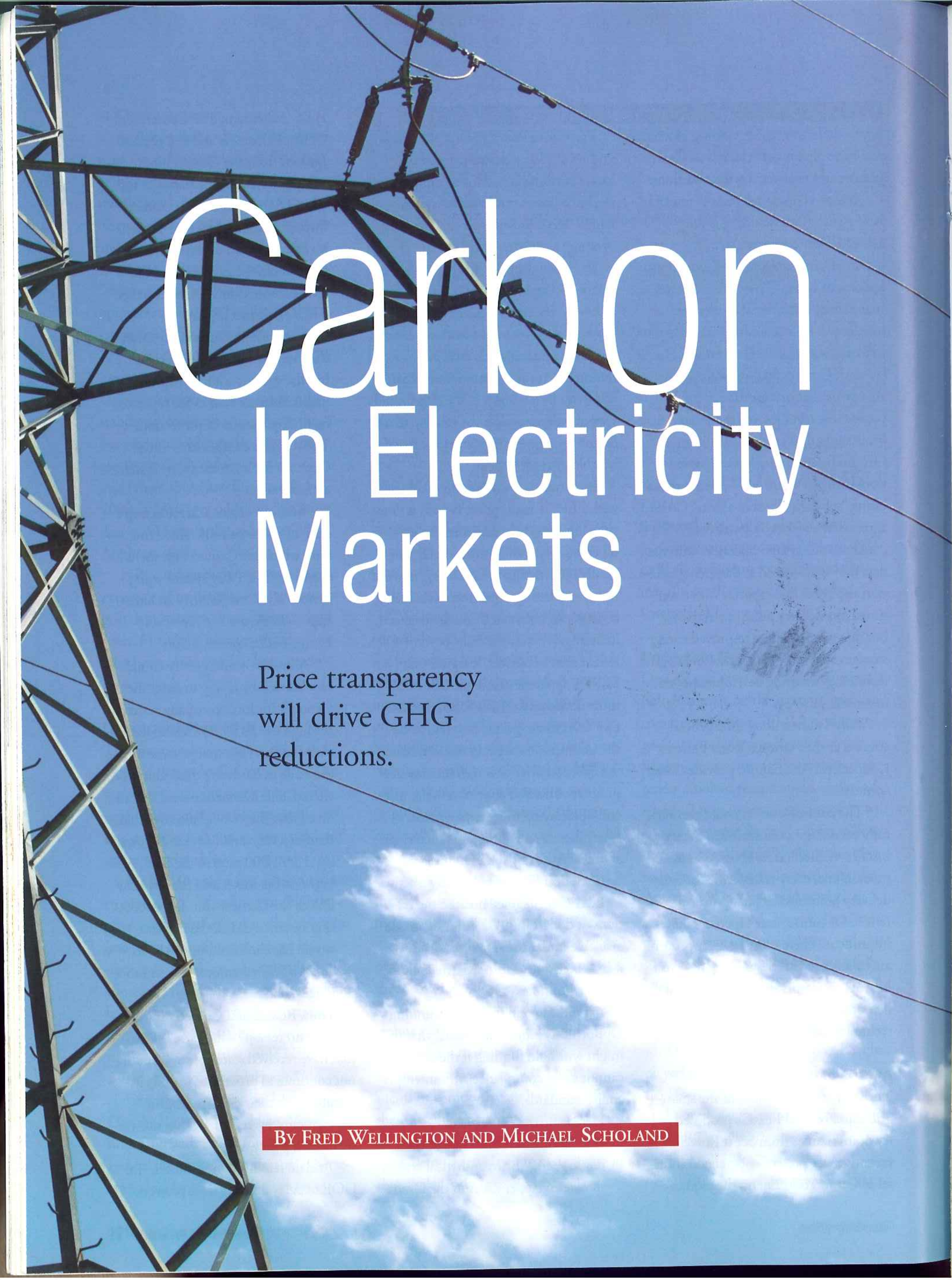


Carbon In Electricity Markets

Price transparency will drive GHG reductions.

By Fred Wellington and Michael Scholand

Political pressure to deliver comprehensive national greenhouse-gas (GHG) reductions is intensifying under the Obama Administration. These reductions will result from legislation, accelerated action by the Environmental Protection Agency (EPA) or both. While 2008 saw considerable debate on the structure and stringency of national GHG legislation, either Congress or the EPA (through the authority granted to it by the 2007 Supreme Court ruling in *Massachusetts v. EPA* [1]) likely will enact comprehensive GHG regulation in 2009 or 2010. The likely legislative outcome will be a market-based approach, with the cornerstone being a cap-and-trade system for CO_2 emissions.

President Obama proposes to reduce GHG emissions to roughly 14-percent below 2005 levels by 2020, and to approximately 83-percent below 2005 levels by 2050. The Waxman-Markey *American Clean Energy and Security Act of 2009* proposes a similar decarbonization of the U.S. economy by 2050. Together, these proposals provide a clear indication of likely future emission-reduction targets. Both proposals advocate a cap-and-trade structure as the principal policy mechanism—as do most other proposed GHG-reduction measures with similar targets for emission reductions.

Regulatory action isn't limited to the federal government. As of April, 2009 almost half of U.S. states are in the process of creating and implementing GHG regulations that feature cap-and-trade mechanisms. For example, the final scoping plan for California's Global Warming Solution Act (AB32), published in October 2008, includes a cap-and-trade system as the central mechanism to achieve the state's GHG-reduction goals. The Western Climate Initiative (WCI), an organization comprised of seven states (including California) and three Canadian provinces, is designing a regional carbon market scheduled to begin operations in 2012. Northeastern states have commenced a cap-and-trade program under the Regional Greenhouse Gas Initiative (RGGI). Midwestern states, through the Midwestern Greenhouse Gas Reduction Accord (MGGA), are designing a carbon-trading system that likely will come online in the next few years, as is the state of Florida.

