FEDERAL ENERGY REGULATORY COMMISSION

2004

STATE OF THE MARKETS REPORT

Staff Report by the

OFFICE OF MARKET OVERSIGHT AND INVESTIGATIONS

JUNE 2005

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2004
State of the Markets Report

An Assessment of Energy Markets in the United States in 2004

A Staff Report by the **Office of Market Oversight and Investigations**

Federal Energy Regulatory Commission

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Preface

This is the Federal Energy Regulatory Commission's third State of the Markets Report. Produced by the Commission's Office of Market Oversight and Investigations (OMOI), the report covers electric, natural gas, and other related energy market activity during 2004. In contrast to seasonal assessments, which focus on the near future, this report examines performance in the recent past. The State of the Markets Report presents findings regarding market conditions relevant to the Commission and identifies emerging trends that may soon require the Commission's attention.

The Commission created OMOI in April 2002 to focus its efforts on energy market oversight. Any errors in this report are the responsibility of OMOI alone and not of the Commission as a whole.

I want to commend the efforts of OMOI staff for this project. Major contributors to this team effort are listed in the Acknowledgments.

A fair energy market is everyone's responsibility. Please do your part. If you encounter inappropriate energy market behavior, contact our Enforcement Hotline toll-free by telephone at 1-888-889-8030 or via e-mail at Hotline@FERC.gov.

Thank you,

William F. Hederman
Director
Office of Market Oversight and Investigations

We encourage readers to provide feedback on this report by filling out the State of the Markets Report Evaluation Card at the end of the report, sending comments in an e-mail to SOM.2004@FERC.gov, or by contacting staff referenced in the acknowledgments by mail or phone.

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Executive Summary

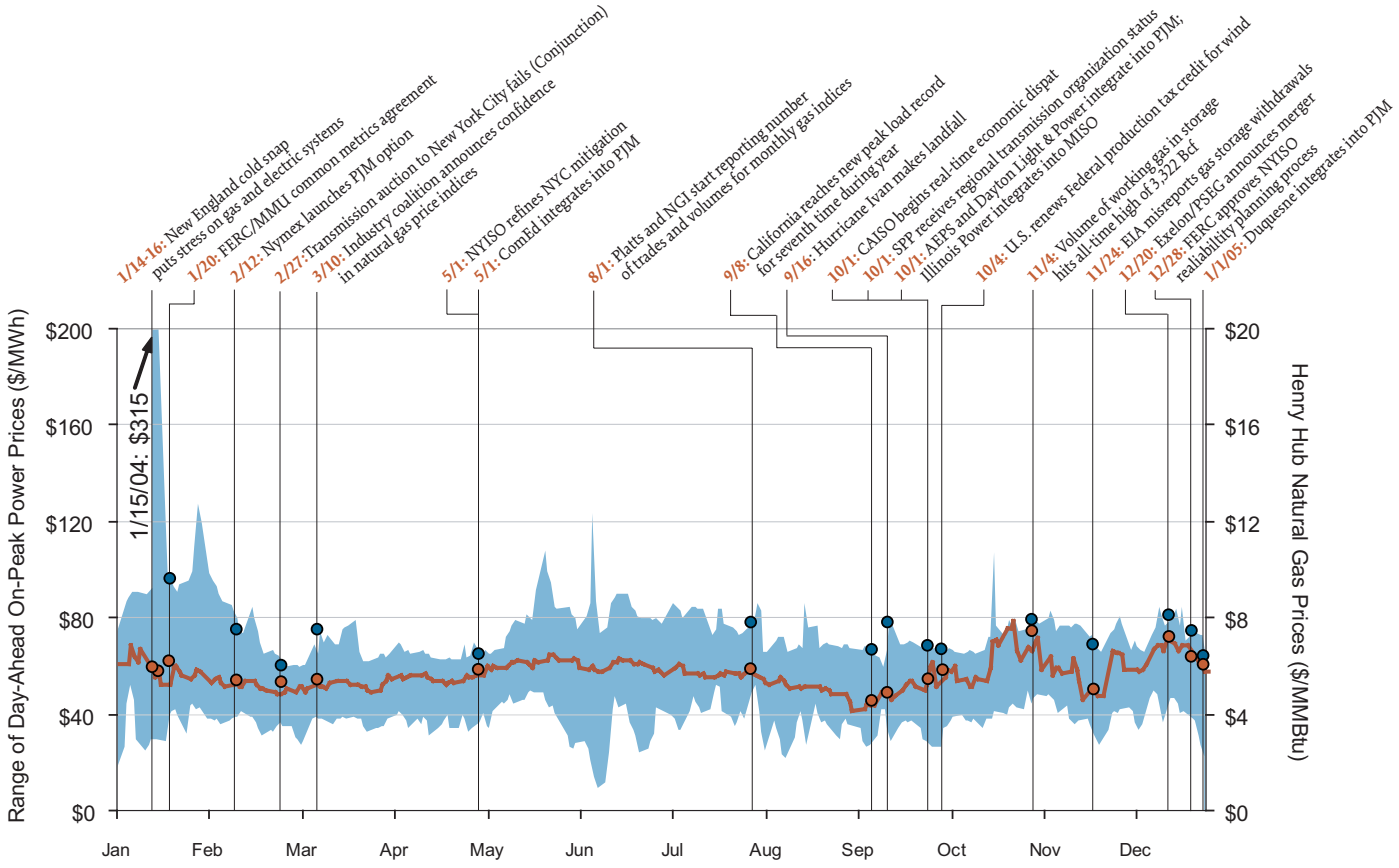
In 2004, U.S. natural gas and electric markets responded to broad upward price pressure as connections among energy markets became tighter. In New England in January, for example, a short, severe cold snap pushed the operational connections between natural gas and electric markets to the limit. During the year, financial energy markets expanded as many participants found it easier to enter the financial markets than the associated physical natural gas and electric markets. Global influences on U.S. energy markets manifested themselves in the form of higher oil prices and (early in 2005) in an early but developing North Atlantic spot market for natural gas.

Pricing

World oil prices rose 34 percent in 2004. This created upward pressure on many energy commodity prices globally and affected energy markets in the United States. For example,

- Average U.S. natural gas prices rose 7 percent nationally from 2003 to 2004, following a rise of 68 percent from 2002 to 2003. Regional patterns persisted. Natural gas prices were relatively higher in the Northeast and lower in the West.
- Spot coal prices rose 69 percent for eastern (central Appalachian) coal, and 7 percent for western (Powder

State of the Markets Timeline: 2004



River Basin) coal. Spot coal prices can influence electric power prices significantly, because marginal generators can choose to sell the coal or burn it to sell power. Because large quantities of coal are purchased under long-term contracts with specified prices, overall average prices for coal rose only 6 percent.

- Sulphur dioxide (SO_2) emissions allowance prices rose by 153 percent in 2004. SO_2 allowances were a major input for coal-fired plants without scrubbers, adding as much as $17.40 per MWh to a plant's cost.

Electricity prices followed the pattern set by fuel and emissions prices.

- In most regions where natural gas tended to be on the margin (e.g., New England, New York, Texas, and for on-peak hours at PJM West) prices increased by less than 5 percent. Florida and California both depended heavily on natural gas, and their price increases were 8 to 12 percent on peak—higher than for other gas-dependent areas.

- In areas where western coal tended to be on the margin (e.g., the Southwest and Great Plains), on-peak price increases were less than 6 percent.

- Where eastern coal (and associated emissions allowances) tended to be on the margin, prices rose more. In the Southeast and the Midwest, on-peak power prices rose by 11 to 19 percent. Off-peak prices in these regions increased even more, as much as 33 percent. Similarly, at PJM West, where coal was more often on the margin during off-peak hours, the average off-peak price increase was 25 percent.

RTO markets continued to administratively adjust prices, especially in reaction to market power concerns in constrained areas.

Weather and Its Effects on Markets

Weather put little stress on energy markets during most of the year. The winter of 2003–2004 was 6 percent warmer than the previous winter, and the summer of 2004 was the ninth coolest on record. There were two major exceptions to this pattern.

- A cold snap in New England in January 2004 underscored the importance of tight integration between the gas and electric markets during periods of stress. Although the two markets successfully responded to the severe weather, both industries subsequently analyzed the event to learn how they could coordinate better in the future.

- Hurricane Ivan hit producing regions of the Gulf Coast in September, reducing overall gas production in the United States by almost 1 percent. This probably contributed to a price increase in October.

Investment

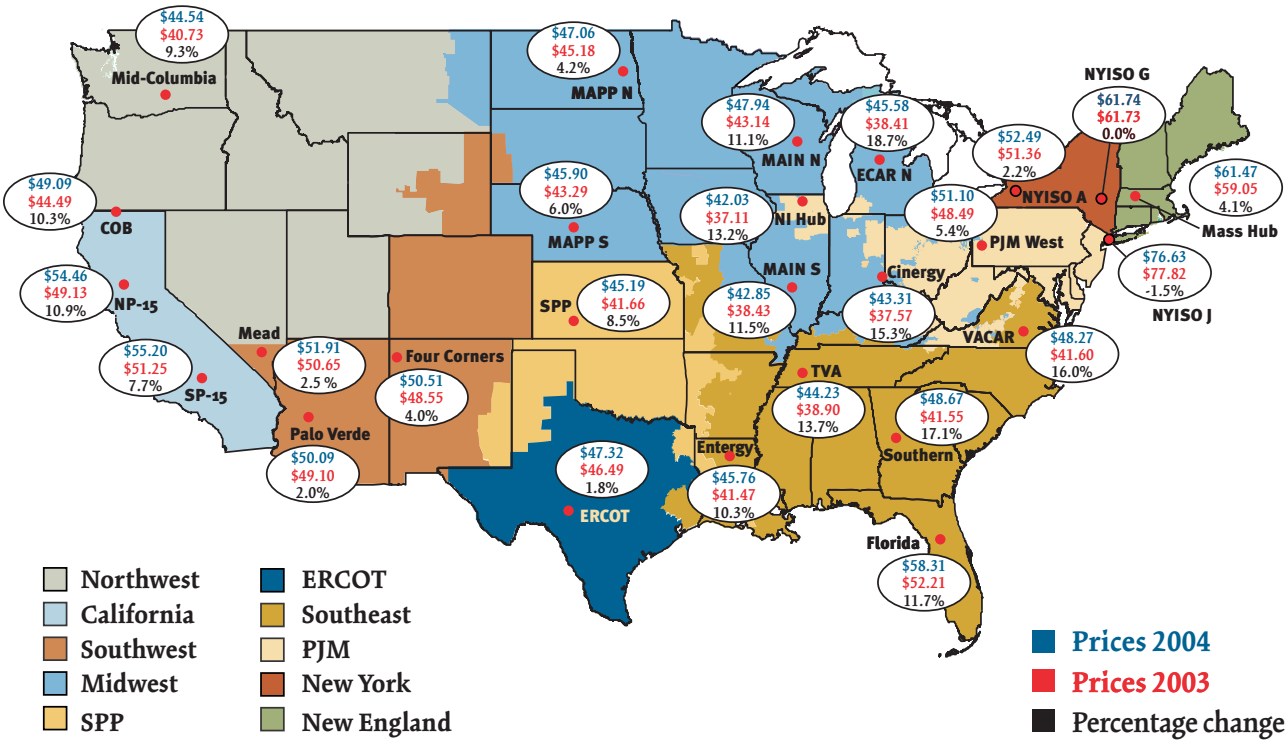
As a whole, the U.S. electric industry had significant overcapacity in generation in 2004. Appropriately, the markets signaled no need for new capacity nationally. At the same time, specific constrained regions did not have adequate capacity. These areas included Boston, southwest Connecticut, New York City, New Orleans, much of southern California, and the San Francisco Bay Area. Most of these areas also saw prices too low to signal new investment.

- In regions without location-specific pricing, price signals cannot distinguish between areas that need capacity and those that do not. Such regions include those outside regional transmission organizations (RTOs); areas within RTOs that do not yet have RTO-managed spot markets (Southwest Power Pool—SPP—and the Midwest Independent System Operator—MISO—in 2004); and zones within RTOs with zonal pricing (California and Texas).

- In New England, the independent system operator (ISO-NE) took many generators "out of market" and required them to run for reliability reasons, reducing price signals. The practice of pricing generators individually was so common that almost no difference existed between the market prices that ISO-NE published for energy in areas that were constrained versus those without constraints.

- New York City prices were high enough to make investment marginally attractive under best-case assumptions. In practice, much of the new capacity coming on line in the city was being built by a state agency.

Electric Regions with Pricing Nodes On-Peak Prices ($/MWh)



- Southern California prices would have provided about two-thirds of the revenue needed to justify investment, despite widespread concerns about the adequacy of reserves going into the next summer (2005).

In transmission, investment increased for the fourth year in a row; up 69 percent since 2001. At the same time, few new high-voltage lines came on line—931 circuit miles nationally—compared with an overall system of more than 150,000 circuit miles.

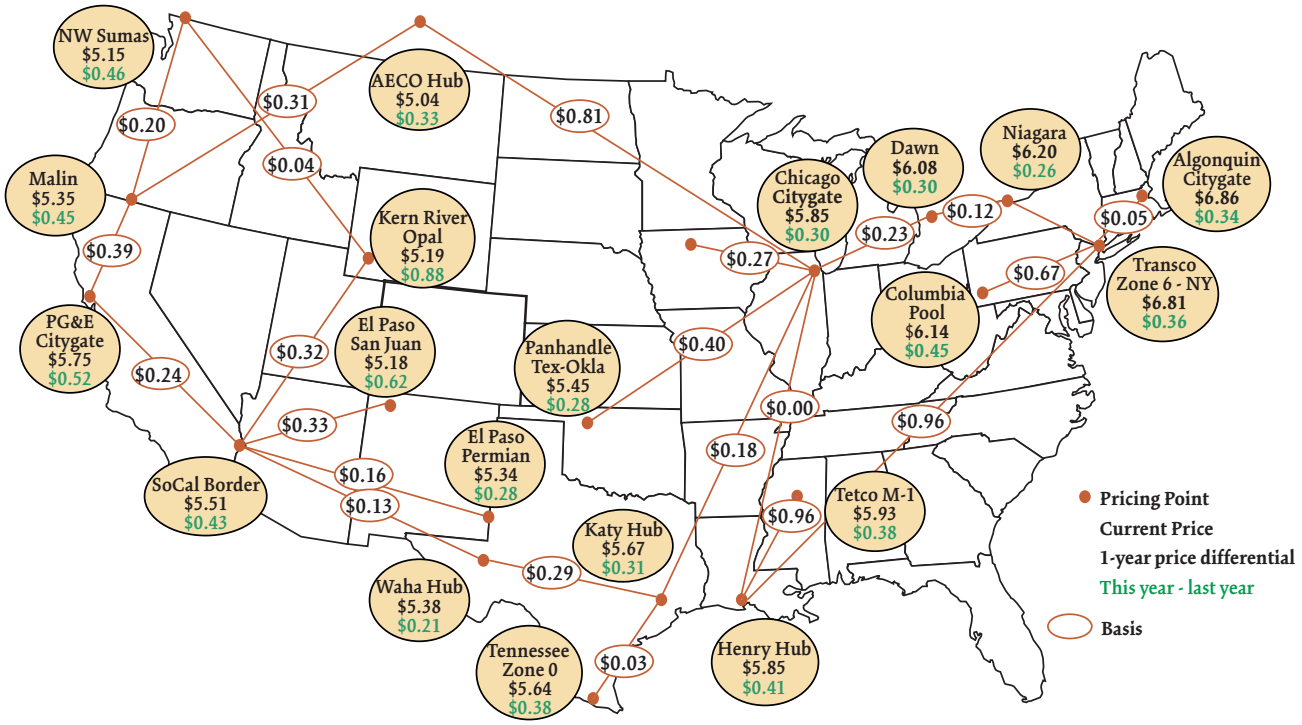
The natural gas industry has responded to price signals effectively for decades. Expenditures on exploration and production were up 45 percent from the average of 2001 and 2002. The industry continued adjusting its pipeline and storage infrastructure in 2004. Total expenditures were lower than in 2003, mostly because there were few projects to increase long-haul pipeline capacity after completion of the Kern River expansion in 2003.

Regional Issues

Electric power remained an essentially regional commodity, with markets that reflected regional institutions. About two-thirds of the country (as a share of gross domestic product) had adopted RTO models for organizing markets. In 2004, SPP formed an RTO, MISO advanced toward successfully implementing full RTO markets in 2005, and ISO-NE filed to become an RTO. Other RTOs continued to develop their markets.

The West (except California) and the Southeast constituted two broad regions without RTOs. In the West, bilateral markets have existed for years, and price quotations were available from liquid trading points in both the Northwest (mid-Columbia and the California-Oregon Border) and the Southwest (Palo Verde, Four Corners, and Mead). In the Southeast, markets were largely opaque—only the "Into Entergy" pricing point provided published prices

2004 Locational Natural Gas Prices



with reasonably high levels of liquidity. Elsewhere, published price indices relied on few trades or substituted analytic judgment for reports of real trades.

A continental market for natural gas has existed in North America for at least 15 years. In addition, a global *long-term* contract market for liquefied natural gas (LNG) has been growing. Entering 2005, there appears to be an emerging North Atlantic *spot* market for gas as well. During February and March, Western Europe experienced a natural gas price spike. When LNG cargoes stopped arriving at Lake Charles, reports followed that some cargoes had been diverted to Europe—just as had happened in reverse in recent years.

Financial Markets

The financial aspects of energy markets became more important in 2004.

Nontraditional buyers (mostly private equity and lenders to distressed assets) acquired almost 30 GW of generation in 2004, close to 5 percent of total capacity in the United States and more than five times as much capacity as in 2003.

Financial trading on the IntercontinentalExchange (ICE) rose by a factor of 10 for electric power. Although ICE represented only a fraction of all financial trading, the increase

appeared to signal a significant increase in overall financial trading of energy. This uptick was consistent with anecdotal reports of increasing hedge fund activity in energy markets. The effect of this trading on physical energy prices was not yet clear.

In natural gas markets, physical and financial market prices converged for most of the year. The exception was a period during the fall when physical prices dropped because storage was full.

During 2004, financial market players significantly improved the efficiency with which companies could address credit risk. Clearing arrangements let companies net out their positions and deal with a single platform instead of having to establish separate credit requirements for each customer.

Information

Energy markets depend on reliable information about prices and basic demand and supply conditions. In 2004, confidence in energy price indices improved, but the natural gas industry remained vulnerable to a lack of information about current supply and demand.

In the aftermath of the western energy crisis of 2000–01, confidence faltered in energy markets in general and price indices in particular. To address the situation, in 2003 and 2004, the Commission encouraged industry to improve the index reporting process. By 2004, reporting companies had better procedures in place to ensure accurate reports to index publishers. Index publishers in turn reported far more details about the indices (such as the number of transactions and total volumes reported for a given price). The Commission laid out requirements for indices to be included in jurisdictional contracts, and many market participants expressed greater confidence in using them. Nonetheless, a rising price environment challenged the new confidence, and pricing mechanisms remained under close scrutiny by policy makers in Congress and elsewhere.

Timely natural gas supply information remained scarce. In its absence, the Energy Information Administration (EIA) storage estimate is the best available indicator of the overall balance of supply and demand—even though it represents a tiny proportion of gas being produced or consumed at any given time. Late in November, one company's clerical error led EIA to underestimate storage injections for the previous week. During the rest of the trading day, gas prices rose by 15 percent. Because the reporting day happened also to mark the close of the Nymex December futures contract and bid week for monthly physical deliveries in December, the overall effects on the market were large.

Guide to This Report

The report has four further sections:

- **Essays.** Analysis of four topics relevant to the energy markets in 2004.
- **Electric Power Markets.** An overview and 10 detailed regional profiles of electric power markets around the country. The overview includes a short guide to the content of the regional profiles.
- **Natural Gas Markets.** An overview, a profile of national financial trading for natural gas, and five detailed regional profiles. The overview includes a short guide to the content of the regional profiles.
- **Other Related Markets and Market Factors.** Profiles of other markets related to natural gas and electric power markets, including coal, emissions trading, oil, petroleum, uranium, and wind; plus a review of 2004 weather.

We offer the State of the Markets Report as a resource for interested policy makers, energy customers, suppliers, traders, and interested members of the general public. We have written this report so that a reader can go directly to subjects of interest, as necessary.

2004 Issues in Energy Markets

This *State of the Markets Report* contains 4 essays: Markets Under Stress: New England Reacts to Record Cold, Electric Market Investment and Merger Trends, Energy Market Information, and Market Behavior Rules: Effectiveness Review.

Overview

Each essay considers a key issue affecting natural gas and electric markets in 2004:

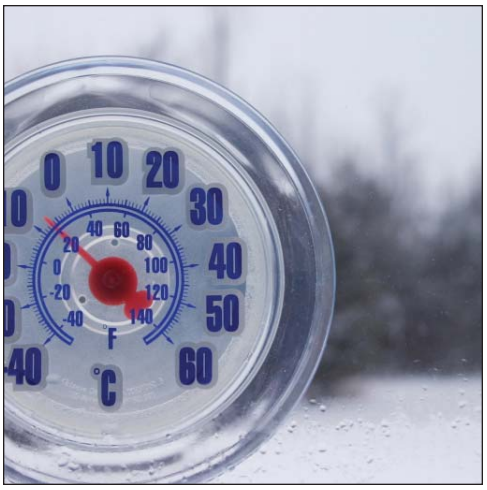
Markets Under Stress: New England Reacts to Record Cold. On January 15 and 16, 2004, New England faced its coldest weather since 1943. Both natural gas and electric markets responded successfully to the cold weather. However, the stresses of meeting demand for both natural gas and electric power during the cold snap showed the need for greater coordination between the two industries in the future.

Electric Market Investment and Merger Trends Investment was a central issue for the electric industry in 2004. Investment in transmission rose in dollar terms, but remained much lower than investment in generation and few high-voltage lines were added. Price signals to build generation were appropriately low in most of the country (which has ample generating capacity). Private equity, hedge funds and lenders acquired almost five percent of the nation's generating capacity.

Energy Market Information. In modern markets, information is essential for market participants of all kinds. During 2004, natural gas and electric industries improved the quality of published price indices by improving the quality of the information reported to index publishers and by publishing more information about published prices. The Commission improved reporting on its *Electronic Quarterly Report* of jurisdictional transactions. An error in EIA's natural gas storage reporting (due to a clerical error in one company's submission) made clear the importance of accurate, timely information. The error led to a 15 percent increase in price during one day in November and affected many related, longer-term natural gas markets.

Market Behavior Rules: Effectiveness Review. This essay reviews the effectiveness of the Commission's market behavior rules during their first full year in operation.

Markets Under Stress: New England Reacts to Record Cold



On January 15–16, Boston faced its coldest successive two-day period since 1943 in what would become New England's eleventh coldest month on record.[1] The extreme weather put simultaneous stresses on both electric and natural gas systems, stresses that were resolved by redistribution of spot gas supply at record high prices between heating and power loads.

The interaction of market forces and electric grid administration met the simultaneous needs for natural gas distribution and electric generation despite significant strains in market operations. The experience was a valuable one for gaining insight into how energy markets more generally perform under stress.

The normally tight supply/demand balance for natural gas in New England became critical when demand spiked and imports declined during the cold wave. High demand in eastern Canada, in the grip of the same cold weather, coupled with recent production declines in the Canadian Maritimes reduced natural gas deliveries below pipeline capacity. The tight gas supply situation made gas-fired generation problematic.

New England has become increasingly dependent on natural gas-fired generation. Developers have installed more than 10,000 MW of natural gas-fired generation capacity since 1999. From January 14 to 16, New England electric grid operator ISO-NE experienced a peak load of 22,800 MW—substantially below the total winter capacity of 32,640 MW. Much of New England's natural gas-fired capacity relies on the spot market for supply. When heating demand increased with the extreme cold, spot natural gas availability dropped and prices spiked. On January 14, 7,073 MW of natural gas-fired generation (53 percent) was out of service, largely because of a lack of fuel. These outages resulted, in part, from electric price signals that failed to attract spot natural gas to electric generation.

As a consequence, some generators with firm natural gas contracts sold their supplies on the spot market rather than produce power. Resulting high outage levels caused an electric reserve deficiency, prompting ISO-NE to urge conservation and issue a potential blackout warning. System stability was restored when several natural gas units returned to service at ISO direction. Warmer weather ultimately ended the crisis.

For the most part, energy markets did an effective job of handling the simultaneous, competing demands on natural gas for heating and electric generation.[2] In particular:

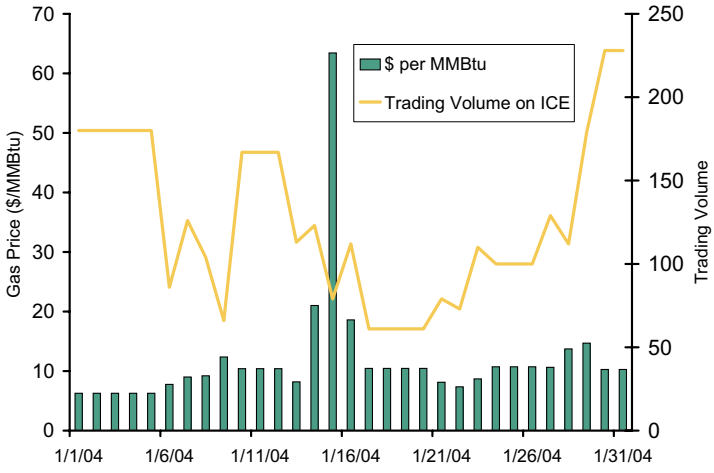
- The natural gas spot market appropriately rationed supply to the highest-value users – to the heating load.
- Regional gas was legitimately in short supply due to pipeline capacity limitations and import supply declines.
- Natural gas sales by electric generators during the cold snap were allowed by ISO-NE rules and were economically rational because the power market cleared at a price below the marginal cost of generating with natural gas.
- Electric prices cleared below marginal cost largely due to ISO-NE day-ahead market operation and reliability unit commitment practices, even though natural gas-fired generation was critically needed.
- Depending on natural gas units that may not have firm fuel supply commitments for reliability reserves when pipeline operations are constrained may overstate realistic available reserve margins.

New England Gas Market Conditions

Although the cold wave spread over the eastern United States and Canada, the most extreme cold weather was concentrated in New England and the eastern Canadian provinces.

For January 14, Platts *Gas Daily* reported 79,000 MMBtu traded for next-day natural gas delivery, less than half of the 167,000 MMBtu reported on January 9. Figure 1 shows the daily prices and trading volumes for the Algonquin citygate for January 2004.[3] Colder weather and reduced supplies pushed next-day spot prices on January 14 to a record New England price of $63.42/MMBtu. Trades ranged from as low as $38 to as high as $75/MMBtu. Prices on the IntercontinentalExchange (ICE) declined at all trading points except New England and New York.

Fig 1: NE Gas Price Spike

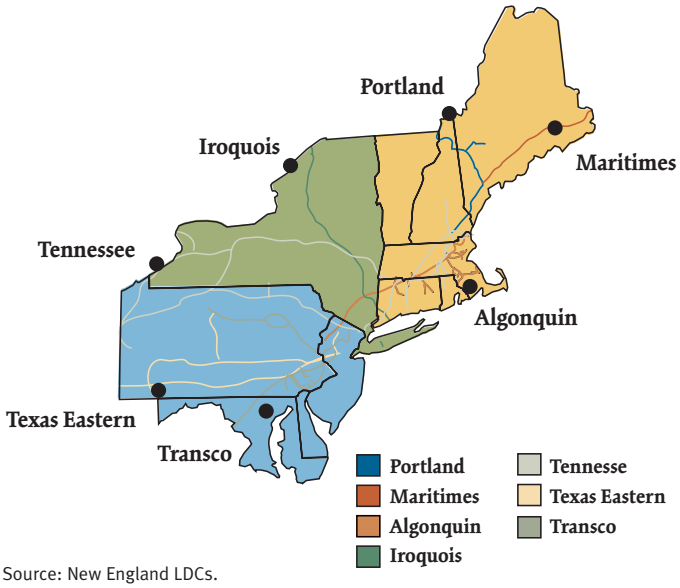


Source: Derived from Platts *Gas Daily* data from January 14-16, 2004.

Interstate Pipeline Operations

Natural gas pipelines serving New England include Algonquin Gas Transmission, Texas Eastern (which ends in New Jersey, but supplies most of the gas delivered in New England through Algonquin), Iroquois Gas Transmission, Tennessee Gas Pipeline, Portland Natural Gas Transmission, and Maritimes and Northeast (see Figure 2).

Fig 2: Pipelines Serving New England



Source: New England LDCs.

Transco, also shown on the map, primarily serves New York City but can reflect price effects from New England.

On January 14, Algonquin, Texas Eastern, Tennessee, and Transco made use of much of their capacity, reaching load factors ranging from 92 to 99 percent. Average capacity use for the region was 92 percent, due to less use of Iroquois (73 percent), Portland (89 percent), and Maritimes (75 percent). Overall regional capacity use averaged 99 percent on January 15 and 96 percent on January 16.

Average regional use was lower on January 14 because of capacity constraints on the eastern side of the TransCanada system. Natural gas exports by a regional marketer fulfilling a peak-service contract with a utility in eastern Canada were also a factor. Physically, gas continued to flow from Canada into the United States on Iroquois, but the marketer fulfilled its Canadian contract by nominating a reverse flow and net import volumes were reduced.

The pipelines and the LDCs serving New England had been issuing flow restriction and operational flow order (OFO) notices for several days before the price spike, indicating that they had little operating flexibility. On January 7, Tennessee, Texas Eastern, and Algonquin posted critical notices, restricting interruptible services and "due shipper" gas[4] in market areas and requesting that shippers remain in balance – actually flow what they claimed they would. Further, Tennessee disallowed "supply to market" nomination increases, limiting supply receipts to the market area.

By the morning of January 14, Tennessee and Algonquin posted critical notice OFOs with penalties for shippers deviating from nominations, in addition to the prior restrictions. Algonquin also issued a critical notice OFO requiring shippers and delivery point operators to limit the daily discrepancy between scheduled and actual deliveries to 2 percent or less, with unauthorized quantities charged a $15/dekatherm penalty. Tennessee Natural Gas Pipeline's balancing alert OFO for Zones 5 and 6 included a potential penalty of $15/dekatherm, plus the applicable index price. Iroquois, in anticipation of cold weather, requested on January 13 that shippers take their exact scheduled quantity (disallowing daily over-runs and hourly takes in excess of 120 percent of contracted capacity during this period).

As conditions moderated from January 16 to 18, the pipelines lifted the balancing OFOs but typically maintained critical-notice restrictions. With improved operating conditions, Tennessee lifted its balancing alert OFO for Zones 5 and 6 effective January 16, 2004. On the same day, Iroquois lifted hourly balancing and flow control conditions. On January 17, the Portland Natural Gas Transmission System lifted a critical notice requiring shippers to stay within 105 percent of their daily nominations and Algonquin lifted its two-percent balancing OFO.

LDC Operations

During this period, LDCs in New England experienced "design" winter weather conditions of -15-degree Fahrenheit wind-chill adjusted average temperatures—heating conditions they are designed to serve. Aggregate New England LDC natural gas delivery, or "sendout" by source, is shown in Figure 3. On January 15, total LDC load exceeded "design" sendout by 112,000 MMBtu/day, or 3 percent of design capacity.

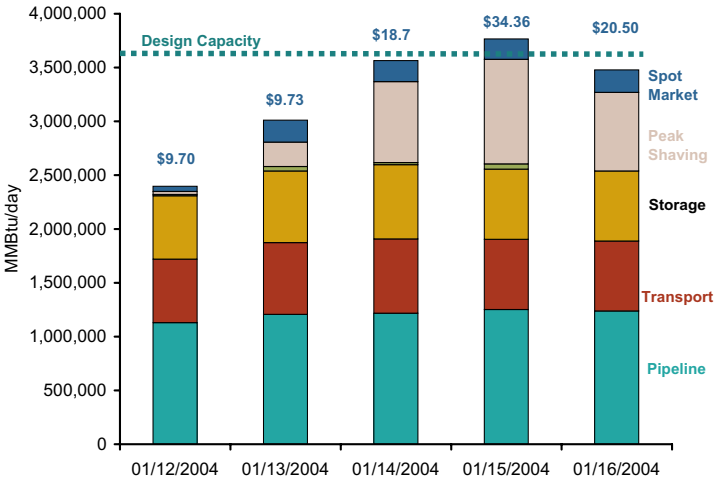
On January 13, LDCs used all available flowing pipeline supplies and began to pull substantial volumes from local "peak shaving" capacity—primarily liquefied natural gas (LNG). The LDCs also bought spot market natural gas to supplement their other supplies. The spot purchases helped LDCs

maintain an orderly drawdown of limited peak-shaving supplies. One instance of loss of natural gas service occurred January 16 in Hull, Massachusetts, when KeySpan lost pressure at the far end of a lateral in the Hull area, causing several hundred customers to lose service. Demand, in that case, exceeded the capacity of the lateral—a situation later remedied by installation of a new distribution line. Service was restored within 12 hours.

Peak-shaving supplies were critical to serving LDC load when heating demand exceeded pipeline capacity. From January 14 to 16, natural gas from peak shaving facilities served 23 percent of total load. Figure 4 shows aggregate New England peak-shaving capacity, usage, and LDC spot purchases during that period. Peak shaving is designed to operate for a brief period, usually one to three days. As a rule, actual peak-shaving capacity varies, depending on factors such as prior use.

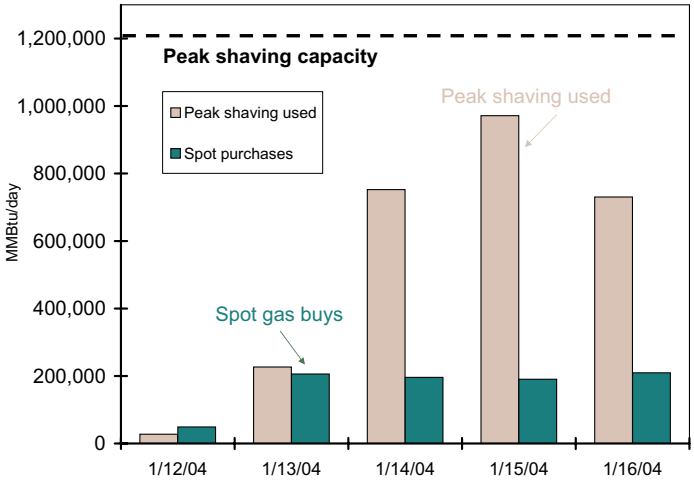
Like the interstate pipelines, LDCs in New England issued OFO balancing notices to protect their systems and to maintain consistency with the upstream pipelines. Beginning January 8, Southern Connecticut Gas Co. and Connecticut Natural Gas posted critical day OFOs for January 9, limiting balancing allowances to 2 percent for under-deliveries and 10 percent for over-deliveries. On January 9, Yankee Gas issued an OFO limiting under-deliveries to 2 percent and over-deliveries to 20 percent. Penalties were significant at three times the prevailing spot price. On January 14, NSTAR and Keyspan Energy initiated "critical days" for under-deliveries, with penalties of up to five times the daily spot price. The same day, the New England Gas Co. and Bay State Gas also issued OFOs for 2 percent imbalance tolerances.

Fig 3: LDC Sendout Reached Design Capacity



Source: New England LDCs.

Fig 4: Spot Gas and Peak Shaving



Source: New England LDCs.

Table 1: Spot Transactions

Largest Sellers			Largest Buyers		
Trader	Volume (MMBtu)	Percent	Trader	Volume (MMBtu)	Percent
A	241,900	10.7	A	354,500	15.6
B	191,999	8.4	F	232,700	10.2
C	168,600	7.4	G	174,300	7.7
D	158,400	7.0	E	170,600	7.5
E	155,200	6.8	H	143,400	6.3

Source: Derived from ICE data January 13-16, 2004.

Analysis of natural gas spot market trading

OMOI analyzed trading statistics obtained from ICE.[5] The data showed no excessive concentration or unusual trading patterns. Table 1 shows market shares for the five largest buyers and sellers in the Northeast physical natural gas markets from January 13 to 16.

Trader names are kept confidential, but the traders are labeled by letter in descending order of sales and purchase volumes.[6] Based on the data in Table 1, the spot natural gas market does not appear to have been dominated by a large seller that might have been in a position to exercise market power.

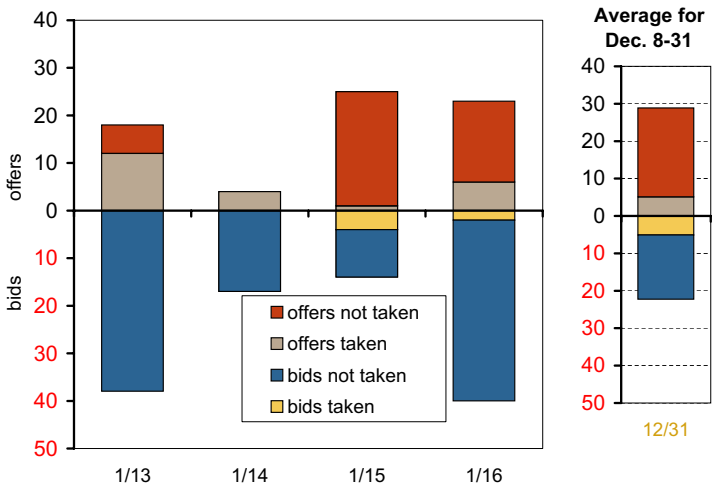
Analysis of individual trades shows that prices were driven by buyers competing for a limited supply of spot market gas during the period. On the ICE platform, prospective buyers post bids to buy and prospective sellers post offers to sell. When supply is unconstrained there is a degree of give-and-take in price formation. A seller may retreat from a high offer to sell and lower its offer to entice a buyer to buy, or accept the buyer's bid as posted. Buyers can effectively do the same. During December 2003 trading, as a comparison when the gas market was unconstrained, the patterns of bids and offers show that sellers would take buyers' bids at about the same rate as buyers would take sellers' offers. A greater number of bids and offers were left on the table. The December pattern is shown in Figure 5. The left side of the figure shows that from January 13 to 16 there was little give-and-take over prices. On January 13, no bids to buy were accepted and only a few offers to sell were rejected. On January 14, prices averaged $63.50/MMBtu when all offers to sell were taken and all bids to buy were rejected. By January 15, buyers were more successful when prices declined to $18.60/MMBtu at the highest. On January 16, the trading pattern reverted to one more like December.

