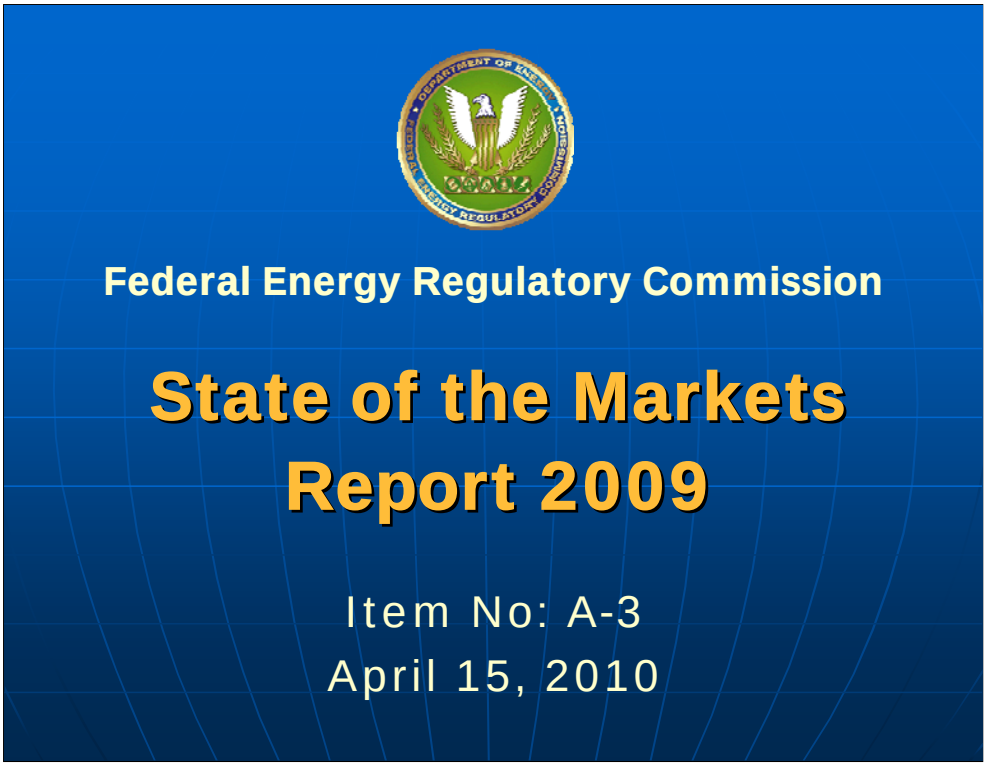
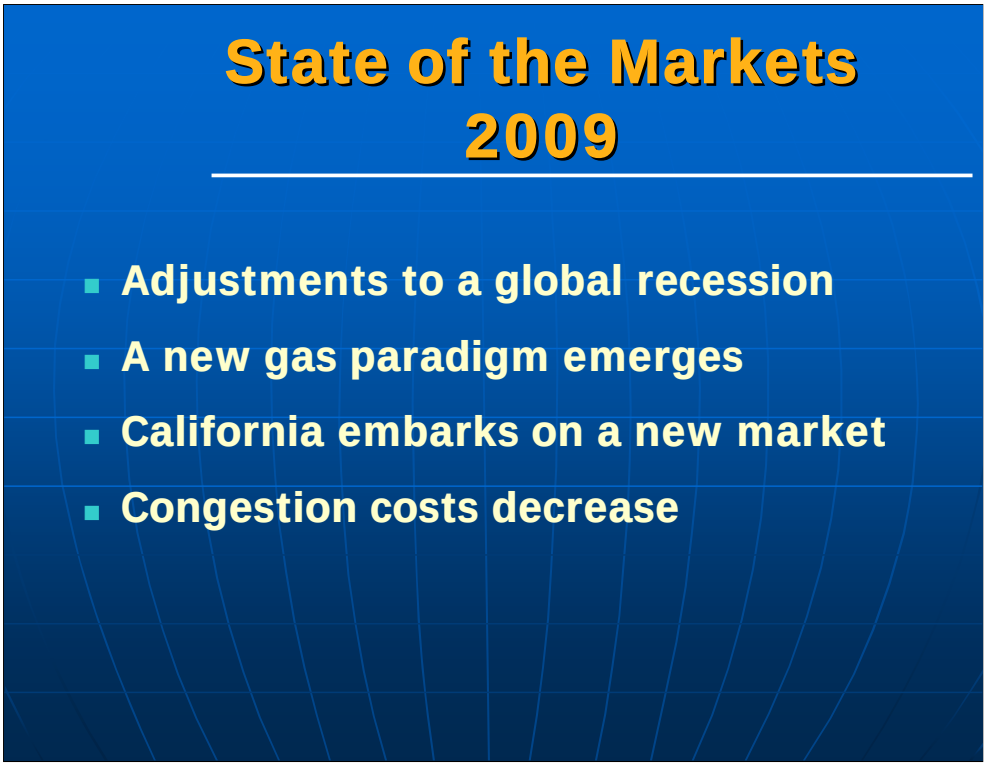


Each year, the Division of Energy Market Oversight in the Office of Enforcement presents a State of the Market report reviewing how the significant events of the past year better inform our understanding of the current and future energy markets.



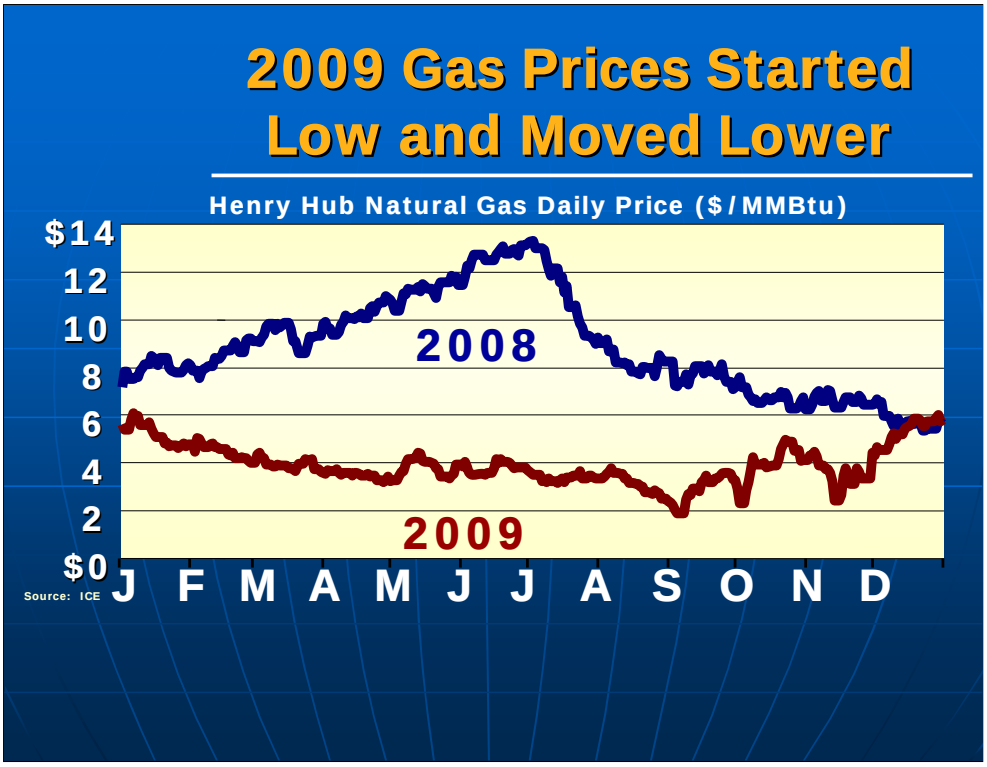
Energy markets underwent considerable change in 2009