How such limits will be administered is in large part a function of the current structure of the power generation market. At one time the electricity industry was a network of vertically integrated operations managing all aspects of energy production and delivery, from generation to transmission to distribution. However, the structure of the electric industry has changed dramatically in the last 10 to 15 years. The Federal Energy Regulatory Commission (FERC) has issued a number of orders designed to open wholesale generation markets to competition, and has promoted institutional structures to facilitate such competition.[2] In addition, nearly half of all states have restructured electricity markets at the retail level in order to promote competition.

Price signals for electricity and CO_2 emissions can act in concert, achieving cleaner generation through the dispatch of lower-carbon sources.

While the restructuring still is evolving, it has resulted in competitive suppliers owning approximately 40 percent of today's installed generating capacity.[3] More dramatically, competitive suppliers have built approximately 80 percent of the new electric generation capacity that has come into service since the mid-1990s.[4] Hence, competitive electricity markets will play a vital role in the successful implementation of regional and national CO_2 emission programs. Therefore, it's important to understand the interaction and synergies between competitive electricity markets and market-based GHG policies. In a competitive environment, market-based environmental policies allow emission reductions to be realized at the lowest possible overall cost to society. Markets provide incentives that encourage reductions by the producers and consumers that can achieve the desired reductions most efficiently. The emission reductions and economic efficiencies achieved by the nation's acid rain cap-and-trade program are well documented.[5]

Under the proposed cap-and-trade program, incentives to change the way electricity is produced and consumed will be fundamentally tied to how carbon costs are reflected in electricity prices. The question will be whether or not carbon costs appropriately are aligned and transparent enough to induce electricity producers and consumers to alter their short- and long-term production and consumption decisions. Below are two characterizations—one for electricity production, one for consumption—of a successful regulatory regime for reducing carbon emissions in today's competitive power market.

Fred Wellington is a managing consultant and Michael Scholand is an associate director with Navigant Consulting. This article reflects their views and not necessarily those of the COMPETE Coalition, which commissioned the white paper from which the article was adapted.

Electricity Production: In competitive wholesale markets, power producers will be rewarded financially for lower CO_2 emissions stemming from more efficient production or the use of lower carbon fuels. In the long term, new power plants will be built based on the level of investor confidence that the appropriate return on investment will be achieved, given the level of risk associated with building and operating a respective power plant. Investment will flow more towards renewable and low-carbon generation options as carbon costs reduce the financial attractiveness of higher carbon options.

Electricity Consumption: When wholesale and retail prices of electricity accurately reflect the marginal costs of CO_2 emissions, they will provide the appropriate incentives to consumers. With fuels and electricity priced to reflect their CO_2 emissions, consumers will make the informed economic trade-off decisions envisioned for GHG policies to reduce carbon. For example, accurate fuel and electricity prices ensure that consumer choices among electric, natural gas and oil-fired heating systems appropriately reflect the significant differences in CO_2 emissions associated with each option (*see Figure 1*).

This article was adapted from a white paper produced for the COMPETE Coalition by Navigant Consulting, which illustrates the potential effectiveness of market-based incentives for CO_2 reduction by drawing on the historical responses of power plant owners and operators to price signals in competitive regional transmission organization (RTO) and independent system operator (ISO) electricity markets. These responses are evidenced by improved thermal conversion efficiency and increased availability of conventional power plants. In addition, the interaction and potential synergies between a competitive market structure and a market-based approach to reducing CO_2 emissions are exemplified by instances in which complementary price signals for electricity and CO_2 emissions can act in concert, achieving cleaner generation through the dispatch of lower-carbon sources and investment in renewable energy capacity.

Price Signals and Restructured Markets

Competition aligns prices with marginal costs to provide efficient price signals to consumers and producers. On the supply side, this alignment stimulates reduction in operating and capital costs and spurs innovation in processes and products. On the demand side, it provides incentives for demand-side management and energy-efficiency investments. In addition, competitive markets provide buyers and sellers with the products necessary to manage price and quantify risk.[6] By contrast, in a vertically integrated market, buyers, sellers, and regulators all have different objectives that can work at cross purposes to achieving GHG reductions.

The analysis focuses on the evolution of heat rates in coal plants and capacity utilization factors in nuclear plants in RTO/ISO markets.[7,8] Since coal and nuclear plants account for approximately 70 percent of total electricity generation in the United States,[9] the performance of these units is an important indicator of how electricity markets have evolved over the last 10 to 15 years. Data shows increased participation in demand-response programs in restructured markets and highlights how electricity markets can accurately inform electricity consumers about the cost of carbon.