From January 13 to 16, natural gas prices appear to have been driven by buyers with unfulfilled obligations competing for limited spot market supplies.

Retail marketers, as a business strategy, often chose to rely on the spot market rather than reserve capacity for unusual conditions. Some LDCs charged penalties of up to five times the prior day's spot market price when load exceeded the supply tendered by the marketer. On January 14, the short supply penalty would have been $105/MMBtu (or five times the prevailing index price of $21.00/MMBtu) for Boston-area markets. A marketer in short supply would rather pay the prevailing $63.50/MMBtu price than incur a $105/MMBtu penalty.

During extreme weather, LDCs rely on peak shaving to serve loads over and above natural gas stored or flowing. Peak-shaving sources typically have a limited inventory that, once exhausted, generally is gone for the season. LDCs husband their peak shaving carefully, especially early in the winter, to be prepared for contingencies that might arise later in the season. For example, supplies are especially short when late winter cold occurs after underground storage inventories have been depleted.[7] Loss of service to customers can be extremely expensive for an LDC. Such events damage a company's reputation and impose costs required for relighting pilot lights house-by-house. Access to spot gas is, consequently, extremely valuable.

Fig 5: ICE Trading



Source: Derived from ICE data.

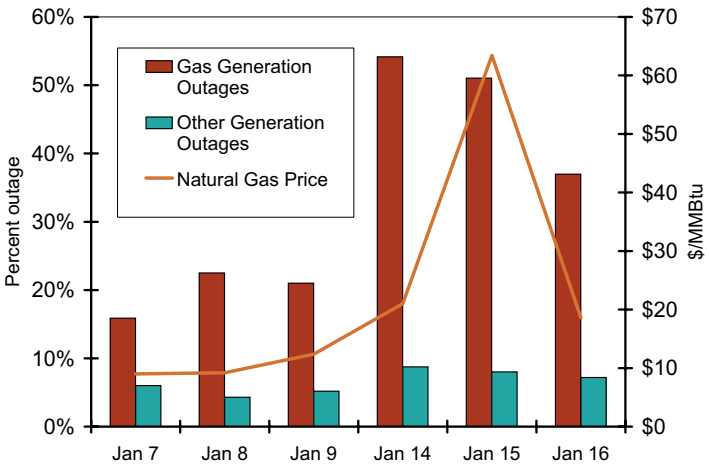
Power Market Operations

From January 14 to 16, ISO-NE struggled to keep the electric grid operating in the face of record winter demand and widespread generation outages. Although New England has more than 32,700 MW of capacity, ISO-NE had difficulty serving winter peak loads that averaged 22,400 MW during the cold snap due to unexpectedly high outage levels for gas-fired generation.

During the past six years, the natural gas portion of New England's generation capacity has increased dramatically,

from 12 percent in 1998 to 41 percent in 2004. As shown in Figure 6, gas-fired generation outages were more frequent than with other fuels, and outages jumped sharply when spot prices spiked. Several factors contributed, including tight gas supplies, pipeline operational conditions, equipment failures related to extreme cold weather and difficulties in aligning fuel acquisition with power market prices and commitment timelines.

Fig 6: Increased generation Outages



Source:Derived from Platts *Gas Daily* and ISO-NE data.

ISO-NE struggled to get enough generation on line

On January 13, ISO-NE's day-ahead estimate indicated it would have enough generation to meet expected electric loads. ISO-NE had granted economic outages of 2,327 MW and estimated that it would still have a surplus of 583 MW for operations on January 14. After declaring economic-outage status, some generators then sold their firm natural gas supply into the spot market, assuming that they would not be called upon to run. Under ISO-NE rules, generators were allowed to request an economic outage if they believed the price of power would be lower than their marginal cost of operation.

By January 14, ISO-NE increased its load forecast by 300 MW. Early that morning, an additional 822 MW of generation became unavailable, 507 MW of which was gas-fired. ISO-NE was left with a projected reserve deficiency of 84 MW. ISO-NE was given little advance notice of the precarious supply situation for most of the natural gas units. At 10:00 a.m. on January 14, ISO-NE ordered all of the generators that had declared economic outages to return to service as soon as possible. It also cancelled prescheduled maintenance and other work on critical transmission lines, generators, and communications links.[8]

Between 5:00 and 7:00 p.m. on January 14, ISO-NE implemented OP4 Actions Number 1 and Number 6 because the

Table 2: ISO-New England Unit Status and Fuel Type on January 14, 2004 at 6:00 pm

	Generation Available (MW)			Type Outage		
	Ran	Didn't Run	Total	No Fuel	Mechanical	Total
Gas only	4,271	6,061	10,332	2,964	3,097	6,061
Gas/Oil	2,020	1,012	3,032	36	976	1,012
Oil/Gas	2,850	165	3,015	56	109	165
Oil+Jet+Diesel	3,994	843	4,837	0	843	843
Hydro	3,007	262	3,269	125	137	262
Coal	2,409	430	2,839	0	430	430
Nuclear	4,399	12	4,411	0	12	12
Wood+	762	143	905	0	143	143
Total	**23,712**	**8,928**	**32,640**	**3,181**	**5,747**	**8,928**

Source: Derived from ISO-NE data. * Generation that sold fuel estimate at 1515 MW based on generator gas sales of 290,396 MMBtu/day, 8000 MBtu/MW-hr heat rate.

large number of outages combined with higher-than-expected loads caused it to experience a 108 MW shortfall in operating reserves.[9] By 6:00 p.m., at the time of the peak, outages had increased to 8,928 MW (see Table 2). Imports during this period totaled 350 MW, nearly half the available interchange capability. Only one of the eleven units on economic outage actually made it back on line. The demand saving from demand-response programs was about 200 MW. Despite the reserve deficiency, all load was served.

The situation seemed to improve on January 15, but conditions deteriorated before they recovered late in the evening. ISO-NE's morning report listed outages of 7,972 MW and a 777 MW capacity surplus, a forecast that proved optimistic for much of the day. Throughout the day generation availability was volatile—some units came back on line, while others declared weather-related outages. During the afternoon, some dual-fired generating units in New York began converting from gas to oil. Coordination between ISO-NE and the New York Independent System Operator (NYISO) resulted in an increase in New York-to-New England transfers from 800 MW to 1,400 MW. During the afternoon, NYISO exported up to 1,100 MW to New England. At 6:00 p.m., actual outages exceeded the morning forecast, totaling 8,369 MW. In Southwest Connecticut, unexpected generator outages led to concerns about the area's ability to cover the loss of its second largest contingency.

At 7:30 p.m., ISO-NE issued a press release, stating that it was "taking precautionary measures, up to and including preparing for rotating blackouts, to maintain the integrity of the bulk power system".[10] The press release also requested that consumers conserve energy. Helpfully, four units, representing another 938 MW that had initially declared economic outages, returned to service and contributed an estimated 278 MW. The net result was that ISO-NE finished January 15 with a 717 MW surplus.

On the morning of January 16, ISO-NE predicted a 701 MW surplus and 22,727 MW of load. The morning forecast turned out to be overly pessimistic. As actual load was nearly 10 percent less than forecast[11] and six more units representing 1,661 MW that had declared economic outages returned to service. At the time of that day's peak, actual outages totaled 6,328 MW compared to the 8,128 MW forecast that morning. The surplus at the time of the peak was 2,184 MW.

Reasons for the outages

A total of 7,073 MW of the natural gas-fired New England generation fleet of was out of service at the time of the peak on January 14, 2004. Fully 3,000 MW was out of service due to lack of fuel. The rest was out for mechanical reasons, much of that weather-related. Many generators reported problems, for example, with frozen fuel and water lines, air and river water intakes clogged with ice and cold-damaged pump seals.

Most of the gas-fired generation capacity in New England was not supported by firm pipeline capacity, but relied instead on interruptible transportation, secondary firm, off-peak supply from LDCs, and spot market natural gas. These supplies were unavailable under high heating-demand conditions. Only 40 percent of natural gas-fired generation was supported by firm transportation capacity.[12]

Lack of physical gas supply due to transportation or supplier interruptions was responsible for approximately one-half of the fuel-related gas outages. All of the units that declared economic outages were Installed Capacity (ICAP) resources.[13]

Several units had dual-fuel capability but were unable to run, with operators contending that air-quality permits allowed them to use oil only when natural gas was physically unavailable. As a consequence, their dual-capability was of no benefit when it was uneconomical to burn gas or when gas was restricted to ratable volumes that were insufficient to run the unit. Another generator stated that it was forced to de-rate its unit because it had reached its daily NOx limits. Finally, owners of several dual-fueled generators stated that, though their units were listed as dual-fueled, their actual ability to use an alternate fuel was (1) limited by the configuration of their units, (2) nonexistent because they ceased to maintain costly reserves of fuel oil onsite or (3) the parts necessary to operate on oil had not been installed.

Generators with firm gas supplies saw few clear economic incentives to operate. Under the ISO-NE tariff, generators

were entitled to elect not to run if it was uneconomical for them to do so.[14] This economic calculus allowed them to consider opportunities lost by committing the generation resource to ISO-NE. Differences between natural gas and electric timelines for activities in advance of gas or power flow would have exposed a generator to significant economic risks, particularly during periods of high price volatility in the natural gas spot market.

Timeline Risks

To assure the availability of natural gas when called upon to run, a generator had to nominate pipeline capacity before it was assured that its offer would be successful in the ISO-NE market. Natural gas transportation nominations were required by 12:30 p.m. to guarantee primary firm-point reservation, well before the 4:00 p.m. day-ahead power market schedule was issued. If the offer were not accepted, the generator would have natural gas it might have difficulty selling or arranging for delivery to an alternate point. If natural gas were undelivered, the generator could have faced a severe imbalance penalty or had difficulty getting the gas returned until "shipper due gas" restrictions were lifted. Figure 7 compares the conflicting timelines for the gas and electric markets.

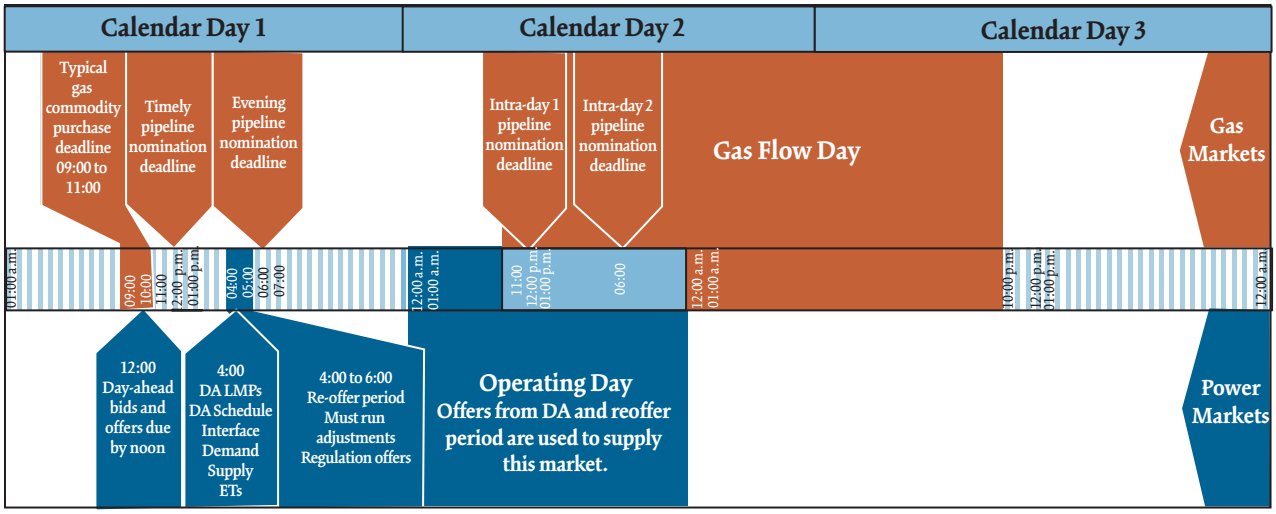
Likewise, if a generator offered its units to ISO-NE without securing gas because it did not expect the unit to be accepted, the company would be at financial risk of having to purchase gas in the intraday market at a price significantly higher than its offer, or purchase replacement power at unpredictable real-time LMP prices. If a generator believed it likely that its offer would not be accepted or that it would have difficulty obtaining gas if it were accepted, opting out of the power market became the economically rational decision.

Negative Spark Spreads

Prices for power in ISO-NE's day-ahead market produced a negative "spark spread" through the cold snap. A spark spread is negative when fuel costs for generation exceed the market value of power. During the cold snap, the real-time market showed a negative spark spread for all but a handful of hours. The failure of electric energy prices to move high enough to make gas-fired generation economical was a root cause of the reserve shortfall during this period. Figure 8 shows spark spreads from January 14 through 16.

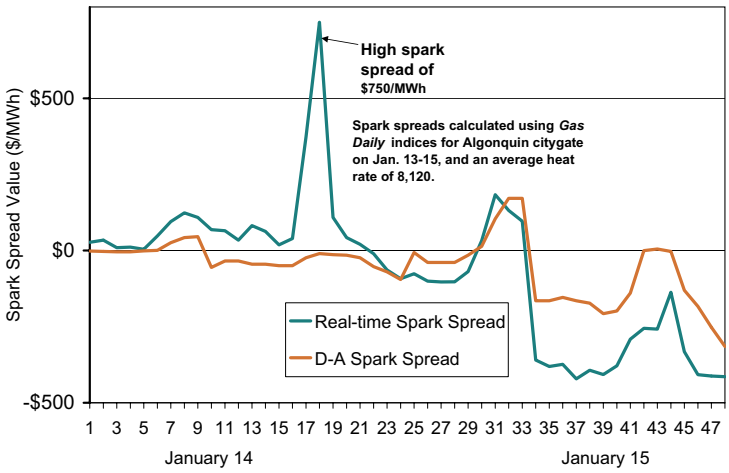
On January 13, the day-ahead market produced a load-weighted average power price of $113/MWh for January 14 operations. The average natural gas price for the January 14 flow day was $21/MMBtu. An efficient, combined-cycle generator with a 7,000 MMBtu/MWh heat rate would require a power price of at least $147/MWh to cover fuel

Fig 7: Natural Gas and Electric Market Timeline



costs. With market prices clearing below what was needed to attract natural gas-fired generation, some operators concluded there would be enough non-gas generation to serve the expected load. In response, they requested economic outages from ISO-NE on January 13 to sell their supply into the natural gas spot market. In approving these requests, ISO-NE believed (at that time) that there would be sufficient non-gas power available to cover anticipated load.

Fig 8: Day-ahead and Real-time Spark Spreads



Source: Derived from Platts *Gas Daily* and ISO-NE data.

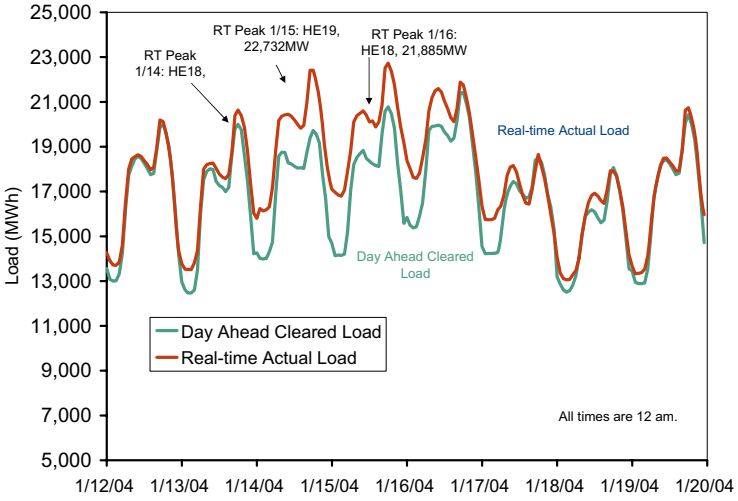
Factors Behind Negative Spark Spreads

Power buyers submitted load-price bids in the day-ahead market that cleared only a portion of the anticipated real-time load. Through their load-price bids, buyers signaled that they were unwilling to pay the marginal cost of gas-fired power, or that they were unaware that gas prices would rise as high as they did. As a result, the day-ahead market cleared at a price below the marginal cost of natural gas-fired generation. This meant that a substantial portion of real-time load would have to be served with power bought in the real-time market. Figure 9 shows the gap that developed between day-ahead and real-time load from January 14 through 16.

Much of the real-time load was served by reliability-dispatched units, reducing the level of load cleared in the real-time market. During the night of January 13-14, ISO-NE experienced a greater-than-anticipated level of outages, leaving ISO-NE with insufficient reserves. ISO-NE responded by recalling natural gas units on economic outage status. Generators that made it back on line were paid their offer price, but that price did not affect the market clearing price. Payments to reliability-committed units were recovered through "uplift" charges that did not directly affect the energy market price.

Day-ahead bids for January 15 also failed to clear at prices high enough to attract gas-fired power generation. The spot gas price at that time averaged $63/MMBtu, indicating that a power price of at least $441/MWh would be needed to make gas-fired generation economical (at a 7,000 heat rate). The load-weighted average day-ahead power price, however, was only $316/MWh. Even though natural gas prices were available then and it was clear that gas-fired generation would be needed, the market still did not clear at a price high enough to attract natural gas-fired generation.

Fig 9: Day-ahead Loads Fall Short of Real-time Loads



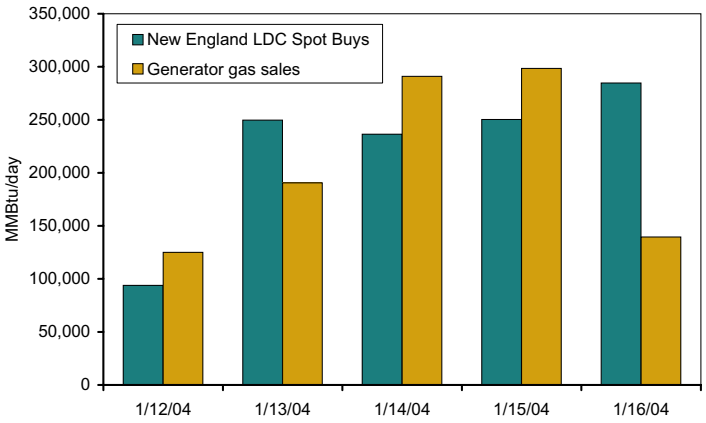
Source: Derived from ISO-NE data.

Gas Sales by Electric Generators Helped LDCs Maintain Service

Power prices in the ISO-NE day-ahead and real-time markets made it more economical for a generator to sell its natural gas supply on the spot market than to produce power.

The spot market served to reallocate natural gas supply from electric generation to heating service in response to clear price signals. Natural gas sales by generators helped increase supply on the spot market, benefiting LDCs needing supplemental natural gas to protect their limited peak-shaving inventory. Absent such sales, spot prices could well have reached even higher levels. Figure 10 compares LDC spot purchases to natural gas sales by electric generators. The quantity of spot natural gas bought by LDCs was comperable to the amount sold by electric generators.

Fig 10: Spot Natural Gas Transactions



Source: Derived from ICE data.

Conclusions

The natural gas spot market functioned competitively in rationing supply. Although spot natural gas prices reached extraordinary levels, a Commission investigation found no indication that these prices were the result of market manipulation. The investigation also found no evidence that pipeline capacity was withheld, no evidence that natural gas supply was withheld, and no evidence of manipulative trading behavior. Prices appeared to be the result of a supply shortage driven by extraordinary demand that left little residual supply available for allocation through the price-driven spot market. Buyers were willing to pay record prices because the consequences of failure to obtain supply exceeded the cost of paying these unusually high prices. The high spot prices provided the driver for the beneficial movement of gas from the power sector to the heating market, without which continuity of gas service and the public health and safety could have been imperiled.

The natural gas-electric interface timeline needs better coordination, but infrastructure constraints will limit benefits. Natural gas-fired generators must coordinate their operations consistent with both natural gas and electric business practice timelines. Under current timelines, generators must purchase and schedule pipeline transportation before day-ahead power schedules are announced. The gas operating day commences at 10:00 a.m., while the power day commences at midnight. Thus, power operations straddle two natural gas days, and vice-versa. Under less stressed operating conditions, the natural gas misalignment can be managed using pipeline imbalance tolerances. When natural gas prices spike and display day-to-day volatility, the operating-day overlap and schedule mismatch can expose a generator to significant costs and potential losses. Making the natural gas and electric day synonymous could reduce the inter-day price mismatch exposure. It may be more difficult, however, to resolve the problem of synchronizing natural gas commitments with power commitments, because one part of the deal must be committed to before the other can be entered into.

Further hourly flexibility for pipeline transportation services could help match power and gas scheduling. Hourly flexibility on pipelines is more difficult to provide when a pipeline is running close to capacity. When natural gas capacity is constrained, pipelines have little flexibility to handle the sudden withdrawals involved with real-time power dispatch.

In response to operational problems revealed by this incident, ISO-NE implemented a set of cold-weather procedures intended to make electric generation more secure when natural gas supplies are tight. Two key provisions would address the timeline problems that arose last winter. First, ISO-NE will cancel scheduled economic outages and request that dual-fuel generation switch to alternative fuels. Second, ISO-NE will move the offer deadline ahead for day-ahead supply bids from midnight to 9:00 a.m. and announce reliability run commitments by 10:00 a.m. This change will allow those units chosen for reliability commitments to make gas supply arrangements within the gas market purchase and pipeline nomination period that closes at 12:30 p.m.

The event revealed the consequences of barely sufficient infrastructure. The extreme weather put the New England gas and electric systems under significant, simultaneous stress. The systems succeeded in serving full electric and firm natural gas load under record demand, but operated very close to physical limits. Natural gas system constraints were the primary driver of high prices, which in turn made the availability of natural gas-fired generation problematic. Increasing demands have been placed on the natural gas transmission system in recent years, both in New England and in eastern Canada. Demand growth in these areas has exceeded the rate of new pipeline capacity additions. Additional pipeline or LNG import capacity would increase supply and reduce the frequency or severity of winter price-spike episodes. Reduced dependence on pipeline transmission for winter peak service is another potential solution. LDC peak shaving played a key role in maintaining service during this period. Expansion of peak-shaving capacity could prove to be more economical than new pipeline capacity. Reduced dependence on natural gas-fired generation during winter peak periods could also reduce exposure to pipeline constraints. Increased oil backup capacity and more flexibility in the use of oil during gas-system stress episodes could play an important role. Expanded electric transmission links to other regions would also reduce the vulnerability of the electric system to gas system constraints.

The ISO should assess relying more on market mechanisms and less on "out of market" reliability measures to assure sufficient real-time supply. Negative spark spreads for natural gas-fired power in the real-time market were largely a result of ISO-NE's practice of scheduling the highest cost units as reliability resources. The energy produced by these units reduced the amount of power clearing the real-time market and consequently avoided the higher-cost portions of the power supply curve. By meeting a substantial percentage of the power requirement with reliability units, the market did not clear at a price high enough to attract natural gas through market signals. Rather than meet a substantial portion of peak demand through reliability run instructions, ISO-NE should evaluate allowing the real-time market to produce the needed power at the marginal cost of incremental production.

Further, depending on natural gas units for reliability reserves under constrained pipeline operations may not provide the needed level of reliability. To be useful for reliability, a generator must be able to ramp up quickly to offset the loss of other system generation or transmission capacity. When the pipeline system is running at full capacity, it may not be possible for a natural gas unit to pull the supplies needed to ramp to full power output on a moment's notice. Thus, ISO-NE's practice of counting stand-by natural gas unit capacity as a reliability reserve may overstate realistically available reserves. From a reliability perspective, assigning generation units with on-site fuel, oil for example, would provide a higher level of assurance that reserves would run when called upon in a contingency situation.

Endnotes

[1] *Energy Risk*, March 2004, 74.

[2] Some observers take a different view. In a July 6, 2004 press release, Connecticut Attorney General Richard Blumenthal stated that "the cold snap revealed that current market rules are not only inadequate to protect the public safety and the region's power grid, but instead may work to undermine the reliability of New England's electric grid." http://www.cslib.org/attygenl/press/2004/util/cold-snap.htm

[3] The Algonquin citygate price reflects spot sales at LDC citygates in Connecticut, Rhode Island, and Massachusetts.

[4] A "due shipper" restriction prevents a shipper from recovering excess gas left on the pipeline during a prior period to preserve line pack.

[5] ICE is, by no means, the only trading platform for spot natural gas on a daily basis. There is no one source for spot pricing information (see the "Energy Market Information" essay for more details). However, ICE does maintain detailed, time-stamped transactions in its system and, consequently, is helpful in understanding trends in trading at the time. ICE prices were cross-referenced with published indices for the dates referenced and found to be similar.

[6] Note that two trading entities show up on both the list of top five sellers and buyers. In effect, these traders were speculating that day in physical next-day gas deliveries, something akin to "day-trading." Given the low concentrations of all participants, this activity does not concern OMOI.

[7] Refer to our February 2003 spike study.

[8] ISO New England, *Interim Report on Electricity Supply Conditions in New England during the January 14-16, 2004 "Cold Snap."*

[9] Action 1 is the notification of generators by ISO-NE that a capacity shortage exists, and Action 6 allows the depleting of 30-minute reserves to begin.

[10] See ISO-NE January 15, 2004 Media Advisory entitled "ISO New England Requests Voluntary Electricity Conservation—Appeal Extended Through Friday Night, January 16, 2004" http://www.iso-ne.com/iso_news/2004_Archive/Conservation_Request_Extended_01_15_04.doc'

[11] Schools were closed because of the cold and the ISO continued to advise customers to conserve energy.

[12] FERC, *New England Natural Gas Infrastructure* staff report, Docket No. PL04-1, December 2003.

[13] The concept of ICAP was instituted by the power pools as a first-line reliability measure to cover electric load in the pool. To insure that there are adequate generation resources to serve load, the ISO calculates the summer and winter capacity requirements. After adjusting this figure to reflect outages, the ISO allocates the requirements to the participants based on their customers' contributions to the previous year's coincident peak. Participants can meet their ICAP obligations either with generation they own or control. They can also procure ICAP in monthly auctions conducted by the ISO or in the secondary market. ICAP resources are required to submit offers into the day-ahead market for all capacity that is not self scheduled. They are also required to adhere to certain reporting, audit, and outage scheduling requirements.

[14] See ISO-NE Market Rule 1.

Electric Market Investment and Merger Trends

In 2004, generation remained the focus of wholesale electric infrastructure investment, just as it has been since the 1990s. The level of investment in generation continued to far outstrip transmission on both an absolute and relative basis. This was so even though investment actually increased in transmission and declined in generation from 2003 to 2004.

Despite the continued dominance of generation, a renewed recognition of transmission's contribution to electric reliability and efficiency led to the announcement of ambitious transmission investment plans by both regulated and unregulated players. The relative paucity of projects completed in 2004 did not reflect this shift in interest, but rather the legacy of less interest in prior years, long investment lead times, and other impedements to transmission investment and construction.

New 2004 generation construction generally reflected investment decisions made in the past as well. Consequently, fuel and sponsor trends remained: gas-fired generation dominated additions across the country and independent power producers (IPPs) sponsored the largest portion of new capacity.

Market fundamentals in 2004 did not generally signal a need for new construction of generation, particularly of gas-fired capacity. New generation announcements focused on coal-fired and renewable projects. Regulated utilities, their affiliates, and public power participants based a greater proportion of their investment decisions not solely on current plant economics but also considered hedges for projected load growth.

Asset acquisitions increased. Many companies strove to stabilize financial profiles through asset sales. Strategic players, such as investor-owned utilities (IOUs) and their affiliates (i.e. affiliated power producers (APPs)) stepped up purchases of generation. Some lenders took equity ownership of facilities as sponsors defaulted on debt obligations. Additional financial players with cash on hand (mostly hedge funds and private equity firms, particularly those that gained experience in the electric markets through secondary debt investments) became more active in asset acquisitions to meet investment targets.

In addition, corporate managers began to reassess company mergers as a strategic option for earnings growth. Private equity funds were frustrated in their attempts to purchase regulated utilities, but utility managers began to advance corporate merger initiatives after a period of retrenchment and balance sheet repair.

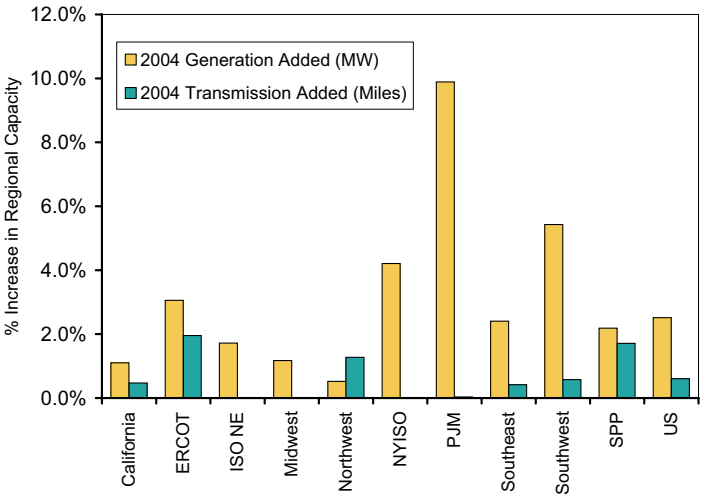
Transmission Investment

About 931 miles of new transmission lines of 230 kV or greater were built in 2004, an addition of roughly 0.6 percent of installed capacity (by mile).[1] In contrast, more than 20 gigawatts (GW) of new generation capacity entered operation, adding 2.3 percent to the electric generating fleet.[2] The low level of transmission investment continued a trend that has existed at least since the beginning of the 1990s. According to a study by Trimaran Capital Partners of FERC Form No. 1 data for the years 1992–2003, the annual growth in net investment in transmission plant by investor-owned utilities has averaged 2 percent.[3] This growth contrasts with higher levels of load growth, generation, and distribution investment in the period.[4] Trimaran's study showed that transmission's 30 percent of total transmission and distribution plant in service in 1992 declined to 26 percent of plant in service by 2003.[5]

Transmission additions varied significantly by reliability region, with no miles added in the independent system operators of New England (ISO-NE), New York (NYISO), or the Midwest (MISO). Additions included 309 miles (1.3 percent) in the Pacific Northwest, 131 miles (1.7 percent) in the Southwest Power Pool (SPP), and 149 miles (0.4 percent) to the installed base in the Southeast (see Figure 1).

Transmission circuit miles are not a complete representation of all the investment in the transmission system.

Fig 1: Transmission vs. Generation Additions



Source: Derived from NERC, ERCOT, Platts, and EIA data. See source note 1.

Substations, conductors, and other devices can also increase transmission capacity and plant in service.

Transmission plant addition figures from FERC Form 1 data indicate a continued increase in transmission investment. Those data show a continuation of steady investment increases of 13.1 percent on a compound annual basis from 2000 through 2004[6] (see Figure 2). FERC Form 1 data for 2004 reflect preliminary filings.

Edison Electric Institute (EEI) data, based on a survey of historical and planned capital expenditures by EEI members, also indicate an increase in annual transmission investment. Specifically, EEI data show that transmission investment by shareholder-owned utilities averaged twelve percent annual growth from 1999 to 2003.[7] In addition, the survey forecasts an unprecedented increase in transmission investment over the next few years. Plans do not always equal completed projects. The EEI survey results for projected expenditures in 2004 did not match preliminary FERC Form 1 data for actual expenditures, which totaled $4.3 billion. The EEI survey's forecasted expenditures were $4.5 billion, an indication that actual expenditures can fall short of estimated budgets even in the near term.

In 2004, equity and debt markets rewarded stable, regulated operations (and the cash flows they generate) with premium valuations. Within this context, transmission investment gained new appeal to investor-owned utilities, which responded with increased plans to build. Successful execution of planned investment goals in the transmission sector can be difficult for several reasons:

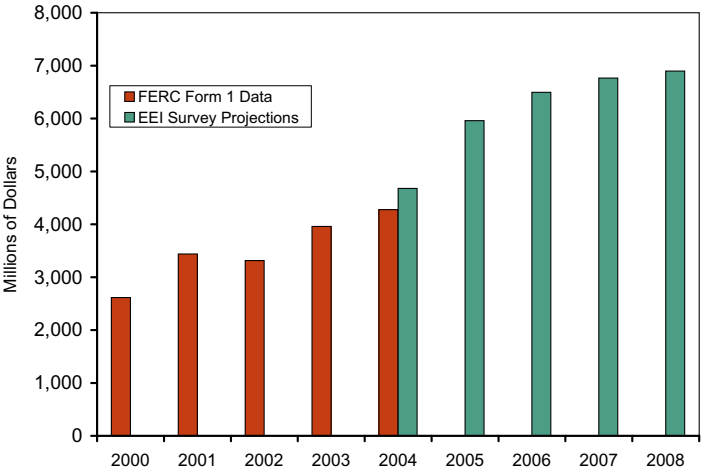
- Developers face challenges in obtaining rights of way, siting, and licensing of electric transmission lines (challenges typically even greater than the ones they face in the permitting process for gas pipelines and electric power plants).

- Regulatory uncertainty poses dilemmas. The uncertainty can be as specific as that related to rate treatment for a planned, delayed, or ultimately frustrated line. Or it can be as pervasive and general as the difficulty in distinguishing reliability from efficiency projects. The resolution of state and federal jurisdictional issues can, moreover, exacerbate cost recovery and cost allocation.

- Revenue uncertainty can reduce incentives in both regulated and merchant contexts. For merchant or contract generators, projecting and capturing future revenue can be difficult.

Anecdotal evidence pointed to difficulties in both areas with and without formal regional planning organizations. Northeast Utilities' Connecticut Light and Power, for example, continues to attempt to build new high-voltage lines

Fig 2: 2000-2004 Transmission Plant Additions



Source: Derived from FERC Form 1 and EEI data.

into southwest Connecticut within the context of a regional transmission organization (RTO). The construction of the new lines has been delayed by local and state opposition and by debate over how to allocate the costs involved within New England. Attempts to enhance the links among southern California, the Pacific Northwest, and the Southwest are impeded by the absence of a formal regional planning organization. Growing recognition of the need to enhance the grid in the wake of the August 2003 Northeast blackout as well as the resulting attention to reliability, have spurred many investor-owned utilities to announce more ambitious transmission investment plans and to push forward on state and regional projects. RTOs and regional planning organizations also pursue their own programs.

In addition to the plans announced by Northeast Utilities, several other significant projects were in the offing in 2004.

- NStar announced plans to spend $200 million to construct a new 345kV transmission line from Stoughton, Mass., a southern suburb of Boston, to south Boston to ensure continued reliability of service and improve power import capacity in northeast Massachusetts (NEMA). The line is projected to be placed in service in summer 2006.

- The Southern Company invested $1.3 billion in transmission lines and substations from 2001 through 2003, expanding the Atlanta Loop and making other improvements to its system. In 2004, Southern constructed

approximately 170 miles of new transmission lines and upgraded an additional 764 miles of line. It also projects an expenditure of nearly $3.1 billion on transmission and distribution from 2005–2007, with slightly less than half the amount to be spent on transmission.

- Southern California Edison announced plans to spend $1.6 billion through 2009 on transmission (as opposed to a current transmission rate base of $1.1 billion) with $680 million to be spent on building a 230-mile, 500 kV line to Arizona.

At the end of 2003, stand-alone transmission companies in the Midwest owned 3 percent of the transmission assets that investor-owned utilities owned nationally. These companies continued to pursue investment levels that far exceeded what they had pursued when they were part of integrated utilities and far exceeded the 3 percent investment planned by investor-owned utilities.

- American Transmission Company of Wisconsin invested more than $500 million in its system from the time of its formation in 2001 through 2004; the company planned to spend an additional $315 million in 2005, as compared with an initial transmission book value of slightly more than $500 million.

- International Transmission Company (formerly Detroit Edison's transmission system) spent $81 million in 2004 and planned to spend an additional $100 million in 2005, compared with a net book value of approximately $775 million on transfer in 2002.

- Michigan Electric Transmission Company (which was formed through the acquisition of Consumer's Energy transmission system) spent and planned to spend roughly $250 million by the end of 2009 as compared with a net book value of $230 million on transfer of the company in 2002.