The deep global recession was reflected in reduced demand, lower prices, and slowed investment. During the year, long-standing price relationships between fossil fuels changed affecting decisions made for their use.

A new gas market paradigm emerged into clearer focus. This paradigm may change the way we look at future energy choices.

California ISO initiated its new nodal market on March 31; and

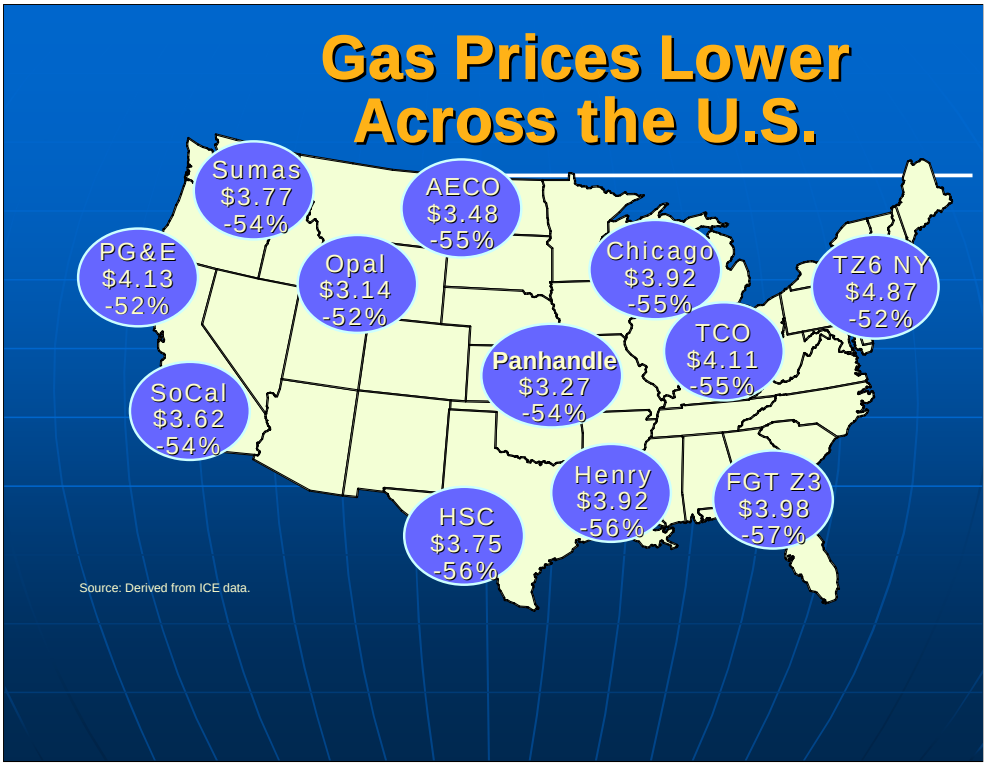
The cost of electric congestion decreased across the country.



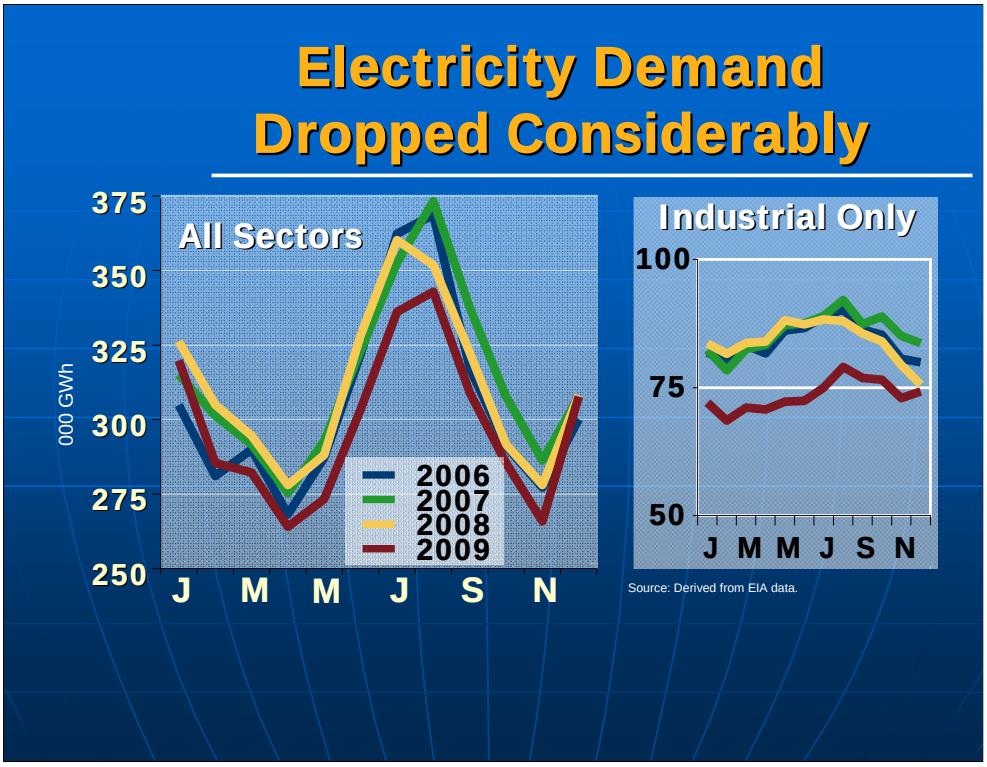
In 2008, a global commodity bubble pulled energy prices to unprecedented levels, peaking just before the Fourth of July. When capital began flowing out of commodity markets, prices began falling and continued doing so as economies around the world plunged into recession.