RTO/ISO wholesale markets were examined because participants in these markets face transparent prices irrespective of state regulatory regimes. These

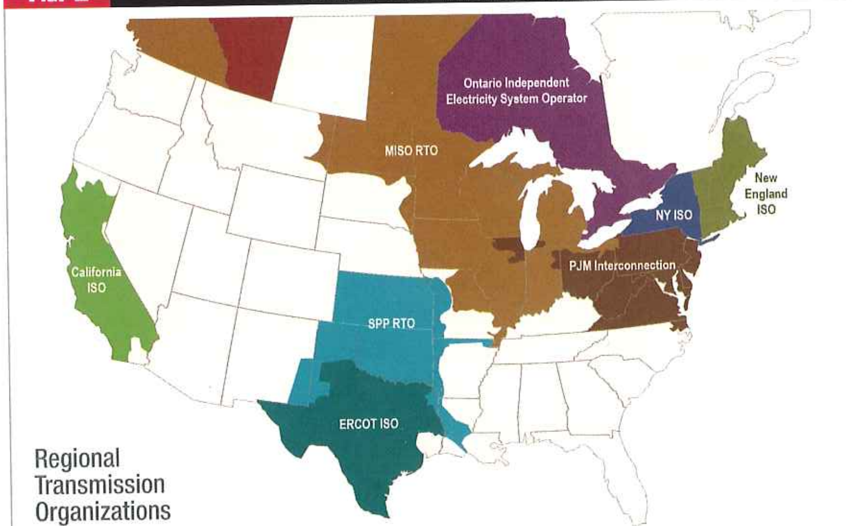
FIG. 1 PRICE SIGNALS AND CO_2 REDUCTIONS

Source: Navigant Consulting Inc.

	Short and Long-term Price Signals Leading to Carbon Reductions	
Electricity Consumption	Consumers are more likely to reduce wasteful electricity consumption if the price they pay more accurately reflects the true cost of production.	Consumers react to higher carbon prices over the long term by altering purchasing decisions on household energy consumption, for example energy efficient applicances or electric vehicles.
Electricity Production	Wholesale power producers that are financially rewarded for more efficient production or utilizing lower carbon fuels are more likely to pursue lower carbon production strategies.	Investors are more likely to integrate carbon abatement costs in investment decisions regarding new power plants if there are accurate and transparent price signals.
	Short Term	**Long Term**

FIG. 2 CURRENT U.S. RTO/ISO MARKETS

Source: FERC



markets include the Northeast (New England RTO, New York ISO), the Mid Atlantic (PJM Interconnect) California (California ISO), parts of the Midwest (MISO), and Texas (ERCOT) (*see Figure 2*). The Southwest Power Pool (SPP) was excluded because it doesn't operate a fully integrated real-time energy market. Rather, SPP only provides an "imbalance service" allowing scheduling entities to balance their generation and load with real-time purchases or sales. Only 6 percent of SPP generation is sold through this market.

The performance in restructured competitive markets to date demonstrates how generator owners and operators respond to the economic incentives provided by that market structure. This can be shown most readily by the improvements in thermal conversion efficiency for coal generating units and by the increased annual capacity factors (availability) of nuclear units.

In restructured competitive markets, these improvements directly translate into economic benefits for both producers and consumers. Generators in restructured wholesale markets sell power under bilateral contract arrangements as well as in the spot market, and therefore are rewarded financially for achieving efficiencies—lower heat rates for coal, increased capacity factors for nuclear—which translates into lower production costs and, in the case of coal, reduced emissions.

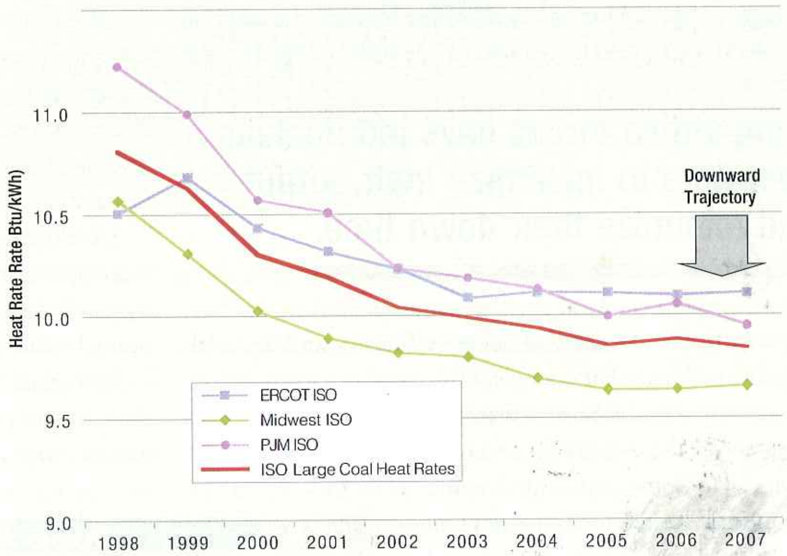
FIG. 3 WEIGHTED AVERAGE HEAT RATES FOR RTO/ISO MARKETS

(10-YEAR PROGRESSION)

10-year trend of weighted average heat rates for large coal fired generating assets in all RTO/ISO markets, with average heat rates for the three restructured competitive markets that have the largest quantity of operating large coal-fired units. The aggregate sample includes 145 coal-fired generating units. The three ISO markets with the greatest number of large coal-fired generating units (*i.e.*, >400MW per unit) are Midwest ISO (61 units), PJM ISO (57 units) and ERCOT ISO (22 units).

This data was developed using Ventyx's Energy Velocity Unit Generation and Emissions database [for which information is taken from the EPA's Continuous Emissions Monitoring System (CEMS) database]. From that dataset, coal-fired units rated at 400 MW and larger were selected. Power stations in Canada were removed, along with those operating in regulated markets. Data was then assigned to the appropriate ISO regions, and the heat rates for each unit were weighted by their annual net generation (MWh) to calculate a weighted average heat rate for each ISO.