Investment in Electric Generating Assets

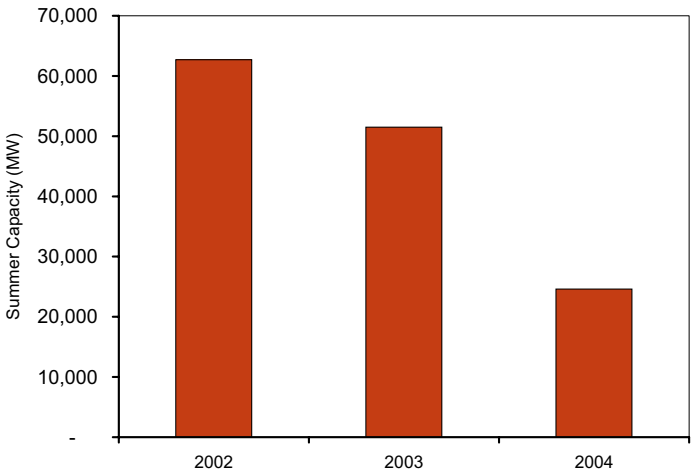
In 2004, almost 25 GW of generating capacity was added across the country, down 50 percent from 2003 (see Figure 3.)

More generation was built by independent power producers (IPPs) than any other market segment. IPPs sponsored 7.7 GW of the generation that reached commercial operation in 2004 (see Figure 4).

APPs and IOUs were more active in their construction programs than they had been in the recent boom period. APPs built just over 6 GW, or 27 percent of total new generation. Investor-owned utilities built 18 percent of the new capacity in 2004. Municipals and cooperatives placed into service 11percent of the new capacity. Lenders completed 2 GW of generation projects that were turned over by troubled sponsors, adding 9 percent of the new generation.

As shown in Figure 5, gas-fired generation dominated additions. Almost 550 MW of coal-fired generators came on line in PJM. Approximately 250 MW of renewable capacity was added, primarily in the Midwest.

Fig 3: 2002-2004 Generation Capacity Additions



Source: Derived from EIA's Electric Power Monthly Table ES3 and Platts POWERdat data, as of 3/01/2005. IPP consists of IPP, COGEN, and Industrial.

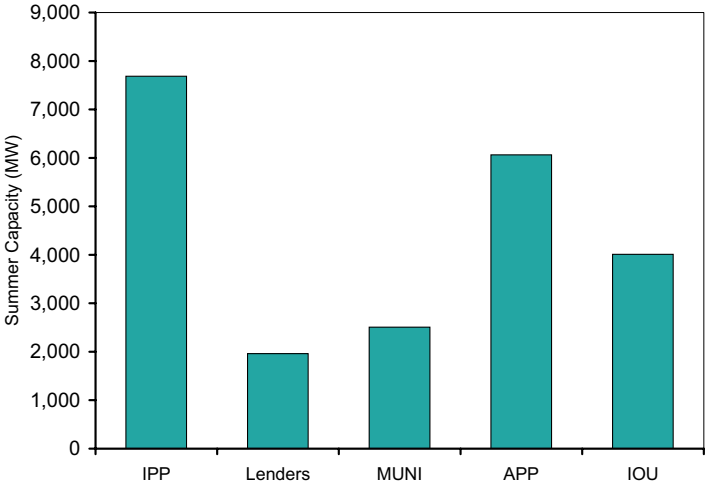
Most additions were built in the Southeast, PJM, and the Southwest, markets already experiencing regional overbuild conditions. When measured as a percentage added to

installed summer capacity by the new construction, PJM added almost 10 percent and the Southwest added 5.4 percent.

These new additions increased excess capacity, adding downward pressure on both energy and capacity prices in the market, and reducing net revenues for gas-fired capacity in most regions during the assessment period.

New generator operations lag original investment decisions by about two years for gas-fired capacity and by up to ten years for coal-fired capacity. Hence, investment decisions made during the period of high energy prices before 2003 drove asset additions in 2004. In many areas of the country, generation additions increased reserve margins and reduced net revenues, suggesting that investment decisions were made using more optimistic projections of market conditions than were realized.

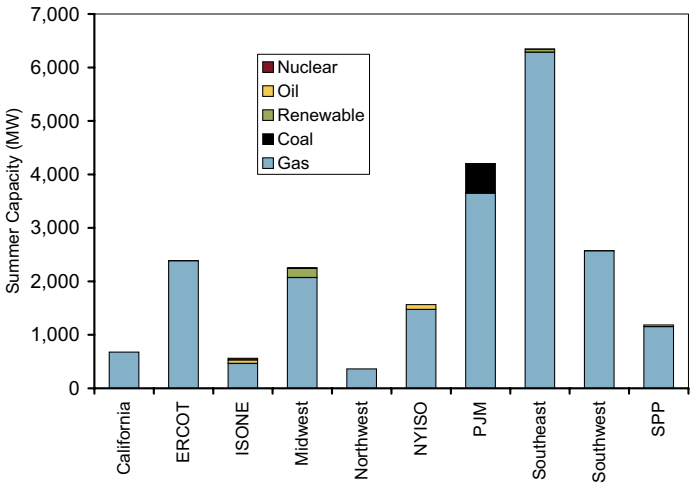
Fig 4: Capacity Additions by Sponsor Type



Source: Derived from EIA's Electric Power Monthly Table ES3 and Platts POWERdat data, as of 3/01/2005. Note: IPP consists of IPP, COGEN, and Industrial.

Reserve margins and load data suggest that there were, in most cases, adequate or excess resources and reserves to meet regional demand during the assessment period. NERC 2004 summer reserve margins, which ran from a low of 12 percent in New York to a high of 77 percent in the Southeastern Electric Reliability Council (SERC), are shown on Figure 6.[8] They are compared with net revenues, calculated by FERC for state of the art gas-fired combined cycle turbine (CC) units (see Electric Almanac Overview and Regional Profiles for regional details). As illustrated, there was a general trend of inverse relations between reserve margins and net revenues—what we might expect as a general pattern.

Fig 5: 2004 Regional Capacity Additions by Fuel



Source: Derived from EIA and Platts data. See Source note 3.

In addition to high regional reserve margins, gas price increases resulted in reduced dispatch and compressed spark spreads for variable operations of gas-fired capacity.

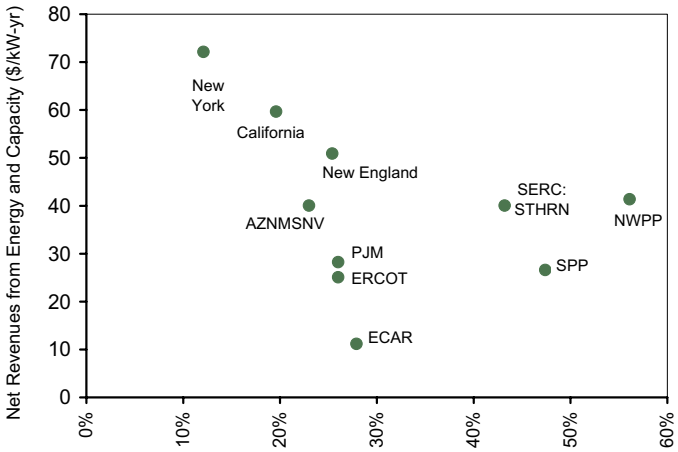
Generation announcements reflected a shift in focus; new generation investment decisions tended to address fuel diversity and environmental concerns, with coal-fired generation and renewable energy resources.

In 2004, natural gas prices reached three times that of coal, with gas generally driving electric market prices. Coal-fired facilities generally experienced higher capacity factors and attractive profits. With the existing coal fleet approaching operating maximums and growing concern over fuel diversity, environment policy effects, and associated price risks, companies began to review the economic feasibility of building advanced technology coal-fired facilities. Though estimates vary, recent studies suggest that as much as 80 GW of new coal-fired capacity has been announced in what appears to be a rush to secure permits and start the seven-to-ten year development process. More

conservatively, Cambridge Energy Research Associates (CERA) estimated in its winter 2004–2005 North American Electric Power Watch that 28.4 GW of coal-fired generation was under active development or under construction.[9]

In addition, "green" energy options, in particular wind projects, were spurred in late 2004 as the production tax credit (PTC) was renewed and an increasing number of states passed renewable portfolio standards (see Wind section). By November 2004, a month after PTC renewal, over 1,400 MW of wind power projects had been announced or put back on track, with 1,000–2,000 MW announced as advanced stage, likely, or in development.[10] GE Wind Energy had already received contracts for 750 MW of turbines for 2004-05, and another 750 MW of commitments, valued together at $1.3 billion in new wind development.[11]

Fig 6: Reserve Margins vs. Net Revenues



Source: Derived from NERC and other data. See source note 4.

Merger and Acquisition Activity

Asset Acquisitions

Most electric acquisitions in 2004 took place at the asset level. Continuing the 2003 trend, many companies strove to stabilize financial profiles through asset sales. The majority of the facilities that changed ownership were sold by utilities and their unregulated affiliates, seeking to exit noncore business lines, particularly those with merchant exposure. Both generation with creditworthy power purchase agreements and with merchant exposure were sold. A portion of the troubled merchant plants that were unable to meet their debt service saw completed formal transfer of equity to lenders. Although a number of the sales were of single assets, two large portfolios were also purchased by new owners: the Texas Genco and American Electric Power (AEP) Texas Central portfolios.[12] In aggregate, almost 36 GW of generation, or nearly 6 percent of installed capacity, changed hands in 2004, more than four times the 8 GW acquired in 2003.

Generation changed ownership in all regions of the country in 2004. Nearly 90 percent of the transfers, however, occurred in four regions: Electric Reliability Council of Texas (ERCOT) (with 39 percent of transfers), SERC (21 percent), Western Electricity Coordinating Council (WECC) (15 percent), and New York/New England (12 percent). These regions had high proportions of merchant assets. In SERC, many assets stranded by the lack of regulatory restructuring (and consequently available markets) were selling at discounted prices. In contrast, the assets in the remaining regions were poised to supply ISO/RTO markets, alternative retail suppliers, or utilities that had divested assets and now needed contracted supplies for load. They could be sold to improve debt repayment abilities.

IOUs bought 1.7 GW of generation in 2004, more than double the 0.7 GW purchased in 2003 (see figure 7). With the backdrop of certain state regulatory and credit rating agency policies, which effectively discourage power purchase agreements (PPAs), utilities in many cases decided against signing PPAs with merchant generators. Instead they purchased facilities from affiliates and non-affiliates alike to secure retail supply for their service territories. In some cases these transfers were proposed despite intervenor claims that some

assets were actually transferred at above market values or that contract options were more economic. An example of generation purchased by a utility from affiliates was Georgia Powers' acquisition of McIntosh from Southern Power.[13] A purchase from a troubled merchant company was NRG's sale of McClain to OG&E. [14] Municipals also actively participated in asset purchase from troubled sponsors to secure supply for their internal load.

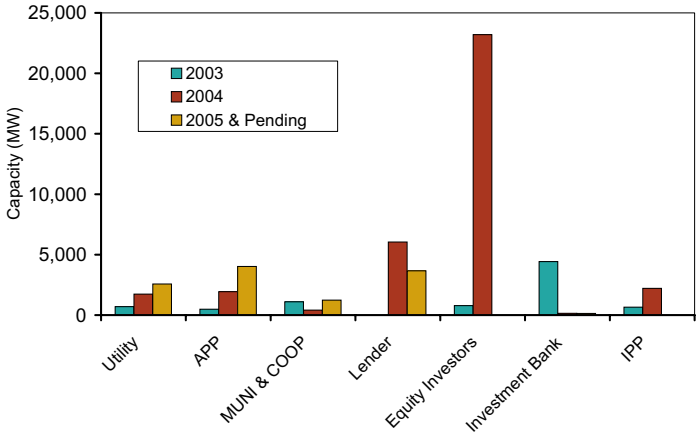
APPs purchased 1.9 GW in 2004, almost a four fold increase from the 0.5 GW purchased in 2003. PSEG Global acquired the remaining 50 percent interest in their joint venture with Panda. Constellation expanded its nuclear portfolio. Sempra purchased a contracted Texas asset as well as half of the portfolio divested by AEP in Texas, including the Coleto Creek coal-fired plant.

In addition, 6.0 GW of capacity were returned to lenders in 2004 as sponsors walked away from projects that defaulted on their debt obligations. Many of the facilities that lenders took equity ownership of in 2004 faced operational or financial problems in earlier years. The official transfer process took some time. The transfers required restructuring to address operations and management of the assets. Lenders, with limited ability or desire to run daily operations, hired asset managers, energy managers, and O&M service firms in an attempt to minimize current cash losses and maximize valuations of these assets for future sale.

An active secondary market for project loans developed in 2004, with original lenders selling debt to other banks and hedge funds.[15] In some cases, debt that banks had traded at a deep discount was resold to hedge funds and other investors at or near par value based on perceived interest in plant equity by buyers, or the ability to seek regulatory solutions to distressed projects.[16]

Equity investors, including private equity investors, income securities, and hedge funds were by far the largest purchasers, acquiring more than 23 GW, a significant increase from the 0.8 MW purchased in 2003. In keeping with their own organizational diversity, financial purchasers had different investment strategies. Much of the contracted generation was purchased for its bond-like yield characteristics. The balance was purchased with the expectation that value would be realized through contract restructuring and monetization. Some financial players bought merchant generation with the hope that they would be able to quickly sell or contract it to load-serving entities with prospective need for additional supply. Assuming that demand growth would eventually eliminate reserve margin overhangs, others bought merchant position at deep discounts with plans to hold plants until values reverted to replacement cost. In the interim these financial players, much like original lenders, outsourced energy and asset management to an emerging group of service providers as well as provided interim capital for working capital carrying costs such as insurance, maintenance, and property taxes.

Fig 7: 2003-2005 Generating Plant Sales and Transfers



Source: Derived from EIA data. See source note 5.

Corporate Mergers & Acquisitions

At the corporate level, utilities and financial institutions exhibited growing interest in mergers and acquisitions, prompting many analysts to herald 2004 as the inauguration of a new round of consolidation in the power sector.

One utility-to-utility acquisition was closed and three were announced, with the largest proposed in December:

- Announced in December 2003, Ameren closed its acquisition of Illinois Power Co. in September 2004.
- In January 2004, Black Hills Corp announced the acquisition of Cheyenne Light, Fuel & Power from Xcel Energy.

- In July 2004, PNM Resources, the parent of Public Service Company of New Mexico, announced the intention to acquire TNP Enterprises, the parent of Texas New Mexico Power Company from a group of private equity investors.

- In December 2004, Exelon announced its intent to merge with PSEG, a plan that would create the nation's largest utility company by generation ownership, market capitalization, revenues, and net income.

However, two high-profile private equity attempts to acquire franchise-regulated electric utility operations, both announced in November 2003, failed in response to stiff local resistance in 2004:

- Kohlberg, Kravis & Roberts' attempt to acquire Unisource, the parent company of Tucson Electric Power, through Saguaro Utility Group was unsuccessful. The Arizona Corporation Commission rejected the aquisition offer in December 2004.

- Texas Pacific Group's attempt to purchase Portland General from Enron's bankruptcy estate (through acquisition vehicle Oregon Electric), met with local opposition and a municipal counteroffer.

Endnotes

[1] Transmission data based on OMOI analysis of NERC's Electricity Supply & Demand Data Base as of April 19, 2005. ERCOT transmission data were retrieved from "Existing and Potential Electric System Constraints And Needs Within The ERCOT Region" report, October 1, 2004.

[2] Generation data based on OMOI analysis of EIA's Electric Power Monthly data and Platts.

[3] Transcript of Technical Conference on Transmission Independence and Investment, Docket No. AD05-5-000 (April 22, 2005), Tr. 31. (Jon Larson, Trimaran Capital Partners).

[4] Transcript of Technical Conference. Tr. 16-17 (Brendan Kirby, Oak Ridge National Laboratories)

[5] Transcript of Technical Conference. Tr. 32. (Jon Larson, Trimaran Capital Partners.

[6] FERC Form 1 data include accounts 352, 353–359.1. *FERC Form 1 data for 2004 is a preliminary data set based on 198 of 221 companies. The missing 23 companies accounted for 6.7 percent of the Year Balance dollars in 2003. It was assumed that their share of the total would remain constant in 2004. Transmission addition levels for the 198 respondents, representing 93.3 percent of the whole ($3.99 billion) multiplied by (100/93.3) provides a preliminary 2004 transmission addition level of $ 4.28 billion.

[7] EEI Survey of Transmission Investment – Historical and Planned Capital Expenditures (1999–2008) at 5 (Edison Electric Institute, May 2005) (EEI Survey). The EEI Survey data are composed of responses from 60 IOUs for 2003 expenditures and for forecasted budgeting. The survey included a breakdown of transmission line construction costs and transmission substation costs, and accounted for all Transmission Plant in Service reported on FERC Form 1.

[8] NERC 2004 Summer Assessment/forecast for August with Uncommitted Resources; net revenues reflect estimated profits from energy and capacity markets as detailed in Electric Almanac Overview and Regional Profiles in Appendix.

[9] US Power Sector: Shifting Capital Spending Patterns, CERA Client Services, January 17, 2005, 5.

[10] See Assessing the State of Wind Energy in Wholesale Electricity Markets, Docket No. AD04-13-000, November 2004. http://www.westgov.org/wieb/meetings/windfall2004/briefing/FERCpaper.pdf

[11] GE News Release October 18, 2004- http://home.businesswire.com/portal/site/ge/index.jsp?ndmViewId=news_view&newsId=20041018005721&newsLang=en&ndmConfigId=1001109&vnsId=681

[12] In July, AEP closed on the sale of most of its Texas Central Portfolio (10 power plants with a generating capacity of approximately 4 GW) to a joint venture of Sempra Energy Partners and Carlyle/Riverstone Global Energy and Power Fund. In December, most of the TX Genco assets (11 power plants with a generating capacity of over 13 GW) were sold by CenterPoint to GC Power Acquisition LLC, an entity owned in equal parts by affiliates of The Blackstone Group, Hellman & Friedman LLC, Kohlberg Kravis Roberts & Co. L.P., and Texas Pacific Group.

[13] Initially, Southern Power, an unregulated affiliate of Southern Company, applied for FERC approval of power purchase agreements (PPAs) with regulated affiliates Georgia Power and Savannah Electric for output from McIntosh. In hearings before the Commission, interveners opposed approval of the PPAs on the basis that they did not meet market-based rate standards for affiliates. The Georgia PSC later directed Georgia Power and Savannah Electric to acquire the facility to secure local supply. Following asset acquisition, ongoing FERC proceedings were terminated. See Southern Power Company, 108 FERC 61,134 (2004); Southern Power Company, 104 FERC 61, 041 (2003).

[14] In 2003, OGE applied for FERC approval of the purchase of 77 percent interest in the McClain facility owned by NRG Energy. The Commission set it for hearing in which interveners opposed approval on the basis that OGE's initial mitigation proposal was insufficient to thwart potential for market power. Ultimately, the acquisition and revised mitigation plan were approved by FERC in 2004. See Oklahoma Gas and Electric Company and NRG McClain LLC, 108 FERC 61,004 (2004); reh'g denied, 111 FERC 61,075 (2005).

[15] An asset that is trading "at par" is selling for its face value. When the asset sells at face value, the bank has recovered the amount of principal owed at maturity of the original loan.

[16] Merchant Power: Short Circuit Could Lead to Mega Returns, Imperial Capital, LLC., January 31, 2005.

Source notes

1. Transmission data based on FERC/OMOI analysis of NERC ES&D Data Base, 2004 Updates from NERC as of April 19, 2005, ERCOT data, and FERC Research. Generation data based on OMOI analysis of EIA's Electric Power Monthly data and Platts PowerDat. Mileage is the number of circuit miles greater than 230 kV added to a transmission system.

2. Based on EEI's planned total industry expenditures estimated from 95 percent response rate to EEI's Electric Transmission Capital Budget & Forecast Survey as of May 20, 2005. FERC/OMOI applied a 2.45 percent annual inflation rate to EEI results in real dollars; 2.45 percent was chosen based on the Handy Whitman Index of Public Utility Construction Costs 2002–2003. 2004 FERC Form 1 reflects preliminary data. Note: EEI Data represent shareholder-owned electric utilities.

3. Analysis of EIA's Electric Power Monthly Table ES3 and Platts PowerDat data as of March 1, 2005. Note: Energy sources are merged in the following way. Renewable consists of black liquor, landfill gas, wood, water, and wind. Oil consists of distillate fuel and residual fuel. NG consists of natural gas. Coal consists of waste coal. Data do not account for retirements.

4. Analysis of reserve margins from NERC 2004 Summer Assessment/forecast for August with Uncommitted Resources; net revenues reflect estimated profits from energy and capacity markets as detailed in Electric Almanac Overview and Regional Profiles in Appendix.

5. Data were gathered from the EIA Electric Power Monthly - Table ES4: Plants Sold and Transferred in 2003 and 2004, and Platt's PowerDat, as of March 15, 2005. Note: The following buyer types were merged into one category: IPP consists of IPP, IPP-Cogen, and a retail supplier. Private equity consists of private equity, financial arm of an industrial company, hedge fund, and royalty income trust. Utility consists of utility and holding company.

Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Energy Market Information

Market efficiency depends on timely, reliable, and pertinent information. In the aftermath of recent crises, the Commission and market participants have become increasingly sensitive to these characteristics of effective markets.

In 2004, the Commission acted to improve energy market information by:

- Working with the industry to improve the quality and credibility of price indices for natural gas and electric power;
- Focusing attention on gas storage data by settling cases with two companies that inappropriately shared storage information and with a third company that may also have done so, by holding a technical conference on reporting, and by investigating an anomalous inventory report that significantly moved the market in November 2004; and
- Improving the quality of the Electric Quarterly Report (EQR), in which jurisdictional companies provide a comprehensive report of their physical electric sales.

Introduction

Information is the lifeblood of healthy commodity markets, including energy markets. Market efficiency depends on the quality and transparency of information. Without pertinent and reliable information, individual participants will make uninformed decisions, and efficiency will decline.

If market participants find information difficult to obtain, transaction costs grow and efficiency drops. Information may also be costly to obtain or to use. Every market participant decides (tacitly, if not explicitly) how much to expend, in effort and money, for market information. Well-functioning energy markets must meet the information needs of a variety of different market participants, including traders, price takers, and regulators.

Traders. The category includes market makers with large trading desks, speculators, and many others. These players need access to pricing that they can trust for many different energy products. Prices can vary by, for example, duration (hourly, day-ahead, monthly, longer term), timing (now or later), location (which implies valuing transmission), and optionality. Traders can obtain such information from transparent information sources, such as exchanges and regional transmission organizations (RTOs), or because of their active participation in the market itself, from less transparent sources like voice brokers and direct negotiation.

Traders also use a wide variety of other information about factors that may significantly affect price (such as weather, outages, and load growth). They compete to obtain the best information about the most important factors, and some set up their own intelligence operations to do so. Market demands drive traders to develop the most pertinent and cost-effective information systems. As a result, the interplay of many active traders can, in theory and probably in practice, create reasonably efficient pricing.

Price Takers. This category includes companies that cannot or will not invest their time or money to obtain detailed market information, generally because they are too small or because their core business interests lie elsewhere. Examples include smaller independent producers and distributors, public power and gas organizations, and many customers, large and small. Price takers depend on reliable, commoditized pricing that does not require much research or expense. In practice, they rely on transparent information available from RTOs, exchanges, and published price indices. They also depend on standardized forward instruments like futures contracts for risk management, though they may actually buy such products through a broker or marketer. In a competitive market, they depend on active traders to generate efficient prices and, crucially, on some reliable mechanism to report those prices to them. Transparency and standardization are the key ways to make information usable for price takers.

Regulators. Relevant regulators include FERC, the Commodity Futures Trading Commission (CFTC), and state public utility commissions. They need enough information to identify serious market abuses and flaws in the way energy markets work. In recently deregulated markets like some electric power, the ability to detect—and then to correct—market flaws is particularly important. Accordingly, it is vital that regulators have enough information to monitor market activity.

What information is available to regulators (and when) depends largely on the structure of the market. Locational marginal, day-ahead, and real-time pricing, along with capacity and ancillary services within RTO markets, are almost entirely transparent and make much information available in real time. Such transparency rests on standardized operations and large, centralized mechanisms to collect and disseminate the information. By contrast, most natural gas markets and bilateral electric markets provide far less detailed information, depending instead on trade publications to provide price indices. These markets are less transparent than RTOs but often serve a variety of industry needs well. In time, such markets may develop more standardized platforms, rather like the IntercontinentalExchange (ICE) and Nymex, to provide comprehensive and reliable information akin to what is now available from RTO markets. Finally, some electric power markets are almost entirely opaque both to regulators and to price takers. In these markets (such as electricity in much of the Southeast), so little information is available that price indices either do not develop or have little value in price discovery.

In practice, the Commission has attempted to identify and make use of all information available to it. For electric

power, it has also developed the Electronic Quarterly Report, a more comprehensive public reporting system than anything available outside an RTO. The EQR reports jurisdictional wholesale power sales, allowing for transparency of physical, bilateral electric markets, although with a delay of several months.

Improving Price Indices

Many energy market participants rely on price indices published in the trade press for basic price information. Price indices are especially important to natural gas and parts of the electric industry that have fairly strong bilateral markets but no RTOs. Published indices are convenient for price takers, as long as they consider them reliable.

Price indices developed as a journalistic service—not as an integrated part of a market structure. In practice, they were not always reliable. Prices were sometimes based on few or no trades and were subject to misreporting and other abuses. These indices often did not convey enough information for market participants to judge the validity of reported prices.

After the misreporting and wash-trading scandals revealed in 2002 and the subsequent false-reporting cases by the CFTC, market sources reported less information to the index compilers, making the indices even less thorough and reliable.[1] Customers expressed a growing lack of confidence in the indices.

Commission Response. The Commission worked to improve indices since early 2003. In July 2003, it issued a policy statement,[2] defining both the reporting standards and desirable characteristics of indices. The Commission sponsored two technical conferences and two index workshops to discuss problems and encourage practical industry solutions. Many in industry worked to find and implement such solutions.

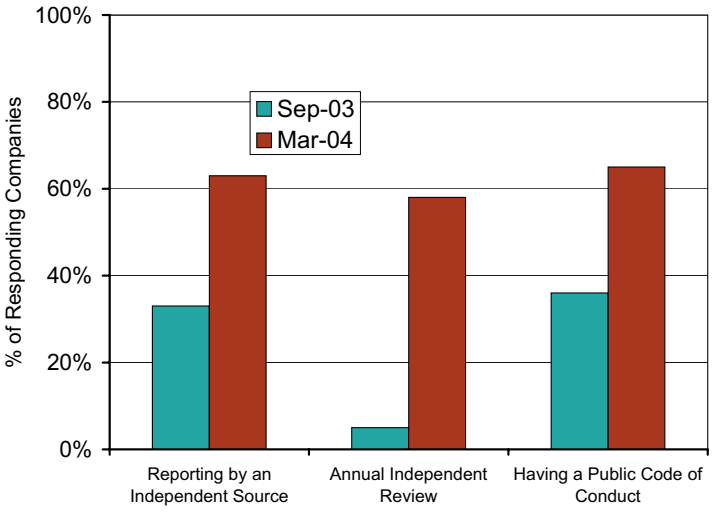
Later in 2003, the Commission issued market behavior rules that require adherence to certain basic standards by those that report transaction data used in Commission-approved tariffs.[4] On May 5, 2004, the Commission released a comprehensive staff report[3] gauging improvement. A follow-up technical conference, in June 2004, featured 26 panelists who assessed progress to date and offered recommendations for further action. Another 29 parties supplied written comments. The Commission also issued an order on the future monitoring of indices.[5]

Amount of Data Reported. Some index compilers have noted an increase in the volume of fixed-price transactions reported. Platts, for instance, found that volumes and transactions submitted for its monthly gas survey from February through June 2004 increased by 35 percent or more, from 2003 levels. Volumes and transactions increased another 34 and 31 percent, respectively, in the first quarter of 2005 compared with a year earlier. In its daily gas survey, Platts reported that the number of natural gas transactions reported in May 2004 was double that of November 2002 and that the number reported in March 2005 was 34 percent higher than a year earlier. In March 2005, the number of daily electricity transactions reported had risen by 74 percent from a year earlier.[6]

Process Improvements. The May 2004 staff report documented improvements in the data reporting process by comparing responses from the first industry survey in September 2003 with the second survey in March 2004 (see Figure 1). The survey showed improvement for each of the key price-reporting standards in the 2003 policy statement:

- The percentage of companies that report to index

Fig 1: Process Improvements



Source: FERC Survey.

compilers through a department that is independent from the trading unit doubled to nearly two-thirds.

- The percentage of companies conducting annual independent audits of their price reporting practices increased from 5 percent to 58 percent.

- The percentage of companies with a public code of conduct for reporting transactions to index compilers rose from 36 percent to 65 percent.

Amount and Quality of Information Provided. Index compilers began providing more information about activity at pricing locations in response to industry interest. For example, the 10xGroup, an affiliate of ICE, provides a service that includes the high, low, weighted average, and change in price, along with the volume, number of trades, and number of trading companies at each location for its daily natural gas and electricity indices.

In 2003, Platts and Natural Gas Intelligence Press Inc. began to designate trading locations in their monthly gas indices as Tier 1, Tier 2, and Tier 3 to provide an indication of the level of activity at each location. A Tier 1 location has volume in excess of 100,000 MMBtu, Tier 2 between 25,000 and 100,000 MMBtu, and Tier 3 fewer than 25,000 MMBtu. In August 2004, both publishers increased the information provided by including the number of trades and volumes traded in daily indices and for Tier 1 and Tier 2 monthly indices. They also discontinued some illiquid price indices.

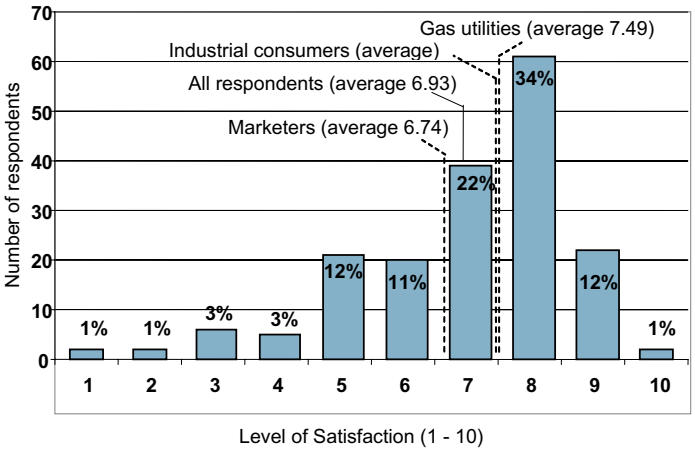
Other index publishers also responded. Energy Intelligence Group began to provide volumes and the number of transactions as a result of the policy statement. Dow Jones began to include the highs and lows with its day-ahead electricity indices. Argus Media announced plans to add the number of transactions to its hourly electricity indices.

Finally, index publishers began to show which price reports rely on data from actual transactions and which are estimates. Platts now notes with an asterisk and a footnote any price that is an estimate rather than a weighted average of reported trades. Other index publishers, including Energy Intelligence Group, Powerdex, Argus Media, and Dow Jones, also identify prices that are editorial estimates rather than an average of actual transactions.[7]

While noting these improvements, however, the staff report also expressed concern about the number of fixed-price transactions in the month-ahead market and the degree of industry reliance on index-based contracts rather than fixed-price contracts. The widespread use of monthly indices for natural gas contracts may be especially problematic. Many monthly indices rely on a few deals covering small volumes.

Increase in Confidence. A survey conducted in March 2004 indicated that confidence in price indices averaged 6.9 on a scale of 1 to 10. By industry group, the average ranged from 7.5 for gas utilities to 6.7 for marketers (see Figure 2).

Fig 2: Customer Satisfaction with Price Indices



Source: FERC Survey.

Moreover, conference participants noted that confidence rose even higher after the release of the staff report that detailed the findings of the March 2004 survey. For example, the Process Gas Consumers Group stated that its "faith in the price indices has been strengthened by the events of the past two years." EnCana Marketing (USA), Inc., said that it had a "high degree of confidence in the prices that are being reported and published." The American Gas Association pointed out that "confidence in price reporting had increased markedly." And the Electric Power Supply Association said "both market liquidity and reporting has increased and … the markets' confidence in indices has also increased."[8]

Given the perceived improvement in the quality of gas and electric indices, the Commission indicated it would contin-

ue to monitor the process but did not think mandatory reporting was necessary. On November 19, 2004, the Commission issued the "Order Regarding Future Monitoring of Voluntary Price Formation, Use of Price Indices in Jurisdictional Tariffs, and Closing Certain Tariff Dockets." The order:

- Directed staff to continue monitoring price formation, including adherence to the standards in the policy statement;
- Reviewed the submissions of 10 index compilers and concluded that they substantially met the standards;[9]
- Adopted criteria that would allow a price index location to be used in a jurisdictional tariff; and
- Applied the newly adopted criteria prospectively only.

Natural Gas Storage

The Energy Information Administration (EIA) releases its *Weekly Natural Gas Storage Report* every Thursday at 10:30 a.m. Eastern Time. Storage inventories show changes in the balance of supply and demand. The report is particularly important because other, more directly relevant, statistics (such as production levels) are not immediately available. EIA's report is the only government-issued, regularly published information that gives market participants a view of current supply-demand dynamics in the natural gas industry.

The report affects the pricing of many transactions. Price volatility for Nymex natural gas contracts increases immediately following the weekly release of the report, as traders adjust their positions to reflect the new information. The release of the EIA report can significantly affect other natural gas commodity prices, transportation, and market and trading behavior.

Given the importance of gas storage reports to markets and the Commission's charge to ensure that prices are just and reasonable, FERC staff members actively monitor storage reporting and its effect on gas markets. The Commission undertook several oversight and enforcement activities in 2004 to ensure accuracy and transparency of storage information.

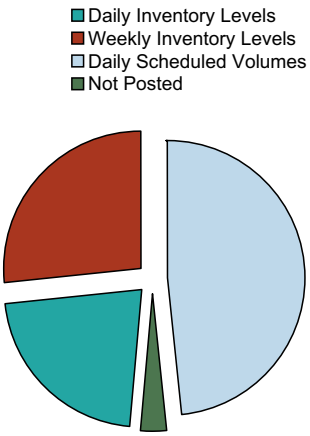
Eliminating Sharing of Commercially Sensitive Data. In 2004, the Commission approved settlements with three companies that communicated nonpublic, daily storage injection, and withdrawal information to customers and other market participants and, in one case, an affiliate, over an extended period of time.[10] The behavior violated the Commission's standards of conduct and rules prohibiting undue preference. The information had commercial value, helping recipients understand and anticipate gas price movements. The information was also potentially helpful to pipeline transportation users, because it provided insights into pipeline operational dynamics and, on occasion, the likelihood of curtailments. The settlements included civil penalties, refunds to customers, and remedial actions to prevent future improper exchanges of storage-related information.

Technical Conference on Storage Reporting. Following the settlements, the Commission invited the public to file comments regarding enhanced storage reporting in advance of an upcoming technical conference.[11] The conference, on September 28, 2004, explored whether the Commission should require interstate pipeline companies and other owners and operators of storage facilities to post each day's inventory levels electronically to increase transparency and deter communication of nonpublic, storage-related information.

Those who filed comments, as well as those who participated in the September 28, 2004, conference, agreed that storage information is relevant to the market's performance. Discussion explored the potential value of publishing storage information daily to assist in decision-making and possibly reduce costs associated with volatility, thereby potentially increasing wholesale market efficiency.

Views differed on whether or how to proceed. Some argued that more frequent postings on pipeline websites would mean that only larger firms could pay for services to collect the information. Others contended that initial confusion and problems with administration and accuracy of postings would overwhelm any market benefit that a more frequent data stream would offer. Still others questioned the merits of daily posting for a market they assessed as operating

Fig 3: Interstate Storage Posting Practices



Source: Interstate pipeline bulletin boards.

satisfactorily. Some expressed concern with the disaggregated and potentially incomplete nature of any proposed reporting requirements.[12] Finally, many argued that current levels of posting by interstate operators already provided adequate transparency.[13]

Investigating an Erroneous Storage Report. Weekly storage inventory reports that stray outside the range of expectations can have dramatic price consequences. On Wednesday, November 24, 2004, the day before Thanksgiving, the EIA released a weekly storage report at noon showing a 49 Bcf withdrawal of natural gas from storage for the week ending November 19. The price of natural gas futures contracts immediately shot up, reacting to the sharp contradiction of published reports that had forecast an announced withdrawal of 13 to 25 Bcf. The December Nymex gas futures contract prices closed on November 24 at $7.98 per MMBtu, up $1.18 on the day. This development was of particular concern because it occurred during the expiration of the December contract and therefore set the price for gas delivered that month.

The withdrawal was so unexpected that, in addition to the price volatility, traders and analysts began to speculate about a possible error in EIA's reporting. Reflecting a widespread belief that the report was wrong, the market began to fall. From Monday, November 29, to Wednesday, December 1, 2004, the January contract dropped more than 50 cents.

EIA policy, meanwhile, stipulated that any revision would not come until the following Thursday, the day of EIA's next regularly scheduled release. Also in keeping with EIA policy, the revision would be unaccompanied by explanatory detail.

Accordingly, on December 2, EIA issued a report that included a revised number for the amount of natural gas withdrawn from storage for the week ending November 19. The revised number was 17 Bcf—32 fewer Bcf than reported originally. Nymex January futures prices dropped by $0.60 to $6.81.

On November 28, the Commission began to investigate the event and subsequently helped identify the cause of the error. The Commission estimated that the error and the associated price increase may have cost market participants from $200 million to $1 billion. The exact financial effect was difficult, if not impossible, to determine because of the many factors that influence gas pricing.