In contrast, 2009 natural gas prices started relatively low and moved lower. Mild weather, the effects of the recession, record storage inventories filling record storage capacity and supply abundance pushed prices to levels not seen since 2002. Late in the year, with the advent of winter, gas prices moved back up to their early-2009 levels.

Interestingly, gas demand was relatively steady between 2008 and 2009 as a 5.5 percent increase in demand for gas for electric generation offset declines in the residential, commercial and industrial sectors.



Prices were not just lower at Henry Hub. Across the U.S., average gas prices were down more than 50 percent from 2008 to 2009. These price changes were largely driven, on a year-to-year basis, by the drop in commodity costs. New pipelines added during the course of the year did affect price relationships among regions for portions of the year. I will discuss those effects later.



The recession left its mark on the electric market. Demand for electricity dropped by 4.2% in 2009. This was the greatest decline in a single year in at least 60 years and, with 2008, the only time electricity demand has fallen in consecutive years since 1949. Falling power demand is rare. There have been 11 recessions since 1949; power demand fell only during three of them.

The drop in demand was largely due to a sharp decline in the industrial sector which was hit hard by the recession. As in many of the previous recessions, there was a discernable reduction in industrial demand. Industrial customers used less power than in any year since 1988. Unlike many earlier recessions, residential and commercial demand also fell, about 1% together.

Demand was also reduced by mild summer weather for most of the country. Yet, even on the most extreme days, electricity demand failed to approach historic levels. The primary exception to this characterization was in ERCOT where demand records were broken twice in July in spite of a large decline in Texas industrial demand. The ERCOT system performed reliably and no interruptible resources were dispatched on either day.

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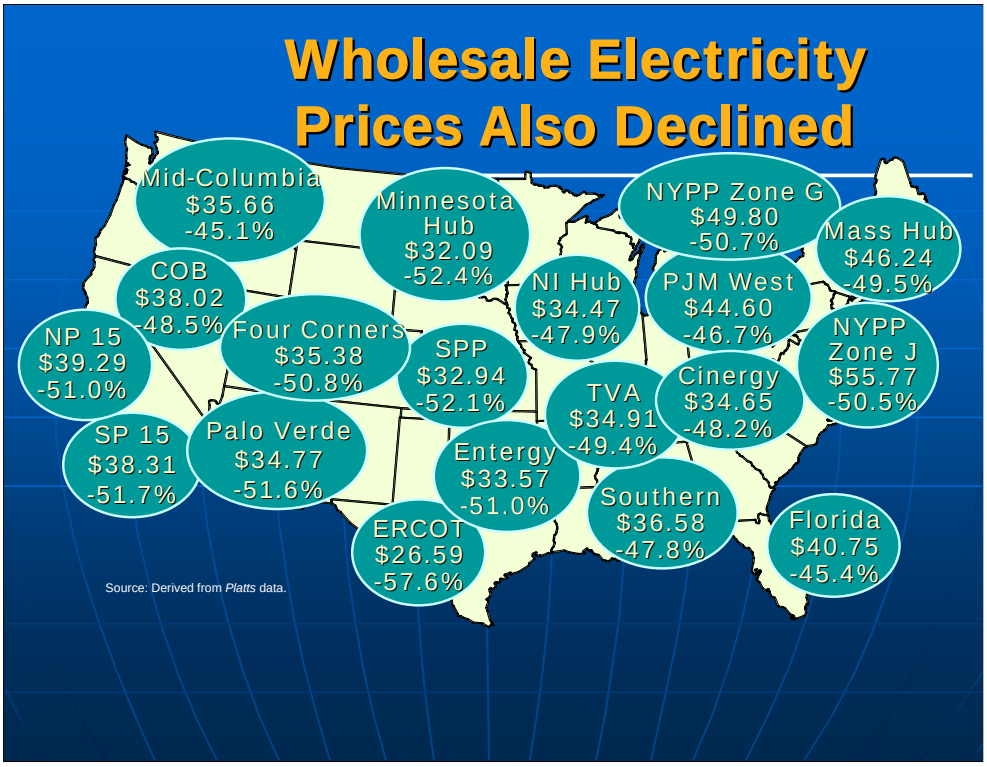
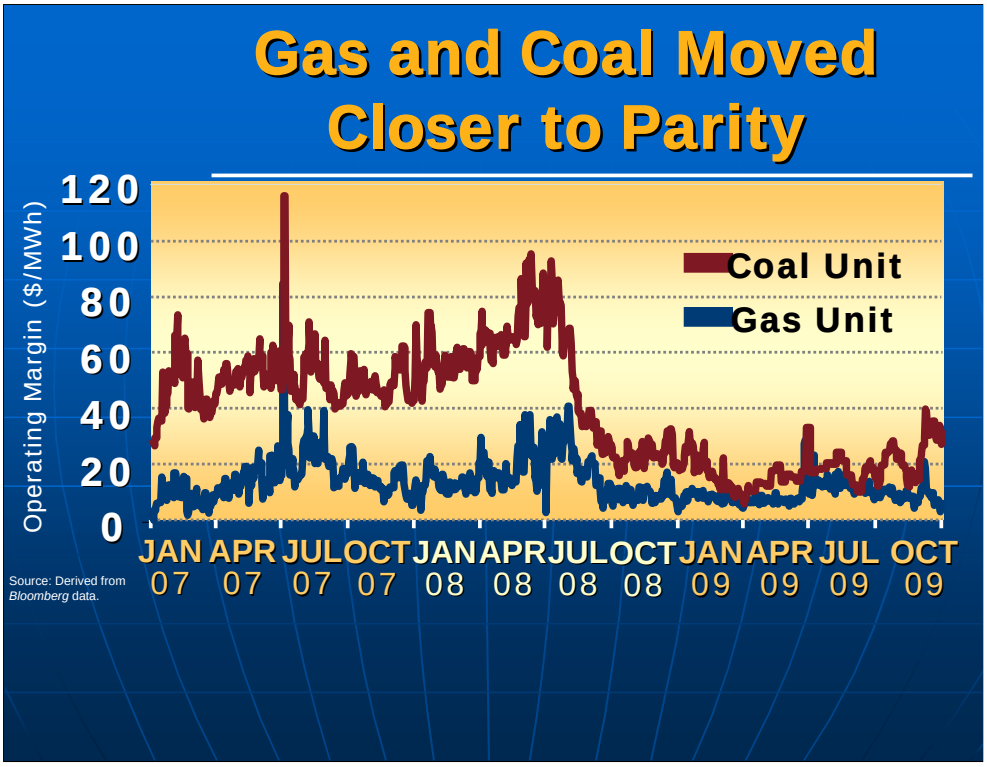
With the recession and mild weather dampening demand, it is difficult to isolate the effect of energy efficiency and demand response programs. These programs are beginning to have a presence in many RTOs. Some allow demand response resources to be bid into the capacity market. In PJM, ISO-New England and the New York ISO, the amount of demand resources cleared through the capacity markets grew to 12 GW.