The generating stations in each RTO/ISO were operated within traditional regulatory structures prior to 1998 when the restructuring that formed the RTO/ISOs began. All RTO/ISOs were formed by 2004.



Source: Navigant, Ventyx and EPA

Efficiency and Availability Improvements

Coal-fired units in each of the restructured markets show a decided improvement in their average heat rates in the years following restructuring (*see Figure 3*). Overall, heat rates improved (declined) from approximately 10,800 Btu/kWh to approximately 9,850 Btu/kWh—an efficiency gain of 9.4 percent over the 10-year period. These improvements were driven, in part, by competitive electricity pricing that provided financial incentives for plant owners/operators to improve plant performance.

Earnings in restructured competitive electricity markets are tied directly to a generating unit's total output. Therefore, there's a significant incentive for the owners of power plants to shorten maintenance and refueling outages, which increases plant availability (that is, operational up-time, the percentage of time that the plant is available to operate). This is particularly true of nuclear units, since the variable costs of operating a nuclear unit are extremely low, and increased availability results directly in increased capacity utilization and higher returns (*see Figure 4*).

On average, the capacity utilization of nuclear power plants in the RTO/ISO markets increased from 81 percent to 93 percent between 1996 and 2007. Capacity utilization is a direct function of two variables: the measure of how closely the plant is operated to its rated capacity when it is running, and the down time the plant experiences each year. Since nuclear plants typically operate at their maximum rating when they are available, plant down time is the main factor impacting capacity utilization. A 93-percent utilization factor represents an average of approximately three weeks of down time per year, or about five weeks over an 18-month refueling cycle. This level is close to the physical limit for refueling and maintenance cycles of typical nuclear plants.

This data indicates that competitive forces and price signals have led nuclear plant operators to seek out and take advantage of opportunities to maximize their output and minimize their down time.[10, 15]

Consolidation of nuclear plant ownership under merchant fleet operators also has led to substantial performance improvement. Data on the performance of 13 nuclear units sold by traditionally regulated utilities to merchant operators between 1999 and 2003 indicates that, for the five-year period prior to the sale, the average capacity factors for these plants was below the five-year industry average, while the average capacity factor for the five-year period after the sale was above the industry average.

Price Signals in Retail Markets

While the elasticity of electricity consumption is difficult to generalize, and the degree to which carbon costs are passed through to retail power prices will differ by state, the addition of carbon costs to electricity prices likely will spur interest and

Competitive forces have led nuclear operators to maximize their output and minimize their down time.

participation in a variety of energy-efficiency and demand-response programs. For example, PJM stated in a recent report, "Regardless of the higher electricity prices that could result from CO_2 prices, the increased market penetration of energy efficiency and some types of demand response can reduce total consumption and customer costs for electricity, and in turn mitigate the wholesale price impacts, and result in additional, CO_2 emission reductions."[11]

Demand-response programs within competitive markets illustrate the linkage between price signals and consumer response, and the ability of markets to provide the innovative products and services necessary for tapping energy efficiency as a resource. RTOs/ISOs are moving rapidly to implement programs that enhance the ability of end-use consumers (and their agents, the demand-response aggregators) to trade off investments in improved end-use efficiency against electricity purchases. By relying on individual companies engaged in the demand-response business to enroll individual end-use consumers, these markets have created opportunities for innovative solutions, while providing the structured oversight necessary to ensure resource delivery. Demand-response programs provide the means for end-use consumers efficiently to evaluate conservation and peak-load reduction options while considering the full costs (including CO_2 emission costs) of available alternatives.

Demand-response programs decrease peak electricity consumption. These programs are based on the economic principle that markets perform well if demand is an active participant in the market in addition to supply. Active participation helps prices reflect the true value of consumption and the marginal cost of supply. Restructured markets accomplish this by providing clear, timely, and transparent price signals that serve as a valuable benchmark for consumers deciding when and how to consume electricity. Also, restructured markets enable customers and demand-response aggregators to participate directly in the market and more fully realize the broad regional value associated with improved efficiencies and reductions in peak demand.

Developments in the ISO-NE market illustrate the significant response to the incentives created in that market; the capacity enrolled in ISO-NE demand-response programs increased nearly fivefold between 2005 and 2008 (*see Figure 5*).

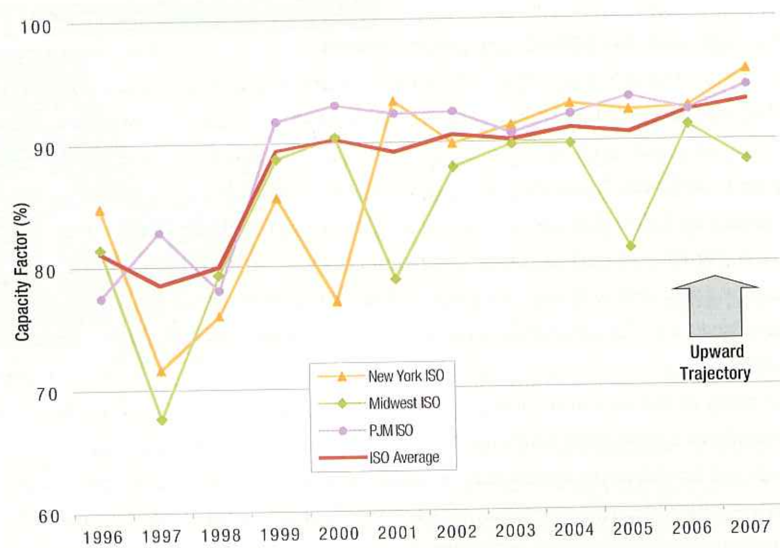
Even more demand-response capacity will come on line over the next two years in response to ISO-NE's incorporation of demand-response capacity into its Forward Capacity Market.[12]

FIG. 4 **RTO/ISO NUCLEAR CAPACITY UTILIZATION**

Source: Navigant and NRC.