Through their investigations, the Commission and the CFTC sought to determine what happened and whether individuals who knew of the mistake had used their knowledge to take advantage of the market responses. The initial approach was to identify large withdrawals and Nymex positions, and then to contact storage holders and operators to ascertain their reasons for making withdrawals.

Fig 4: Natural Gas Futures - November 24, 2004

Source: Derived from Nymex data.

Based on its investigation, the Commission was able to assure market participants that it found no indication that Dominion traders knew of the mistaken report or that Dominion based any trading strategies on the incident. The results indicated good standards of conduct training and compliance at Dominion. An analysis of broader market activity, especially on Nymex in coordination with the CFTC, found no evidence of any trading strategy that involved the erroneous report.

As a preventive measure, Dominion instituted reporting process improvements that require a designated Dominion manager to call to confirm the accuracy of all data that EIA receives in storage reports from Dominion management employees.

Electric Quarterly Report—Enhancing Market Oversight

The Commission requires public utilities and power marketers to file an Electric Quarterly Report 60 days after the end of each quarter.[14] An EQR must summarize the contractual terms and conditions in all jurisdictional sales service agreements (including market-based power sales, cost-based power sales, and transmission service) and set out detailed transaction information for power sales (and merchant transmission negotiated rate transactions) during the most recent calendar quarter. Data for each sale are to include the identity of the seller and purchaser; the product sold (e.g., energy, capacity); the exact date and time of each sale; key terms of each sale (e.g., whether it was short- or long-term, peak or off-peak, hourly or weekly); and the quantity, rate, and amount charged. Filing EQRs quarterly is required to maintain market-based rates. The EQR makes part of the overall physical electric market fully transparent after the fact. In doing so, the report enhances regulatory oversight.

The EQR is not fully comprehensive. It excludes:

- Generation to serve native load;
- Sales by federal authorities such as Tennessee Valley Authority (TVA) and Bonneville Power Authority (BPA);
- Sales by other public entities;
- Sales within the Electric Reliability Council of Texas (ERCOT); and
- Sales by qualifying facilities (QFs) under QF contracts.

FERC has worked to improve the EQR by introducing and improving filing software, directing filers to review their submissions for errors, conducting EQR workshops, streamlining entries, and standardizing control areas.

Most recently, staff implemented several validation checks. In an ongoing effort to improve data quality, staff updated "flags" to detect such incorrect entries as disaggregated transaction data, mistakes in reporting affiliate status, suspiciously high or low prices, trading companies not reporting book outs, and data inconsistent with other filings (e.g., Form 1, 10-K). Such measures have improved quality although, in some cases, the new stringency has led to increases in late filings (see Figure 5).

Checks for outlying data have reduced identified errors in reported data (see Figure 6).

FERC continues to improve EQR data collection and to make requirements clearer for respondents. As of the end of 2004, 991 respondents at 1,165 companies reported approximately 5.5 million lines of transaction data each quarter. The EQR data provide important insights into the bilateral physical power market, which otherwise remains largely opaque. Omissions remain a concern, as sales by nonjurisdictional entities (detailed earlier) are not included in the data.

Conclusion and Future Issues

Cost-effective provision of timely, reliable, and pertinent information is crucial to the health of all markets. Different market participants require different kinds of information. The Commission supports the development of market information systems that meet diverse needs. It has shown its willingness to help develop practical approaches to improving information quality and access to all participant types.

The Commission also continues to develop its own information resources to monitor energy markets better.

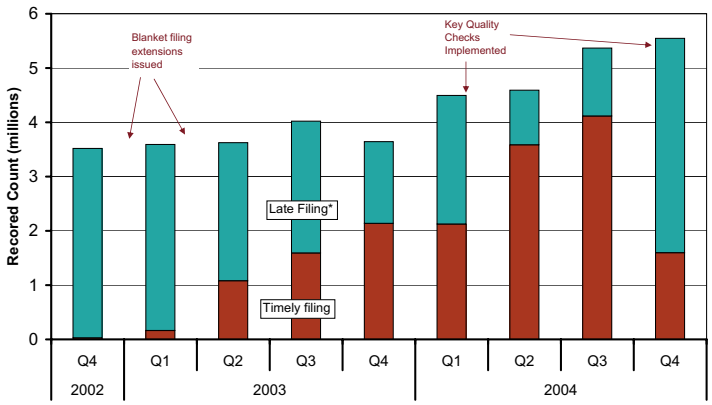
Information resource development includes maintaining access to many publicly available information sources, developing data collections (such as the EQR), and obtaining more detailed information when needed in particular situations or individual cases.

Energy markets face further information challenges. Among the most important of these are:

The jurisdictional split between physical and financial trading. The CFTC regulates financial trading, whereas the Commission regulates (most) physical trading. Because market players can structure most transactions to be either physical or financial, it can be difficult for either the Commission or the CFTC to get a picture of the interconnected market.

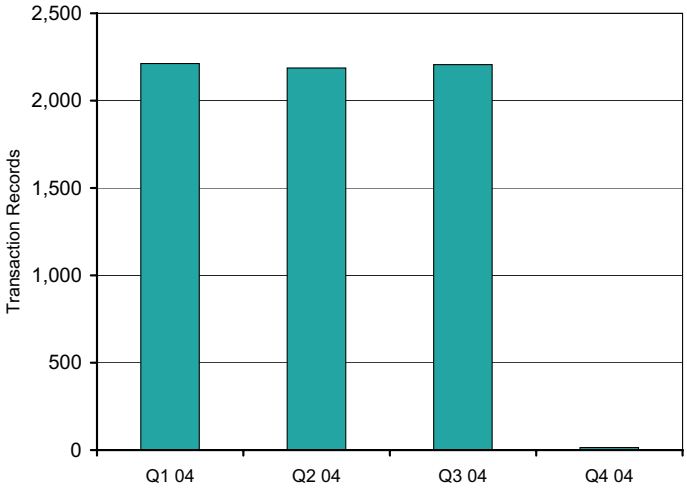
The jurisdictional splits within the physical side of the power industry. The Commission does not regulate municipalities, cooperatives, and other public electric entities. As a result, it is very difficult to get fully comprehensive information about the overall physical market.

Fig 5: 2002-2004 EQR Filings



Source: FERC EQR filings.

Fig 6: 2004 EQR Reporting Errors



Source: FERC EQR filings.

The different market platforms within the electric industry. Much of the electric industry uses RTO market structures that are similar. Other parts of the industry have fairly strong bilateral markets, as does natural gas. These structures tend to produce information that is less transparent than that of an RTO, but still allows a fairly wide range of markets to develop. Other regions (e.g. the Southeast) tend to have very little information available and therefore see only rudimentary markets. The challenge, therefore, is twofold: how to integrate the information aspects of different functioning market platforms (such as natural gas and electric RTOs) and how to develop the information infrastructure for regions that barely have functioning markets today.

Endnotes

[1] Events since the bankruptcy of Enron in late 2001 have reduced confidence in price indices. In 2002, the Commission's Western Markets Task Force investigated the role that natural gas indices played in the high prices charged for electricity in California in 2000–01. *The Final Report on Price Manipulation in Western Markets,* issued March 2003 in Docket No. PA02-2-000, determined that employees of several companies reported false information to publishers of price indices in an effort to skew indices in favor of their trading activities positions (short or long) taken in both the physical and financial markets. Subsequently, the CFTC and certain U.S. attorneys also initiated investigations into false price reporting that resulted in significant civil penalties on a number of energy companies and indictments of some individuals.

[2] *Policy Statement in Natural Gas and Electric Price Indices,* 104 FERC 61, 121 (2003).

[3] Report on Natural Gas and Electricity Price Indices, Docket Nos. PL03-3-004 et al. May 5, 2004.

[4] Order Amending Market-Based Rate Tariffs and Authorizations, 105 FERC 61,218 (2003), *reh'g denied* 107 FERC 61,175 (2004), and Order No. 644, *Amendment to Blanket Sales Certificates*, FERC Stats. & Regs. 31,153 (2003), *reh'g denied* 107 FERC 61,174 (2004).

[5] Order Regarding Future Monitoring of Voluntary Price Formation, Use of Price Indices in Jurisdictional Tariffs, and Closing Certain Tariff Dockets (2004) 109 FERC 61, 184.

[6] Platts comments (June 14, 2004) at 1–3 and discussion with staff on April 6, 2005. Platts also noted that its gas survey now has more than 60 contributors and that all but one of the top 12 trading companies are reporting their natural gas transactions. *Id.* at 3–4.

[7] Platts Technical Conference Comments (June 14, 2004).

[8] Ibid.

[9] Argus Media Inc., Bloomberg LP, Btu/Data Transmission Network, Dow Jones and Co., Energy Intelligence Group, Natural Gas Intelligence Press Inc., IntercontinentalExchange Inc. (10x), Io Energy LLC, Platts, and Powerdex Inc.

[10] The Commission issued an order in Docket IN04-2-000 approving three stipulation and consent agreements. The agreements state that the signatories—two interstate, natural gas pipeline companies and one local distribution company—communicated their respective, nonpublic storage inventory information to customers or industry participants.

[11] Enhanced Reporting of Natural Gas Storage Inventory Information, Docket No. AD04-10-000.

[12] Technical Conference (September 28, 2004).

[13] Analysis of informational postings. Daily scheduled does not always include no-notice storage activity.

[14] Revised Public Utility Filing Requirements, Order No. 2001, 67 FR 31043, FERC Stats. And Regs. 31,127.

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Market Behavior Rules: Effectiveness Review

In November 2003, the Commission issued Market Behavior Rules to fill a void in the regulation of market-based trading activity.[1] In its order, the Commission also required that the effectiveness and consequences of the behavior rules be evaluated annually in the State of the Markets Report.

To date, indications from the wholesale energy markets are that the behavior rules are effective and achieving their purpose. The attention being paid by companies to the behavior rules, evidence of widespread training of market participants, and the relative absence of complaints indicate that the behavior rules have had an overall beneficial effect on wholesale energy markets. Market participants have expressed concerns, however, about the clarity of the rule related to market manipulation. A few parties described how concern regarding this rule is hindering innovation and reasonable but aggressive postures by company traders.

The Market Behavior Rules

The behavior rules resulted from the Commission's investigation of trading activity in western markets during 2000-2001, which uncovered a number of trading schemes intended to take advantage of the then-existing electricity market in California. The Commission also discovered abuses in reporting of natural gas prices to price index publishers for purposes of manipulating price indices.

The behavior rules were adopted to establish clear guidelines applicable to the conduct of market-based rate sellers in wholesale power markets and to pipelines and companies engaged in natural gas transactions under blanket certificate authority in natural gas markets. The rules also provide a balanced approach to remedies for anticompetitive behavior or market abuses.

The behavior rules for market-based trading of electricity address six topics:

Rule 1, Unit Operation: Requires sellers to operate and schedule generating facilities, undertake maintenance, declare outages, and commit or otherwise bid supply in a manner that complies with the rules and regulations of the applicable power market.

Rule 2, Market Manipulation: Prohibits actions and transactions without a legitimate business purpose that are intended to, or foreseeably could, manipulate market prices, conditions, or rules. Specifically prohibits certain types of conduct, such as wash trades, transactions based on false information, transactions to create and relieve artificial congestion, and collusive transactions.

Rule 3, Communications: Maintains that sellers must provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission, market monitors, regional transmission organizations (RTOs), independent system operators (ISOs), or similar entities, under a due diligence standard.

Rule 4, Reporting: Provides that if sellers report transactions to price index publishers, they must provide accurate and factual information in accordance with the standards of the July 2003 *Policy Statement on Natural Gas and Electric Price Indices.*[2]

Rule 5, Record Retention: Requires sellers to retain for three years all data and information necessary for the reconstruction of the prices they charge and the prices they report for use in published price indices.

Rule 6, Related Tariffs: Prohibits sellers from violating or colluding with another party in actions that violate seller's tariff code of conduct or applicable standards of conduct.

The behavior rules applicable to market-based rate sellers of electricity became effective December 17, 2003, and were automatically deemed incorporated into the tariff of every seller with market-based rate authority. All such sellers were directed to file the behavior rules in prescribed form in their tariff, with the effective date of December 17, 2003.[3]

For natural gas wholesale transactions subject to the Commission's jurisdiction, the applicable rules (parts of Rule 2; Rule 4 and Rule 5) have been incorporated in 18 CFR §§ 284.288 and 284.403, making them applicable to interstate pipelines and to all holders of blanket certificate authority to engage in sales of natural gas for resale subject to the Commission's jurisdiction. The behavior rules applicable to natural gas wholesale transactions became effective December 23, 2003.

To provide balance between enforcement of rule violations and certainty for past energy transactions, complaints alleging violations of the behavior rules must be filed with the Commission within 90 days of the calendar quarter in which the violation is alleged to have occurred, or within 90 days of the time the complainant knew or should have known of the behavior. Similarly, if the Commission becomes aware of potential violations of the behavior rules, it must take action, such as initiating an investigation, within 90 days of learning of the alleged conduct. The principal remedy for a violation of the behavior rules, in addition to any other applicable remedies, is disgorgement of unjust profits from the violation. Given the evolving energy markets, the Commission also required that the effectiveness and consequences of the behavior rules be evaluated in the annual *State of the Markets Report.*

Reaction to Behavior Rules

Many parties presented views and concerns to the Commission on the proposed rules, and the Commission made several modifications to the proposed rules in response to these comments. Since issuance of the final rules, however, direct comments to the Commission have been limited to requests for rehearing, all of which were denied. [4]

The Commission adopted rules that attempt to combine adequate notice of prohibited conduct while retaining enough flexibility to address facts and circumstances not currently envisioned. It was the Commission's expectation that future cases will present concrete circumstances in which the behavior rules are applied, permitting the Commission to highlight specific prohibited conduct on a case-by-case basis.[5] At the present time, however, no cases have yet reached the Commission for decision. In addition, no formal complaints have been filed with the Commission alleging violations of the behavior rules.

A common theme expressed by industry participants is that Behavior Rule 2, dealing with market manipulation, is vague. As noted earlier, Behavior Rule 2 bars actions or transactions without a "legitimate business purpose" that are intended to or foreseeably could manipulate market prices, conditions, or rules. The Commission provided specific examples of actions that violate Behavior Rule 2 (such as wash trades or creation of artificial congestion) and explained that if a transaction were undertaken to provide service to a buyer with rates, terms, and conditions disciplined by competitive forces, the transaction would have a legitimate business purpose.[6] This has given a degree of guidance to the industry, although some participants may find uncertainty in specific circumstances and others may adopt a cautious (or overly cautious) approach to new trading strategies until more information about the scope and meaning of the behavior rules is available.

We have received reports that market participants have begun incorporating the behavior rules into their training programs and are providing guidance for trading personnel and managers of market activity. This is an essential step to translating the principles of the Behavior Rules into specific guidance for the personnel involved in day-to-day market activities.

Notification Concerning Price Reporting

Behavior Rule 4 required that sellers notify the Commission whether they report prices to publishers of price indices in accordance with the standards of the Price Index Policy Statement and to report any subsequent change in reporting status. The Commission received notices on behalf of 756 companies. While most notices stated the companies were not reporting energy trade data to price index publishers in accordance with the Policy Statement standards, many of the companies that notified the Commission they are reporting are among the most active traders. Moreover, subsequent filings of update notices indicate that more companies are now reporting transaction data. Consistent with this, the volumes of transactions reported by price index publishers indicates a continuing increase in the number of transactions being reported, thus providing additional price information to interested market participants (see essay on "Improving Energy Market Information").

Effectiveness of Behavior Rules

On May 6, 2005, the Commission hosted a technical conference and workshop on both the standards of conduct and the behavior rules. Speakers representing segments of industry addressed the behavior rules and noted that, while some confusion remains about the scope of Behavior Rule 2, companies are providing training to employees and understand the importance of common ground rules for market activity. Feedback from conference participants indicates that most companies have provided training in the behavior rules and that many companies have made changes in their market operations as a result of the adoption of the behavior rules. When asked whether the behavior rules have had a positive or negative impact on wholesale energy markets, a majority of those responding said that the behavior rules have had a "somewhat beneficial" effect.

The attention being paid by companies to the behavior rules, evidence of widespread training of market participants, and the absence of complaints indicates that the behavior rules have had an overall beneficial effect on

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Endnotes

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2. 104 FERC 61,121 (2003)(Price Index Policy Statement). See Essay in "Improving Energy Market Information."

3. Order Clarifying Prior Notice, 105 FERC 61,277 P 9 (2003).

4. The behavior rule orders now are on appeal. Cinergy Serivces Inc., et al. v. FERC, Nos. 04-1168, et al. (D.C. Circuit, filed May 28, 2004).

5. Behavior Rule Order 172.

6. Behavior Rule Rehearing 43.

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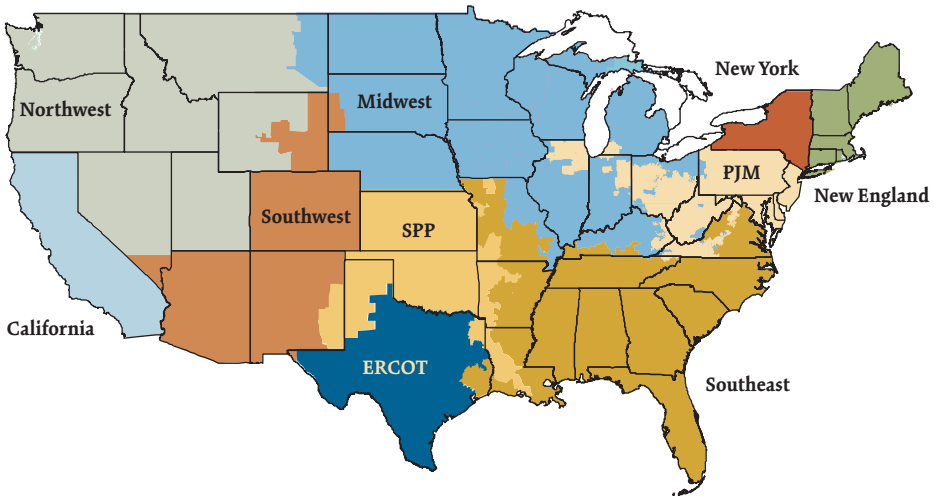
Electric Power Markets in 2004

This *State of the Markets Report* contains an overview of electricity markets and individual profiles of 10 major electric regions: New England, New York, PJM, the Midwest (MISO and MAPP), the Southeast, SPP, ERCOT, the Southwest, the Northwest, and California.

National Overview



Nationally, four keys to understanding U.S. power markets in 2004 were:

Electric markets remained essentially regional. Market institutions continued to differ greatly among regions, as did resource mixes and ways of addressing transmission congestion. During 2004, the most notable change was the further development of Regional Transmission Organizations (RTOs) in several regions. In regions without RTOs, independent generators continued to complain about lack of equal access to the grid.

Average electric power prices rose in almost all regions. New York, New England, and Texas (regions with RTOs that depend largely on natural gas) had relatively small increases. Regions that depend heavily on eastern coal saw the highest price increases. This pattern reflected the relative price increases of the fuels used in each region.

The country as a whole had overbuilt generating capacity, but was underinvesting in load pockets. Regions without RTOs provided few price signals to give an incentive to invest in load pockets. In RTO regions, price signals within load pockets were often insufficient to provide an incentive to build, either because of administrative procedures that would mitigate prices or because of a lack of location specific pricing. Even in New York City, which had a stronger price signal than other load pockets, state agencies were building much of the new capacity that will eventually come on line. Transmission investment had increased in recent years, but large-scale upgrades remained hard to site and build.

Financial institutions emerged as major players in the electric industry. In 2004 alone, hedge funds and lenders acquired 4.7 percent of generating capacity in the United States. Financial trading overall increased significantly in energy.

Regional Diversity

The most important structural feature of the electric power market in the United States is its regional diversity—in resource mix, consumption patterns, and market institutions. The resource mix for power generation differs from region to region (see figure 1). The most significant differences are the importance of hydropower in the Northwest and the relative mix of natural gas generation compared with coal or nuclear steam generation in other regions.

Overall consumption for the country totaled 3,711,667 GWh in 2003 and increased to 3,827,325 GWh in 2004.[1]

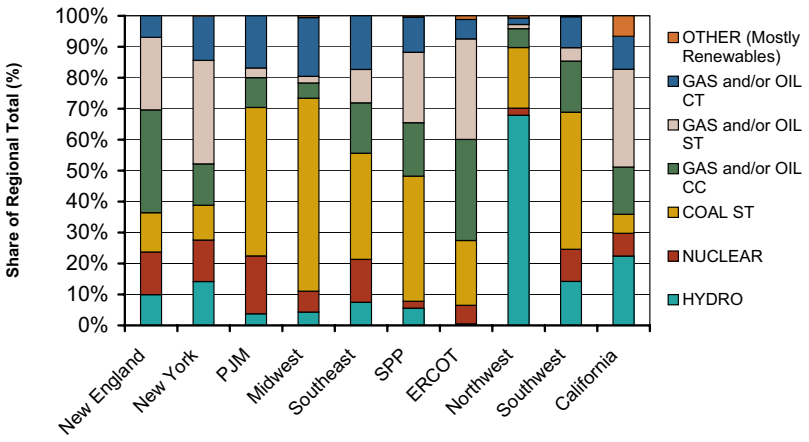
Market institutions also differ among regions. In the East, California, and Texas, regional transmission organizations (RTOs) operate the transmission grid and the basic spot market for power. During 2004, the Midwest and the Southwest Power Pool (SPP) moved toward adopting RTO markets, with the Midwest considerably more advanced than SPP. By the end of 2004, regions accounting for 68 percent of all economic activity in the United States had chosen the RTO option.[2]

In the West, long-distance electric transmission and trading are essential for the entire region. Fairly deep and liquid bilateral spot markets exist at 10 to 12 locations inside and outside California. These trading locations provide price discovery for the markets outside California and supplement the California Independent System Operator's (CAISO) balancing market within California.

Southeastern bilateral markets have few liquid trading points, except for a moderately liquid index for power moving into Entergy. Southeastern markets have little or no transparency, and serious concerns remain about access to transmission for independent generators.

Table 1 summarizes the market services available in each region in 2004.

Fig 1: 2003 Capacity by Fuel and Prime Mover



Source: Derived from data from Platts data. See Source Note 1.

Table 1: Wholesale Electric Markets in 2004

	Real-time market		Day-ahead market		Virtual Bidding	Ancillary services markets	Financial transmission rights	Capacity (UCAP) markets	Associated financial markets
	(RTO/ISO)	Bilateral	(RTO/ISO)	Bilateral	(RTO/ISO)	(RTO/ISO)	(RTO/ISO)	(RTO/ISO)	
New England	■	■	■	■	■	■	■	■[1]	■
New York	■	■	■	■	■	■	■	■[2]	■
PJM	■	■	■	■	■	■	■	■[3]	■
Midwest	05	■	05	■	05		05		■
Southeast		■		■					■
SPP	06	■		■					
ERCOT	■	■		■		■	■		
Northwest		■		■					■
Southwest		■		■					■
California	■	■		■		■	■		■

[1] Systemwide [2] Locational [3] Systemwide with the exception of the Northern Illinois control area.

RTO Spot Markets

All RTOs in current operation:

- Dispatch the generators in their systems and operate at least one short- term market that prices energy, congestion, and losses—Eastern RTOs all offer day-ahead and real-time markets and California and Texas offer real- time market alone;
- Use some form of locational pricing, though the level of granularity differs from locational marginal pricing (LMP) in the northeastern RTOs to Texas' and California's zonal system; and
- Have independent market monitors. In 2004, the Midwest Independent System Operator (MISO) and the Southwest Power Pool (SPP) also had market monitors in place in preparation for starting their markets in 2005 and 2006, respectively.

Table 2 shows the different variety of services available within each RTO.

Overall, RTO markets offer efficient systems of economic dispatch, price transparency for market transactions, and methods for addressing possible abuses of market power. Each RTO market continues to find it necessary to administratively adjust outcomes with mitigation authority. In many cases, other markets have grown up around the RTO markets. PJM West, for example, is among the most heavily traded bilateral markets and Nymex offers a futures contract for PJM. Similarly, ERCOT and both NP-15 and SP-15 in California are among the most heavily traded bilateral markets in the country. In contrast, visible bilateral trading in New York City has essentially disappeared over the past 2 years.

Table 2: RTO Market Characteristics in 2004

■ Existing ☐ Projected for '05 or '06 ♦ Cost-Based ● Other

Services Provided	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Bilateral transactions	■	■	■	■	■	■	■
Active online physical trading (1)	■		■	■		■	■
Active online financial trading (1)	■	■	■	■			■
Real-time energy market	■	■	■	☐05	☐06	■	■
Locational energy price	■	■	■	☐05	☐06	■	■
Hourly energy price	■	■	■	☐05	☐06	■	■
Congestion price	■	■	■	☐05	☐06	■	■
Losses price	■	■	♦[2]	☐05	☐06	■	■[3]
Day-ahead energy market	■	■	■	☐05			
Locational energy price	■	■	■	☐05			
Hourly energy price	■	■	■	☐05			
Congestion price	■	■	■	☐05			■
Losses price	■	■	♦[2]	☐05			
Ancillary services market	■	■	■	♦	♦	■	■
Regulation service market	■	■	♦[4]	♦	♦	■	■
Operating reserves market	■	■	■[5]	♦	♦	■	■
Reactive power market	●[6]	●[7]	♦	♦	♦	♦	♦
Black start market	♦	♦	♦	♦	♦	●[8]	♦
Financial transmission rights	■	■	■	☐05		■	■
Capacity market	■	■	■				♦[9]
Regional transmission scheduling	■	■	■	■	■	■	■
Regional economic dispatch	■	■	■	☐05	☐06	■[10]	■[10]
Regional transmission planning	■	■	■	■	■	■	■
Regional interconnection process	■	■	■	■	■	■	■
Independent market monitor	■	■	■	■	■	■	■
Mitigation	■	■	■	☐05	☐06	■	■

[1] An active market is defined as one that currently provides a historical price series.
[2] Losses allocated to market participants based on a pro-rata share of total transmission losses.
[3] Allocated to sellers using generation meter multipliers, which reflect scaled marginal losses.
[4] Regulation is cost-based outside of MAAC.
[5] Non-spinning reserves are derived from market-based offers.
[6] Units needed for VAR taken out-of-merit.
[7] Fixed monthly Mvar payment plus opportunity cost.
[8] RFP procurement process.
[9] CAISO has cost-based contracts for RMR.
[10] No day-ahead energy markets; economic dispatch used in real-time balancing markets.

RTO Spot Markets

In 2004, the areas covered by RTOs expanded. Figure 2 shows the current configuration:

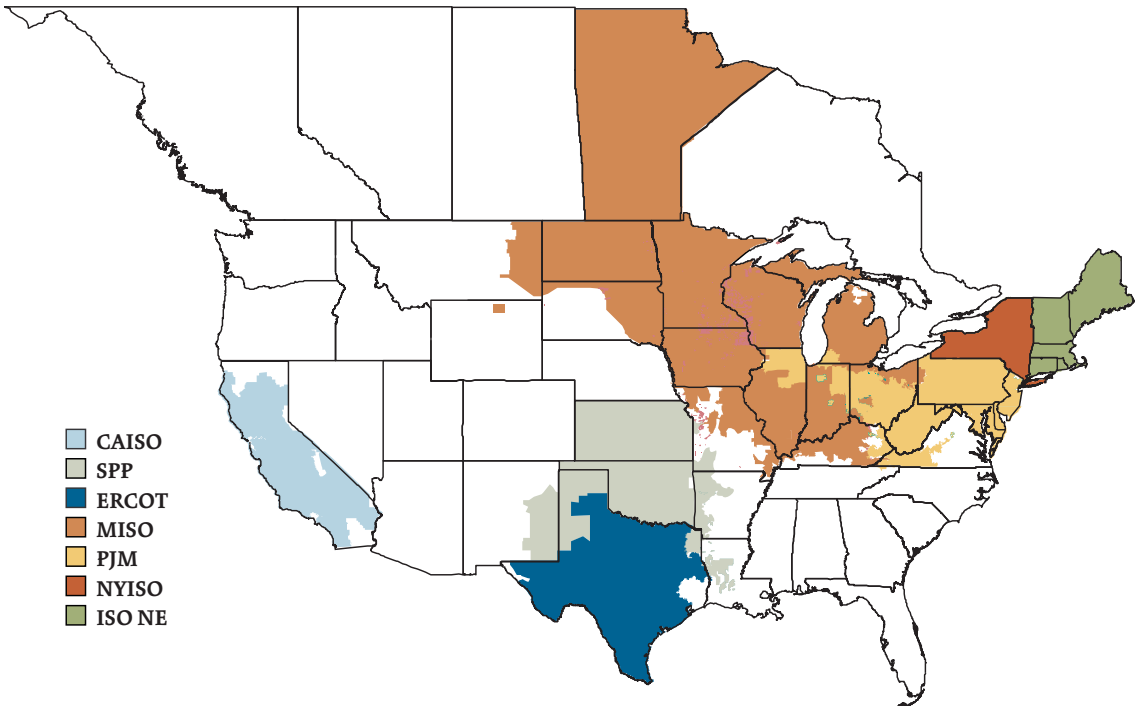
- Several large service territories joined PJM, which now includes many areas in Virginia, West Virginia, Ohio, and Illinois as well as its historical region in the mid-Atlantic. The area now in PJM covers about 18 percent of total electricity consumption in the United States.
- MISO continued developing its day-ahead and real-time markets for deployment in 2005.
- The Commission approved RTO status for SPP. It will begin with a balancing market (planned for early 2006). It has already set up a Regional State Committee (RSC) to facilitate regional transmission planning and oversight.
- The Commission approved the Independent System Operator for New England (ISO-NE) for RTO status, effective in 2005.

Other Spot Markets

In the desert Southwest and the Pacific Northwest, large volumes of energy have long traded in bilateral markets. The two most liquid points are Mid-Columbia (Mid-C) in the Northwest and Palo Verde in the Southwest. Other pricing points with significant quantities of visible bilateral trading include the California-Oregon Border (COB) and Mead.

In some ways, bilateral power markets in the West resemble natural gas markets more than they do RTO markets. They do not provide the same level of services or information as RTOs. Nonetheless, many of them appear to be reasonably liquid and transparent. One indication of the health of bilateral markets in the West has been the length of contracts one can obtain on the open market. Some services advertise deals going out as long as 12 years—3 years is more common in the East—indicating a degree of confidence in bilateral western markets.

Fig 2: RTO Configurations in 2004



Bilateral markets in the Southeast tend to be much less liquid and more opaque than in other regions. The number of bilateral trades reported at the Into Entergy trading point is higher than at any other southeast point. Traders report few trades for other points in the Southeast and almost none for Florida.

Approaches to Congestion

Transmission congestion is a central feature of the electric power industry. It arises when there is not enough transmission available to deliver less costly power into an area that then must run more costly generators instead. The electric industry in the United States addresses transmission congestion mainly in four ways.

- **Locational Marginal Pricing (LMP).** In New England, New York, and PJM, the RTOs use LMP to set a value for power at each node in the grid. Security-constrained economic dispatch ensures efficient use of transmission and determines which generators must change their operations to account for transmission congestion. This process yields LMPs where price differences among nodes indicate the costs of congestion. Beginning in 2005, MISO will join the eastern RTOs in using LMP to address congestion.

- **Zonal Prices.** ERCOT's and California's zonal prices represent a hybrid approach. Zonal pricing uses separate aggregate prices for each zone aggregate. Such a system shows market participants the incidence and value of congestion among but not within zones, reducing transparency.

- **Transmission Loading Relief (TLRs).** TLRs are orders to customers to limit their transactions and thereby reduce loads on particular transmission lines. Operators use TLRs to limit the use of transmission lines in some regions where LMP does not ration capacity. TLRs relieve congestion, but they are administrative, not market mechanisms. As a result, TLRs indicate where congestion occurs but give little indication of how much cost the congestion causes. In 2004 (and until MISO's markets began operation in 2005), TLRs were the primary method to address congestion in the Midwest. Entergy, SPP, and TVA also make wide use of TLRs.

- **Redispatch.** In some regions, system operators redispatch their systems to accommodate congestion without giving any clear signal as to how much congestion has occurred or how much it is worth. The Southern Company uses this approach, as does much of the West.

Capacity Markets

RTOs have complemented their energy markets with installed capacity markets. RTOs use capacity markets to ensure that load-serving entities pay for the cost of having enough capacity available to meet reserve margin requirements. RTOs intend that capacity markets will provide an additional stream of revenue to generators that can make it financially possible to invest in new generating plants when needed.

As estimated by the PJM, the New York Independent System Operator (NYISO), and ISO-NE market monitors, net revenues from installed capacity (see Table 3) varied by region in 2004. Except in New York City, the revenues in capacity markets were generally low, particularly in New England.

Table 3: Net Revenues from Installed Capacity

Region	$/kW-yr
NYISO NYC	$135.25
NYISO Rest of State	$16.65
PJM	$5.38 for CT/ $5.24 for CC
ISO-NE	$0.36

Source: PJM Interconnection, NYISO, and ISO-NE market monitoring units.

Average Spot Price Levels

Most market participants use spot markets for a small fraction of their purchases and sales. (The volatility of electricity markets makes heavy reliance on the spot market problematic for many players.) Nonetheless, healthy spot markets are critically important for the functioning of all wholesale power markets. Spot markets establish the value of power at each time period as short as 5-minute intervals. Spot markets provide price signals that:

- Enhance short-term decisions—power traded at the margin ensures that the most efficient mix of generators provides power to those who most value it, without necessarily changing the total bills for most customers; and
- Influence the value of longer term contracts and expectations for future spot prices.

All competitive electric markets ultimately rest on well-functioning spot markets, either bilateral or as part of RTOs. However, spot markets in some regions, in 2004, remained opaque with no RTO markets and few or no bilateral trades reported to index publishers. These regions include imminent RTO regions SPP and the MAPP and MAIN regions of MISO, as well as the non RTO Southeast. As a result of the underlying nature of the markets in these regions, any pricing information is at best indicative of the regional prices, although the published indices are the best pricing information available publicly. Price transparency in MISO and SPP should improve with the implementation of RTO markets.

Pricing

Electric prices for on-peak periods increased for most major pricing points around the country between 2003 and 2004. The levels of price increases varied by region as shown on Figure 3. On-peak prices for pricing points in Texas, New York, New England, PJM, the desert Southwest and the Great Plains, rose by 6 percent or less. Pricing points in other regions—the Southeast, the industrial Midwest, and much of the West Coast—increased more than 10 percent. Some areas (Southern, VACAR, Cinergy, and ECAR North) showed increases of more than 15 percent.

In the Eastern Interconnection and Texas, the lowest on-peak price increases came in areas where natural gas is typically the marginal fuel. In the West, California, and Northwest, prices moved together, maintaining $4 to $5 gaps between Mid-Columbia and the California-Oregon border and again between COB and northern California.

Off-peak prices generally increased more on a percentage basis in 2004 than on-peak. Much of this increase was due to coal price increases.

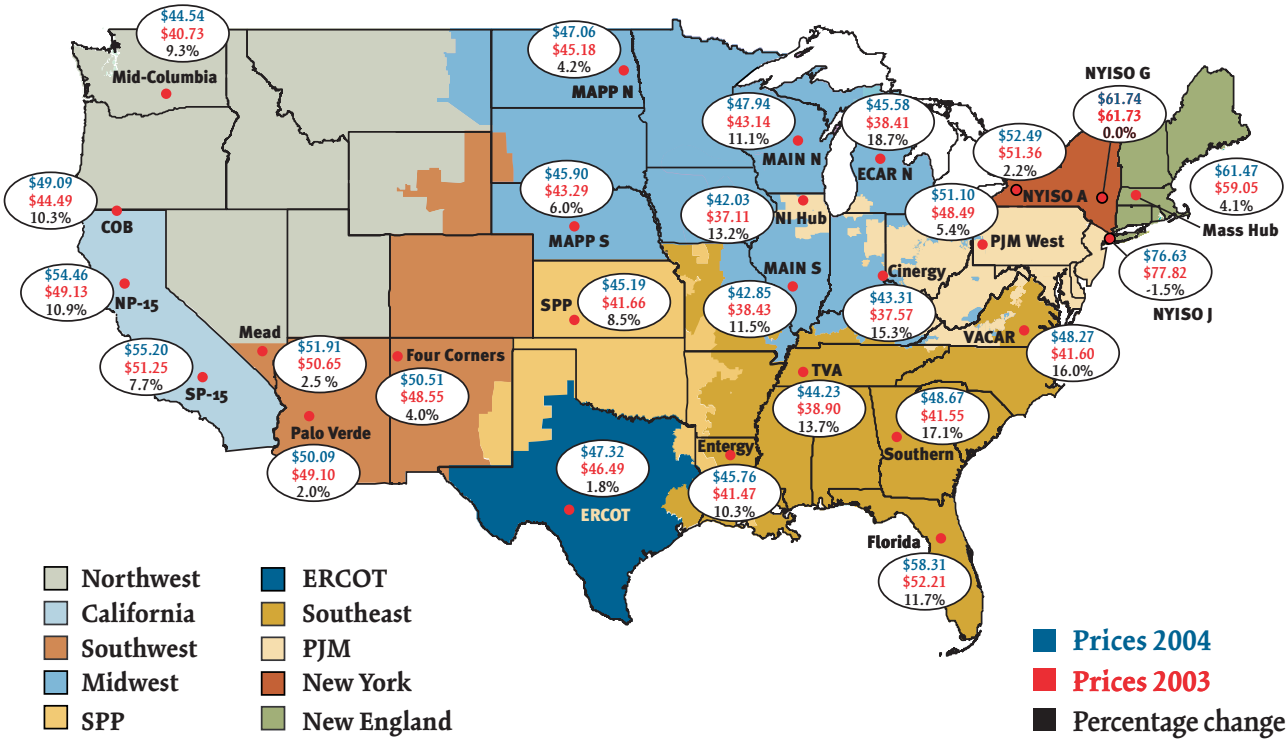
Two key factors often drive electric power prices—weather and input fuel prices. In 2004, weather extremes were rare and input prices increased.