Five states (Iowa, Delaware, Indiana, Arizona, and Massachusetts) added Energy Efficiency Resource Standards (EERS) in 2009, bringing the total number of states with EERS to 23. Two of these new EERS states, Arizona and Delaware, include peak reduction targets from demand response programs, joining nine other states with similar provisions. EERS are pending in 4 states (NJ, FL, UT, WI). This count of EERS states does not include West Virginia and Virginia, which have non-binding energy efficiency goals instead of EERS.



With lower electricity demand and lower fuel costs, electricity prices fell by half. In the New York ISO and ISO-New England, the average electricity price in 2009 was the lowest since the markets began in their current form (NYISO in 1999, ISO-NE in 2003). The majority of the drop in prices is attributable to the drastic declines in fuel prices. In addition to lower natural gas prices, spot coal prices declined by over 40% in the East and #2 fuel oil was down 42% in New York. In wholesale electric markets, lower fuel costs translated to lower prices.

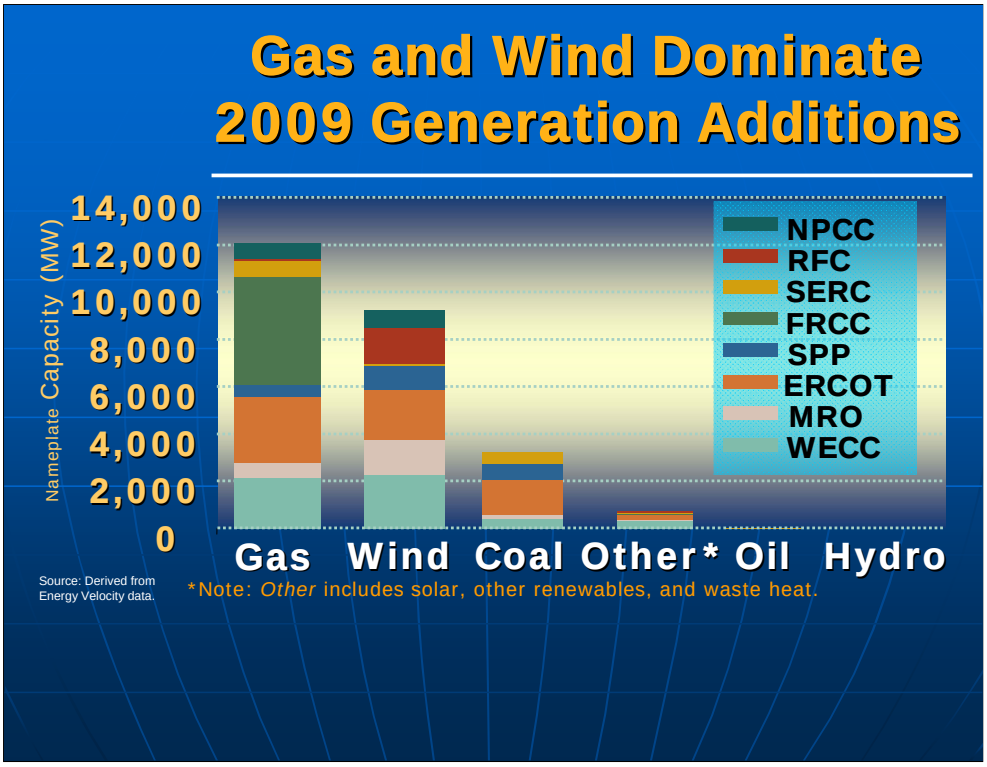
But even absent the steep drop in fuel, the effects of the recession would likely have lowered electric prices. For example, Monitoring Analytics reported in its 2009 PJM State of the Markets Report that fuel adjusted prices fell 10% from 2008 as a result of lower demand.



As fuel prices fell during 2009, the traditional price relationships among the leading fossil fuels became more malleable. Fuel oil prices separated from gas prices, moving at one time to more than seven times as much on a Btu basis. The spread narrowed for the winter but has returned to last fall's levels.

We noted in last year's report that lower gas prices were pushing coal plants up the dispatch stack in parts of the country. This change meant that natural gas sales to power plants increased as more gas fired plants moved to baseload service. During the year, gas demand for power generation increased 5 percent, even as electric demand fell. This demand growth was particularly pronounced in the Southeast where gas burn in power plants averaged 4.2 Bcfd, up 14% from 2008.

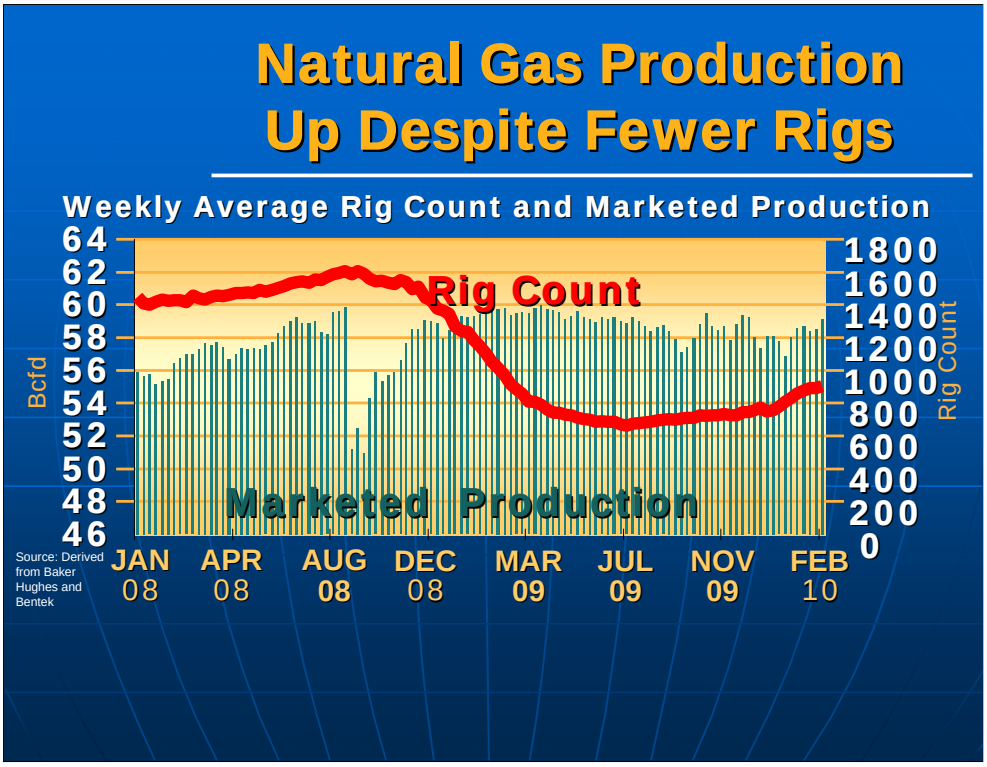
The change in the relationship of gas and coal, coupled with the reduced demand for power, likely contributed to the reduction of NOx and SOx emissions which fell 30 and 25 percent, respectively, during the year, according to the EPA. These changes also squeezed spark spreads and dark spreads, a measure of coal- and gas-fired plant operating margins after accounting for fuel costs. Monitoring Analytics estimates that PJM's coal plants' margins fell by three-quarters of their after-fuel revenues while combined cycle gas plants' margins fell less than one-quarter between 2008 and 2009.