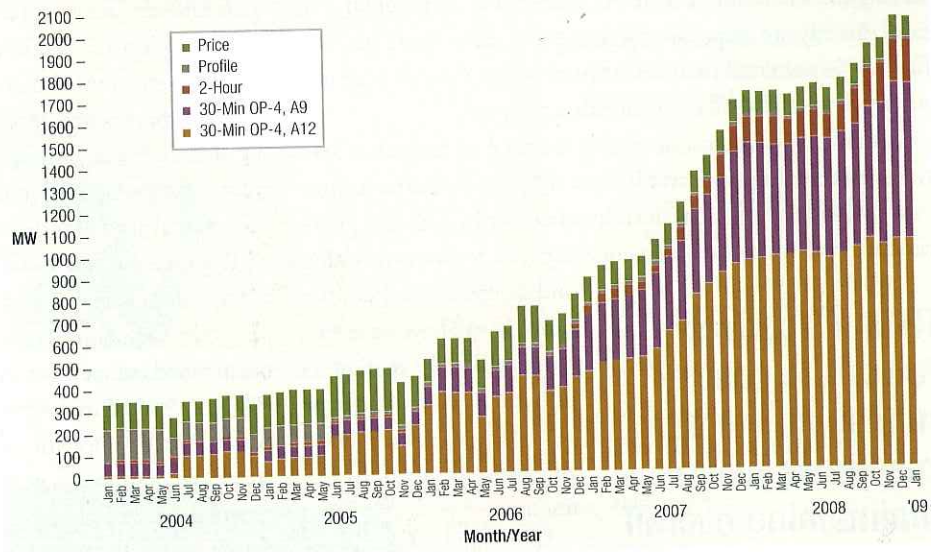
The average change in the capacity utilization of nuclear power plants operating in all RTO/ISOs between 1996 and 2007, plus the average capacity utilization within each of the three ISOs containing the largest number of nuclear power plants—PJM, MISO, and New York.

These data were developed from the Nuclear Regulatory Commission (NRC) 2002 Information Digest and the NRC 2008-2009 Information Digest. The 2002 digest provides capacity utilization for 1996 through 2001. The 2008-2009 digest provides data for 2002 through 2007. The analysis removed power plants that were decommissioned during that time period, including Big Rock Point, Haddam Neck, Maine Yankee, Zion 1 and Zion 2. Also, to avoid biasing the average, any reactors that were shut down for one full year within the analysis period were removed. The following reactors had zero capacity utilization for at least one year between 1996 and 2007: Clinton Power Station, Donald C. Cook 1 & 2; Davis Besse, La Salle County 1 & 2, Millstone 2 & 3, and PSEG Salem 1 & 2.



The 3,424 MW of new and existing demand response that qualified for the 2010/2011 auction represents 12 percent of the forecasted ISO-NE peak load for the summer of 2010. Approximately, 2,554 MW of demand response cleared in the auction. Hence, demand response resources will represent approximately 9 percent of the 2010 peak load.[13]

FIG. 5 ISO-NE DEMAND RESPONSE PROGRAM ENROLLMENTS



Source: ISO-NE

Restructured markets were created largely to provide price signals that encourage more efficient production and consumption of electricity. Likewise, a cap-and-trade system will harness market reactions to a price ascribed to CO_2 emissions in order to induce a change in how the United States produces and consumes electricity.

Carbon cap-and-trade policies are based on the assumption that the dispatch of electricity generators will reflect the marginal costs of CO_2 emissions and therefore cause a market response. In other words, carbon cap-and-trade policies are based on the premise that market-derived price signals accurately reflect the underlying cost of production.

In competitive electricity markets, prices reflect supply-and-demand conditions at the time electricity is generated and consumed. Thus, competitive markets facilitate the trade-off of all scarce resources, including tradable CO_2 emission allowances, on an equal footing. Competitive electricity markets operating in conjunction with market-priced carbon emissions support the relationship between electricity value and carbon prices. This likely will lead to more accurate price signals in the marketplace, resulting in a preference of both generators and consumers to avoid higher costs, which will achieve the intent of climate-change policy—to reduce CO_2 emissions.

However, evaluating the eventual impact of CO_2 reduction policies requires a detailed examination of how carbon markets interact with the electricity market structure and how this dynamic impacts investment decisions about low carbon energy resources and load-management technologies. In competitive markets, investors and developers bear the risk of investment decisions concerning new generating capacity in order to maximize returns. In regulated markets, investment returns are set by regulators and the risk of investment is borne by ratepayers. Ultimately, if a cap-and-trade system is to shift electricity generation to low-carbon sources, investors will need to be adequately compensated for the risk they incur as a function of their investment decisions. Analyzing a project's potential risk and return is made easier, and can be done more accurately, when prices in the market are transparent.

Marginal Pricing and Carbon Reductions

It's widely recognized that economic efficiency (social optimality) involves the market price of a good being equal to the marginal cost of producing that good. This often is referred to as the marginal-cost pricing principle. A situation in which the market price is greater than marginal cost is less than optimal because another unit of the good could be produced at a marginal cost below what the market is willing to pay. Both producer and consumer are better off if production is increased in this situation. Alternatively, if prices are below marginal costs, welfare is increased by reducing production levels, since the marginal production cost is greater than consumer willingness to pay (market price).

