $1.20 per pound. When aluminum is scarce, prices increase until the stockpiles have been consumed and consumers—primarily packaging and structural metals—turn to alternative metals. At no point in the aluminum price cycle do we actually see beer

Figure 1. Frequency of Curtailment Based on Cost



* Costs incurred by a utility to make consumers indifferent to a given frequency of curtailment.

Figure 2. Energy Intensity of Major Industries



go unconsumed or airplanes uncompleted for lack of inputs. Inventory is an important component. Since metal prices do vary, maintaining a stockpile of aluminum against periods when the price is high is economically efficient for producers and speculators. A simple calculation proves that aluminum purchased at $0.40 against market peaks eventually can be sold at $1.20 even if years pass between lows and highs in the market.

Electricity is very different. Electricity has no real storage capability. Although some hydroelectric systems theoretically can hold water for future generations, practical considerations (often environmental) preclude filling the reservoirs against future high prices. Electricity also doesn't have many substitutes. Computers cannot operate with natural gas. Some industries can shift between fuels for process heat, but that marks the exception rather than the rule.

Can knowing the level of curtailment costs prove useful in understanding how markets behave?

The credibility of curtailment-driven markets depends on the curtailment's depth and its frequency. Figure 3 shows the scale of curtailment (percentage of the market curtailed) for North America's West Coast for 1996, if the regions started with load and resources in balance.

One Department of Energy study argues passionately for the future of energy-only markets and used 85 mills for the curtailment penalty. This study would predict curtailments of 10 percent of total load during high peak periods, such as August.

Spot Prices (A Window on Supply Costs)

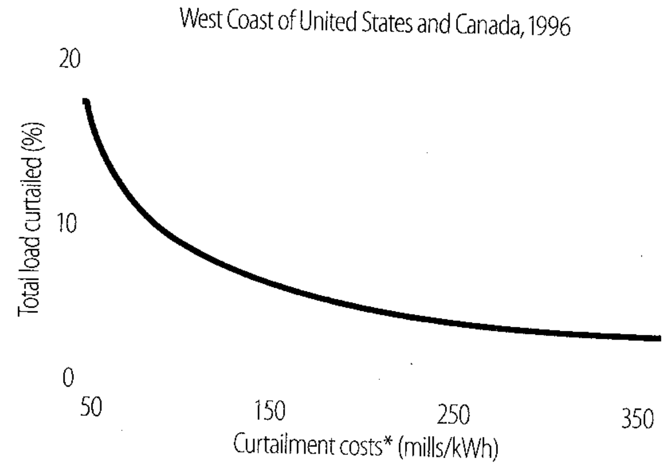
By definition, if the only incentive to build base load generation comes from electric spot markets, the spot price must quickly increase to the fully allocated cost of a combustion turbine and stay at that level (on an annual average basis) in perpetuity.

By comparison, however, historical spot market prices for electricity have never approximated the level of fully allocated costs of new resources. The Bonneville Power Administration, one of the continent's largest utilities, maintains data on both spot sales revenues and the fully allocated costs of new resources (see Figure 4).

The falling level of fully allocated costs reflects the shift from nuclear generation to units fired by natural gas. BPA's spot sales reflect market forces since it is allowed to sell into the wholesale market at prices up to its average costs.

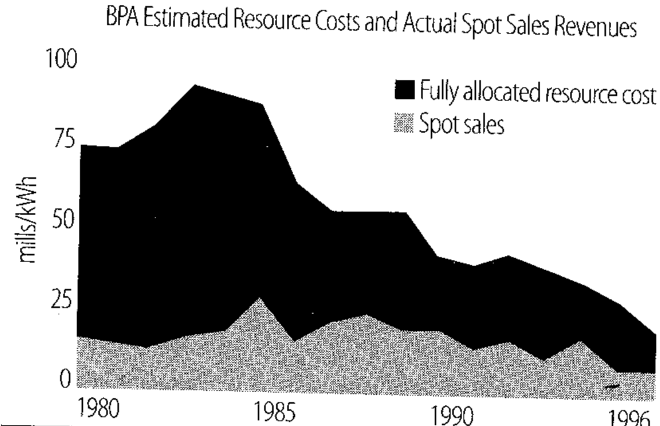
Devotees of monomic prices believe that the two lines

Figure 3. Percentage of Load Curtailment Based on Cost



* Costs incurred by a utility to make consumers indifferent to a given frequency of curtailment.

Figure 4. Will the Curves Converge?



shown in Figure 4 will converge in the 25-to-40-mill range. The requirement that average spot rates climb steeply enough to cover the fully allocated cost of new generation completely determines the value for the spot market.

