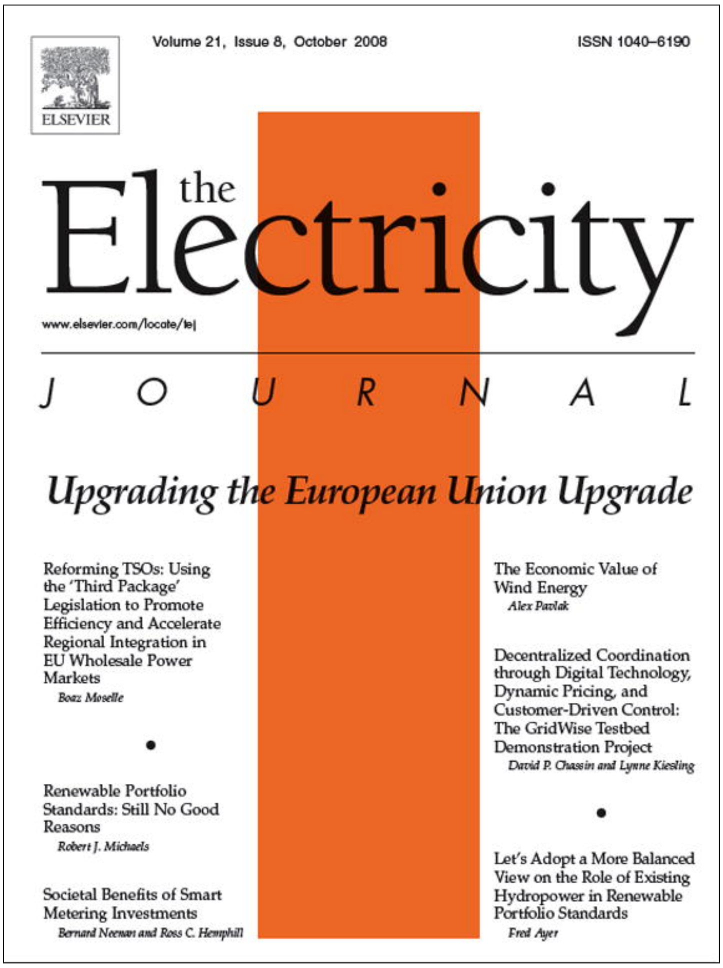

Volume 21, Issue 8, October 2008 ISSN 1040-6190

ELSEVIER

the Electricity JOURNAL

www.elsevier.com/locate/tej

Upgrading the European Union Upgrade

Reforming TSOs: Using the 'Third Package' Legislation to Promote Efficiency and Accelerate Regional Integration in EU Wholesale Power Markets
Boaz Moselle

Renewable Portfolio Standards: Still No Good Reasons
Robert J. Michaels

Societal Benefits of Smart Metering Investments
Bernard Neenan and Ross C. Hemphill

The Economic Value of Wind Energy
Alex Pavlak

Decentralized Coordination through Digital Technology, Dynamic Pricing, and Customer-Driven Control: The GridWise Testbed Demonstration Project
David P. Chassin and Lynne Kiesling

Let's Adopt a More Balanced View on the Role of Existing Hydropower in Renewable Portfolio Standards
Fred Ayer

The Economic Value of Wind Energy

Today's wholesale electricity market passes intermittency costs to the ratepayer in the form of increased overall system cost, a hidden subsidy. Market managers need a competition that correctly allocates cost and provides consumers with the lowest price. One solution is for buyers to contract wind farms to provide energy on demand.

Alex Pavlak

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I. The Competitive Wholesale Electricity Market

In many regions of the world, electricity is wholesaled in a competitive market. This market emerged as a result of the privatization of electrical power systems. The underlying concept is to separate the competitive functions of generation and retail from the natural monopoly functions of transmission and distribution.

The role of the wholesale market is to allow trading between generators, retailers, and other financial intermediaries both for short-term delivery of electricity (spot market) and for future delivery periods (day-ahead market). The market is run by a regional transmission organization. The United States has five wholesale markets: ERCOT, PJM, New York, Midwest, and the California ISO. Typically, an RTO establishes a nodal (locational) marginal price by accepting offers from generators and bids from users. The RTO also schedules transmission bilateral transactions.

 1040-6190/$–see front matter doi:/10.1016/j.tej.2008.09.004

In theory, by bidding for the day-ahead market, baseload generators with the lowest levelized cost run 24/7. Intermediate-cost plants will cycle on during daylight hours. Peak generators with high fuel cost but low capital cost will switch on during periods of exceptional demand.