In electricity markets, market-based marginal-cost pricing reflects the variable generating cost of the most expensive unit needed to meet load. It provides the proper price signal for dispatch of existing resources, new entry of generation, innovation, and customer demand response, since the incremental cost is fully reflected in the price earned by suppliers and paid by wholesale purchasers. Market-based marginal-cost pricing ultimately will lead to an efficient allocation of resources and resulting in optimal average prices over the long-term.

Traditional average-cost regulated pricing will mask CO_2 price signals and potentially limit their effectiveness.

Because marginal costs represent the incremental cost of serving the final unit of demand, market-based marginal-cost rates directly are impacted by changes in input costs (such as fuel, environmental costs and capital costs) and the marginal supply-demand balance of generation and load.

The incremental cost of serving the final increment of load represents the true opportunity cost that new resources appropriately can benchmark against. In other words, if market prices rise to a level where they allow new capacity to cover operating and capital costs, then that capacity will have an incentive to enter the market. If market prices remain below this level, the market will utilize cheaper existing resources.

RTOs effectively lower the cost of managing variable resources while maintaining overall grid reliability.

The choice of electricity generating technologies depends on the forward-looking economics of different types of generation using the various price signals generated by competitive markets. The price signal for revenues is the forward price of electricity that reflects a market consensus on future electricity supply and demand and the marginal costs of converting different fuels into electricity. The price signals for costs are the forward prices for different types of fuel (*e.g.*, gas, coal, *etc.*) that reflect supply and demand conditions in those markets.

Decision makers can integrate these price signals into a consistent picture of the relative economics of different generation types and then decide accordingly. Different decision makers may have different long-term expectations and different appetites for risk, but each decision maker will monitor market prices and invest capital derived from decisions based on these differences in expectations and risks.

Carbon Prices and Dispatch Order

Price signals for electricity and CO_2 emissions can act in concert to change the dispatch order and increase investment in new renewable energy capacity, leading to cleaner generation on the electricity grid.

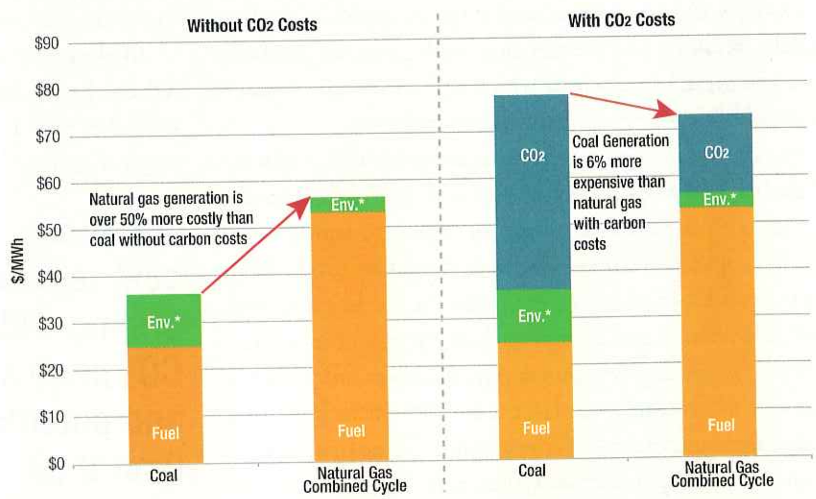
The most immediate effect a price on CO_2 emissions will have in the power sector is to alter the relative cost of generating electricity with different fuels and technologies. Under a cap-and-trade program, electricity generation costs should reflect the costs of the CO_2 emissions that are produced by a generating plant. In order to appropriately reflect CO_2 emissions costs in dispatch decisions, CO_2 emissions costs (as well as the associated opportunity costs) will need to be factored into all decisions regarding optimal generator dispatch.

Regardless of the eventual structure of GHG regulations, the overall financial impact on generation owners will be determined by the manner in which carbon costs are recovered. In restructured competitive wholesale power markets, carbon costs will be recovered through the wholesale prices received by generators. Since competitive markets are designed to clear at prices set by the marginal generator, market prices reflect marginal generation costs. Suppliers with generating costs that are lower than the marginal cost of production (or the market price) earn a profit on their output. If the marginal generator's cost of production increases as a function of carbon-compliance costs, then wholesale prices increase, as do the profits accruing to lower-cost generators, therefore rewarding low-carbon generation. Since market prices reflect the carbon costs of the marginal generator, those with carbon costs that are higher than those of the marginal generator will not be able to recover fully their carbon-related expenses. This eventually will lead to the retirement of carbon-intensive generating units.

The ultimate impact of market-based CO_2 regulations on the energy mix will depend on the relative cost of fuels, other variable operating costs, and the cost of carbon emissions. In its

Fig. 6 **Carbon Impacts on Dispatch Order**

Analyzing the relative impacts of a $40/ton cost for CO_2 on the relative costs of various types of generation. Environmental costs include controls for VOM, NOx, SOx and Mercury. Analysis assumes coal costs of $2.50 /mmBtu and Natural Gas costs of $7.5 /mmBtu.