About 25 GW of new generating capacity was put into service in 2009. For the second consecutive year, gas and wind led the additions, accounting for 84 percent of the new capacity.

The advent of the recession may have had a small effect on the amount of capacity coming on line during the year; most plants put into service last year would have been too far along to stop construction. The amount of generation capacity coming online during the year was down 5% from 2008. Industry reports indicate that 82 GW of capacity has been cancelled or postponed since the beginning of the recession. This rate was not out of the norm compared to recent years.

About one-quarter of the cancelled plants were wind generators. However, plans for several new wind generators are still going forward, a possible result of the prepaid tax credits in the American Recovery & Reinvestment Act (ARRA) that cover 30 percent of construction costs for wind, solar, geothermal and other innovative energy projects. In the second half of 2009, 37 large wind generation facilities received $1.9 billion under this program. Going forward, even with the announced cancellations, another 85 GW of new wind capacity has been proposed to be online by the end of 2012.



In contrast to 2008 when the commodity bubble, Gulf Coast hurricanes and the advent of the recession buffeted the gas market, 2009 provided clarity on gas supply. Even as prices and drilling were dropping from record highs, domestic gas production remained strong. The strength stems from technological innovation in producing gas from shale in Texas, Louisiana, Oklahoma, Arkansas and Pennsylvania. Production from these new sources is also creating a subtle shift in the market as supply activity increases onshore in northern Texas and Louisiana at places such as near Perryville, Louisiana, and decreases in and around the Gulf at places such as Henry Hub.

Not that long ago, it would take several months from the start of drilling to initial production. Average-time-to-drill in 2009 was about 20 days. Nowadays, production is almost certain before drilling begins, and well efficiency increases as producers learn the particular nuances of a given play. Because shale production has many of the characteristics of gas in storage, companies have greater flexibility to produce gas when the market calls for it. Production can be deferred without risking the integrity of the well. Ending long production lead times and the risk of failure or loss may dramatically temper the gas market's systemic boom-and-bust cycle.

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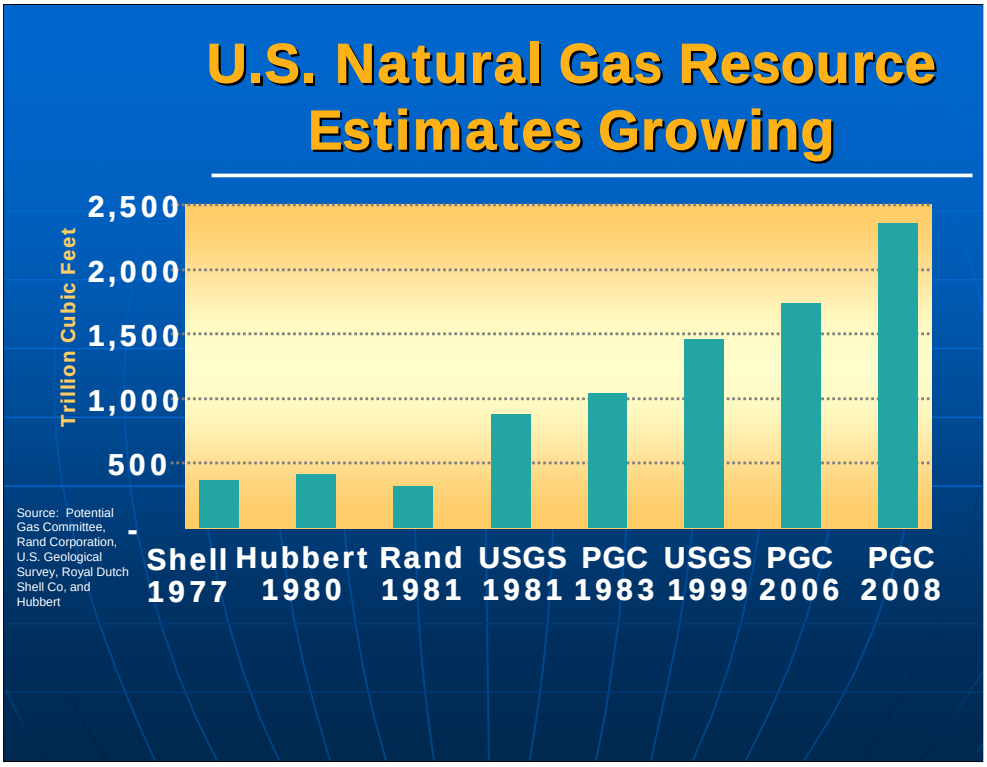
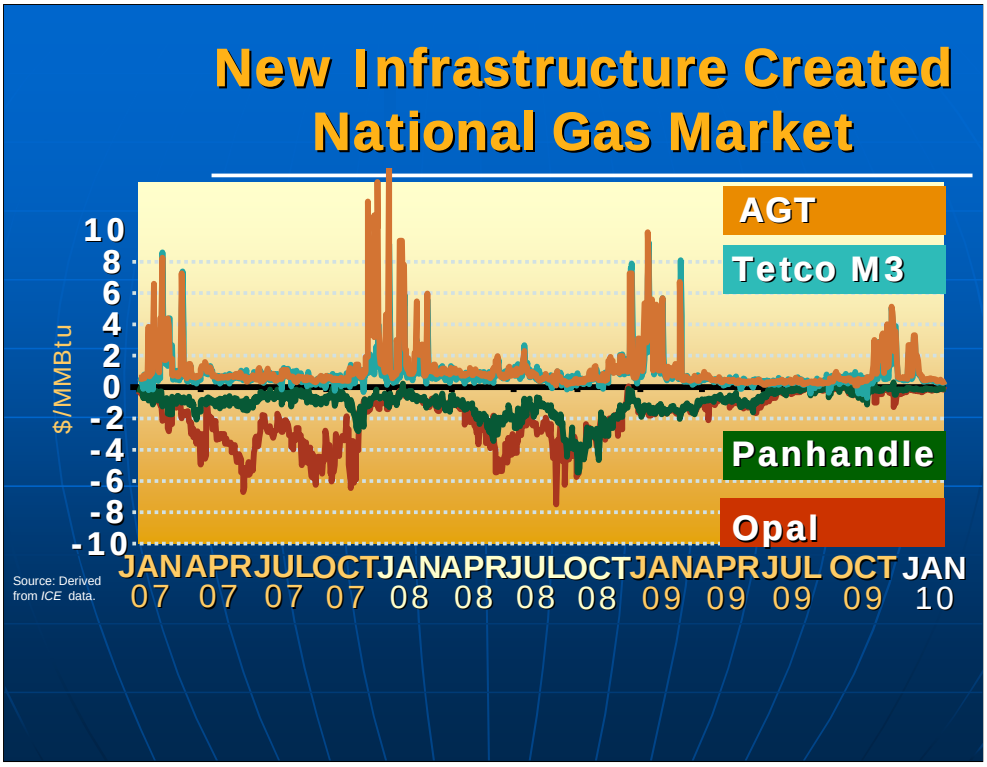
New storage capacity may be expected to complement this trend. More than 107 Bcf of incremental working gas capacity was added in 2009, including more than 50 Bcf in the Gulf region. Additional production area storage, in particular, allows suppliers to respond more adeptly to market signals, and as a result, those signals are moderated. EIA says that U.S. peak working gas capacity is around 3,900 Bcf. In late November 2009, U.S. inventories were 99% of capacity.