Weather

Average winter temperatures in 2003–2004 were about normal for the nation—cooler on the East Coast, warmer in the Midwest. The summer was the ninth coolest on record nationally. Spring and fall were both warmer than usual. Overall mild weather, particularly in the summer, lowered demand and probably moderated price increases. This pattern also made severe price events less likely.

The year's two major price events both occurred in the Northeast in the winter. The first was a severe weather episode that affected New England and put the combined markets for natural gas and electric power under unusual stress (see Figure 4). This episode produced the largest differences between day-ahead and real-time prices during the year for any RTO market because market participants failed to anticipate either the severity of the weather on the first day or the rapidity with which normal conditions would return on the next day.

Fig 3: Electric Regions with Pricing Nodes On-Peak Prices ($/MWh)



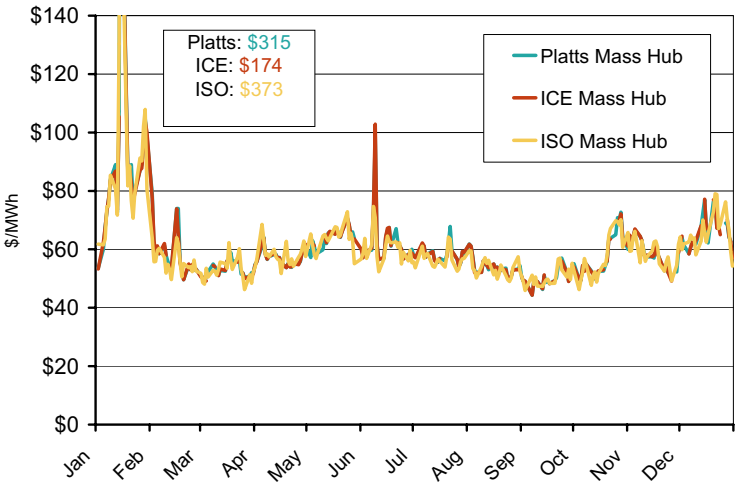
Source: Derived from Platts *Megawatt Daily* and Dow Jones data. See source note 2.

During the New England cold snap, market participants found it difficult to coordinate their activities in the natural gas and electric markets (see separate essay). Even so, on balance, the market worked well during the event. Prices rose and both the power and gas markets cleared without curtailments or blackouts. As soon as the severe weather passed, prices returned to normal levels.

The second incident occurred in December and affected New York and New England. The stresses were not as severe as the January incident. Again, the markets worked well, clearing without physical disruption and returning prices to normal levels when the weather returned to normal.

In the West, hydro conditions were somewhat worse than normal. Mild summer temperatures helped avert major price events.

Fig 4: New England Daily Average On-Peak Prices



Source: Derived from ISO-NE data. See source note 3.

Effects of Input Prices: Natural Gas, Coal, and Emission Allowances

A major factor contributing to the pattern of electricity price increases was the relative price of fuel and other inputs. Led by oil, natural gas prices continued to rise in 2004, by about 8 percent over 2003. Gas prices rose slightly less in the Northeast (in percentage terms) than elsewhere (see Table 4). In the Northeast and Texas, average on-peak power prices rose less than natural gas prices did (minus 1.5 percent in New York City to 5.4 percent in PJM West). In California and Florida, on-peak power prices rose somewhat more than natural gas prices (7.7 percent to 11.7 percent).

Coal prices present a more complex story than natural gas prices. Nationally, the EIA reports that average coal prices increased by about 6 percent.[3] However, the national average coal price includes a large percentage of coal that moves under long-term contracts with fixed price terms. In looking at spot market prices for electric power, the more important coal price is the spot coal price because a generator could sell the coal on the spot market instead of generating power. Increases in spot coal prices varied by region. Some key eastern coal prices rose by 69 percent. For western coal from the Powder River Basin, the spot price increased 6 percent.

Finally, prices for emission allowances (effectively another key input for many coal-fired generators) rose significantly through the year. This pattern of coal and emission allowance prices is consistent with the observed small electric price increases in areas where plants typically use western coal in the marginal generating unit. Greater price increases are to be expected where eastern coal and associated emissions allowances are more often on the margin.

Table 4: Change in Input Price 2003–2004

Input	2003 Price	2004 Price	Change
Natural Gas ($ per MMBtu)			
Henry Hub	$5.44	$5.85	8%
Southern California	$5.08	$5.51	8%
New York	$6.45	$6.81	6%
Coal ($ per ton)			
Central Appalachian (Eastern)	$32.19	$54.39	69%
Powder River Basin (Western)	$6.16	$6.56	6%
SO_2 Allowances ($ per ton)	$175.53	$436.31	149%
Oil			
WTI (Crude - $ per barrel)	$31.06	$41.51	34%
Residual Fuel, New York ($ per barrel)	$27.47	$27.95	2%
Distillate Fuel, New York ($ per gallon)	$0.85	$1.12	32%

Source: Derived from Platts, Bloomberg, and Cantor Fitzgerald data. The SO_2 Allowances are based off of monthly averages.

Table 5: Peak Spot Prices for Major Pricing Points ($/MWh)

	On-Peak Spot Prices			Off-Peak Spot Prices		
	2003	2004	% Change	2003	2004	% Change
Northeast						
Mass Hub	$59.05	$61.47	4.1%	$41.80	$42.94	2.7%
NY Zone G	$61.73	$61.74	0.0%	$42.12	$42.86	1.8%
NY Zone J	$77.82	$76.63	-1.5%	$48.70	$48.28	-0.9%
NY Zone A	$51.36	$52.49	2.2%	$35.78	$36.82	2.9%
PJM West	$48.49	$51.10	5.4%	$24.14	$30.15	24.9%
Southeast						
VACAR	$41.60	$48.27	16.0%	$19.44	$25.23	29.8%
Southern	$41.55	$48.67	17.1%	$19.51	$26.01	33.3%
TVA	$38.90	$44.23	13.7%	$18.73	$22.14	18.2%
Florida	$52.21	$58.31	11.7%	$22.25	$29.02	30.4%
Entergy	$41.47	$45.76	10.3%	$18.39	$23.04	25.3%
Midwest						
Cinergy	$37.57	$43.31	15.3%	$15.91	$19.88	24.9%
ECAR North	$38.41	$45.58	18.7%	$16.54	$21.00	26.9%
MAIN North	$43.14	$47.94	11.1%	$16.47	$20.28	23.2%
NI Hub	$37.11	$42.03	13.2%	$15.44	$17.57	13.8%
MAIN South	$38.43	$42.85	11.5%	$16.06	$18.41	14.6%
MAPP North	$45.18	$47.06	4.2%	$17.22	$19.12	11.0%
MAPP South	$43.29	$45.90	6.0%	$16.93	$19.00	12.3%
South Central						
SPP North	$41.66	$45.19	8.5%	$18.48	$20.55	11.2%
ERCOT	$46.49	$47.32	1.8%	$30.51	$31.45	3.1%
Southwest						
Four Corners	$48.55	$50.51	4.0%	$32.28	$35.45	9.8%
Palo Verde	$49.10	$50.09	2.0%	$32.84	$35.44	7.9%
Mead	$50.65	$51.91	2.5%	$33.75	$37.43	10.9%
Northwest						
Mid- Columbia	$40.73	$44.54	9.3%	$34.04	$39.27	15.3%
COB	$44.49	$49.09	10.3%	$35.23	$40.58	15.2%
California						
NP 15	$49.13	$54.46	10.9%	$35.76	$41.35	15.6%
SP 15	$51.25	$55.20	7.7%	$35.15	$39.26	11.7%

Source: Derived from Platts and Dow Jones data. See Source Note 4.

Table 5 shows average 2004 power prices both on-peak and off-peak for pricing points around the country. Consistent with fundamental market drivers, both on-and off-peak price increases were greatest for regions and times that were most likely to depend on eastern coal for the marginal generating unit—Virginia, Southern, and the eastern Midwest. Price increases were relatively low for coal-burning regions further west—the Great Plains and the Southwest.

The off-peak effects of eastern coal prices were more pronounced than the on-peak effects. Coal is more often on the margin in off-peak periods. (Spot electric prices tend to track the running costs of the on-line unit with the highest operating costs. The operating costs are mostly from fuel and emissions allowances.) Many pricing points in the Southeast and Midwest showed off-peak price increases of 20 percent or more. PJM West showed a striking difference between on and off-peak power price increases—5.4 percent on peak and 24.9 percent off peak. This dichotomy reflected the tendency of PJM to have natural gas on the margin during peak periods and coal in off-peak periods. Entergy showed a similar pattern.

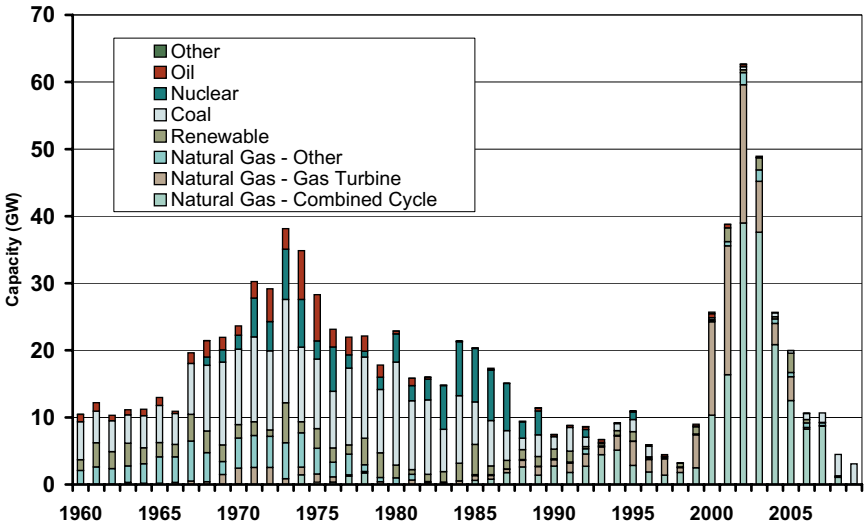
Overcapacity and Underinvestment

During 2004, the generation sector of the industry faced different circumstances:

- In aggregate across the country, the industry had a significant degree of overcapacity as a result of the building boom for combined cycle natural gas plants.
- Some specific load pockets had inadequate capacity (either in local generation or in transmission capacity) and saw an insufficient incentive to construct new facilities to alleviate the problems.

In transmission, investment increased for the fourth year in a row. Still, large-scale transmission additions remained rare.

Fig 5: Annual U.S. Capacity Additions 1960–2009



Source: Derived from Platts PowerDat data (February 2005).

Generation Overcapacity

The United States built more generating capacity between 2000 and 2004 than in any earlier 5-year period (see Figure 5). Almost all of this capacity is combined cycle gas plants—far more fuel-efficient than earlier gas plants. Independent generating companies built most of this capacity—traditional utilities built less than a quarter of it. Most regions now have a surplus of generation (see Table 6).

The surplus of generation has reduced the profitability for many combined cycle plants because:

- They do not run as expected. Investment studies typically were excessively optimistic in the predicted hours of dispatch. In reality, new plants have fewer opportunities to earn money. Many combined cycle plants now run as intermediate, not baseload plants. As a result, system operators call on them to cycle on and off more than originally expected, which adds to maintenance costs. In some cases, too, the plants cannot get transmission service.
- They make less money than expected when they do run. They tend to compete against other combined cycle plants most of the time, not against less efficient, older gas-fired plants. This competition reduces spark spreads (the difference between what natural gas costs and what the power it generates sells for) so that each plant typically makes less money than expected when it does run.

Taken together, these factors help explain why many independent generating companies face financial difficulties and why many individual assets are financially distressed.

Table 6: 2004 Reserve Margins

	Summer Reserve Margin %		Summer Reserve Margin %
New England	30%	SPP	20%*
New York	25%	ERCOT	26%
PJM	36%	Northwest	23%
Midwest	16%	Southwest	29%
Southeast	32%*	California	22%

* Reserve margins include uncommitted capacity not included in the regional market profiles. They also exclude all derates, which may overstate the available reserves in some regions.

Source: Derived from NERC 2004 ES&D and RTO/ISO data.

Underinvestment

Although the nation as a whole has access to more electric power generation than it needs, some local areas suffer from underinvestment. Price signals in those areas have not provided incentives for needed investments.

Table 7 shows the results of a net revenue test for each region, with New York City broken out separately. The net revenue tests shown here differ from those that a regional entity might prepare in that we use price and cost estimates from the same sources for all regions.

Table 7: Net Revenue

Region	Point	CC Net Revenue (as % of Target Revenue)	CT Net Revenue (as % of Target Revenue)
New England	Mass Hub	59%	NA
New York	NYC (J)	285%	246%
	Hud Val (G)	83%	27%
PJM	West Hub	34%	9%
Midwest	Cinergy	13%	0%
Southeast	Southern	32%	0%
SPP	SPP	32%	1%
ERCOT	ERCOT	30%	0%
Northwest	COB	48%	1%
Southwest	Palo Verde	48%	2%
California	SP-15	68%	3%
	NP-15	58%	1%

Source: See regional overviews and "Analytic Note on Net Revenue Calculations".

A net revenue test:

- Totals the market-related revenue streams a generator could have received in 2004 (The estimates reported here include spot market revenues for all hours when financially feasible to operate and capacity payments from RTO capacity markets, when relevant, but not ancillary service payments.);
- Subtracts variable costs (fuel and variable operation and maintenance); and
- Compares the result to the target revenue needed to pay for the fixed costs of a new plant. Estimating the revenues needed to pay for fixed costs requires many assumptions, and different analysts arrive at significantly different estimates. (The estimates reported here use EIA cost estimates, which tend to be lower than most.)

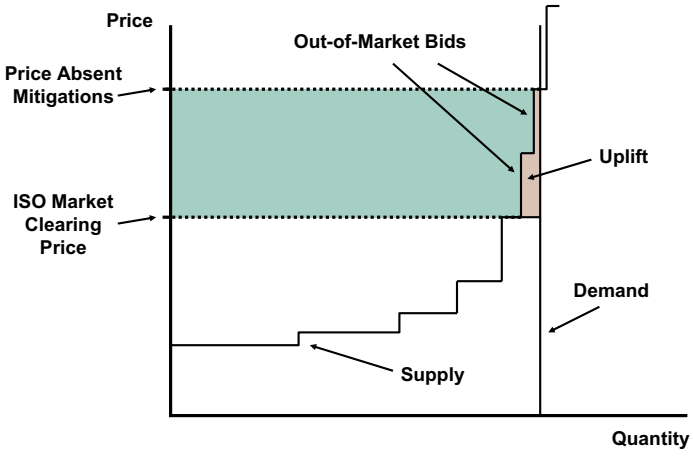
Making net revenue estimates consistently across the country inevitably leads to compromises that do not precisely reflect individual regions. The results in the table would change if the estimates used different assumptions for fixed costs or if other revenue streams such as ancillary services were used. In most cases, such changes do not affect the overall results. The two major exceptions are:

- In New England, most of the revenue for a combustion turbine (CT) would come from the forward reserve market that ISO-NE introduced in 2004—part of the revenue stream for ancillary services. ISO-NE estimates that a CT could recover between 66 percent and 88 percent of the revenues needed for investment.[4]
- EIA's estimates of fixed costs are misleading for New York City. EIA's estimates are regional averages and fail to take account of the unusually high costs of building power plants in the most populated city in the country. The table overstates the net revenue percentage for New York City significantly. NYISO's independent market advisor estimates that the cost recovery for a New York City combined cycle (CC) plant was marginal in 2004 and probably would not have provided quite sufficient revenues.[5] He further estimated that a New York City CT would have recovered just over half the needed costs.

These results reflect the overall surplus of generation in the country. Net revenues should be low in such circumstances, reflecting the lack of need for investment. However, the lack of market incentives is evident in most load pockets, and there is little incentive to build new plants in places that need them as well.

Non RTO Regions. Utilities in regions that do not have RTO markets usually fail to provide market signals for investment inside load pockets. For example, New Orleans is a load pocket, as are several cities within SPP. In the absence of locational price signals in either Entergy or SPP, price signals neither show the need for investment in a particular area nor promise to give the investor a return for investing in the right place nor raise the cost of consumption. Investment in load pockets or in transmission lines to avert congestion rely on traditional utility planning approaches rather than market signals.

Fig 6: Out-of-Market Bids



In the West, rapidly growing Las Vegas has become a load pocket. The relatively robust bilateral power market in the West does not appear to provide enough locational detail to justify investing in Las Vegas in particular.

RTOs. Proponents of LMP often tout its ability to provide a locational price signal for investment that would otherwise be lacking. However, pricing in load pockets must deal with two key issues at the same time—load pockets are subject both to scarcity and market power, either of which can raise prices. It has proven difficult in practice to allow the full exercise of scarcity pricing while preventing any abuse of market power. For this reason, RTOs use a variety of mechanisms to mitigate prices within load pockets that can sometimes blunt incentives for investment.

New England has two significant load pockets: Boston and southwest Connecticut. Though both areas are short of generation, their average revenues were essentially the same as for the rest of New England (except Maine, where generation is abundant). In southwest Connecticut, there is no separate price zone for the load pocket.

In both New England load pockets, ISO-NE frequently dispatched units that bid more than the prevailing market price—"out-of-market" bids. Figure 6 illustrates this concept where market prices remain lower and "uplift" side payments are collected outside the market and paid to certain generators. Similarly, units called on for VAR and local support can receive a higher than market price. ISO-NE then charges the additional payments to customers. In 2004, the total amount of these out-of-market payments was $334 million.

Many buyers see uplift payments as a way to force them to pay prices that are above "market" value, that is, above the published market-clearing price. However, from an investment perspective, such out-of-market payments remove from the energy market the primary incentive to invest in new generation or transmission. A net revenue analysis for New England suggests that a new generator would have received 59 percent of the revenues needed to justify having invested in a combined cycle gas plant. That reflects the market realities of New England outside the load pockets. But given the lack of price differentiation between the load pockets and other areas, it is also the price signal for the load pockets.

In response to these problems in ISO-NE proposed a locational capacity market. This would provide revenues to plants in load pockets and could give an incentive for localized new investment. ISO-NE and some local authorities are also working hard to build a new transmission line into southwest Connecticut. The fact remains that in 2004, there were virtually no energy market signals to show the need for such investment.

New York City is the one major load pocket in which a net revenue analysis indicates that revenues from a combined cycle plant might have justified the investment in 2004. In

fact, some market players are building new capacity in New York City. However, even there the investment response has not come easily. Between 2001 and 2005, NYPA, a state agency, has built or is building the majority of the in-city generation. A merchant transmission proposal to deliver power from upstate into the city (the Conjunction project) failed during the year.

Southern California could become a load pocket under certain conditions. Recent concerns about possible shortages if summer is hot there in 2005. During 2004, the net revenue test showed a southern California generator receiving 68 percent of the revenues needed to justify investment in a new combined cycle plant, higher than any other region except New York. The price differential between the desert Southwest and southern California also increased. These are both market signals consistent with a growing need for new capacity, but they do not appear to be strong enough to justify building a new plant. Given potential problems in southern California in the summer of 2005, the question is whether electric power price signals for new investment will provide enough lead time to build new plants or transmission before shortages occur.

Transmission Investment

Electric transmission owners have increased their investments in transmission every year since 2000 (see Table 8). Net plant additions in transmission, as reported in the 2004 FERC Form 1, were $3.828 billion—4.7 percent of the total transmission plant in service. Transmission investment grew 69 percent between 2000 and 2004.

These reported investments include all plant and equipment associated with transmission, not just transmission lines. Large transmission lines remain difficult to site and to build. In 2004, a total of 931 circuit miles of new transmission lines above 230 kilovolts came into service in the United States, a 0.6 percent increase to the transmission system already in service (more than 150,000 circuit miles over 230 kilovolts).[6]

Table 8: Transmission Investment by Companies ($Billions)

Year	Gross Transmission Additions	Transmission Retirements	Net Transmission Additions
2000	$2.6	$0.4	$2.3
2001	$3.4	$1.1	$2.3
2002	$3.3	$0.4	$2.9
2003	$4.0	$0.4	$3.5
2004	$4.3	$0.4	$3.8

Source: Derived from FERC Form 1 data including accounts 352, 353-359.1. See source note 5.

Growing Role of Financial Institutions and Private Equity

During 2004, financial institutions and private equity entities became more important players in electric power markets in three ways. They:

- Acquired individual assets, at both the corporate and the plant level,
- Helped facilitate rapidly expanding trading in key power markets, and
- Helped improve systems for doing business in the power industry by, for example, addressing credit risk and clearing.

Asset Acquisition

Financial institutions acquired significant holdings in the electric power industry in 2004. At the corporate level, Goldman Sachs acquired Cogentrix, Credit Suisse First Boston (CSFB) acquired United American Energy (UAE) and AIG-Highstar Capital acquired 50 percent of Duke/UAE American Ref-Fuel. Most of the electric power holdings aquired by financial institutions and private equity in 2004, however, were at the facility level.

During 2004, almost 36 GW of generation assets changed hands, a four-fold increase from 2003. Table 9 provides details by buyer type. Effectively 5.8 percent of total capacity in the industry changed hands.

Who acquired the assets? Investors within the electric industry doubled their acquisitions in 2004, but financial players increased their acquisitions nearly six-fold, despite the fact that investment banks virtually stopped buying power assets. The new acquirers were private equity and hedge funds (23.2 GW) and lenders to assets that defaulted or were in danger of

default (6.0 GW). Private equity itself accounted for 65 percent of all the capacity that changed hands in 2004, 3.7 percent of all generation capacity in the United States. The rise of private equity and hedge funds represents a change from 2003, when investment banks accounted for most of the asset acquisition at the plant level.

Increased Trading of Financial Products

During 2004, financial trading on the IntercontinentalExchange (ICE) increased by a factor of 10. Figure 7 shows nationally the volume of power traded financially for a given month, looking at contracts for a month or longer. For example, the December volume includes all trades made for the month of December or for a strip of months which included December during all earlier periods prior to the month.

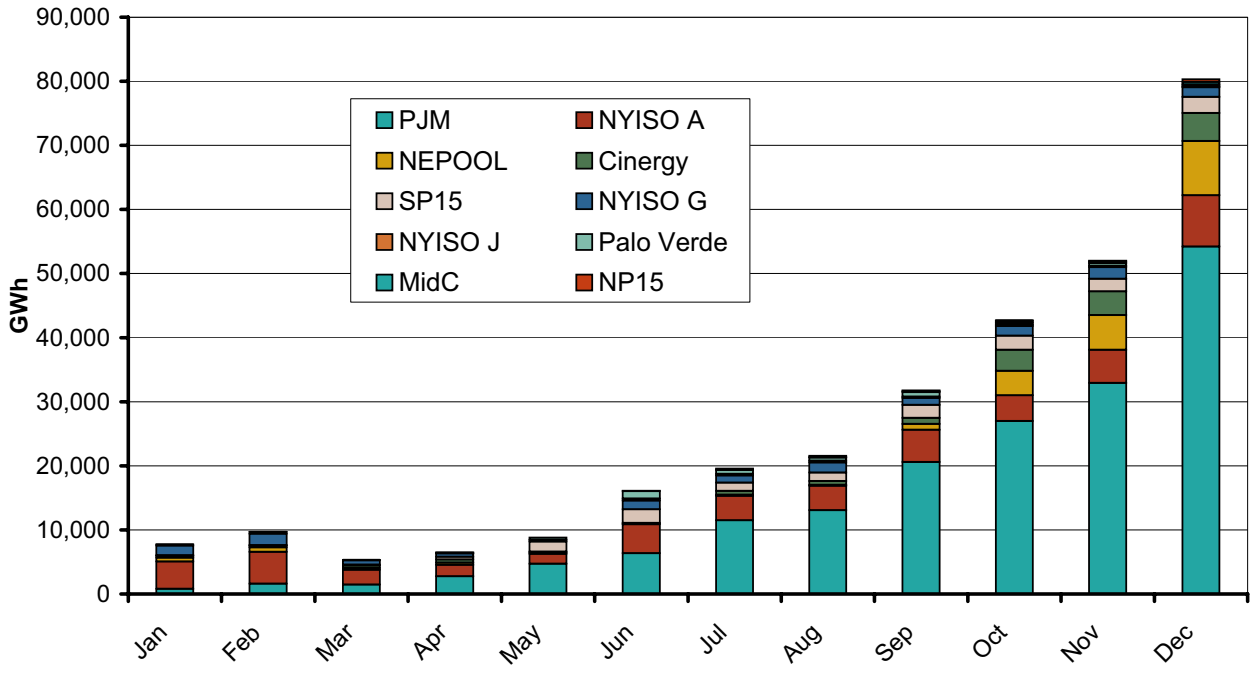
Trading in ICE financial swaps[7] designed for market participants to trade future power quantities financially increased in many regions around the country. This change was most pronounced in PJM, where its products accounted for over 50 GWh per month in forward contracting. Most regions also saw large percentage increases in the volume of ICE trading during the year. The increase became especially pronounced starting in September for most regions. Western New York (Zone A) was an exception, having been fairly high throughout the year.

Table 9: Asset Acquisition by Company Type (GW)

	2003	2004
Electric Industry Buyers		
Utilities	0.7	1.6
Affiliated Power Producers	0.5	2.1
Public Sector (Munis and Coops)	1.1	0.4
Independent Power Producers	0.7	2.2
Total Electric Industry Buyers	2.9	6.3
Financial Buyers (Acquirers)		
Private Equity and Hedge Funds	0.8	23.2
Lenders	0	6.0
Investment Banks	4.4	0.2
Total Financial Buyers	5.2	29.4
Total Acquired	8.1	35.7

Source: Derived from EIA data, confirmed with Platts PowerDat software.

Fig 7: Financial Trading on ICE



Source: Derived from ICE on-peak financial swaps volumes. ICE products evaluated include monthly, dual monthly, quarterly, and calendar year contracts traded for 2004.

The increase in ICE swaps volumes follows ICE's introduction of a clearing service[8] in late 2003 for several hubs (PJM, NYISO, Cinergy, SP-15, Palo Verde) and again in the summer of 2004 for others (ISO-NE, NP-15, Mid-C). Participants may have moved some pre-existing business to ICE to take advantage of the clearing service. The number of financial transactions on ICE may have increased for other reasons as well. ICE trends provide the best indication available for changes in trading volumes in electricity, as information on over-the-counter trading is lacking.

Financial trading in the electric industry appears to be one part of a web of energy markets that link physical and financial markets for both fuel and power. The best indications available are that financial trading in electric power is a more important part of that web of energy markets than it was a year ago. Financial instruments are more attractive in many circumstances—the delivery obligation in physical deals can be both cumbersome and costly. The increase in trading also suggests an increasing ability for market participants to arbitrage between physical and financial markets for reasons of cost, convenience or regulatory regime.

Improvements in Credit and Clearing

Industry events during 2000 and 2001—from the California "meltdown" to the PG&E and Enron bankruptcies to financial distress among most energy merchants—heightened awareness of credit issues. Credit concerns, in turn, lowered market liquidity.

Market liquidity is, among other things, a function of the availability of capital and (inversely) the credit capital required to transact business. From 2000 through 2003, market liquidity declined and credit capital requirements increased as market participants made the costs of credit more explicit for their counterparties. They became more diligent at assessing credit quality, set tighter credit limits and collateral requirements, and revised credit requirements more frequently. At the same time, energy merchants had less capital available for energy transactions.

In 2004, liquidity improved as surviving energy merchants continued recovering, producers and some utility affiliates became more active, and financial players joined long-established investment banks Goldman Sachs and Morgan Stanley in building energy trading capabilities. Overall, these changes increased capital available to market participants. Increased capital improved the industry's ability to address credit issues, increased the ability of companies to buy and sell energy, and increased market liquidity.

At the same time, market participants sought to reduce credit exposure by netting, clearing, and more efficient settlement. Clearing platforms including Nymex ClearPort,[9] ICE with the London Clearinghouse (LCH),[10] and EnergyClear[11] developed. More recently, more specialized approaches have grown up to address more specific issues. For example, North American Energy Credit and Clearing (NECC)[12] entered physical clearing and Virtual Markets Assistance Corp. (VMAC)[13] netted insurance coverage.[14] These activities are helping to reduce required credit capital.

FERC has addressed credit issues. It organized a joint credit and clearing conference with Commodities Futures Trading Commission (CFTC) in early 2003[15] and issued a notice of proposed rulemaking for pipeline creditworthiness[16] and received comments later in 2003. FERC issued an electric credit policy statement[17] in late 2004 for transmission providers and RTO/ISOs. The policy statement requires greater transparency for all and calls for RTO/ISOs to accelerate settlements and develop other means to reduce mutualized credit risk among their market participants. These efforts also facilitate the reduction of required credit capital.

Together, increased capital availability and reduced required credit capital improved market liquidity in 2004. The linkage of credit and market liquidity is important to the Commission because liquid markets are a strong indicator of the competition that the Commission relies on to provide just and reasonable rates.

Conclusion and Remaining Questions

Electric power markets faced less stress in 2004 due to generally benign weather. They responded successfully in the few cases of difficult weather conditions—in New England in January and more broadly in the Northeast in December.

RTOs developed significantly during the year:

- MISO prepared for starting its markets in 2005.
- SPP became an RTO and prepared for a balancing market in 2006.
- ISO-NE received approval for RTO status.

Overall, areas accounting for over two-thirds of the national economy have opted for RTOs. At the same time, the Southeast and the West outside California showed little sign of moving toward RTOs in the near future.

Longer-term markets continued to show signs of being prone to boom-bust cycles. During 2004, generating companies finished the last major group of combined cycle natural gas plants started during the last boom. Most of the country was in the bust part of the cycle with a glut of generating capacity and financial distress for many companies. At the same time, most load pockets with supply shortages did not see market price signals that would justify new investment.

The major questions facing electric power markets in the future include:

- **How well will short-term markets perform when faced with more severe, more widespread, or more prolonged weather incidents?** Both winters and summers have been mild for the last 2 years, so the markets have not faced a major test recently.
- **How will RTO markets adapt to regions that have a history of many separate control areas, such as MISO?**
- **Can markets signal the need to build capacity (generation, transmission, or price responsive demand) long enough in advance to prevent shortages that lead to price explosions or blackouts?** The capacity markets of the Northeast are one major effort to address this issue. Other possible approaches include letting energy prices rise to clear the market and traditional utility planning. Much of the country has no obvious market mechanism to signal the need for new building in advance of shortages. The success of capacity markets in addressing the issue is not yet proven.
- **Can electric markets institutions foster the development of more price responsive demand?** With little price response from demand, markets are more subject to price spikes (in response to short-term shortages), to overbuilding (to avoid price spikes), and to greater cost (since a large fraction of total investment is designed to meet peak demand). Developing more price-responsive demand raises a host of institutional issues including the difficulties of reconciling the jurisdiction of states over retail markets and federal jurisdiction over the purchasing as well as selling side of wholesale markets.
- **How will the industry integrate market institutions and reliability requirements?** Well-designed markets should reinforce reliability, and reliability should support markets.

Guide to the Regional Profiles

The individual regional profiles cover 10 regions: New England, New York, PJM, the Midwest (MISO & MAPP), the Southeast, SPP, ERCOT, the Southwest, the Northwest, and California.

Each profile stands alone as a summary of the region's electric markets in 2004. The profiles are designed to be as standard as possible but differ somewhat because of differences in the information available from each region. RTO regions, for example, have much more information available than others. The profiles generally include the following sections:

Summary. The opening section of each profile includes:

- A brief description of the region and important factors that affect its electric market.
- A map with average on-peak prices for 2004 for available pricing points.
- A summary price table that includes annual on-peak prices for the region for 2003, 2004 and a 5-year average. It also provides price estimates from different sources, where available, so the reader can compare, for example, the RTO's price with those provided by the trade press (such as Platts) or an electronic exchange (such as ICE).
- Overall statistics for supply and demand, including estimates of reserve margins.

Major Focal Points for 2004. This section summarizes the most important developments that affected the regional market during 2004.

Spot Market Prices and Volumes. This section includes a graph of key daily regional prices during the year. In many cases it will include more than one price series so that the reader can compare different data sources or different pricing points. It is especially useful for identifying price spikes and seeing the overall range and volatility of prices through the year. Where relevant, this section includes a second pricing chart. In some cases, the second chart shows a second pricing point in more detail (as in southern and northern California). In others, it shows the difference between day ahead and spot prices during the year. The text describes key events that affected prices—for example heavy loads that drove prices higher.

Financial Prices and Volumes. This section contains two graphs:

- A plot of the forward price curve at several times during 2004. This graph shows how market expectations of future prices changed during the year.
- A graph of the quantity of power for the region that traded under forward contracts on ICE during the year. This indicates the change in the amount of financial trading and shows striking increases in some regions.

Capacity Auctions. This section applies to those regions that have RTO capacity markets (New England, New York, and PJM). It includes a brief description of the market, a graph of prices through 2004, and a graph of quantities traded in the auctions.

Resource Mix. This section shows the mix of generation in the region (by fuel and generator type)—both by capacity installed and by amount of power generated in 2003.

Market Concentration. This section shows the top 10 generating companies in each region (by capacity and total power generated) in 2003.

Net Revenues. This section provides an estimate of how much revenue a marginal plant could have generated from energy and capacity markets during 2004 and compares the result with an estimate of how much revenue it would take to justify constructing the plant. It supplies estimates for both a combustion turbine (for peaking) and a combined cycle plant (for base and intermediate load). These estimates reflect the signal to investors as to whether it would be (or would have been) worthwhile to make investments in the region. Market signals should lead to higher net revenue estimates in regions that are short of power and lower estimates where there is a surplus.

Regional Exports and Imports. This section shows a daily

graph of overall net imports for 2004. It also shows average and maximum flows over major interfaces with other regions.

Generation and Transmission Additions and Retirements. This section shows changes to the physical infrastructure over the last 3 years.

Short Articles. Each regional profile includes at least one brief discussion that highlights an important event or development during the year in greater detail than is possible in the standard sections.

Endnotes

[1] Data collected from 2004 NERC ES&D database.

[2] FERC/OMOI analysis of Bureau of Economic Analysis, Regional Economic Accounts (Revised as of 12-15-04), and EIA 2003 Forms 906 and 861 data.

[3] US Coal Supply and Demand: 2004 Review by Fred Freme; US Energy Information Administration, April 2005.

[4] ISO New England State of the Market Report 2004. May 4, 2005, 28-9.

[5] 2004 State of the Market Report—New York Electricity Markets. May 4, 2005, 6, presentation discussion.

[6] Transmission data derived from NERC ES&D Data Base 2004, updates from NERC as of 4/19/05, ERCOT data, and FERC research.

[7] A fixed for floating financial swap exchanges dollar obligations and liability based on a firm established price, which is liquidated against a price that is based upon an index, but physical commitment is never established.

[8] Clearing is the mechanism used to erase the risk of principal-to-principal transactions (trading) through a transfer to an anonymous pool. Clearing typically involves futures commission merchants, regulated exchanges, membership liability, insurance products, margin, and settlements to ensure the financial security of the transactions to all the markets participants.

[9] New York Mercantile Exchange (Nymex) began clearing over-the-counter energy transactions in 2002 and formed the Clearport platform for clearing and execution for a growing list of gas and power products. Nymex Clearport volumes were 6,040,165 contracts in 2003 and 14,455,848 in 2004.

[10] IntercontinentalExchange (ICE) is an online trading platform (electronic broker), which began clearing through the London Clearing House (LCH) in 2002. Cleared volumes were 4,529,781 contracts in 2003 and 17,965,076 contracts in 2004.

[11] EnergyClear was a membership clearing model where each participant had to be a member and contribute to a pool of guaranty funds to protect against the default of a member. This model is different from that of Nymex ClearPort and ICE/LCH where the protection is mutualized among the Clearing Members (or Futures Commission Merchants—FCM) and each participant must clear through an FCM. EnergyClear started with five members and shut down in early 2004 after growing beyond the initial membership over the 2-year start up effort.

[12] North-American Energy Clearing Corporation (NECC) is gearing up to start clearing of physical transactions on ICE in the summer of 2005, beginning with power products from the ERCOT market and Henry Hub gas.

[13] VMAC (previously Virtual Markets Assurance Corporation) utilizes an insurance model to provide multi-lateral netting—the primary focus of clearing to reduce credit risk. VMAC anticipates start up during the summer of 2005.

[14] Commodity Futures Modernization Act (CFMA), enacted December 14, 2004, reauthorizes the Commodity Futures Trading Commission (CFTC) and contains provisions for the regulation of designated clearing organizations (DCOs) for over-the-counter products by complying with a set of core principles.

[15] Joint FERC and CFTC conference on "Credit Issues in the Energy markets; Clearing and Other Solutions," held February 5, 2003.

[16] Docket No. RM04-4-000, "Creditworthiness Standards for Interstate Natural Gas Pipelines" Notice of Proposed Rulemaking (NOPR) issued February 12, 2004. FERC received comments. A decision is pending.