Costs need to be correctly allocated for competition to provide the lowest price. Today's wholesale electricity market does not acknowledge intermittency costs, that power available on demand has more value than intermittent power. It does not acknowledge that wind energy saves fuel and should compete with the cost of fuel, not with the wholesale cost of electricity.

II. The Correlation Between Wind and Peak Load

A central question is whether wind farms can reliably deliver power during peak demand periods. A common assumption has been that wind power and load are uncorrelated. Data now exists to show that there is correlation and it can be negative.

Many utilities are summer peaking, that is, the greatest demand for electricity occurs during the summer and is driven by air conditioning load. During July 16–24, 2006, California experienced a heat storm. The contribution of the wind resources at the time of peak was less than 5 percent of the total wind installed capacity.[1] **Figure 1** shows wind energy production at time of peak load as measured by the California Independent System Operator.[2] During days of peak demand wind farms averaged only 5.3 percent of rated power. ''We absolutely need other types of generation to guarantee the reliability for system for peak hours.''[3]

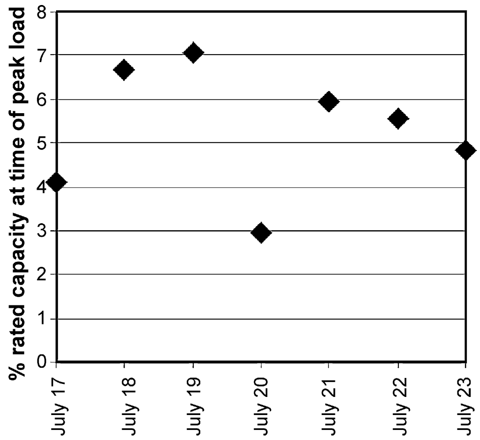

Figure 1: Wind Performance during Peak Demand

In addition, there is anecdotal data that wind is typically not available when customers have the greatest need.[4] Also, there are instances where wind farms have abruptly failed to provide power during the winter.[5] It has been hypothesized that peak demand may occur because there is no wind.

III. Demand Capacity

The word ''capacity'' needs to be more precisely defined for intermittent generators. Historically, ''capacity'' is the ratio of average annual power divided by rated power and it is assumed that rated power is available during peak demand. That assumption is not true for wind and other intermittent generators. This report distinguishes between ''average power capacity'' (the usual definition) and ''demand capacity.'' Demand capacity is that fraction of rated capacity that can relied upon during peak demand. Calculating demand capacity for wind generators requires extensive site-specific data sets and a decision to accept a finite probability of failing to meet demand.

Advocates argue that a given wind farm, or multiple widely dispersed wind farms have a statistical probability of some demand capacity. Such statistical design can be dangerous. It involves predicting the probability of rare calamities. The improbable ''perfect storm,'' e.g., little wind over a wide area during peak demand, results in a serious blackout. Without exceptional data sets, grid system engineers have no choice but to assume that wind has zero demand capacity.

IV. Denmark

It has been reported that the country Denmark gets over 20 percent of its electricity from wind today. There are times when the country gets over 100 percent of its electricity from wind. Also, there are calm days when there is little or no wind and it is necessary to rely mainly on conventional coal-fired generators. Denmark is tied into the European electric grid, so excess wind energy is exported and electricity is imported when there is no wind. This simple example foreshadows some important economic lessons:

- Wind turbines do not allow the country to reduce its dependence on conventional generators, which are necessary to carry full peak load when there is no wind.
- System cost consists of fixed capital cost plus variable operating cost. Wind turbines do not allow the utility to reduce conventional fixed cost (mainly interest on capital investment) but do reduce operating cost (mainly fuel).
- Wind turbines by themselves save fuel. Denmark reduces its dependence on coal by 20 percent.
- The whole electrical system has both conventional power plants plus wind turbines, each of which can satisfy demand. The consumer is now paying fixed costs for two redundant generators, wind turbines for when the wind is blowing, and coal plants for when the wind is not blowing.
- When the wind is not blowing and Denmark draws on the European grid for electricity, it is shifting intermittency costs to the rest of Europe.

V. Value of Wind Energy

To illustrate the value proposition, we need to look at whole system costs: generation, transmission, and distribution. Consider the costs of a hypothetical coal-fired utility both before and after the installation of a wind farm. Demand is assumed to be constant and the same for both cases.