A key distinguishing characteristic of last year's gas supply rally is that it appears to be sustainable. In June 2009, the Potential Gas Committee, an independent group that develops assessments of gas resources, raised its estimate to over 2 quadrillion cubic feet, almost 100 years of gas supply at current consumption levels. The large increase is almost entirely due to improvements in our ability to produce gas from shale with certainty and control.

There is concern about the possible environmental effects of shale production. In March, in response to a congressional request, the EPA announced that it would spend $1.9 million to conduct a transparent, peer-reviewed study to answer questions about the potential impact of hydraulic fracturing on human health and the environment. This study is expected to address potential groundwater and air pollution concerns.



In addition to the advances in gas supply that may be reducing the cyclical nature of the natural gas market, 2009 brought important expansions and extensions of gas transmission capacity that will reduce volatility in the price of gas delivered to market. The largest change in the physical infrastructure of the gas market came with the completion of the Rockies Express Pipeline from Wyoming to Eastern Ohio. REX serves the dual role of relieving the constraints that suppressed prices in the West while, at the same time, relieving the constraints that increased prices in the East.

Other, smaller, projects have had similar effects. New pipelines to increase the flow of Barnett shale gas into the interstate network have had the secondary effect of reducing congestion across the Texas-Louisiana border, a remnant of the pre-1978 days of strict delineation between inter- and intrastate supplies. The United States is closer than ever before to being a single natural gas market with congestion limited to a few markets for a few periods during the year. This chart shows that the price difference from Henry Hub at places as diverse as New England, western Wyoming, the Mid-Atlantic and North Texas are coming closer together and that, when they do diverge, the divergence is much less than in the past.

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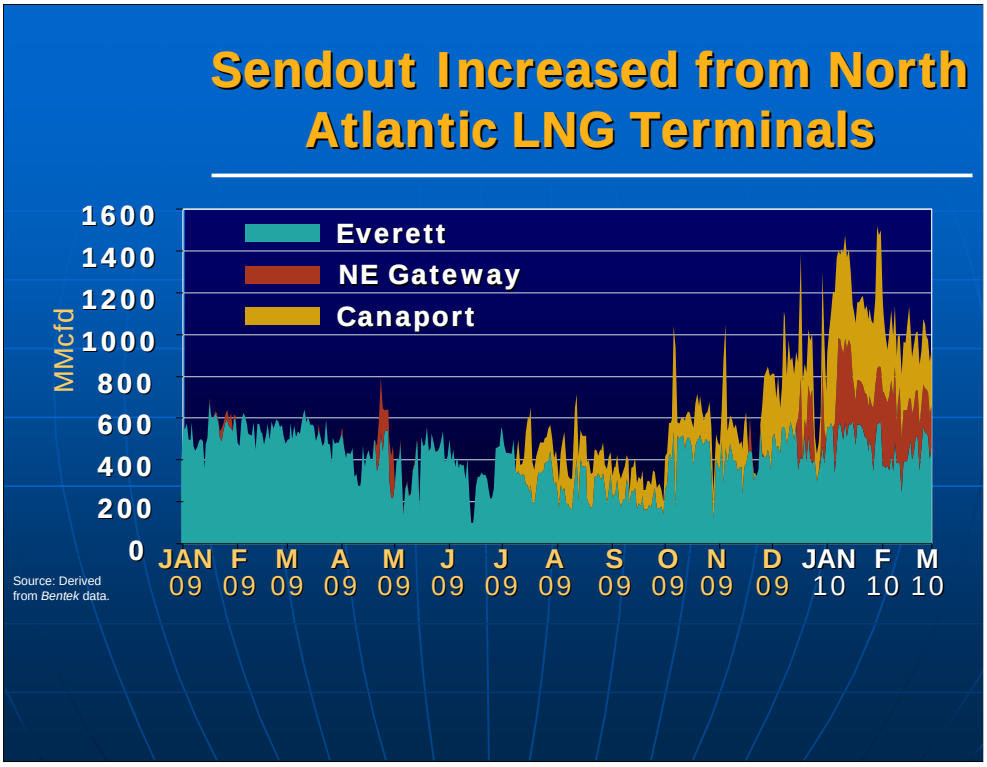
The Florida peninsula and Northern California now seem to be the most frequently constrained parts of the country, but each is slated to receive significant new pipeline capacity next year. In November 2009, the Commission issued a certificate to the Phase VIII expansion of Florida Gas Transmission which is slated to add about 800 MMcfd of gas transmission capacity to peninsular Florida. Additionally, this month, the Commission authorized construction of 1,500 MMcfd Ruby Pipeline from Opal, Wyoming to Malin, Oregon. Both pipelines are expected to be in service in the Spring of 2011.