* Environmental costs include controls for VOM, NOx, SOx and Mercury.
Note: Analysis assumes coal costs of $2.50 /mmBtu and Natural Gas costs of $7.5 /mmBtu

Source: Navigant Consulting Inc.

recent report on the impact of proposed GHG policies can have on its markets, PJM states, "The greater the relative cost of natural gas to coal, the higher is the CO_2 price required to make the natural gas combined-cycle units less expensive to dispatch than the representative coal unit, and to achieve emission reductions from re-dispatch."[14]

PJM's analysis points to the interrelationship between carbon costs and fuel costs, and to the importance this relationship has on the dispatch order (*see Figure 6*).[15]

With no CO_2 costs, the dispatch costs of coal-fired generation are lower than those of a gas-fired combined-cycle plant by at least $20/MWh, assuming gas price of $7.50/mmBtu and coal price of $2.50/mmBtu. But an assumed CO_2 price of $40/ton raises the dispatch costs of the coal unit substantially over the dispatch costs of the gas-fired combined-cycle unit, reflecting the higher CO_2 content of coal, as well as the less efficient (higher heat rate) coal-generating process.

The result of this dynamic is the market-clearing price appropriately reflects the marginal cost of carbon emissions. If electricity prices are distorted by erroneous production costs, dispatch decisions will be based on suboptimal information. If the full marginal CO_2 cost of electricity generation isn't reflected in prices, then GHG policies will not reduce emissions as effectively as desired. Traditional average-cost regulated pricing will mask price signals and potentially limit their effectiveness.

Carbon Prices and Renewable Investments

Investment in renewable energy is driven by many factors, including resource availability, renewable portfolio standards (RPS) requirements, and regional transmission access, capacity, and availability. The cost of installation, which is aided by federal and state tax credits, is also a principal driver. Taken together, these policies and market dynamics largely determine where, when, and how much investment in renewable energy occurs.

A price on carbon emissions likely will increase investment in renewable energy generation. As carbon-compliance costs rise, there will be an increased incentive for entities with a carbon-compliance obligation to use renewable resources to meet future load growth. Moreover, the increase in electricity prices caused by carbon-related costs will make renewable energy more cost-competitive. Electricity price increases driven by carbon costs also can encourage more diverse and innovative energy applications, such as renewable and distributed generation resources.

Carbon Prices and Electricity Costs

Electricity prices are based on production costs. These include fixed costs, such as the cost of building the power plants and transmission lines, as well as variable costs, such as the cost of fuel, operation, and maintenance. Policies that assign a cost to CO_2 emissions will add to the variable costs of producing power from fossil fuels, therefore increasing the cost of electricity.

The price for carbon allowances will be driven by supply and demand, which in turn is a function of many factors. The supply of carbon allowances ultimately depends on political decisions such as setting the level of the cap (equal to the total allowances in the market) and allocating compliance targets among regulated sectors. Demand for carbon allowances from the electricity sector will depend on how much fossil fuel is burned and what type it is, which in turn will manifest differently at the regional level due to differences in the generation mix. Therefore, demand for carbon allowances is fundamentally tied to variables affecting the price of electricity. This is complicated by the fact that demand for carbon allowances also will stem from sectors other than electricity as well as from speculators in the market. Regardless, carbon prices and electricity prices will be inextricably linked, given that variables affecting demand and supply of these two commodities are so closely interrelated.—***BB, FW and MS***

When electricity prices reflect the marginal abatement cost of the most carbon-intensive fuel, renewable energy and load management will tend to benefit. Restructured markets dispatch generators in the order of their operating costs; the more expensive units are dispatched later and set the price at which all units in the region earn revenues. Price-taking zero-carbon resources such as wind energy can benefit from this dynamic because they receive prevailing wholesale-market clearing prices even though they don't have a corresponding carbon compliance cost. In other words, generators are rewarded based on performance in the marketplace.

While roughly two thirds of wind capacity exists in states having organized wholesale markets (*see Figure 7*), assessing the degree to which market structure leads to increased levels of renewable energy development is highly complex because of the jurisdictionally fractured, stop-and-start history of renewable resource development. The salient questions are whether or not organized electricity markets are conducive to optimizing and increasing the value of renewable energy on the grid, and whether or not investors have enough information to adequately value future investments in renewable energy.

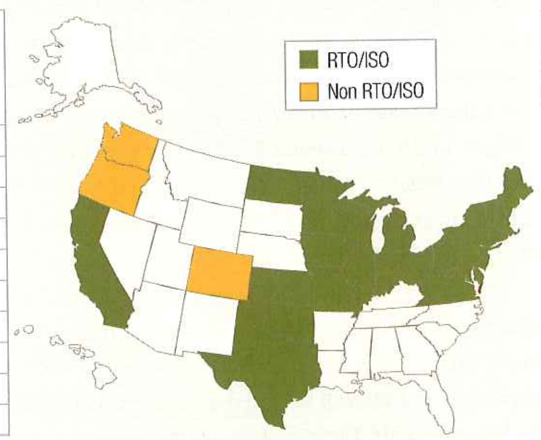
Reduced uncertainty and risk make investment decisions easier. Without a publicly visible, readily determined dispatch price, valuing an investment in new generation capacity is more difficult. Well-functioning liquid hour-ahead and day-ahead markets provide useful information and data to energy developers that can inform decision makers whether or not prices will support the cash flows needed to meet required investment returns. For CO_2 prices to induce a shift in the capital stock to low-carbon generation sources, investment decisions need to incorporate the impact that carbon costs will have on electricity prices. In markets with transparent pricing mechanisms and market rules, investors will be better able to assess the risk-and-return trade-offs of their decisions.