In **Figure 2**, the left hand bar presents a cost breakdown for the hypothetical coal-fired utility. This chart is rooted in statistics published by the Energy Information Administration (EIA) for investor-owned utilities in 2006. According to the EIA, the average cost of producing electricity in the U.S. in 2006 was about 7.7 ¢/kWh. A capital carrying charge of 10 percent per year is used to annualize capital costs. Coal cost is assumed to be $60/ton and generation efficiency is 35 percent. This left hand bar is also consistent with a study conducted by the OECD[6] on the cost of generating electricity.

Assume the wind farm is installed at a site with a 25 percent average power capacity, 0 percent demand capacity. The wind farm is sized so that at rated power it provides 100 percent of the constant load. Annualizing the cost of wind farm assumes a 10 percent discount rate, no special renewable incentives, and a capital cost of $1.43/W.[7]

Adding the wind farm does not change the 4.5 ¢/kWh conventional fixed cost. The utility must still provide 100 percent of peak load without wind. The wind farm cuts coal cost by 25 percent, or about $0.8 ¢/kWh. The wind farm adds an additional capital

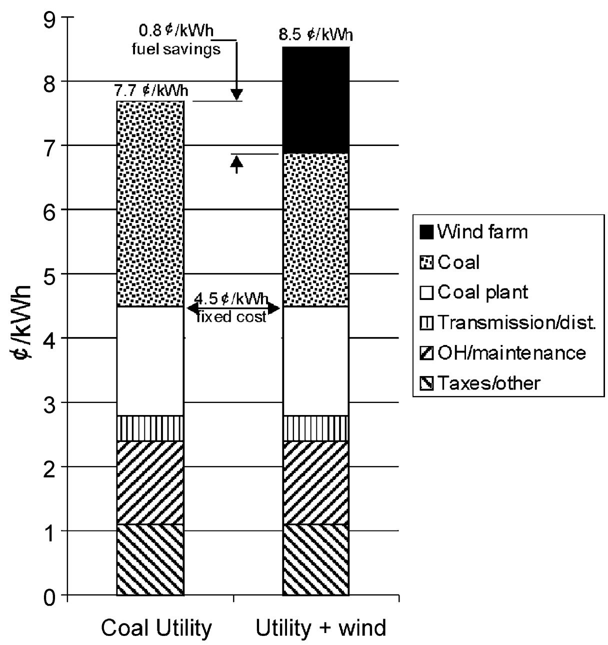

Figure 2: Total System Costs

 1040-6190/$–see front matter , doi:/10.1016/j.tej.2008.09.004

carrying charge of 1.6 ¢/kWh (6.4 ¢/kWh with 25 percent utilization results in a blended rate of 1.6 ¢/kWh). The net result is to increase consumer costs from 7.7 to 8.5 ¢/kWh.

The main conclusion of Figure 2 is that wind farms compete with the cost of fuel, in this case coal. They do so at the expense of redundant generating capacity. For the assumptions used in this example, wind loses the competition and increases overall system costs.

The analysis that developed Figure 2 can be generalized to compare the cost of electricity as a function of fuel cost. The results are presented in **Figure 3**.

The solid line is the cost of electricity from the hypothetical coal-fired utility discussed earlier. The intercept is 4.5 ¢/kWh, the same fixed cost as in the left bar chart of Figure 2. The slope of the line shows how electricity cost varies with fuel cost.

The dashed line represents electricity costs for the coal fired utility plus wind farm discussed earlier. The intercept is total fixed cost, the 4.5 ¢/kWh conventional fixed cost plus the 1.6 ¢/kWh capital carrying charge for the wind farm. Wind turbines save fuel, so the slope of the dashed line is less than the utility without wind. The dashed wind line is anchored at the ordinate, its slope is proportional to the wind average capacity factor.

The cost of other fuels is noted in Figure 3. These fuels cannot be directly compared because the capital cost of the generating plants using those fuels would be different from the coal-fired plant.

The real world has complexities that are not included in this simple example:

- Utilities use a variety of fuels and generator types;
- Demand is not constant and varies with time of day and season of the year;
- Assets are depreciated;
- Supply and demand must be matched instantaneously with little control over demand and no control over wind;
- Fuel, particularly coal, has environmental costs which should be priced explicitly.