How realistic is this forecasted dramatic shift in spot prices? The primary concept isn't very accurate at all. By assumption, entrepreneurs will forecast the high prices caused by curtailment costs and construct base load resources in response. Wiser entrepreneurs would certainly preempt the activities of the base load entrepreneurs by constructing simple-cycle turbines. Since simple-cycle turbines are a vastly more efficient choice for serving short-duration, high-cost periods (curtailments), the simple-cycle turbines would become the resource option of choice.

Logically, simple-cycle turbines (and other inexpensive peakers) will serve all load growth until the percentage of the time where simple-cycle units were operating on the margin was sufficient to pay for combined-cycle units.

Using standard assumptions, simple-cycle units are less expensive to operate than combined-cycle units for loads that occur as much as 40 percent of the time. *(See sidebar, "Energy Prices Don't Tell All.")* One absurd result from energy-only pricing would have the variable costs of simple-cycle units define marginal production costs for much of the year. If this were the case, the price might never increase enough to build combined-cycle units.

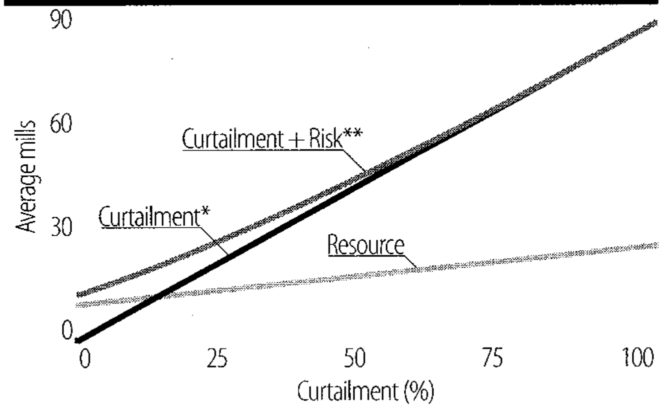
Several recent "energy only" analyses assume generators are the active parties in the electric markets and consumers are simply passive recipients of market prices. This view suggests that the engineering cabal still retains enormous influence in the electric utility industry. The truth is that consumers' preferences have an enormous impact of market prices and the cost of generation. In a fully deregulated market, consumers always have the choice of finding their own solutions despite the preconceptions of the suppliers.

Risk Aversion (A Factor in Resource Choice)

Figure 5 represents a simple example of what utility planners call a resource scoping curve. These curves are a standard industry tool that identifies the optimal operating range for a particular type of resource. Resources can be plotted with expected operations from zero to 100 percent of the year. The resource with the lowest cost will prove the best choice for loads whose durations match the percentages of curtailment shown along the bottom of the chart.

Compare the cost of curtailment for a low percentage of load with the cost of a peaker unit. Curtailment is clearly always the best choice for loads with annual duration of less

Figure 5. Curtailment Costs vs. Peaking Unit



* Direct cost.
** Illustrates that consumers face financial risk from curtailment above and beyond direct costs, but that risk diminishes as curtailment increases.

Energy Prices Don't Tell All
Gas Turbines Help Refute Monomic Pricing

CONSIDER this example, in which capacity costs dictate that combined-cycle units (not simple-cycle) should serve as the marginal unit for loads of a duration of 54.4 percent or more.

FIXED COSTS. A combined-cycle, natural gas turbine costs $500/kW to build, with a heat rate of 7,000 Btu/kWh. A simple-cycle unit costs less to construct, $300/kWh, but runs at the less efficient heat rate of 10,000 Btu/kWh. Financing (assume a 10-percent cost of capital) adds $50 and $30, respectively, leaving fixed costs at $550/kW and $330/kW.

RUNNING COSTS. Assume fuel (natural gas) costs $1.66 per MMbtu. For the combined-cycle unit, the operating cost for the first kWh is 11.6 mills ($1.66 × 7,000 ÷ 1,000,000). For the simple-cycle unit, the cost comes in higher, at 18 mills ($1.80 × 10,000 ÷ 1,000,000).

COMPARISON. For short loads, it is cheaper to pay the lower capital cost and higher operating costs (simple cycle). The inflection point occurs at 3,995 hours a year; for loads lasting longer, the combined-cycle plant will cost less overall. At 8,760 hours per year, a simple-cycle unit will prove more efficient 45.6 percent of the time. Combined-cycle units should be used for loads of 54.4 percent and more. This calculation changes with the price of natural gas, of course, but the current range used in planning studies, $1.50 to $2.00, gives similar results.

than 14 percent. In fact, since the cost line for a peaker unit always starts at its capital cost, it is a mathematical certainty that curtailment is always the best option, no matter cost.