In addition to increased gas production in the mid-Atlantic area and expanded pipeline and storage capacity, new market area Liquefied Natural Gas import capacity appears to have reduced winter price volatility in New England. Over the course of 2009, 2 Bcfd of sendout capacity was added at the Northeast Gateway terminal in Massachusetts Bay and the Canaport terminal in New Brunswick, Nova Scotia. A fourth terminal, Neptune, off the northern coast of Massachusetts, began operation with a possible additional sendout of 750 MMcfd.

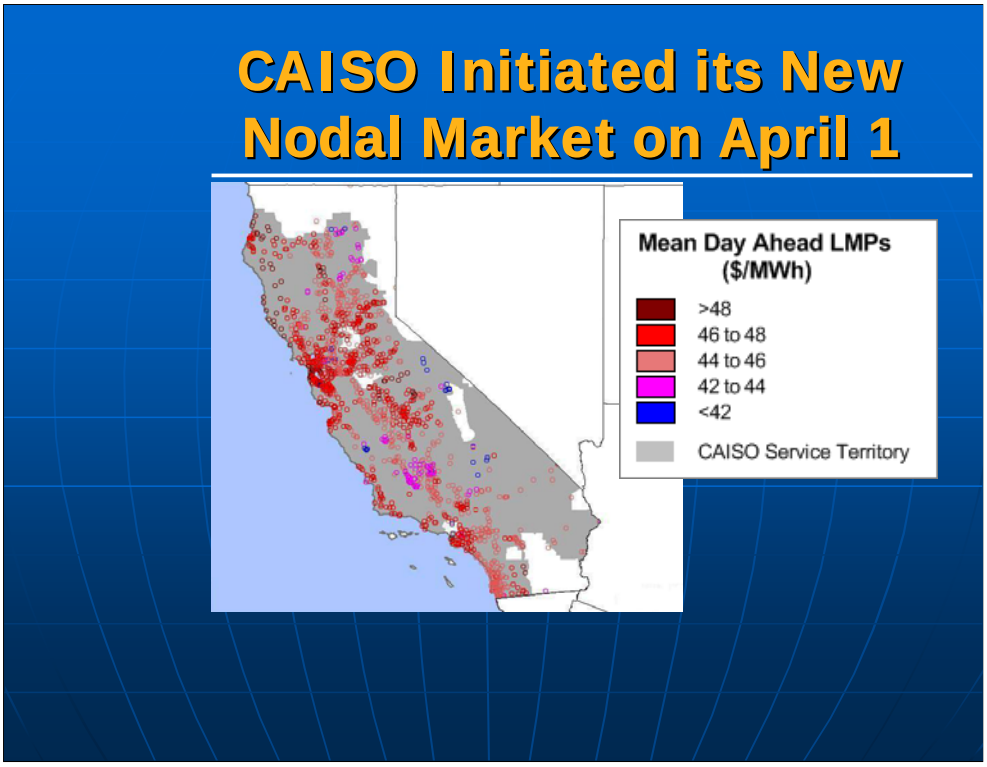
During the course of this winter, there were days when these terminals as well as the Everett terminal near Boston accounted for half of New England's gas supplies. On those days—days nearing all-time natural gas demand peaks in the Northeast—the basis from Henry Hub never exceeded $5.25 MMBtu. In the past, gas commonly reached a premium of $10-15 per MMBtu on peak days.

In contrast to the New England terminals, Gulf Coast LNG terminals such as Sabine Pass and Freeport last year sought authorization to re-export gas supplies elsewhere.

Last year, on January 6, the Midwest ISO began its new Ancillary Services Market at the same time it consolidated its operations into a single balancing authority area. The consolidated procurement of reserves with energy across the entire market yielded reliability and efficiency benefits and, it appears, lower price volatility.

Also in MISO, three Iowa utilities, Mid-American Energy Company, Muscatine Power and Water, and the Municipal Electric Utility of Cedar Falls integrated into MISO on September 1, bringing to the market over 4,000 MW of load and 7,500 MW of generation. Mid-American, alone, brought 1,500 MW of wind resources on the expectation that the renewable generation could be more efficiently used across the wider market footprint. The addition of the Iowa utilities did change congestion patterns in and around Iowa, but these changes were all manageable.

The integration of Nebraska utilities and Missouri Public Service into SPP's Energy Imbalance Service market added lower cost coal and nuclear generation to the RTO. Limited available transmission capability within the SPP footprint, north to south, resulted in frequent visible congestion and price separation in the market. SPP has approved several transmission projects that are intended to reduce congestion and bring down prices throughout the entire footprint; those projects are scheduled to be completed by 2013.



The biggest RTO development of the year was the long-awaited initiation of CAISO's new market on March 31. Since the market started, prices have been generally consistent with nation-wide trends, though CAISO experienced some early start-up issues.

During the first few months of the new market, energy price volatility in the real-time market lead to some extreme price outcomes, principally during the morning ramp hours in Southern California. On April 19, for example, San Diego experienced very high 5 minute prices caused by the dispatch of distant generators to solve a transmission constraint. Lack of flexibility in dispatching reserves in San Diego also contributed to this situation.

The California ISO addressed that problem and similar ones by moving in the direction of greater transparency, adapting and relying increasingly on the results of the market model and less on devices outside the model run such as exceptional dispatch and manually managed transmission constraints. This allows market participants to better understand the system as more of the market operations are reflected in locational prices and less is reflected in uplift and other out-of-market add-ons.