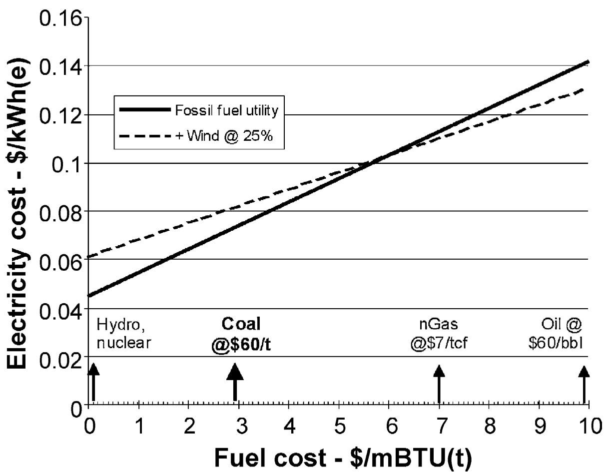

Figure 3: Electricity Cost vs. Fuel Cost

VI. Intermittency Cost

Assuming 0 percent demand capacity, one way to solve the intermittency problem is to install a peak generator with the same rated capacity as the wind farm. This peak generator provides rated power during peak demand and no wind. Ignoring fuel, intermittency cost is then the capital cost of the peak generator. Natural gas turbine peak generators have a capital cost about one-third that of a wind turbine.[8] So to a first approximation, intermittency cost is one-third the cost of the wind farm.

If a government contracts with a wind farm to purchase electricity at 0.06 ¢/kWh, the utility rate base has to pay an additional 0.02 ¢/kWh for peak generators to keep the lights on during peak demand. The impact on the rate payer's bill is small when wind market share is small. Intermittency costs become more significant when wind market share is large.

VII. Implications of Saving Fuel

The central theme of this article has been that wind energy saves fuel at the cost of redundant generators. While this theme seems to be accepted by certain segments of the electric power industry, its implications have not been explored.

If wind turbines save fuel, wind energy should compete with the cost of fuel rather than the wholesale price of electricity.

Today's competitive marketplace is not configured to correctly allocate such costs. As a result intermittency costs are exported to the rate base.

In a well-constructed market, wind turbines would have the greatest value at locations or market nodes where they compete against high fuel costs, as in Hawaii. Wind turbines would have the least value at locations where they compete against low-fuel-cost electricity as with hydro or nuclear.

VIII. The Way Forward

As wind energy becomes a significant part of our energy supply, intermittency costs should be priced explicitly. While the specifics are complex, there are several general approaches that would enable the competitive wholesale market to provide the consumer with the lowest price:

1. A simple approach is for buyers to contract for what they need – demand capacity – energy on demand. Wind farms would configure themselves as a business unit that provides robust demand capacity. Wind farms could purchase peaking gas turbine generators of equal rated power capacity and bid them both as a unit in the existing competitive wholesale market place.

2. A modification to this approach would be for the wind farm to partner with an existing gas turbine generator with equal rated capacity and coordinate generation.

3. Still another modification is a hybrid wind turbine that uses the wind turbine blades and/or a combustion engine in the nacelle to drive a common generator.

4. A different approach is to correct all bids with a credit reflecting demand capacity and competitive fuel cost. The financial credit could also reflect incidental costs such as managing short-term power fluctuations.

If wind turbines save fuel, wind energy should compete with the cost of fuel rather than the wholesale price of electricity.

5. The converse to a financial credit is to tax generators that cannot provide energy during periods of peak demand.

6. In another approach, wind farms can purchase storage capacity and bid both generation and storage as a unit. This could take the form of business partnerships with consumers using load leveling technologies such as ice air conditioners. (Ice air conditioners level load by producing ice at night. During afternoon peak demand, the ice is used for air conditioning.) With this approach, the marketplace stimulates development of storage technologies.

7. Still another approach is to think system solutions. Wind farms could partner with intermittent-tolerant applications like desalinization or pumping and use the transmission grid as common carrier.

8. A carbon tax that doubles the price of coal could make intermittent wind competitive. ■

Endnotes:

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3. Hawkins *supra* note 2.

4. W. Brunetti, former CEO of Xcel Energy, cited in E. Rosenbloom, A Problem with Wind Power, Sept. 6, 2006, available online at http://www.wind-watch.org/documents/wp-content/uploads/ProblemWithWind.pdf.

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6. OECD Projected Costs of Generating Electricity, *2005 Update*, OECD 2005, available online at http://www.iea.org/textbase/nppdf/free/2005/ElecCost.pdf.

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