In theory, coordinated dispatch can optimize the output of large wind farms because grid operators call on the lowest-cost producers available and shift generation away from more expensive units. In practice, the ability to coordinate different control areas and an availability of transmission capacity are needed to optimize resources in markets with a diverse fuel mix and varying generator performance in order to allow for accommodation of variable and non-disptachable resources.

The broader the geographical reach of the market, the more renewable energy producers' variable output efficiently can be accommodated. This accommodation is achieved through ancillary services, which are needed to manage the variable nature of wind generation. By broadening the supply of ancillary services, RTOs effectively lower the cost of managing variable resources while maintaining overall grid reliability. This is evidenced by MidAmerican Energy Company's recent announcement that it intends to integrate fully into the MISO

Fig. 7 Organized Wholesale Markets and Wind Capacity

	Current Wind Capacity (MW)	Wind Capacity Under Construction (MW)
TX	7,116	1,651
IA	2,790	20
CA	2,517	275
MN	1,752	0
WA	1,375	70
CO	1,068	0
OR	1,067	250
IL	915	201
NY	832	464
KS	815	199



Source: Navigant analysis of AWEA data.

as a transmission-owning member.[16] According to recent reports from the Department of Energy and the National Renewable Energy Laboratory, this can lead to increased value for wind energy operators.[17, 18]

The degree to which investors can assemble accurate data to inform an investment decision, and increase the value of their investment through optimizing the output, improves the investor's ability to make rational risk return trade-offs as renewable energy investments are considered.

Conclusion

Competitive electricity markets will play a vital role in the successful implementation of regional and national CO_2 emission-trading programs. If the intended results of a carbon market are to be achieved, CO_2 prices will need to alter the manner in which the U.S. produces and consumes electricity.

Empirical analysis of the history of coal-plant heat rates and nuclear-generator capacity factors demonstrates how electricity generators react to price signals in order to improve operating profit margins. The expectation of a similar price-signal reaction is at the core of market-based GHG policies. Behavioral changes stemming from accurate and transparent prices—and the financial incentives and disincentives they create—will drive decisions that likely will reduce emissions from existing generation sources. As a corollary, these price signals likely will lead to increased penetration of renewable energy and load-management technologies, which in turn will facilitate a faster transition to a lower-carbon electricity grid.

Regional, federal, and state policymakers designing GHG policies need to consider the inter-dependant nature of carbon markets and electricity markets—and more important, how prices in these two markets are related. Policymakers need to understand that consumers' and producers' abilities to increase efficiency and improve utilization of innovative technologies will be enhanced and rewarded in a market-based environment, which will ensure the best opportunity for success in achieving the goal of significant CO_2 reduction nationwide.

Footnotes

1. *Massachusetts v. Environmental Protection Agency*, 549 U.S. 497 (2007).
2. For example, Order No. 888 prevented transmission owners from discriminating against wholesale sellers of electricity. Order No. 889 set standards of conduct related to a utilities communications between the transmission and wholesale power functions. Order 2000 encouraged the formation of ISOs and RTOs.
3. NCI analysis of Ventyx generating unit data. Capacity owned by unregulated entities in the Ventyx data base have been referred to as "competitive suppliers." Unregulated entities are defined as entities that do not have a designated franchised service area and that do not file forms listed in the Code of Federal Regulations, Title 18, part 141, which are considered unregulated entities. This includes qualifying CHP, qualifying small power producers, and other generators that are not subject to rate regulation such as independent power producers. This ownership designation is reported in several government reports including the EIA 860, the NERC ES&D and the EIA 906/923.
4. Navigant Consulting, Inc. estimates based on Ventyx data.
5. See for example, Ellerman, D., *Markets for Clean Air: The U.S. Acid Rain Program*, New York: Cambridge University Press, 2000.
6. United States of America Federal Energy Regulatory Commission; Conference on Competition in Wholesale Power Markets, Docket No. AD07-7-000; Prepared Remarks of Professor Paul L. Joskow; Feb. 27, 2007.
7. Heat rate is a measure of the efficiency by which a fossil-fired electricity generating unit converts its fuel into electricity. It is measured in terms of the amount of fuel required to generate one kWh of electricity—the lower the heat rate, the more efficient the generating unit.
8. The net capacity factor of a power plant is the ratio of electrical output of the plant over a period of time to its output if it had operated at full nameplate capacity the entire time.
9. Navigant Consulting, Inc. based on Ventyx data.
10. EPSA Forcefully Rebuts APPA Paper on "Nuclear Power Plant Performance: What Does Restructuring Have To Do With It?" Five-page report by EPSA, June 2007.
11. "Potential Effects of Proposed Climate Change Policies on PJM's Energy Market," PJM, January 2009.
12. The objective of the Forward Capacity Market is to purchase sufficient capacity for reliable system operation for a future year at competitive prices where all resources, both new and existing, can participate.
13. ISO New England Press Release, "Wholesale Marketplace Helping to Achieve Long-term Power System Reliability Goals," Feb. 13, 2008, Holyoke, MA.
14. "Potential Effects of Proposed Climate Change Policies on PJM's Energy Market" PJM, January 2009.
15. The \$40/ton price for CO_2 emissions used in this analysis is indicative only, and is not based on an analysis of future CO_2 prices.
16. Midwest ISO Press Release, "MidAmerican Energy Declares Intent to integrate Into Midwest ISO as a Transmission-owning Member," April 27, 2009.
17. Kirby, B. and Milligan, B. "Facilitating Wind Development: The Importance of Electric Industry Structure," NREL Technical Report NREL/TP-500-43251, May 2008.
18. "20 Percent Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply;" U.S. Department of Energy Report, May 12, 2008.