Given this effect, why is it that utilities (and their customers) don't plan for substantial degrees of curtailment? The simplest answer proves also a bit facile: Utilities don't plan for curtailment because rigid operating rules promulgated by regulators don't allow them to. This answer is facile because rules denying curtailment as a resource choice aren't an international law, or even a federal regulation. Operating standards promulgated in Canadian provinces, U.S. cities, rural cooperatives, federal marketing agencies and state regulatory bodies have set operating rules at zero curtailment level.

A more insightful answer would suggest that governments, utilities, cooperatives and regulators have all perceived that customers are not indifferent to risk. Electric customers are highly risk-averse. Estimating risk aversion is never easy. Figure 5 contains a second resource cost line for curtailment, "Actual Curtailment," which reflects the compensation that real customers would demand to curtail load. This line differs from the utility's cost curve for curtailment in that it includes an additional element for the risk incurred by the customer. It shows that the first curtailment in a year marks a real crisis for a customer; risk is greatest at that point. However, the high risk for small levels of curtailment diminishes rapidly as curtailment becomes more frequent. This situation is not as counterintuitive as it seems, at least for a thinking consumer. A completely passive consumer (the price-taker envisioned in monomic pricing) would not respond to additional interruptions. By contrast, a rational customer would quickly determine ways to respond. A utility planning 20-percent curtailments would find that the customers had given themselves emergency backup equipment and alternative fuels, thus lowering risk.

Modeling efforts that ignore the risk aversion of consumers tend to suggest unusual results. They predict short-term periods in which spot prices will rise to curtailment costs of consumers. The electricity market has never experienced such unusual prices for one reason: Customers will take measures to avoid short-duration curtailments.

The level of risk aversion is clearly very high for electricity consumers. One tool of modern economists, "revealed preference," uses customers' actual choices to reveal their degree of risk preference. The choices customers have made over the past 100 years indicate the degree of risk aversion is greater than the cost of a simple-cycle turbine. Their choices have never revealed a preference for curtailment.

Except on an anecdotal basis, we don't have a good idea what these costs are. Analyzing specific industries indicates they are high. A one-minute interruption can destroy the output of an electronic fabrication that has been under way for hours. A one-hour interruption can freeze a continuous caster at a steel mill. A one-day interruption can freeze aluminum to the "pots" and require an enormously expensive repair of the entire facility.

The revealed preference is that consumers are willing to pay insurance—the price of a simple-cycle turbine—to avoid the risk of curtailment even if they were willing to pay the cost of curtailment. These numerical exercises reflect the fundamental point that using the history of commodities with dissimilar characteristics as a guide to the future of electricity is inherently risky.

The Capacity Price (It's Like Medical Insurance)

Given the difficulty of storage and the near impossibility of substitution (gas lights during curtailment periods, anyone?) a better metaphor might be medical care. Medical care cannot be stored. For example, taking antibiotics when you are not sick is actually bad for you. And it is very difficult to find substitutes for medical care. In the extreme, the curtailment cost of medical shortages is death. While this comparison may seem farfetched, the result of curtailment in either industry is that the lights do go out.

The markets for medical care are similar to those for electricity. Most consumers appear willing to pay a considerable surplus above marginal cost to assure service. While this margin is called capacity in electric markets, it is known as insurance in medical care. An HMO that could not assure you critical care in an emergency would soon be struck off your list, even if the premiums were higher for one that did guarantee to take care of you on a hell-or-high-water basis.

The most likely result is that in a completely open market, some consumers will choose to gamble to receive lower overall prices. Most consumers will pay a margin—a capacity charge—to guarantee their costs will never reach curtailment levels, or never have to sit in the dark waiting for their office equipment to power up after the most recent blackout.

What does this mean for price forecasting? The most logical forecast is for spot prices to remain in the same basic relationship to fully allocated costs that they have for many years. Spot prices will continue to reflect variable operating costs, which falls somewhere in the mid-teens for most of the United States and Canada. Prices with a supply and price guarantee, firm prices will converge to the marginal firm resource. At current gas forecasts, this would likely be in the mid-twenties.

Does this mean that merchant plants are a bad idea? Actually, this model of future prices appears far more conducive to merchant plants than the pure energy model. Merchant plants can sell both capacity and energy. The capacity will provide insurance to ultimate consumers against interruption and price volatility. The energy can be sold into the spot markets if the prices are attractive. The economics does not change. The degree of producer and consumer choice does change and with it the efficiency of the market.

Robert McCullough is the managing partner of McCullough Research, an energy consulting firm based in Portland, Ore., which specializes in energy and public policy issues throughout North America. As officer at Portland General Corp., McCullough helped start the nation's first electric brokerage. His work last appeared in Oct. 1, 1996 in the article entitled, "Trading on the Index: Spot Markets and Price Spreads in the Western Interconnection."