[17] Docket No. PL05-3-000, "Policy Statement on Credit-Related Issues for Electric OATT Transmission Providers, Independent System Operators and Regional Transmission Organizations" issued November 19, 2004.

Source notes

1. Demonstrated capacity data are from Platts PowerDat, RDI Modeled production Costs data set for calendar year 2003, reflecting self-reporting from all utility and non-utility electric power generating facilities with nameplate capacity of 50 MW or more.

2. On-peak days for western nodes (NP-15, SP-15, Mid-Columbia, COB, Mead, Palo Verde, and Four Corners) are defined as Monday through Saturday excluding NERC holidays. On-peak days for all other nodes are defined as Monday through Friday excluding NERC holidays. Some regional prices will differ from the almanac prices as other data sources were utilized at the regional level.

3. FERC/OMOI analysis of 2004 ISO day-ahead on-peak LMPs from http://www.iso-ne.com/smd/operations_reports/hourly.php. Platts *Megawatt Daily* 2004 on-peak index prices are for the Massachusetts Hub. ICE 2004 on-peak index prices are for the Nepool Mass Hub. On-peak hours are 7am to 11pm. On-peak days are Monday through Friday excluding NERC holidays.

4. The price increases reported here are for individual pricing points in Platts, with the exception of Mead on-and off-peak Dow Jones firm on-peak prices and NYISO off-peak ISO prices (off-peak hours are all weekend and NERC holiday hours as well as weekday hours 11pm to 7am). In particular, the PJM West pricing point reflects activity at only that point, not for the whole of PJM. Looking just at this point avoids the problem that PJM grew during the year, so that average prices for the whole of PJM represent different areas at different times during the year.

5. FERC Form 1 data for 2004 is a preliminary data set based on 198 of 221 companies. The missing 23 companies accounted for 6.7 percent of the Year Balance dollars in 2003. It was assumed that their share of the total would remain constant in 2004. Transmiss-ion addition levels for the 198 respondents, representing 93.3 percent of the whole ($3.99 billion) multi-plied by (100/93.3) provides a preliminary 2004 transmission addition level of $ 4.277 billion.

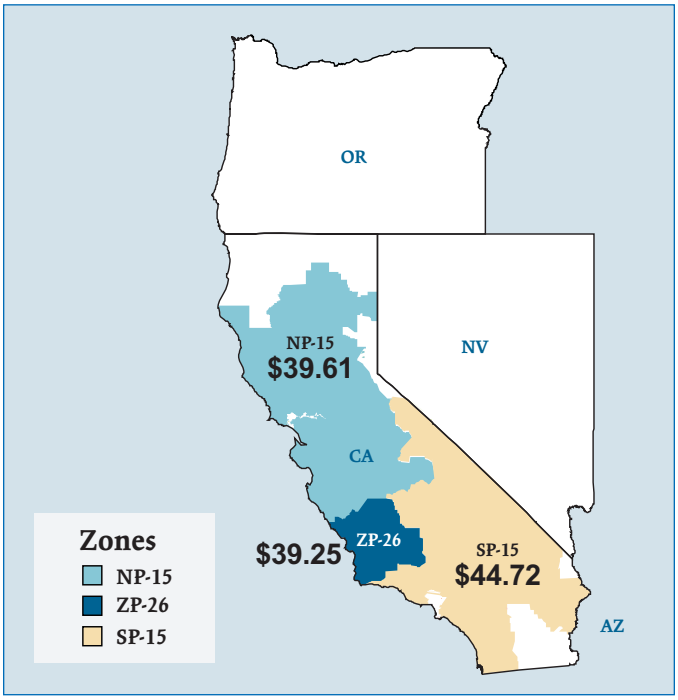
Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

California (CAISO) Electric Market Profile

The California electric market comprises primarily the California-Mexico Power Area (CAMX) subregion, as designated by the North American Electric Reliability Council (NERC). Within CAMX an open-access, wholesale market is managed by the California Independent System Operator (CAISO), representing approximately 80% of demand within the California electricity market. The portion of the CAMX power area within Mexico consists of a small section along with transfer capability limited to 800 MW total into California. CAISO manages more than 25,000 miles of transmission owned by Pacific Gas & Electric Company (PG&E), Southern California Edison Company, San Diego Gas & Electric Company, and participating municipalities.[1] The remaining 20% of California's load is managed by municipal utilities and irrigation districts such as the Los Angeles Department of Water and Power, the Sacramento Municipal Utility District, and the Imperial Irrigation District.

CAISO manages markets for imbalance energy, ancillary services, and transmission usage. Wholesale energy and ancillary service costs, including CAISO's imbalance energy, totaled approximately $11.8 billion for 2004, compared with $10.8 billion for 2003. Imbalance energy (the difference between scheduled energy and actual load) represents less than 5% of energy consumed in CAISO.[2] Ancillary services (A/S) allow for generation to be held in reserve to provide a margin of supply above the demand requirement. CAISO provides access to, and allocates the capacity of, California's transmission to market participants.

2004 Average Zonal Prices for On-peak Hours ($ per MWh)



Source: Derived from CAISO data. See source note 1.

During the year CAISO experienced 4% demand growth with less than comparable growth in generation.

NP-15 Zone Prices

	2003	2004	5-Year
ISO (Incremental only)	$37.08	$39.61	$61.35
Platts	$49.13	$54.46	$75.12
Dow Jones	$49.08	$54.47	NA

SP-15 Zone Prices

	2003	2004	5-Year
ISO (Incremental only)	$39.89	$44.72	$57.60
Platts	$51.25	$55.20	$72.04
Dow Jones	$51.17	$55.17	NA

Source: Derived from CAISO, Dow Jones and Platts data. See source note 2.

Supply Demand Statistics

	2003	2004	Exp. 2005
Summer Generating Capacity MW	56,766	55,726	54,421
Summer Peak Demand MW	42,689	45,597	46,668
Summer Reserves MW	14,077	10,129	7,753
Summer Reserve Margin	33%	22%	17%
Annual Net Generation Gwh	180,740	184,168	NA
Annual Load GWh	231,241	239,769	NA
Annual Net Exports/Imports Gwh	(51,110)	(56,581)	NA

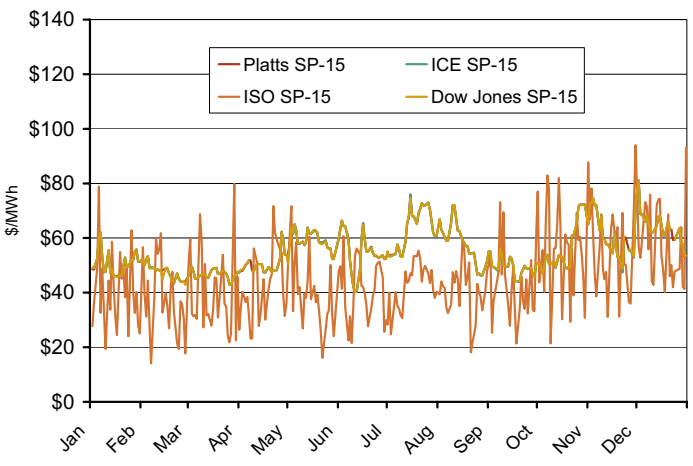
Source: Derived from CAISO data. See source note 3.

Focal Points for 2004

- **High-level goals** for resource procurement were issued in January when the California Public Utility Commission (CPUC) set in motion policy for long-term procurement rules for load-serving entities. Stakeholders sought more definition, and the CPUC opened a new omnibus proceeding on electric utility resource planning. Workshops on implementation are forthcoming in 2005.[3]
- **Insufficient new generation** is coming on line either to meet demand growth or to compensate for generation retirements, the California Energy Commission (CEC) reported. The CEC expected California to have adequate supplies through 2009, but has since qualified that expectation, stating that, under hot weather conditions or with significant retirements of aging power plants, the state's reserve margins could become "dangerously thin, primarily in southern California."[4]
- **A new power plant** received conditional approval of a power purchase agreement between Southern California Edison (SCE) and a subsidiary it created to complete and operate the partially constructed power plant, Mountainview, located in Redlands, Calif. The CPUC granted conditional approval of the project to address generation supply needed for southern California. State agencies and SCE had expressed concern that as early as 2006 there could be insufficient new generation to meet demand growth, if new plants were not built.[5]

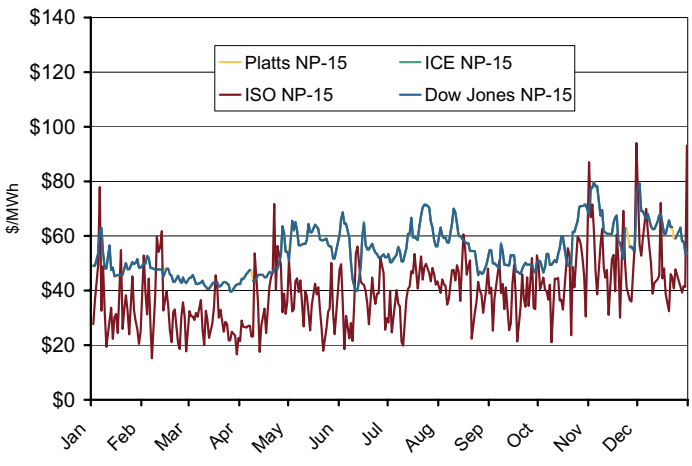
SPOT MARKETS: PRICES AND VOLUMES

Daily Average of Southern California On-Peak Prices



Source: Derived from CAISO, Dow Jones, Platts and IntercontinentalExchange (ICE) data. See source note 4.

Daily Average of Northern California On-Peak Prices



Source: Derived from CAISO, Dow Jones, Platts and ICE data. See source note 4.

Day-ahead, peak bilateral prices from Platts, IntercontinentalExchange (ICE), and Dow Jones are illustrated, as well as CAISO real-time prices. Prices in 2004 were affected by the following: implementation of Phase 1B; nuclear unit outages; a major transmission line failure near Palo Verde that tripped over 4,000 MW of generation throughout the West and pushed imbalance energy prices in SP-15 to more than $116; and derating of the Pacific DC Intertie (PDCI) for repairs and upgrades through the summer and fall.

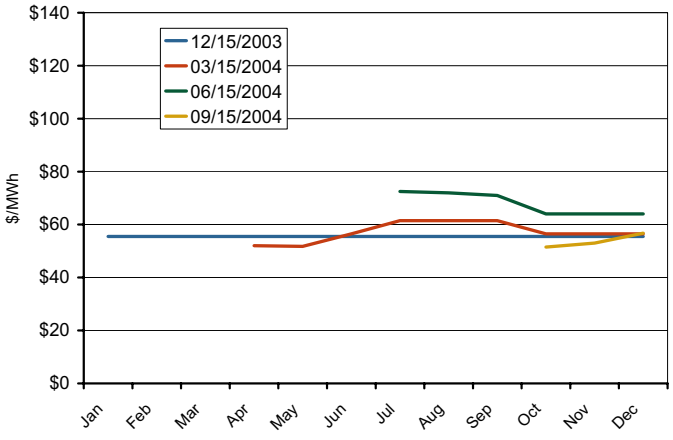
Implementation of a new Real-Time Market Application on October 1 contributed to an increase in real-time price volatility and price spikes. The real-time price volatility declined later in the year as CAISO adjusted software parameters and generation and transmission resources returned to service.

Ancillary Services saw significant price spikes for spin, nonspin, and regulation services throughout the year. Offers to sell A/S were often less than the capacity requirement for reserves. Typically, less supply is available during "shoulder periods" (seasonal off-peak periods) when generators and transmission lines are taken out of service for repairs. In 2004, capacity was further reduced after the loss of a Diablo Canyon nuclear unit, a San Onofre nuclear unit, and some capacity on the Pacific DC Intertie. The lack of generation resources led to unusual price spikes for reserves, such as A/S for lower quality resources exceeding prices for the higher quality resources. The daily weighted average nonspin price exceeded $100 for at least one day during each of the months from August to December.

In 2004, the daily peak load hours averaged 30,275 MW. Day-ahead forecasted loads for the California ISO generally tracked real-time volumes, but the two diverged by as much as 12% on a few occasions. In NP-15 bilateral trading, Platts-reported volumes averaged 1,470 MW and peaked on November 26 and 27 at 2,975 MW; ICE volumes averaged 16,852 MW and peaked on July 9 and 10 at 50,400 MW. In SP-15 bilateral trading, ICE volumes averaged 26,072 MW and peaked on October 29 and 30 at 88,800 MW; Platts-reported volumes averaged 2,459 MW and peaked on September 1 and 2 at 5,800 MW.

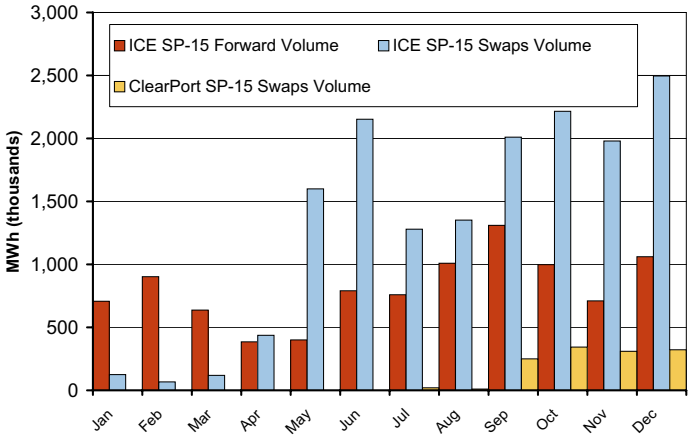
FINANCIAL MARKETS: PRICES AND VOLUMES

SP15 Swaps Prices from Trade Date



Source: Derived from ICE data. See source note 5.

SP-15 Forward and Swaps Volume



Source: Derived from ICE and Nymex data. See source note 5.

For California, financial markets consist of both physical forwards and financial swaps. Market participants use many platforms for their financial transactions. Data are available only for ICE and the New York Mercantile Exchange (Nymex). ICE began clearing SP-15 in December 2003 and NP-15 in August 2004. Nymex ClearPort began trading NP-15 and SP-15 financial swaps in June for July and future months.

Trading of ICE NP-15 and SP-15 monthly physical products for 2004 was highest in the third and fourth quarters. Trading for the fourth quarter was twice first-quarter volumes for NP-15 and 20% higher for SP-15. SP-15 volume was higher than NP-15 trading on both ICE and Nymex ClearPort for both physical and financial products.

Financial trading of SP-15 on ICE overtook physical trading in the second quarter and by December was more than double physical volume. On ICE, financial trading increased 21-fold for SP-15 over the course of trading for 2004; NP-15 trading increased more than 61-fold, although the overall volumes for NP-15 were 10% of SP-15. From August, trading of NP-15 on Nymex ClearPort outweighed trading on ICE.

The increase in trading of NP-15 and SP-15 financial products is consistent with general trends in electricity trading as more non-traditional electricity trading entities (hedge funds and banks) have become active in these financial markets, and as industry credit has improved. Some of the increased trading on ICE might be due to its starting to offer clearing of trades, as noted above.

CAISO Continued to Experience Congestion Challenges

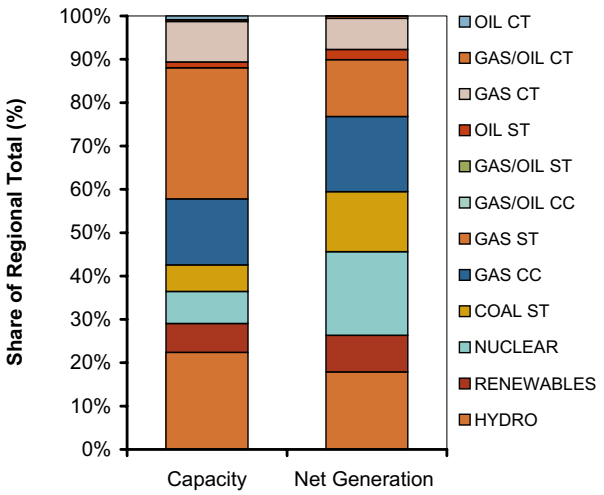
Congestion costs occur when transmission facilities are constrained and cannot carry more power. At those times the system must use higher cost generators located close to load, rather than lower cost generators elsewhere. CAISO estimates that congestion costs in 2004 were $482 million, up from $177 million in 2003. Intra-zonal congestion was $426 million.

In California, suppliers may schedule power transfers without regard to transmission constraints—for example, the constraint at the Miguel substation regarding energy transmission into San Diego—but the scheduled power may be physically undeliverable. This practice increases congestion costs. The long-term "seller's choice" contracts entered into by the state in 2001 account for much of this. Congestion was also increased by the seven-week San Onofre refueling outage (approximately $9 million in congestion costs) and intermittent outages of the Sylmar substation during the summer (approximately $22 million).

CAISO uses Reliability Must Run (RMR) contracts for certain generating units in load pockets to meet local reliability needs (e.g., voltage support and contingency reserves) and to mitigate local market power (see Offer Mitigation box, p. 74). RMR units may also be dispatched in real time in response to intra-zonal congestion. When the RMR units were dispatched for this purpose, CAISO calculated the net real-time costs (variable costs in excess of reliability costs) for intra-zonal congestion as $49 million in 2004, up from $27 million in 2003.[6]

2003 RESOURCE MIX

Capacity and Generation by Fuel and Prime Mover

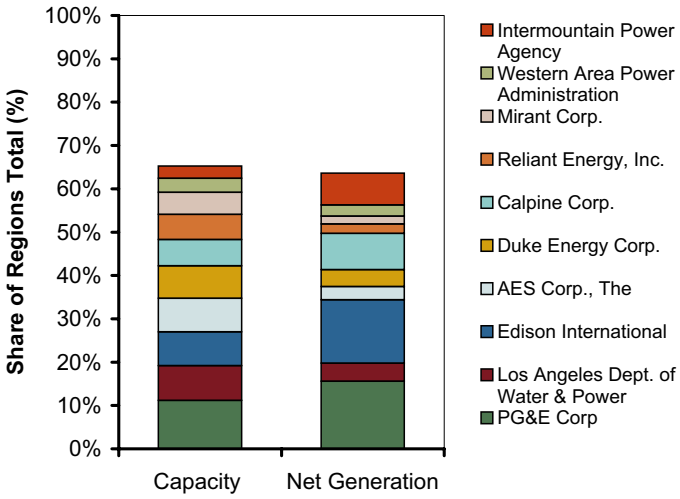


Source: Derived from Platts data. See source note 6.

In 2003, hydroelectricity, wind, nuclear energy, and coal constituted 43% of total California capacity and provided 59% of net generation. The region depends heavily on gas-fired capacity providing 45% of the capacity in 2003 and contributing 30% of annual net generation.

2003 MARKET CONCENTRATION

Capacity and Generation of Top 10 Companies



Source: Derived from Platts data. See source note 6.

The top 10 owners provided 59% of capacity and 55% of generation in California in 2003. Seven of the top 10 generation owners in CAISO were independent power producers or utility affiliates, who built or acquired generating assets outside of their traditional service territories. The major investor-owned utilities in California have divested substantial portions of their generating assets or transferred them to unregulated affiliates.

The residual supplier index (RSI) is one measure of the extent to which a single generation supplier is pivotal in the real-time energy market on an hourly basis. CAISO's Department of Market Analysis (DMA) calculated that the RSI for 2004 decreased from 2003 levels, but was still significantly above the 1.0 RSI Index level for all hours in the year. The RSI dropped below the 1.1 level for 22 hours in the year. This indicates competitive conditions in the ISO control area and less potential for market power.[7]

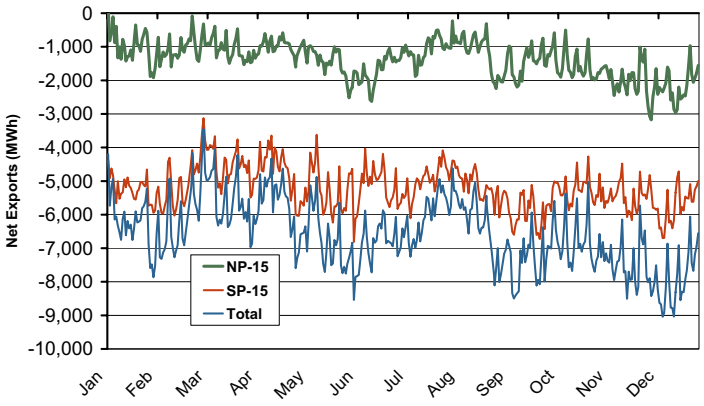
Capacity for thermal units, and in particular natural gas-fired units, changed the most in 2004. More than 97% of the new generation that came on line in 2004 was fueled by natural gas. The CAISO initiated the return of the two Reliant Etiwanda thermal units in mid-2004, accounting for 640 MW of the 750 MW of generation additions. These units were brought back into service under RMR contracts that preclude them from setting market prices.

REGIONAL EXPORTS AND IMPORTS

CAISO was a net importer of energy, importing an annual average of 6,587 MW. The highest daily net imports were on December 9, averaging 9,041 MW, whereas the lowest daily net imports were on February 29, averaging 3,448 MW. The highest hourly net imports were for hour 15 on September 7 for 11,024 MW; the lowest hourly net imports were for hour 2 on March 1 for 2,197 MW.

Regionally, CAISO receives most of its power from the Northwest and Arizona, and on average is a net exporter of energy to the Sacramento Municipal Utility District. Zonally, both NP-15 and SP-15 were net importers from external control areas, although, on January 1, NP-15 was a net exporter. On net, SP-15 imported more than three and a half times the amount that NP-15 did.

Average Daily Net Interchange



Source: Derived from CAISO data. See source note 7.

Hourly Net Interchange

External Interface	Max Exports - MW	Max Imports - MW	Avg Net Exports (Imports) MW
Arizona	1,830	6754	(3765)
Imperial Valley	365	597	(331)
LADWP	1,176	1626	(135)
Mexico	270	515	(125)
Nevada/Utah	335	1196	(569)
Northwest	1900	5867	(2457)
SMUD	1973	430	795

Source: Derived from CAISO data. See source note 7.

Average Hourly Zonal Exports

Zone	Max Exports - MW	Max Imports- MW	Avg Net Exports (Imports) MW
NP-15	2292	4595	(1383)
SP-15	3069	10280	(5203)

Source: Derived from CAISO data. See source note 7.

CAISO Experiences Seven New Record Peak Load Days

During 2004, CAISO set seven new records for energy usage, reaching 45,597 MW on September 8. The previous record of 43,609 MW was set in July 1999. Demand peaked at levels not projected to be reached until 2006. This was a tight year for operating reserves for the CAISO. In May, California reached record temperatures, running about 10 degrees above the forecasts for southern California. A record temperature on March 29, combined with 770 MW of generation tripping, resulted in the ISO declaring a Stage 1 Emergency. CAISO projected supply margins on the thin side for the remainder of the summer in SP-15 and initiated the return to service of two mothballed Etiwanda power plants located within the Los Angeles Basin load pocket for a total capacity addition of 640 MW.

The two plants were designated as Reliability Must Run (RMR) units, which allowed the ISO to use them to meet local reliability needs. The timing was fortunate. The second unit came on-line the day before the CAISO experienced its record peak for SP-15 of 25,743 MW on September 10. During this record peak load day, the ISO grid operator depleted its entire operating reserves in SP-15 and reach transfer capability limits on its transmission into that area. The CAISO avoided blackouts, but expressed concern about the deliverability of reserves to SP-15. The rest of the West experienced high heat during some of the same periods and had power still available to export to California with the exception of varying amounts of transmission congestion.[8]

GENERATION AND TRANSMISSION ADDITIONS AND RETIREMENTS

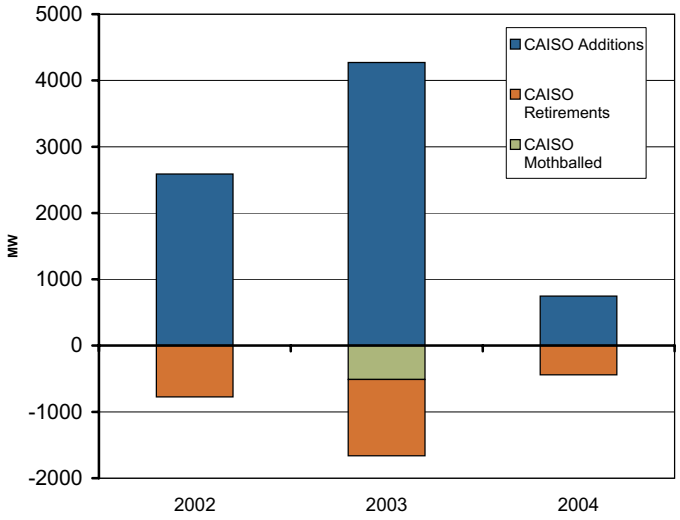
Generation Additions. In the CAISO region, 10 generation units came on line. The largest were two previously mothballed 320 MW units at Reliant's Etiwanda plant, located in SP-15 to serve load in the Los Angeles Basin. The Etiwanda units were brought back into service under RMR contracts that preclude them from setting market prices. Capacity additions in 2004 were lower than in the two previous years. Total capacity in 2004 increased by 748 MW of which the net additions of new plants was approximately 110 MW, generation retirements totaled 180 MW, and the Etiwanda reinstatement accounted for 640 MW.[9]

Transmission Additions. Three significant transmission projects were completed in CAISO: the Path 15 upgrade, the Miguel substation upgrade, and the Pacific DC Intertie at Sylmar substation.

The Path-15 upgrade is a new 84-mile, 500 kV transmission line, providing an additional 1,500 MW of transfer capability between the southern and the northern portions of the state.[10] After the upgrade took effect on December 14, Path-15 energy flows increased 40% in the south-to-north direction.

San Diego Gas & Electric's Miguel substation was upgraded to allow an additional 100 MW to 400 MW of power into the San Diego area. This substation effectively limited transmission transfers from Arizona into southern California. San Diego Gas and Electric estimated that the $30 million project would reduce congestion costs by $18 million annually and would ease access to more efficient generation from the Southwest. These benfits should accrue once a second upgrade is completed in 2005. The upgrade took effect October 31.

Capacity Additions



Source: Derived from CAISO, EIA and Platts data. See source note 8.

The Pacific DC Intertie was upgraded between early summer and year end. The addition of a transformer bank at the Sylmar (Los Angeles) substation doubled its transfer capability from 800 to 1,600 MW, increasing capability between the Los Angeles Department of Water and Power and CAISO. Maintenance was performed at both ends of the line (Los Angeles and the Pacific Northwest) to update equipment and improve reliability. The line was down for short periods in early summer, operated at reduced capacity throughout the summer, was taken off-line again September 30, and was restored to full 2,200 MW capacity by December 30.

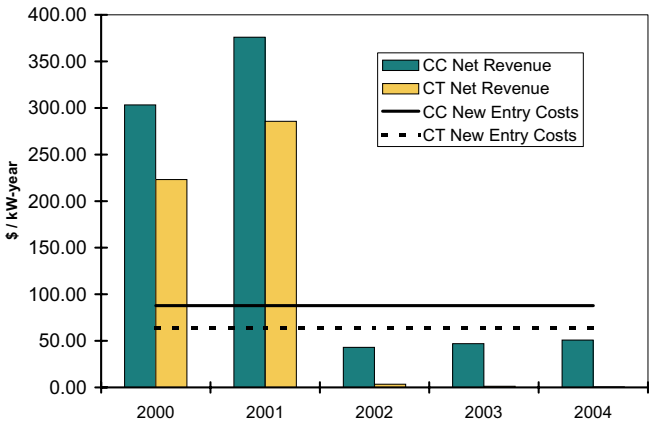
Offer Mitigation

CAISO uses a Bid Cap and Automatic Mitigation Procedures (AMP) to address economic withholding, complementing its Must Offer requirement to address physical withholding. The Bid Cap of $250/MWh is a "soft" cap because sellers can submit bids above this price, but the bids do not set the market clearing price (and are subject to justification and refund). Therefore, the market clearing price cannot exceed $250.

AMP operates in CAISO's real-time market. It mitigates an energy offer if the offer violates an explicit threshold ("conduct test") and materially affects the market clearing price ("impact test"). AMP takes effect only when prices are expected to exceed $91.87. AMP operates system-wide (System AMP) and also locally on offers from resources that are taken out of merit order to alleviate intra-zonal congestion (Local AMP). During 2004, System AMP mitigated no bids (i.e., no bids failed both the conduct and impact tests). Local AMP mitigated fewer than 2% of the out-of-merit dispatches, totaling $318,507.

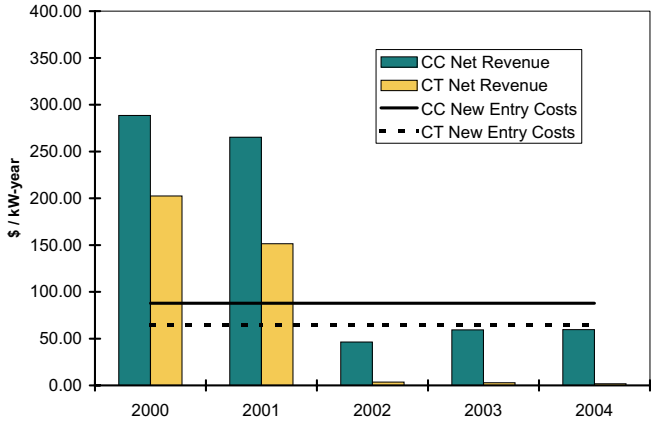
NET REVENUE

Northern California Net Revenue from Energy



Source: Derived from Platts day-ahead gas prices for PG&E Citygate and Socal Gas Large Packages and Platts day-ahead power prices for NP15. See "Analytical Note on Net Revenue Calculations" in the Other Material section for details.

Southern California Net Revenue from Energy



Source: Derived from Platts day-ahead gas prices for PG&E Citygate and Socal Gas Large Packages and Platts day-ahead power prices for SP15. See "Analytical Note on Net Revenue Calculations" in the Other Material section for details.

As shown, 2004 annual net revenues from energy for gas-fired technologies were below the five-year average for the third consecutive year, in part, because of relatively large net revenues in 2000 and 2001. Annual net revenues from energy increased from 2003 for a combined cycle in NP-15 and SP-15 of 8.3 and 0.5 percent, respectively. In both NP15 and SP15, revenues from energy for a combustion turbine declined to a five-year low.

We estimate that new gas-fired combustion turbines in California require $64.29/kW-yr, and gas-fired combined cycle plants require about $87.85/kW-yr, to meet debt and equity requirements.

In 2002, 2003, and 2004 estimated net revenues for gas-fired combined cycle and combustion turbine plants in California were below these thresholds. (The five-year average net revenues exceed these thresholds only because of exceptionally large revenues from high-priced periods in 2000 and 2001.) Energy markets alone did not signal the need for new investment in 2004.

Endnotes

[1] The Participating Transmission Owners (PTOs) in the ISO Control Area are PG&E, SCE, SDG&E, City of Vernon, City of Anaheim, City of Azusa, City of Banning, and City of Riverside. All PTOs are also utility distribution companies (UDC). Other UDCs are City of Pasadena and Lassen Municipal Utility District. Metered Subsystem (MSS) customers in the ISO Control area are Northern California Power Authority, The City of Roseville, and Silicon Valley Power. Other load-serving entities that the ISO provides services for include (but are not limited to) Western Area Power Administration, California Department of Water Resources, Metropolitan Water District of Southern California, Modesto Irrigation District, Turlock Irrigation District, and City of Redding.

[2] Most energy within CAISO's control area is generated by the utilities and purchased under bilateral contracts with suppliers such as merchant wholesale generators and qualifying facilities. State-procured "sellers choice" contracts (procured during the 2001 energy crisis) covered 32% of the three, large investor-owned utilities' peak energy requirements in 2004.

[3] California Public Utilities Commission, Decisions 04-01-050, 04-10-035, and 04-12-048.

[4] Integrated Energy Policy Report 2004 Update [100-04-006CM], California Energy Commission, November 2004, vi.

[5] FERC granted conditional approval of the Mountainview project, subject to certain modifications such as accounting provisions and pass-through of actual operating costs. FERC also ordered that it would hold all future power purchase agreements to the Edgar standards. 106 FERC 61,183.

[6] Source: CAISO. Total RMR costs for 2004 were $649 million, up from $490 million in 2003. The amount attributable to intra-zonal congestion costs was $49 million in 2004, $27 million in 2003. RMR units rose in 2004 by a net of 10. The RMR cost increase was attributable mostly to higher natural gas prices and the need for congestion management in southern California because of unexpected generation outages.

[7] April 2004 Annual Report on Market Issues and Performance, the California ISO Department of Market Analysis.

[8] CEC and CAISO.

[9] CAISO, Platts NEWGen as of March 1, 2005, EIA Form 860. All generation is in summer capacity unless otherwise indicated. Capacity Additions and Retirements are for calendar year 2004, based on Platts and EIA net summer capacity estimates and FERC staff research. They may differ from the Summer Generating Capacity in the Supply Demand Statistics table. Summer Generating Capacity may be projected for the summer peak, may omit some calendar year additions, and may reflect actual demonstrated capacity and deratings.

[10] Path-15 south-to-north transfer capability increased by 1,500 MW to 5,400 MW from 3,900 MW; the north-to-south transfer capability increased by 1,100 MW to 3,300 MW from 2,200 MW.

Source notes

1. Prices are CAISO on-peak balancing prices for the zones identified. Peak hours are from 6:00 a.m. to 10:00 p.m. Monday through Saturday excluding NERC holidays.

2. CAISO balancing, Platts *Megawatt Daily* and Dow Jones day-ahead prices are firm on-peak for the SP-15 and NP-15 zones. CAISO data are from http://oasis.caiso.com. CAISO prices include only that segment of the market reflected in the real-time balancing market, which may lead to differences with published price indices.

3. Data are from CAISO Summer Assessments for 2003, 2004 and 2005. Reflects CAISO load only. Summer peak demand is instantaneous. Excludes the Los Angeles Department of Water and Power, Sacramento Municipal Utility District and Imperial Irrigation District. Generation capacity includes dynamically scheduled generation and excludes all derates of resources and other imports.

4. CAISO balancing, Platts *Megawatt Daily*, IntercontinentalExchange (ICE) and Dow Jones day-ahead prices are firm on-peak for the SP-15 and NP-15 zones. CAISO data are from http://oasis.caiso.com.

5. ICE on-peak forward and swap prices and volumes are for SP-15 and include monthly, dual monthly, quarterly, and calendar year contracts traded for 2004. New York Mercantile Exchange (Nymex) ClearPort on-peak swaps volumes are for SP-15 and are traded by month.

6. Data from Platts PowerDat, RDI Modeled Production Costs dataset for calendar year 2003 reflecting self-reporting from all utility and nonutility electric power generating facilities with nameplate capacity of 50 MW or more.

7. Average net interchange based derived from CAISO real-time scheduled tie values from http://oasis.caiso.com.

8. Data from CAISO, Energy Information Administration (EIA) Form 860, Platts NewGen and Platts PowerDat. All generation is summer capacity unless otherwise indicated.

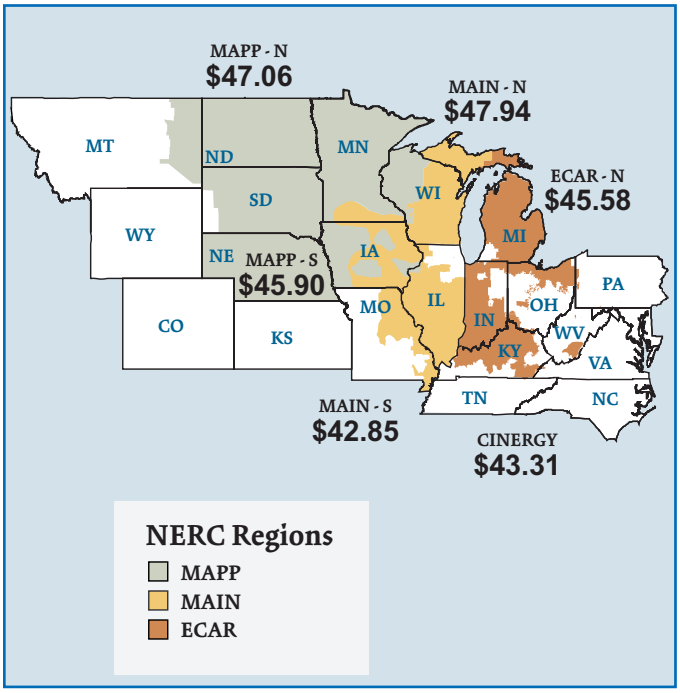
Disclaimer: This report contains analyses, presentations and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Midwest (MISO) Electric Market Profile

The Midwest electric market includes the East Central Area Reliability Coordination Agreement (ECAR), Mid-America Interconnected Network (MAIN), and Mid-Continent Area Power Pool (MAPP) regions, excluding those areas in PJM Interconnection LLC (PJM) at the end of 2004. The Midwest independent Transmission system operator (MISO), a regional transmission organization (RTO) since 2002, operates in all three regions. MISO did not administer an energy market in 2004, but started operating one in 2005. In 2004, market participants traded bilaterally at several trading points, including Cinergy Corp., Northern Illinois, and Northern MAPP, based on prices reported in Platts or using IntercontinentalExchange (ICE).[1] Average 2004 prices for firm, peak deliveries into Cinergy increased 15% in nominal dollars from 2003.

The region has ample reserves. Overall, 2005 summer reserve margins are projected to be 23% and are expected to stay at or near this level through 2009, with expected capacity additions keeping pace with projected demand growth of around 2% (North American Electric Reliability Council (NERC) 2004 Long-Term Reliability Assessment). Persistent transmission constraints in Wisconsin and the Upper Peninsula of Michigan (WUMS) have led to higher prices there than in other parts of the region. Although transmission congestion occurs throughout the region, it is generally not sustained in other locations.