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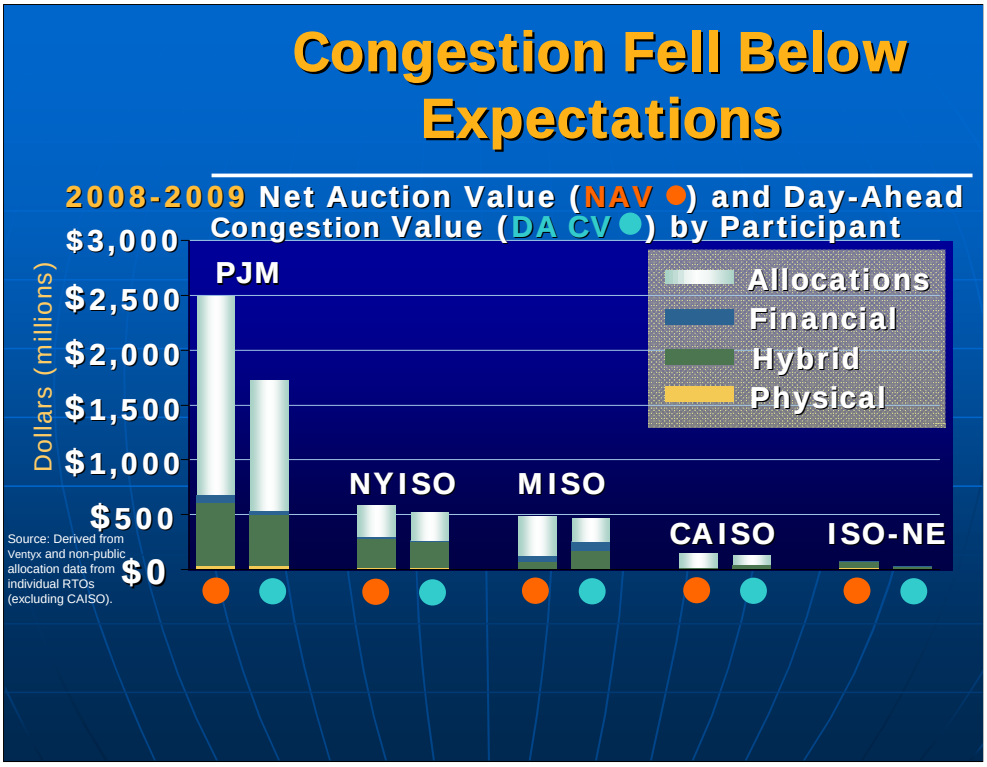
From the start of the market, over the course of 2009, average Day-Ahead Market locational prices of wholesale electricity in the California ISO fell into a relatively tight band across the state. Prices were highest in Northwest California and lowest at in-state hydro facilities in the mountains.

A major component in the difference in prices is the cost of congestion. This congestion component is what a financial transmission right (FTR), or in CAISO's case a congestion revenue right (CRR), is designed to hedge against.



One key impact of the recession has been a decline in the cost of congestion in the RTOs. RTOs allocate congestion revenues through instruments commonly known as financial transmission rights (FTRs), but they are also known, more descriptively, as congestion revenue rights (CRRs) in California and Transmission Congestion Contracts (TCCs) in New York. FTRs determine the net amount of FTRs based on the physical structure of the transmission system. Because the payout for an FTR comes from the cost of congestion over a path, the value of an FTR represents an expectation of that congestion costs or, in the case of a hedge, the value of eliminating the risk associated with market results.

It is not easy to compare congestion consistently across markets. Each RTO's Commission-approved tariff provides unique rules for how the congestion revenues and rights are allocated and/or sold. This analysis of congestion costs has delved into this painstaking detail because it is important to understand the role they play in the RTOs.

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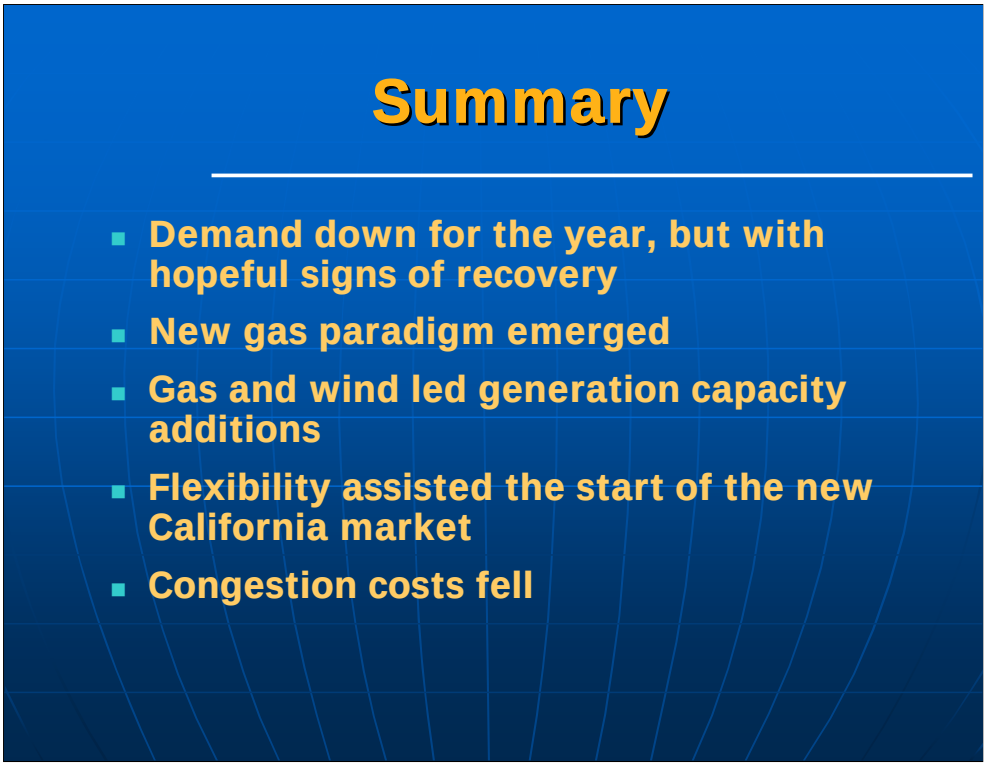
In each of the RTO markets, the cost of congestion fell below expectations as expressed in the RTOs' FTR markets. While congestion costs in the largest market, PJM, fell by a quarter, the largest drop in percentage terms was in ISO-NE, where falling demand and fuel prices were complemented by transmission additions that reduced congestion.

Much of the change in congestion costs was related to the congestion rights allocated to physical participants that account for over two-thirds the net value in the FTR market. These allocated rights are typically given to load serving entities to be used as hedges against congestion. This means the changing market value of the rights have little effect. In the market for purchased FTRs, purely financial players, participants who have no discernable physical position in the market, made approximately $3 million in net revenues on the change in congestion costs in 2009 primarily because congestion increases in MISO offset losses in PJM and ISO-NE.



In summary, while 2009 did not resemble 2008's rollercoaster ride, it was not boring. Gas, coal and electricity prices fell, and demand was off for the year.

A new gas world came into sharper focus with technological innovation possibly changing the paradigm for the gas market; the EPA will be studying the environmental implications of new production methods in new areas.

Almost 25 GW of new generation was added during the year, with natural gas and wind leading the way.

The California ISO embarked on a new market with enough flexibility to respond to start-up issues that arose; and

The cost of congestion fell in the RTOs as prices and demand fell.

Federal Energy Regulatory Commission

State of the Markets Report 2009

Item No: A-3

April 15, 2010