2004 Average Regional Prices for On-Peak Hours ($ per MWh)



Source: Derived from Platts data. See source note 1.

Cinergy Hub Prices

	2003	2004	5-Year
Platts	$37.57	$43.31	$37.29
ICE	$37.48	$43.25	NA
Dow Jones	$37.67	$43.39	$37.75

Source: Derived from Platts, ICE and Dow Jones data. See source note 2.

Supply Demand Statistics

	2003	Projected 2004	Projected 2005
Summer Generating Capacity MW	155,929	158,211	159,369
Summer Peak Demand MW	134,066	136,284	129,789
Summer Reserves MW	21,863	21,927	29,580
Summer Reserve Margin	16%	16%	23%
Annual Net Generation GWh		705,696	715,823

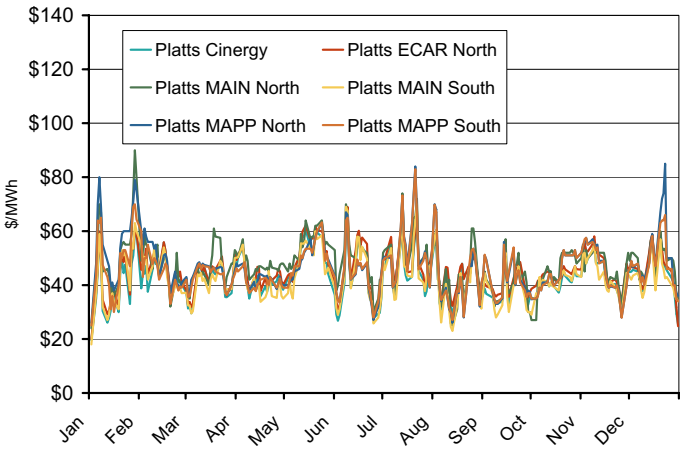
Source: Derived from NERC and Platts data. See source note 3.

Focal Points for 2004

- **Transmission Loading Relief (TLR).** As a bilateral market in 2004, the Midwest managed congestion in real time with TLRs. Significant congestion (TLR level 3 and higher) in 2004 totaled 10,208 hours and 10,736 hours in 2003. TLRs were concentrated at the border with TVA, in Wisconsin and the Upper Peninsula of Michigan, and in Iowa. The most significant event, an emergency TLR Level 6, occurred in northern Indiana in October, just after AEP joined PJM. A rapid increase in flows from west to east threatened to overload critical transmission lines.
- **Deepening Drought.** Missouri River flows have been below normal and dropping for the last 4 years. At Fort Peck Dam near the Missouri River headwaters, flows were at record lows of 60% of the 30-year average. Drought affects the entire region, including Canada, reducing hydropower imported from Manitoba. Resulting 2004 transmission flows increased from south to north, and prices were higher in the north as a result. Low water could lead to environmental restrictions on about 10,000 MW of generating plants that use the river for cooling.[2]
- **Shifting Mix of Generation.** Ample supplies, big reserve margins, and high natural gas prices scuttled many natural gas projects. Long-term plans are shifting to coal, with some coal plants under construction and others planned. Wind energy was the near-term technology of choice, aided by renewal of the wind power tax credit and state efforts toward renewable energy. Half of new U.S. wind capacity in 2004 (204 MW) was built in the Midwest.[3]
- **Increases in Financial Trading.** The Cinergy Hub continued to be very active in trading of standard physical products such as firm fixed contracts with liquidated damages. Financial products became important, with new players such as hedge funds entering the electricity market and volumes increasing throughout the year. By year's end, trading of financial swaps on ICE reached about one-third the volume of physical trading, up from very small volumes early in the year.

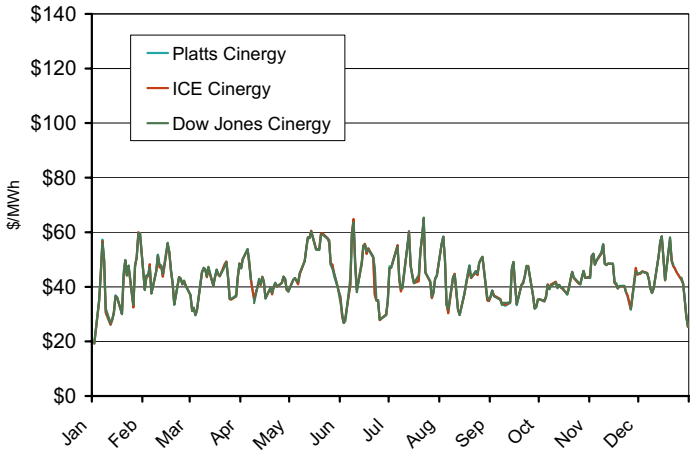
SPOT MARKETS: PRICES AND VOLUMES

Daily Average of Various Midwest On-Peak Prices



Source: Derived from Platts data. See source note 1.

Daily Average of Various Cinergy Prices



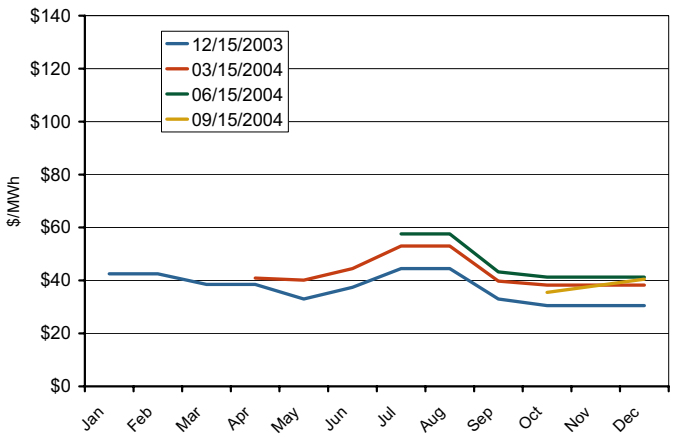
Source: Derived from Platts, ICE, and Dow Jones data. See source note 2.

Day-ahead peak bilateral prices from Platts, ICE, and Dow Jones are shown in the illustrations. Summer prices remained at moderate levels, consistent with generally mild summer weather. Cinergy prices remained below $60, with only a few exceptions, despite high gas prices. The most noticeable exception to these moderate prices occurred in December, when the prices in northern MAPP were $20 above other prices and reached $85 during a cold snap just before Christmas.

In reports of bilateral trading at the Cinergy Hub, Platts volume peaked on February 20 at 13,470 MW and averaged 4,327 MW; ICE volume peaked on February 20 at 133,600 MW and averaged 53,647 MW. For bilateral trading at the ECAR North Hub, Platts volume peaked on January 22 at 2,600 MW and averaged 943 MW.

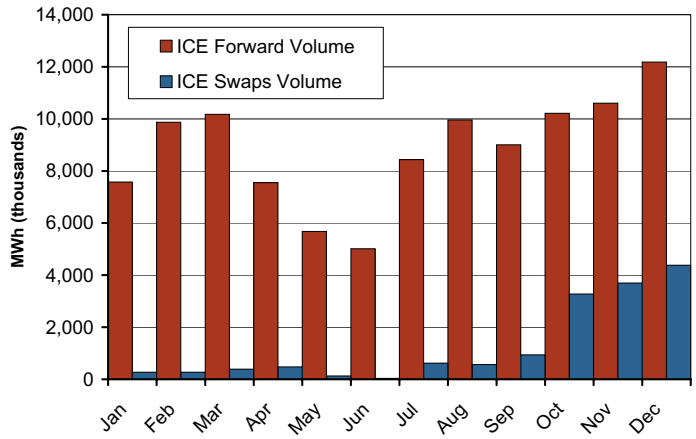
FINANCIAL MARKETS: PRICES AND VOLUMES

Cinergy Swaps Prices from Trade Date



Source: Derived from ICE data. See source note 4.

Cinergy Forward and Swaps Volume



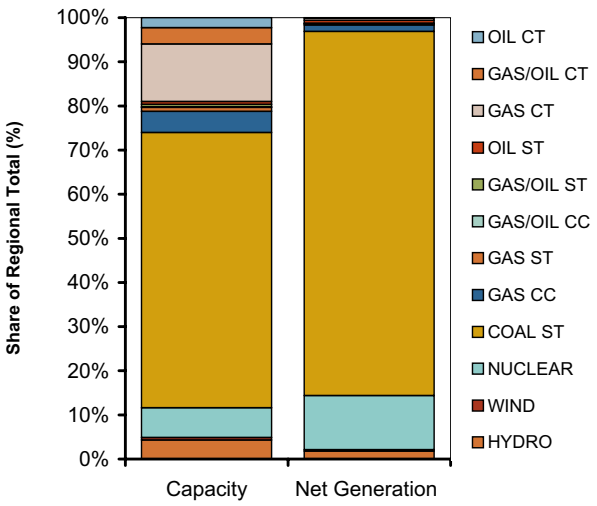
Source: Derived from ICE data. See source note 4.

For the Midwest, financial markets consist of both physical forwards and financial swaps. As illustrated in the volume graph, physical trading outweighed financial trading at the Cinergy Hub on ICE for 2004. However, the financial trading position increased relative to physical trading over the year. For the first quarter, ICE physical trading volumes were 30 times greater than the financial trading volumes, whereas for the fourth quarter ICE physical trading volumes were three times greater than the financial trading volumes. ICE financial trading increased 12-fold for fourth quarter trading over first quarter trading, whereas physical trading increased roughly 20% for the same period.

The increase in trading of Cinergy financial products is consistent with the trend in electricity trading as more nontraditional electricity trading entities, namely hedge funds and banks, have become active in these financial markets and as industry credit has improved.

2003 RESOURCE MIX

Capacity and Generation by Fuel and Prime Mover

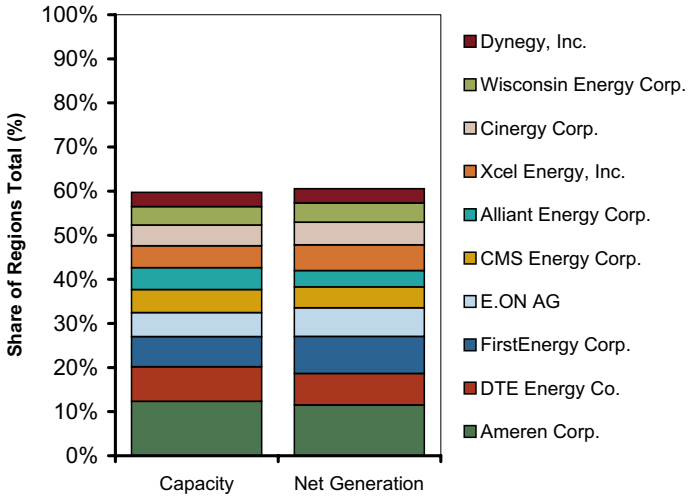


Source: Derived from Platts data. See source note 5.

In 2003, hydroelectric power, wind, nuclear energy, and coal totaled 74% of total Midwest capacity and provided 97% of net generation. The region depends primarily on coal resources, which made up almost two-thirds of total capacity and provided more than 80% of the annual generation in 2003, and nuclear generators, which made up 7% of total capacity and provided 12% of 2003 generation.

2003 MARKET CONCENTRATION

Capacity and Generation of Top 10 Companies



Source: Derived from Platts data. See source note 5.

The top 10 owners provided 60% of capacity and 61% of generation in the Midwest in 2003. Many of the largest suppliers of load in the Midwest were also the largest owners of generation and able to cover much of their load through self–supply.

In 2004, capacity concentration was approximately the same as in 2003.

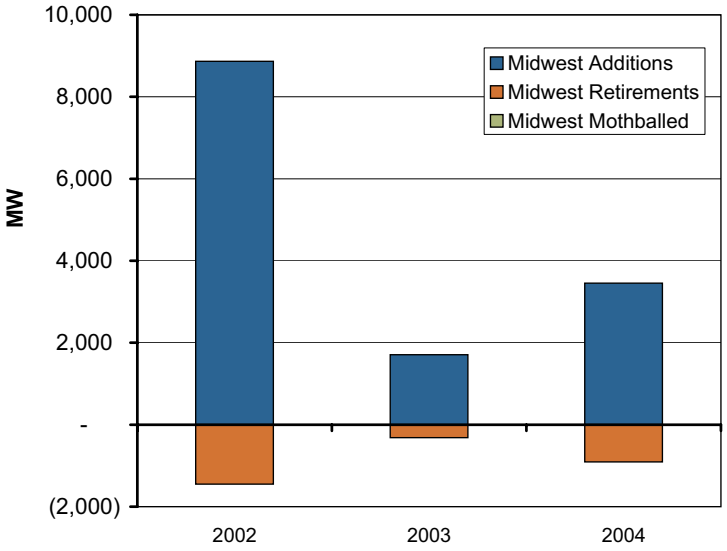
GENERATION AND TRANSMISSION ADDITIONS AND RETIREMENTS

In 2004, 3,452 MW of generation was added in the Midwest, and 935 MW of generation retired.[4]

Generation Additions. In the Midwest region, 10 generation projects came on line. The largest is the 1200 MW Covert Plant near Lake Michigan, one of three new independent power producer (IPP) projects in the region. The other IPPs are the 598 MW Riverside Energy Center and a 12-MW addition to an existing wind project. The capacity additions in 2004 were greater than in 2003 but significantly fewer than in 2002. During 2004, 935 MW of capacity retired. The largest plant to retire was the 542 MW, natural gas powered, Greater Des Moines Energy Center.[5]

Transmission Additions. No transmission projects (of 230 kV or higher) were completed during 2004 in the Midwest.[6]

Capacity Additions



Source: Derived from EIA and Platts data. See source note 6.

MISO Prepares for 2005 Market Operations

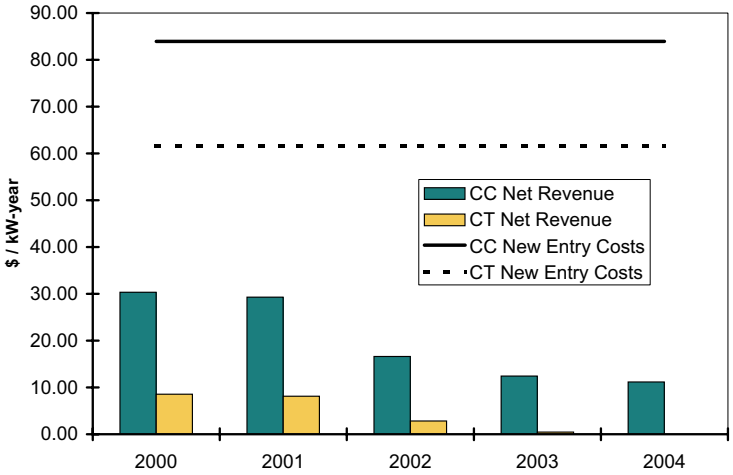
Before the August 2003 blackout, MISO was planning to start operating energy and transmission markets in March 2004. The blackout prompted a review of the market schedule and postponed the start date to December 2004, with subsequent revisions to March 1, 2005, and April 1, 2005, to ensure reliable incorporation of grandfathered agreements and sufficient testing of market systems. During 2004, MISO resolved many issues of market design; developed system models to support reliability and market functions; tested dispatch and market software and accounting and settlement procedures; and allocated transmission rights at the start of the market. Key events during 2004 included installation of an improved state estimator to provide MISO with the advanced state of the art software needed to reliably operate the power system; development of a Joint Operating Agreement (JOA) with PJM and development of seams agreements with MAPP, the Southwest Power Pool (SPP), and TVA; extensive review and revision of transmission systems models with transmission owners and market participants; increasingly realistic testing of operational and market systems through direct testing with market participants; and realistic system tests, where MISO assumed direct centralized dispatch of participant generators. Finally, in November, MISO began allocating financial transmission rights to market participants on the basis of their current transmission rights, with the goal of ensuring a smooth transition to the MISO market environment.

NET REVENUE

Estimated 2004 annual net revenue from energy for gas-fired technologies were below the 5-year average for the third consecutive year. For a combined cycle, revenues from energy declined 10% from 2003 and 63% from 2000. For a combustion turbine, revenues from energy declined from $8.55/kW-yr in 2000 to $0/kW-yr in 2004.

We estimate that new gas-fired combustion turbine plants in the Midwest require $61.57/kW-yr, and gas-fired combined cycle plants require $83.94/kW-yr, to meet debt and equity requirements. Midwest 2004 net energy revenue estimates were well below these targets, which suggests that market-based investments in new generation were not attractive.

Cinergy Net Revenue from Energy



Source: FERC/OMOI analysis of Platts day-ahead gas prices for Columbia, Appalachian and day-ahead power prices for Cinergy. See "Analytic Note on Net Revenue Calculations" in the Other Material section for details.

OMS, the Organization of MISO States

The Federal Energy Regulatory Commission has encouraged regional state committees as a means of increasing the effectiveness of regulation and oversight in areas where federal and state responsibilities overlap. The Organization of MISO States (OMS) was the first regional state committee, established in June 2003. It is also the largest–its members include 14 states and one province of Canada. The OMS purpose is to coordinate regulatory oversight among the states, including recommendations to MISO, the MISO board of directors, FERC, other relevant government entities, and state commissions as appropriate. During 2004, the OMS was instrumental in the development of the design of the Day 2 MISO markets, actively participating in stakeholder groups at MISO, and commenting on the design through filings at FERC. The OMS structure includes eight working groups that focus on key aspects of MISO design and operation, including transmission planning, congestion management and financial transmission right (FTR) allocation, resource adequacy, market monitoring, and seams issues. The OMS was particularly effective in assisting the FTR allocation process to respect both historical contract rights and the need for competitive market development.

Endnotes

[1] In April 2005, the Cinergy Hub replaced the existing Into Cinergy, the Michigan Hub replaced ECAR North, the Illinois Hub replaced MAIN South, and the Minnesota Hub replaced MAIN North and MAPP North.

[2] "Impact of Possible Changes in Missouri River Flows on Nebraska's Electric Energy Industry," Nebraska Power Association, Joint Planning Subcommittee, December 17, 2003, 2.

[3] American Wind Association, www.awea.org/newsroom/projects2004.pdf.

[4] Capacity Additions and Retirements are for calendar year 2004, based on Platts and EIA net summer capacity estimates and FERC staff research. They may differ from the Summer Generating Capacity in the Supply Demand Statistics table. Summer Generating Capacity may be projected for the summer peak, may omit some calendar year additions, and may reflect actual demonstrated capacity and deratings.

[5] EIA Form 860, Platts NEWGen, MISO.

[6] NERC Energy Supply and Demand database, Midwest Reliability Organization.

Source notes

1. Prices are from Platts *Megawatt Daily* for day-ahead on-peak delivery at the identified pricing locations.
2. Platts *Megawatt Daily*, IntercontinentalExchange (ICE) and Dow Jones prices are for day-ahead on-peak delivery to the Cinergy Hub.
3. Data are from NERC's 2004 ES&D Database and Platts PowerDat (annual net generation). Statistics are calculated by combining four NERC Regions: ECAR, MAIN, MAPP and MAAC and removing corresponding quantities for PJM. Generation capacity excludes all derates of resources and imports.
4. ICE on-peak forward and swap prices and volumes are for the Cinergy Hub and include monthly, dual monthly, quarterly, and calendar year contracts traded for 2004.
5. Data from Platts PowerDat, RDI Modeled Production Costs dataset for calendar year 2003 reflecting self-reporting from all utility and nonutility electric power generating facilities with nameplate capacity of 50 MW or more.
6. Data from Energy Information Administration (EIA) Form 860, Platts NewGen and Platts PowerDat. All generation is summer capacity unless otherwise indicated.

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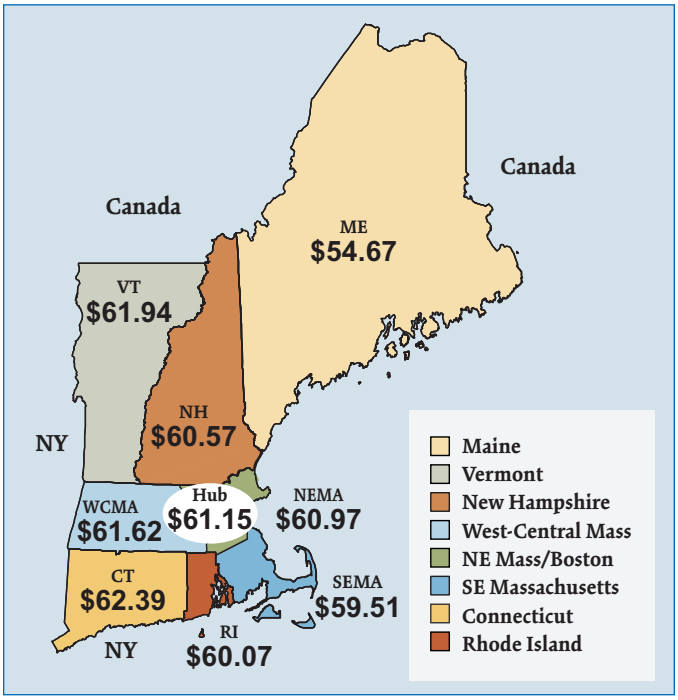
New England (ISO-NE) Electric Market Profile

The New England electric market encompasses the New England sub-region of the Northeast Power Coordinating Council (NPCC) as designated by the North American Electric Reliability Council (NERC). In 1999, an independent system operator–ISO New England (ISO-NE) began operating the region's power grid and wholesale electric markets. ISO-NE now operates a two-settlement spot energy market with locational marginal pricing (LMP), a regional capacity market, a forward reserve market, and a financial transmission rights market. Market participants also actively trade electricity bilaterally, often using the ISO-NE Internal Hub as the pricing point. Average 2004 peak prices for the ISO-NE Internal Hub, also known as the Mass or Nepool Hub increased 3%–5% over 2003 prices, due mainly to higher fuel prices.

The region is currently oversupplied. The 2004 regional reserve margin increased from 2003 as peak demand fell due to mild temperatures and supply increased slightly with the addition of new plants. However, northeast Massachusetts/Boston and southwest Connecticut need generation capacity and transmission additions to achieve local reliability. These load pockets did not exhibit materially higher locational prices in 2004, probably because the costs of expensive units used to ensure resource adequacy and transmission security in these areas are frequently not eligible to set the clearing price. Maine, with much more regional generation, had slightly lower average prices.

2004 Average Zonal Prices for On-Peak Hours ($ per MWh)



Source: Dervied from ISO-NE data. See source note 1.

ISO-NE/Nepool/Mass Hub Prices

	2003	2004	5-Year
ISO-NE	$57.80	$61.15	$48.69
Platts *Megawatt Daily*	$59.05	$61.47	$48.58
ICE	$58.88	$60.69	NA

Source: Derived from ISO-NE, ICE and Platts data. See source note 2.

Supply Demand Statistics

	2003	2004	Exp. 2005
Summer Generating Capacity MW	30,260	31,299	31,504
Summer Peak Demand MW	24,685	24,116	26,355
Summer Reserves MW	5,575	7,183	5,149
Summer Reserve Margin	23%	30%	20%
Annual Net Generation GWh	127,195	129,460	
Annual Load GWh	130,776	132,518	
Annual Net Exports/Imports GWh	(5,441)	(4,907)	

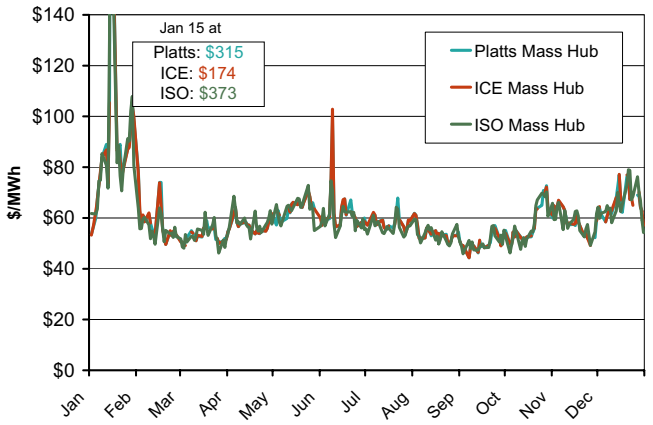
Source: Derived from Nepool, ISO-NE data. See source note 3.

Focal Points for 2004

- **The Cold Snap** of January 2004 resulted in high prices, reflecting rational behavior by market participants under severe weather conditions. All electric customers were served, but high prices resulting from the cold revealed poorly coordinated market rules and incentives for gas and electricity. Consequently, ISO-NE changed its rules to increase coordination between gas and electric markets and enhance reliability.
- **Southwest Connecticut** faced local transmission constraints that worsened with continued economic growth. The high cost of addressing constraints in the load pocket through mitigation was not reflected in the price but rather in uplift. The lack of comprehensive locational prices, reflecting the full cost of service, sent distorted signals to customers concerning the costs they imposed on the grid. Incentives for market-based generation and transmission investments were not provided. ISO-NE and Northeast Utilities proposed transmission upgrades to the southwest Connecticut system, but these have been delayed by controversy over cost allocations and siting.
- **Uplift,** a make-whole payment to generators whose bid costs exceed the locational marginal clearing price, totaled $334 million in 2004. Of this, $169 million was the result of units being committed after the day-ahead market closed or dispatched out-of-merit order for daily reliability or transmission support. The balance of uplift, $165 million, was for reliability (RMR) agreements. The bulk of the daily uplift occurred in the NEMA/Boston and Connecticut zones, which saw 49% of the day-ahead uplift payments and 87% of real-time uplift. To decrease daily uplift, the ISO was developing changes to the mitigation rules and the dispatch and commitment process. The ISO also was designing an ancillary service market to encourage the addition of quick-start units and market enhancements to capture out-of-merit dispatch costs in reserve prices. A number of transmission projects and operational changes were also in the works, which should reduce the amount needed for reactive power support.

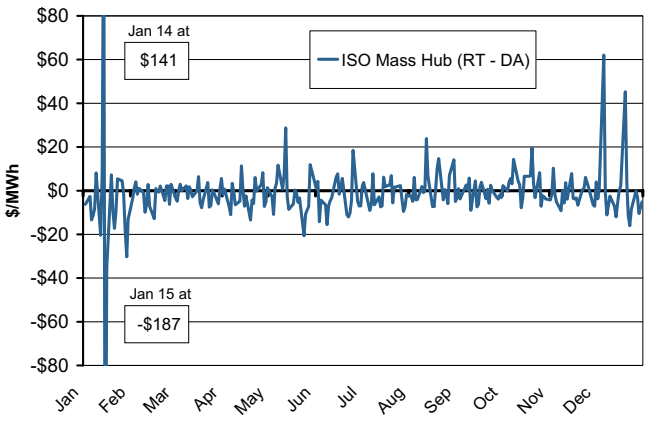
SPOT MARKETS: PRICES AND VOLUMES

Daily Average of On-Peak Prices



Source: Derived from ISO-NE, ICE and Platts prices. See source note 4.

Daily Average RT vs. DA On-Peak Prices



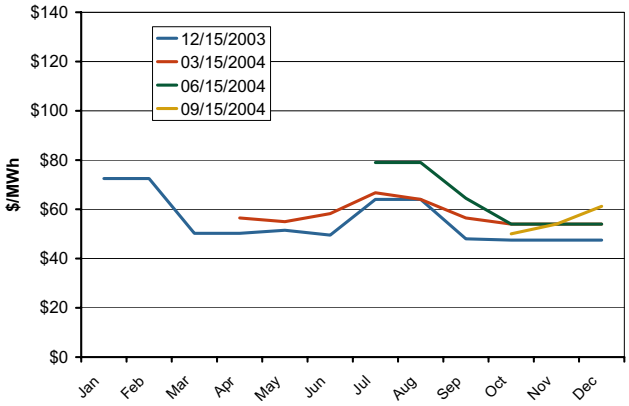
Source: Derived from ISO-NE prices. See source note 4.

The above charts illustrate day-ahead (DA) peak bilateral prices from Platts and the IntercontinentalExchange (ICE) as well as ISO day-ahead and real-time (RT) LMPs. On January 15, day-ahead prices for both ISO-NE and Platts rose to more than $300 per MWh, almost twice as high as the next highest day–January 16. The differences between ISO day-ahead and real-time price were small throughout most of the year, except during the cold snap, when the real-time price was $141 per MWh higher on January 14, and the day-ahead price was $187 higher on January 15. The real-time price was also substantially higher than the day-ahead price during two weather events later in the year (December 6 and December 20).

New England reached its peak hourly load of 24,116 MW on August 30. In 2004, the daily peak load hours averaged 17,247 MW. Day-ahead volumes for ISO-NE generally tracked real-time volumes, but diverged during the cold snap by as much as 11%. In bilateral trading, Platts reported volumes averaged 378 MW and peaked on July 28 at 2,250 MW; ICE volumes averaged 5,163 MW and peaked on June 23 at 24,000 MW.

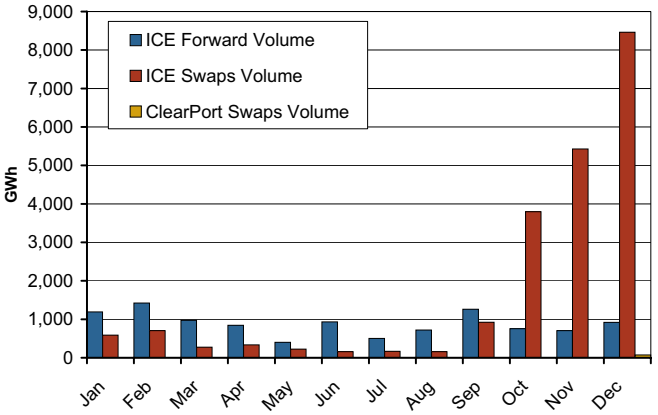
FINANCIAL MARKETS: PRICES AND VOLUMES

Swaps Prices from Trade Date



Source: Derived from ICE and Nymex data. See source note 5.

Forward and Swaps Volume



Source: Derived from ICE and Nymex data. See source note 5.

For New England, financial markets consist of both physical forwards and financial swaps. Nymex ClearPort began trading New England financial swaps in November for December and future months.

Through the first three quarters of 2004, New England forward transaction volumes on ICE averaged two-and-a-half times the swap transaction volumes. Fourth-quarter ICE swap transaction volumes averaged seven times the volume of forward transactions.

In Nymex ClearPort's first month of New England trading, a total volume of 73,600 MWh was traded for December.

The increase in trading of New England financial products was consistent with the general trends in electricity trading as more nontraditional electricity trading entities, such as hedge funds and banks, have become active in these financial markets, and as industry credit has improved.

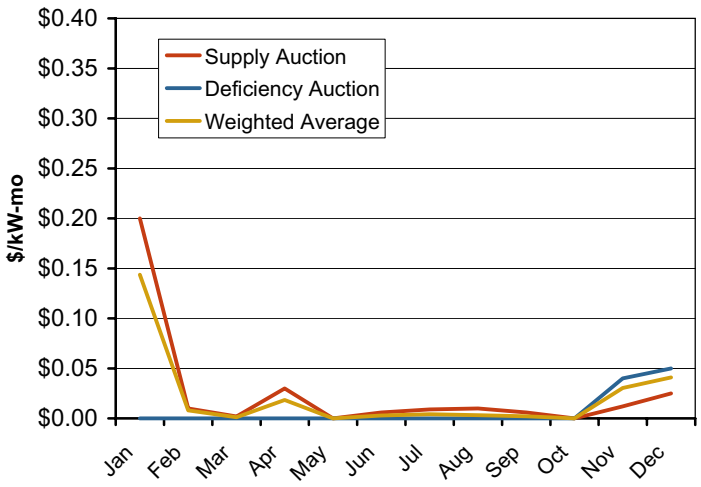
CAPACITY AUCTIONS

Capacity auctions provide for adequate reserve margins as well as sending market investment signals. Capacity can be procured through ISO-NE auctions or through bilateral agreements or self-supply. The ISO-NE capacity markets consist of a supply auction and then a deficiency auction, both for unforced capacity (UCAP). In the supply auction, load-serving entities can submit price-sensitive capacity demand bids, whereas capacity resources offer price-sensitive supply bids. In the deficiency auction, load-serving entities that have not procured sufficient resources to meet their capacity requirements must do so at the cleared auction price.

Through October, the price in the deficiency auction was $0.00/kW-month, whereas the average supply auction price was $0.03/kW-month. For November and December, the average deficiency auction price was $0.04/kW-month and the average supply auction price was $0.02/kW-month.

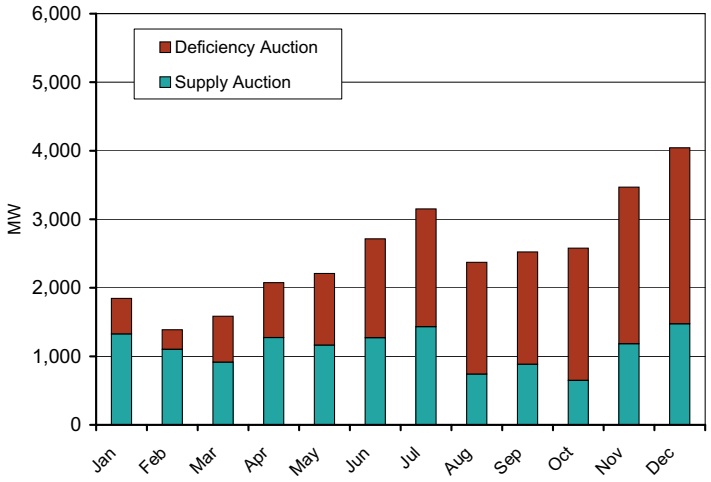
Total auction volumes more than doubled from January to December. Although the supply auction volumes increased and decreased throughout the year, the deficiency auction volumes increased consistently. By December, deficiency auction volumes were nine times the volumes in February, the lowest volume month.

Capacity Auction Prices



Source: Derived from ISO-NE data. See source note 6.

Capacity Auction Volume



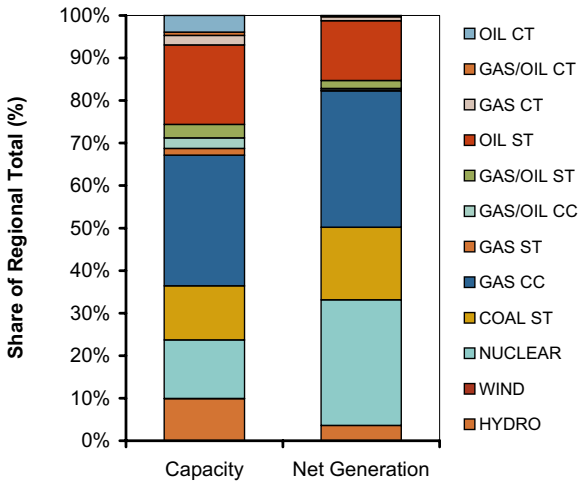
Source: Derived from ISO-NE data. See source note 6.

Capacity Delists Increase

Load-serving participants in New England, like those in New York and PJM, must purchase installed capacity (ICAP) from generators in proportion to the load-server's share of the system's peak load. Capacity markets like ISO-NE's attempt to maintain adequate generation resources in the region by requiring such purchases, and by auctioning ICAP. Each auction generates a single clearing price for ICAP. Outside New England, some generators receive significant revenue from the capacity market, but prices in New England have been low: The clearing price in the supply auction was zero in 10 months in 2004. In November and December, deficiency auction prices increased to $0.04 and $0.05 per kW-month, respectively. Even the January Supply Auction price of $0.20 per kW-month was low compared to other regions. By comparison, PJM's average 2004 price was $0.51 per kW-month, and New York's (outside of New York City) was $1.31 per kW-month. Faced with low prices, increasing numbers of New England generators have delisted, or withdrawn from the capacity market, probably to pursue more desirable export opportunities or to avoid the obligations associated with being an ICAP recipient. A delisted unit is not obligated to participate in New England's day-ahead energy market but must offer energy from that unit in real time. The increase in delistings coincided with increased trading in the capacity deficiency auctions, for which monthly volumes grew more than ten-fold during 2004.[1]

2003 RESOURCE MIX

Capacity and Generation by Fuel and Prime Mover

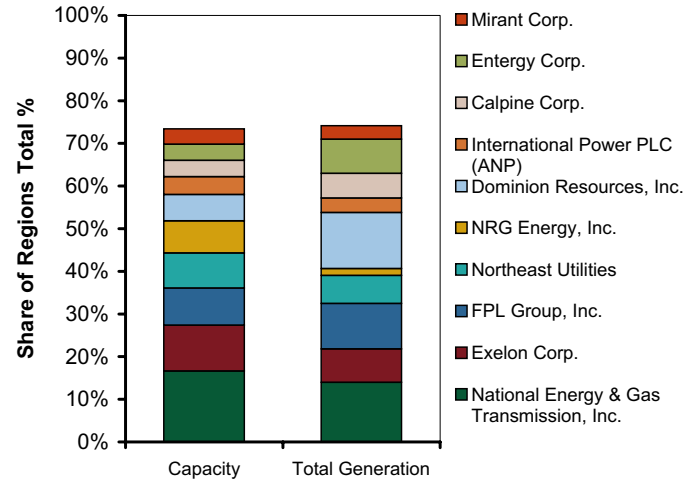


In 2003, hydro, wind, nuclear, and coal provided 36% of total New England capacity and half of net generation. The region depends on gas-fired combined-cycle units to meet some base and intermediate loads. In 2003, these units provided 31% of capacity and 32% of annual net generation.

Source: Dervied from Platts data. See source note 7.

2003 MARKET CONCENTRATION

Capacity and Generation of Top 10 Companies



As shown, the top 10 owners provided 73% of capacity and 74% of generation in New England in 2003. Nine of the top 10 providers in New England were independent power producers or utility affiliates that built or acquired generating assets outside of their traditional service territories.

In 2004, capacity concentration decreased as lender syndicates received the keys to more than 3,600 MW of defaulting assets, most prominently the 2,600 MW Boston Generating asset portfolio. Dominion Resources acquired 2,400 MW of the USGen New England portfolio.

Source: Derived from Platts data. See source note 7.

Offer Mitigation

ISO-NE's mitigation efforts attempted to stop the effects of any market conduct that would substantially distort competitive outcomes while avoiding unnecessary interference with competitive price signals and normal market operations. ISO-NE could impose mitigation only to remedy conduct that it believed was significantly inconsistent with competitive conduct, would result in a material change in one or more prices in the New England Markets or Operating Reserve payments to a Market Participant, and was unexplained. ISO-NE used a variety of indices, screens, and reference prices to identify bids or other conduct that was suspect. If suspicions were raised, the conduct was tested against a threshold to determine whether it has a "material impact" on prices. If the suspicious conduct appeared to have an impact, the monitor called the company to determine if the conduct was justified by competitive conditions. If justified, the investigation ended. If the conduct was not justified, mitigation was implemented for a period of up to 6 months.

In 2004, ISO-NE mitigated one unit on two days, December 17 and 18. The mitigation occurred in the real-time market for a total of about 26 hours. The ISO explains that mitigation occurred infrequently because the participants knew what the reference levels and thresholds were, and tend to tailor their bids to avoid mitigation.

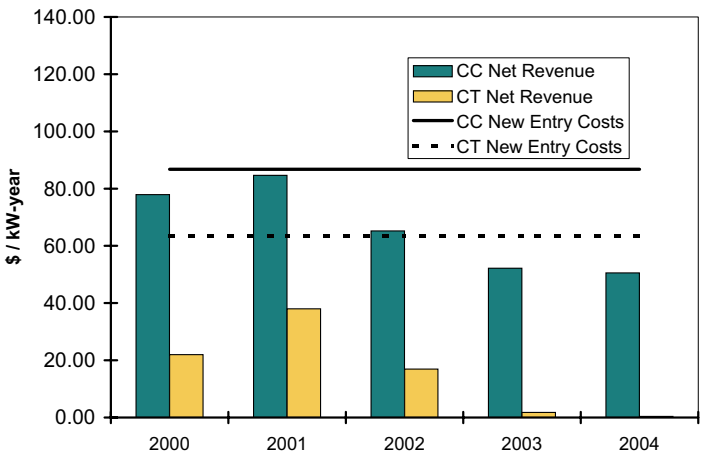
NET REVENUE

Net revenue for generators was less than the estimated costs of entry in New England in 2004 (see "Analytic Note on Net Revenue Calculations" for details of the net revenue test reported here). A combined cycle plant could have recovered 59 percent of the revenue needed to justify the investment in 2004, down from earlier years. For combined cycle plants, most of the contribution to net revenue came from the energy market. (Capacity payments were at or near zero for most of the year and totaled $0.36/kW-yr for the year as a whole.) A major factor in the decline in net revenues may have been the mild summer weather, which reduced average prices compared to a normal summer.

For combustion turbines, the major source of revenue would have been ISO-NE's ancillary service market (not included in the figure). ISO-NE's market monitor estimated that in 2004, a combustion turbine could have received $44/kw-yr from the ancillary services market, between 66 and 88% of the amount needed to justify investment.[3] A higher net revenue for combustion turbines is consistent with New England's need for more quick-start resources.

Using estimates based on Energy Information Administration (EIA) data, new gas-fired combustion turbines in New England would require an estimated $63.53/kW-year, and gas-fired combined cycle plants require about $86.76/kW-year to meet debt and equity requirements. Others' estimates of entry costs in New England vary. John J. Reed, at FERC on behalf of ISO-NE, testified that the cost of a new combustion turbine in New England's "Rest of Pool" was $92.34/kW-year.[4] Reed's new combustion turbine entry cost estimates varied from $99.16 /kW-year in southwest Connecticut to $87.22 in Maine.

Mass Hub Net Revenue from Energy



Source: Derived from Platts data. See "Analytic Note on Net Revenue Calculations" in the Other Material section for details. See source note 8.

REGIONAL EXPORTS AND IMPORTS

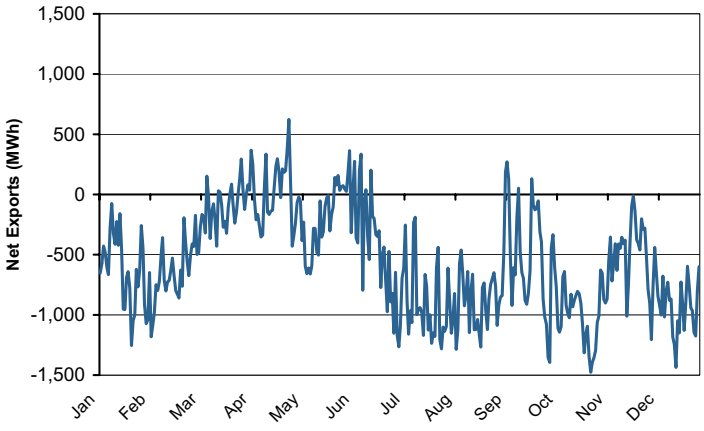
New England was a net importer of electricity for an average of 555 MW in 2004. Eliminating exports over the Cross Sound Cable, which links Connecticut with Long Island, New England imported an average of 637 MW in 2004. Power tended to flow out of the region in spring and in early fall, when capacity margins increased.

Hourly Net Interchange

External Interface	Max Hourly Exports - MW	Max Hourly Imports - MW	Avg Hourly Net Exports MW
Hydro Quebec - Highgate	82	218	(130)
Hydro Quebec - Phase I/II	707	1643	(293)
New Brunswick - Keswick	300	678	(151)
New York - Cross Sound Cable	330	50	82
New York - Roseton	1219	1048	(63)

Source: Derived from ISO-NE data. See source note 9.

Average Daily Net Interchange



Source: Derived from ISO-NE data. See source note 9.

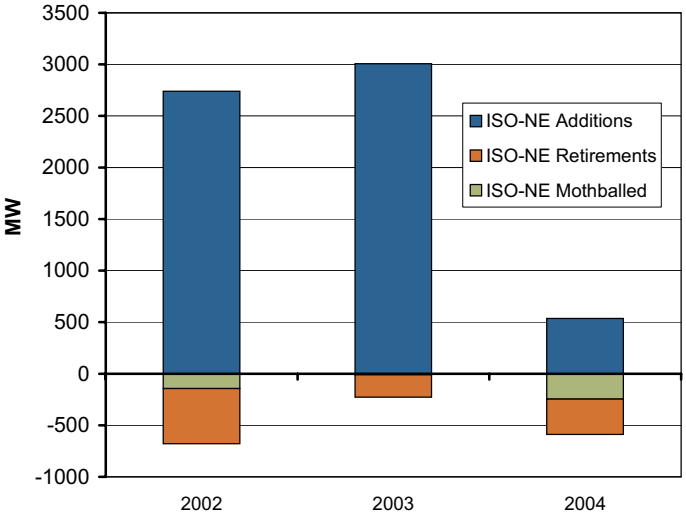
GENERATION AND TRANSMISSION ADDITIONS AND RETIREMENTS

Generation Additions: In the ISO-NE region, four generation projects came on line. In Connecticut two additions came on line—the Milford plant, a 464-MW combined cycle facility, and Waterside Power, a 60-MW distillate fuel oil facility. Two 6-MW additions, one in Rhode Island and one in Massachusetts, also came on line. Capacity additions in 2004 were less than in the two previous years. Generation retirements in 2004 totaled 343 MW, of which 212 MW are the deactivated reserves at the Devon plant.[5]

Seven projects, representing 538 MW, were proposed to be added between 2005 and 2007.[6]

Transmission Additions: In 2004, transmission upgrades totaled about $80 million including 11.1 miles of low voltage (115kv) transmission costing $4.2 million.

Capacity Additions



Source: Derived from ISO-NE, EIA Form 860 and Platts data (summer capacity).

ISO-NE Reliability Costs Rising as RMR Contracts Increase

Reliability must run (RMR) is a contract term that refers to power generation resources identified by the ISO as necessary for the provision of operating reserve requirements and adherence to North American Electric Reliability Council (NERC), Northeast Power Coordinating Council (NPCC), and Nepool reliability criteria. These units provide power beyond the first contingency reliability criteria within a region. Most of these units are located in import constrained areas, such as southwest Connecticut and Boston, and are run during certain periods to alleviate transmission constraints and, thus, are likely to have market power at those times. RMR contracts, also known as reliability agreements, are available to generation units that are not able to operate profitably. An RMR contract compensates the unit for its fixed costs.

In 2004, New England load-serving entities (LSEs) paid $165 million to cover the fixed costs of generators under RMR contracts. These are out-of-market payments to generators, which, like the daily reliability/transmission support uplift payments discussed earlier, are not reflected in market prices. Also like daily uplift, these are side-payments not reflected in the LMP that serve to keep prices in constrained areas low; in fact, every new RMR contract essentially lowers the marginal unit in the bid stack and further reduces prices that occur in the market.

In 2004, six new RMR contracts became effective to secure almost 1,437 MW from ISO-NE generators for an annual fixed cost of $98.9 million. Another $66.4 million in RMR contracts became effective in January 2005. The ISO estimates that total annual fixed-cost payments to generators in 2005 for all RMR contracts will be about $345.1 million for 4,394 MW. This amount does not include the 1,194 MW awaiting FERC approval. Generators outside southwest Connecticut and Boston have begun requesting RMR status. ISO-NE has stated that bankrupt generators may not continue to operate without RMR contracts or market changes such as locational installed capacity (LICAP).

ISO-NE's LICAP proposal is intended to improve market-based indicators for economic addition/retirement decisions and to remedy local reliability issues and remove the need for RMR contracts. The proposal is pending before the Commission, which has directed that all RMR contacts expire when LICAP becomes effective. In the interim, more New England generating units continue to seek approval for RMR contracts.

Endnotes

[1] Analysis of capacity auction volumes and prices; ISO–NE.

[2] Robert Ethier, ISO-NE market monitor in a presentation of the State of the Market to FERC, May 4, 2005.

[3] Information provided by ISO New England.

[4] Docket No. ER03-563-030.

[5] Capacity Additions and Retirements are for calendar year 2004, based on Platts and EIA net summer capacity estimates and FERC staff research. They may differ from the Summer Generating Capacity in the Supply Demand Statistics table. Summer Generating Capacity may be projected for the summer peak, may omit some calendar year additions, and may reflect actual demonstrated capacity and deratings.

[6] Information provided by request from ISO-NE.

Source notes

1. Prices are ISO-NE's day-ahead locational marginal prices for the zones identified and the Internal Hub. Data located at http://www.iso-ne.com/smd/operations_reports/hourly.php.

2. Platts *Megawatt Daily* prices are day-ahead on-peak for the Massachusetts Hub. IntercontinentalExchange (ICE) prices are day-ahead on-peak for the Nepool Mass Hub. ISO-NE prices from March 1, 2003 through 2004 are day-ahead locational marginal prices for the Internal Hub, data located at http://www.iso-ne.com/smd/operations_reports/hourly.php. ISO-NE prices before March 1, 2003 are from http://www.isone.com/Historical_Data/daily_monthly/daily_postmarkets.txt.

3. Nepool 2004-13 Forecast Report of Capacity, Energy, Loads, and Transmission (2004 CELT Report) and conversations with ISO-NE staff. Annual net generation from ISO-NE. Generation capacity excludes all derates of resources and imports.

4. Platts *Megawatt Daily* prices are day-ahead on-peak for the Massachusetts Hub. ICE prices are day-ahead on-peak for the Nepool Mass Hub. ISO-NE prices are day-ahead locational marginal prices for the internal Hub, data located at http://www.iso-ne.com/smd/operations_reports/hourly.php.

5. ICE on-peak forward and swap prices and volumes are for the Nepool Mass Hub and include monthly, dual monthly, quarterly, and calendar year contracts traded for 2004. New York Mercantile Exchange (Nymex) ClearPort on-peak swaps volumes are for the ISO-NE Internal Hub traded by month.

6. ISO-NE capacity price and volume information is located at http://www.iso-ne.com/settlement-resettlement/SMD_ICAP/SMD_ICAP/NEPOOL_ICAP_Auction_Report.xls.

7. Data from Energy Information Administration (EIA) Form 860, Platts NewGen and Platts PowerDat. All generation is summer capacity unless otherwise indicated.

8. The analysis is based on Platts *Megawatt Daily's* day-ahead on-peak electric prices for the Nepool Mass Hub or, prior to March 1, 2003, the Nepool Trading Point and from Platts *Gas Daily's* day ahead natural gas prices from Tennessee Zone 6. The figure does not include revenue from capacity or ancillary services. For a detailed discussion of the calculation method, see "Analytic Note on Net Revenue Calculations" in the Other Material section of the Report.

9. Average hourly net interchange data are from the ISO-NE and are available at http://www.isone.com/smd/operations_reports/ext_int_actual.php.

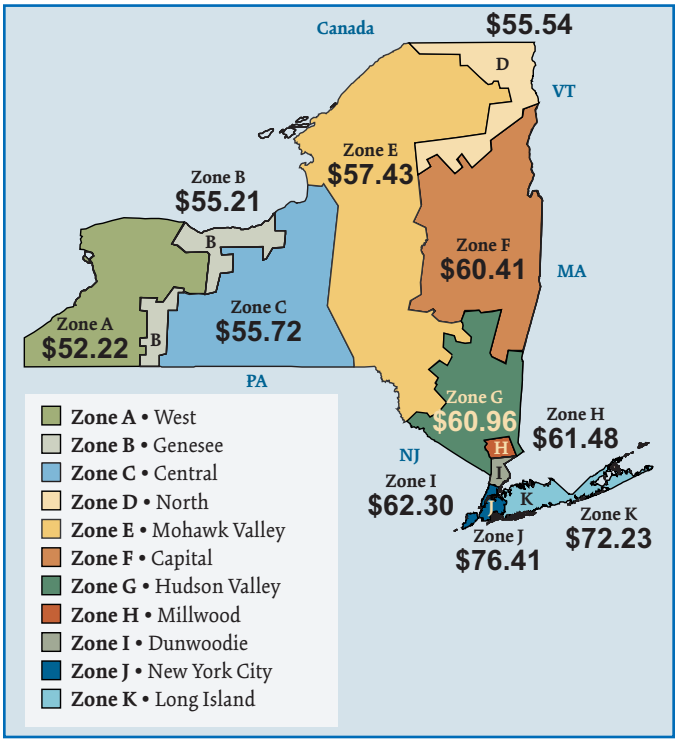
Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

New York (NYISO) Electric Market Profile

The New York electric market encompasses the New York Power Pool (NYPP) subregion of the Northeast Power Coordinating Council (NPCC), as designated by the North American Electric Reliability Council (NERC). Late in 1999, the independent system operator–New York ISO (NYISO)–began operating the region's bulk power system and certain wholesale markets. NYISO operates a two-settlement spot energy market with locational marginal pricing (LMP), a regional and locational capacity market, and a financial transmission rights market. Market participants trade electricity bilaterally through brokers, the IntercontinentalExchange (ICE) and the New York Mercantile Exchanges (Nymex) ClearPort, using Zone A (West) as the primary pricing point. The average 2004 NYISO total price (for energy and ancillary services in all hours) increased 0.4% over 2003.[1]

The New York City metropolitan area (NYC) and Long Island (LI) are areas of concentrated demand. Both localities have requirements for installed generating capacity more stringent than the rest of the region to ensure reliability of service. In 2004, there was enough installed capacity to meet these requirements in NYC and LI, and there was surplus capacity elsewhere in the region. Reserve margins increased in 2004 as new plants entered commercial operation in NYC and elsewhere, and mild summer weather reduced peak loads. The map shows that prices in NYC (Zone J) and LI (Zone K) were significantly higher than elsewhere in the New York region. The higher prices resulted from a lack of inexpensive local generation and limited transmission capacity in those localities.

2004 Average Zonal Prices for On-Peak Hours ($ per MWh)



Source: Derived from day-ahead NYISO prices.

NYISO Hudson Valley (Zone G) Prices

	2003	2004	5-Year
ISO	$61.26	$60.96	$53.28
Platts	$61.73	$61.74	$50.26

Source: Derived from NYISO and Platts data. See source note 1.

Supply Demand Statistics

	2003	2004	Exp. 2005
Summer Generating Capacity MW	37,094	38,111	37,548
Summer Peak Demand MW	30,333	28,432	31,962
Summer Reserves MW	6,761	9,679	5,586
Summer Reserve Margin	22%	34%	17%
Annual Net Generation GWh	158,015	160,210	164,050

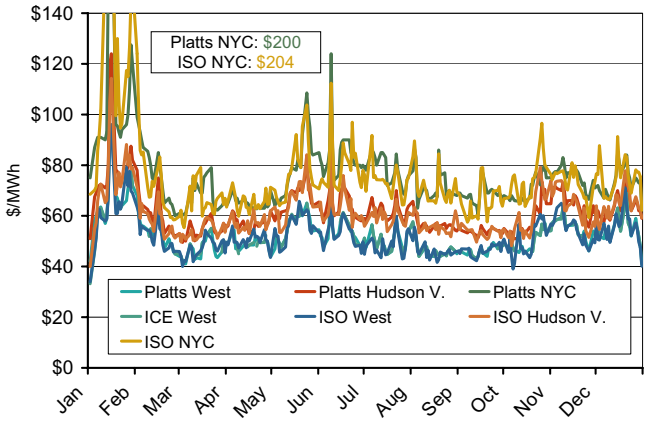
Source: Derived from NYISO data. See source note 2.

Focal Points for 2004

- **Cold weather brings high prices, loads.** NYISO set a winter peak load record on January 15, 2004, (25,262 MW) and again on December 20, 2004 (25,541 MW). Natural gas prices were high on both occasions ($11.64/MMBtu average during January and $7.80/MMBtu during December) because of gas delivery limitations in the northeastern United States. Some generators were unable to procure gas during these cold weather periods, but New York's substantial stock of dual-fuel generators buffered it from significant reductions in generation.
- **NYC mitigation changes.** In May NYISO changed how AMP mitigates bids in the day-ahead market in New York City. Mitigation dropped from about 30% of all unit-hours (a unit-hour is one generator for 1 hour) to less than 10%. One refinement allows NYISO to mitigate bids for particular hours, rather than for an entire day, when bidding thresholds are exceeded. Despite the change, mitigation continued to be commonplace in New York City; elsewhere in the state, no mitigation occurred.
- **Reliability planning process approved.** In December FERC approved NYISO's reliability planning process, which will look ahead 10 years to identify reliability needs in the bulk power system, report annually on the needs, evaluate proposed market-based and regulatory solutions, and track implementation progress. Participants continued work on a planning process to evaluate economic needs of the bulk power system.

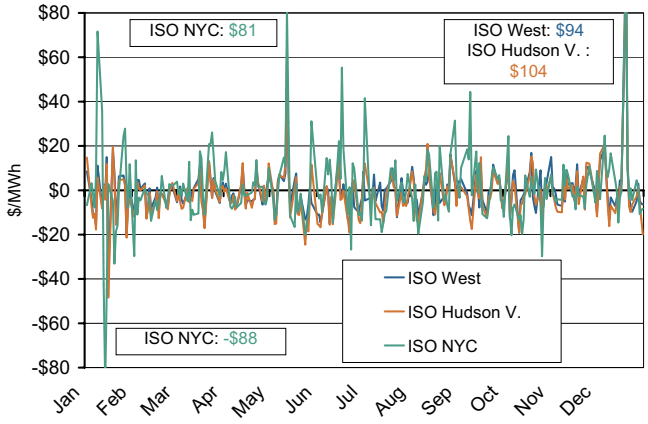
SPOT MARKETS: PRICES AND VOLUMES

Daily Average of On-Peak Prices



Source: Derived from NYISO and Platts data. See source note 3.

Differences Between Real Time and Day-ahead Prices



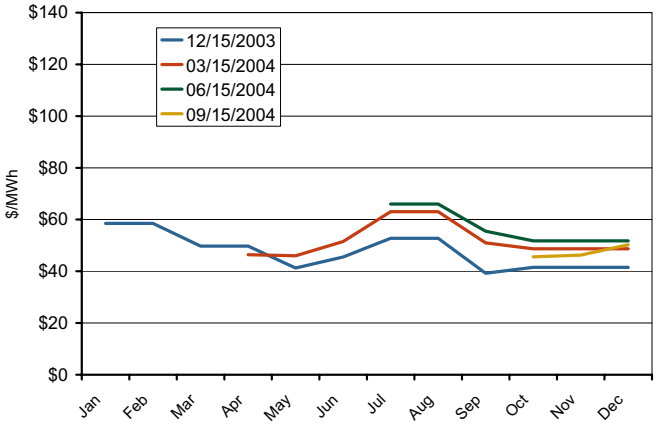
Source: Derived from NYISO data. See source note 3.

The figure "Daily Average of On-Peak Prices" (above) shows day-ahead peak bilateral prices (from Platts and ICE) and NYISO day-ahead and real-time location-based marginal prices (LBMPs.) Prices were highest during January because of high cold-weather demand and high natural gas prices. Mild summer weather kept loads and prices moderate. During December high gas prices and cold weather raised prices modestly, but many generators burned oil instead of gas, which moderated the effect of fuel costs on electricity prices.

New York reached its peak hourly load of 28,433 MW on June 9, 8% below the 2001 historic peak (30,983 MW). In 2004, daily peak load hours averaged 20,447 MW. In bilateral trading, ICE Western New York (Zone A) volumes averaged 3,455 MW and peaked on May 12 at 18,400 MW.

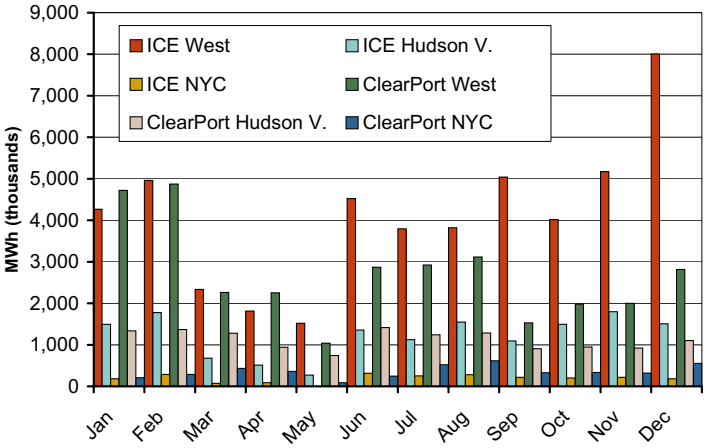
FINANCIAL MARKETS: PRICES AND VOLUMES

Western New York Swaps Prices from Trade Date



Source: Derived from ICE data. See source note 4.

Various New York Swaps Volume



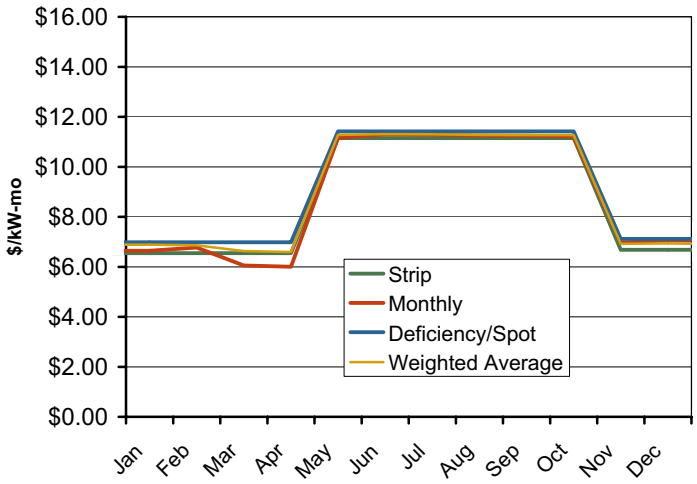
Source: Derived from ICE and Nymex data. See source note 4.

The western zone (A) had the most actively traded financial product for New York on both the ICE and Nymex ClearPort trading platforms. Forward prices increased through June and declined somewhat during the second half of 2004. Trading volumes increased noticeably in December, exceeding 10,000 GWh for the first time. Financial trading for the Hudson Valley (G) and New york City (J) remained low.

CAPACITY AUCTIONS

Capacity markets provide for adequate reserve margins and encourage investment in generating capacity. In New York, load-serving entities (LSEs) may procure capacity through NYISO's capacity market or through bilateral agreements; they may also supply it themselves. NYISO's capacity market consists of a semi-annual strip auction of six month supplies, a monthly auction for individual months remaining in the six month season, and a monthly spot auction for the following month. All capacity trading and requirements are in unforced capacity (UCAP). In the strip and monthly auctions, capacity resources make price-sensitive offers and LSEs submit price-sensitive bids, which are matched to give a single clearing price. The spot auction differs: NYISO is unique in setting spot auction prices with a demand curve, a sliding price scale that declines as capacity supply moves from shortage to surplus. NYISO submits bids, at a price determined from the demand curve, on behalf of LSEs that have not procured all of their capacity obligations before the spot auction. LSEs in New York City and Long Island must acquire locational capacity (capacity from generators in those locations), so three distinct capacity products–New York City, Long Island, and Rest of State–are traded.

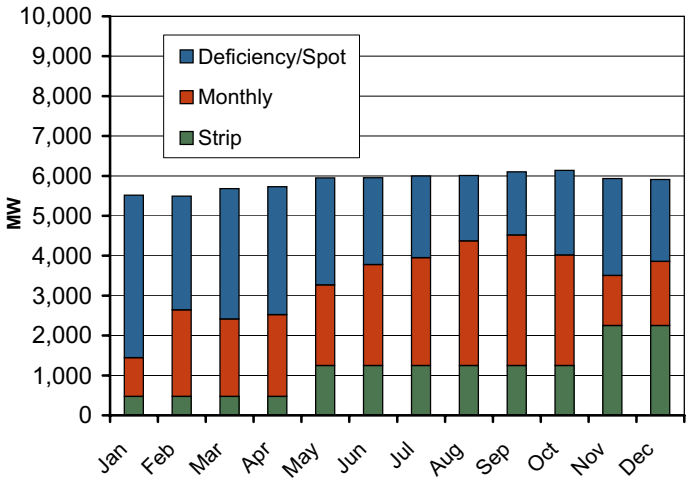
NYC Capacity Auction Prices



Source: Derived from NYISO data. See source note 5.

NYC's constrained transmission and relatively tight supply led to high NYC capacity prices. Most New York City generators have regulated caps on their capacity offers, causing summer capacity prices to clear in a narrow range of $11.15 to $11.42/kW-month. Winter capacity cleared between $5.60 and $7.12. Volume in the

NYC Capacity Auction Volume



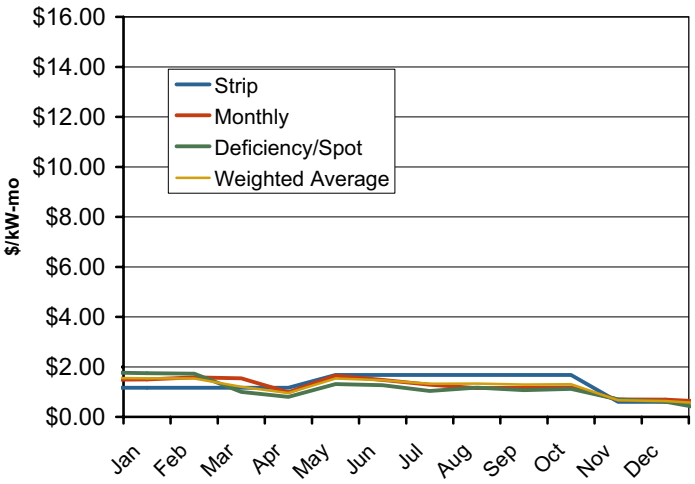
Source: Derived from NYISO data. See source note 5.

NYISO capacity market was a significant fraction of the NYC requirement (8,445 MW for summer) because most NYC generators must offer through the NYISO market. Strip volumes for winter 2004–05 increased substantially over winter 2003–04.

Software Problems Reflect Market Complexities, Vulnerabilities

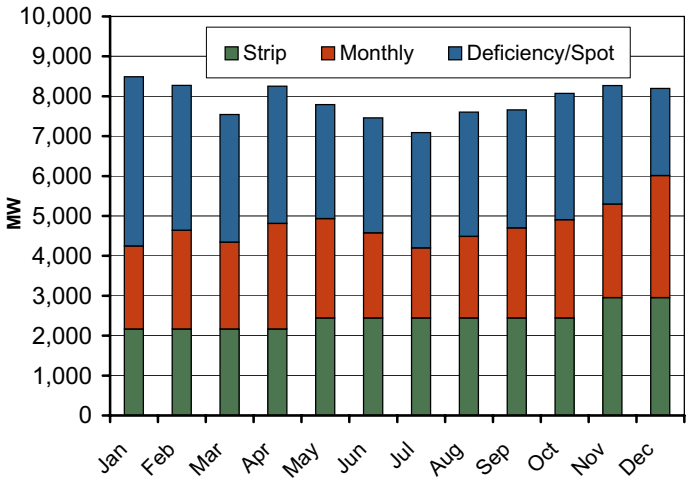
NYISO faced several challenges to its software systems in 2004. A long-standing error in a database of financial transmission rights (called Transmission Congestion Contracts in New York) was found to have distorted their value in auctions as far back as winter 2002, forcing NYISO into a complex redistribution of revenue and a legal settlement with affected participants. A major redesign of NYISO's real-time market system, known as SMD 2, was repeatedly delayed as software designers missed deadlines and extensive market trials were run and analyzed. (When SMD 2 began operating in February 2005, it produced erratic real-time prices for a few weeks while problems were addressed.) An error also was discovered in the AMP system that mitigates real-time bids in New York City. NYISO continued to improve its import-export scheduling system and a system to allow third-party scheduling of capacity on the Cross Sound Cable by June 2005.[2]

NY Capacity Auction Prices



Source: Derived from NYISO data. See source note 5.

NY Capacity Auction Volume



Source: Dervied from NYISO data. See source note 5.

Statewide capacity prices ranged from $0.60 to $1.75 per kW-month, as a consequence of ample supplies in the region outside of NYC and LI. NYISO market volumes averaged about 7,900 MW monthly, compared with the statewide requirement of 35,585 MW (summer), and were about evenly divided among the strip, monthly, and spot auctions.

Offer Mitigation

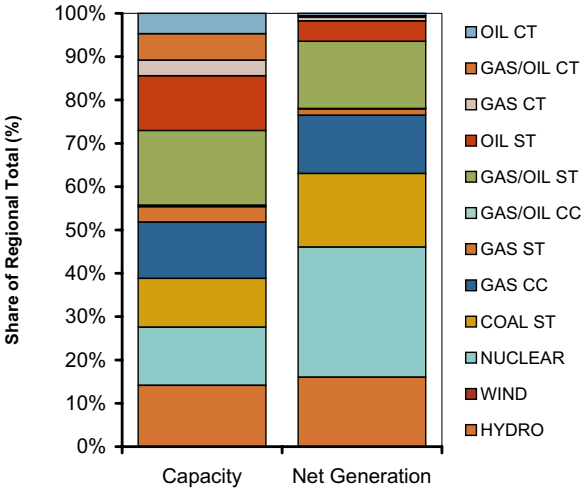
NYISO may mitigate offers for energy, start-up costs, minimum generation, reserves, and regulation of output. It employs a "conduct-and-impact" scheme, meaning it mitigates only those offers that exceed specified thresholds ("conduct" test) and that would, if not mitigated, raise prices by a specified amount ("impact" test). The conduct test measures offers against a pre-existing reference level assigned to each generator based on its offer history, price history at its location, or a level negotiated with NYISO. Reference levels adjust for changes in fuel prices.

For example, a generator's energy offer would fail the conduct test if it exceeded its reference level by $100/MWh or 300% (whichever was lower.) The same offer would fail the impact test if it would cause a price increase of $100/MWh or 200% (whichever was lower), and it would be mitigated, meaning it would be lowered to its reference level.

These thresholds apply everywhere except in New York City (Zone J). The city's large demand, constrained transmission, and concentrated generation ownership are judged to give each generator significant market power, so NYISO uses much tighter mitigation thresholds (ranging from about $3 to $38 in February 2005). All mitigation in 2004 occurred in New York City, where about 10% of unit-hours in the day-ahead market and about 20% of unit-hours in the real-time market were mitigated.[3]

2003 RESOURCE MIX

Capacity and Generation by Fuel and Prime Mover

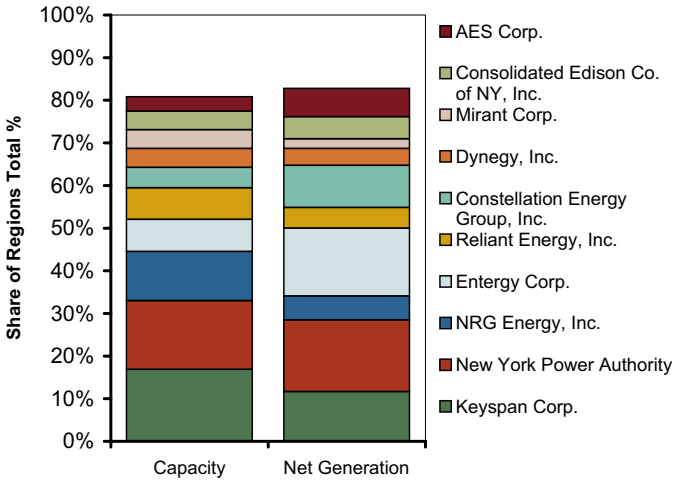


In 2003, hydro, wind, nuclear, and coal constituted 39% of total New York capacity and provided almost two-thirds of net generation. Dual fuel (gas/oil) generators provided 23% of the capacity and contributed 16% of annual net generation. Gas-fired combined-cycle units provided 17% of capacity and 15% of annual net generation.

Source: Derived from Platts data. See source note 6.

2003 MARKET CONCENTRATION

Capacity and Generation of Top 10 Companies



The top 10 companies owned 81% of capacity and 83% of generation in New York during 2003. Eight of those owners were independent power producers or utility affiliates that built or acquired generators outside of their traditional service territories. One was utility Consolidated Edison of New York and one was the New York Power Authority (NYPA), a state entity that provides low-cost power to state businesses, owns about a third of the high-voltage transmission system, and, with the New York State Energy Research and Development Authority (NYSERDA), promotes energy efficiency and clean energy. Major utilities were required to divest their generating assets when retail markets were restructured; they now serve load by buying supply bilaterally or through the ISO. (Consolidated Edison retained 688 MW of generation that is part of its steam supply system.)

Source: Derived from Platts data. See source note 6.

REGIONAL EXPORTS AND IMPORTS

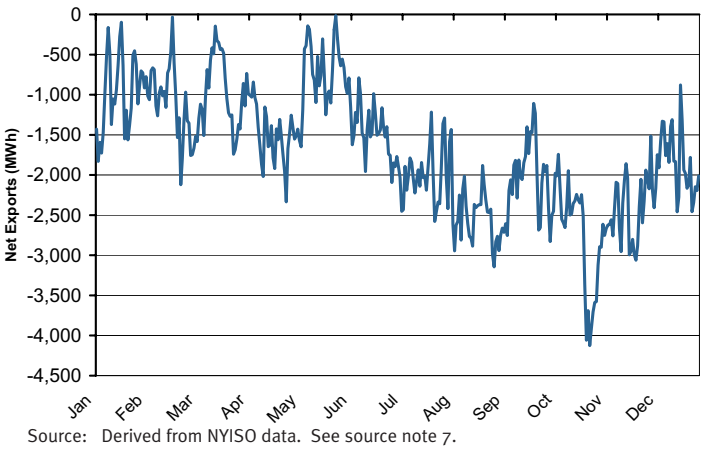
In 2004, NYISO was a net importer of energy, importing 1,697 MW in an average hour. Most imports came from PJM and Ontario. NYISO was a net exporter of energy 2.5% of the time during the year. NYISO net exports were to ISO-NE only.

Average Hourly Interchange

External Interface	Max Exports - MW	Max Imports - MW	Avg Net Exports (Imports) MW
Hydro Quebec (HQ)	1,001	1,325	(97)
New England (ISO-NE)	1,030	1,219	54
Ontario (IESO)	1,731	2,400	(798)
PJM	2,656	2,807	(856)

Source: Derived from NYISO data. See source note 7.

Average Daily Net Interchange



Source: Derived from NYISO data. See source note 7.

NET REVENUE

In New York, revenues from capacity payments can be as significant as revenues from energy sales. When 2004 net revenue estimates from capacity are combined with energy, market-based investments, particularly in New York City, begin to appear attractive.

Annual net revenue from energy for gas-fired technologies declined from 2003 in both the Hudson Valley (Zone G) and New York City (Zone J). For a combined cycle in New York City, revenue from energy declined 12% from 2003, but remained 2% above the four-year average. In the Hudson Valley, combined cycle revenue from energy declined 14% from 2003 (28% from 2001) and was below the four-year average for the second consecutive year. For combustion turbines, revenue from energy in both areas fell to a four-year low.

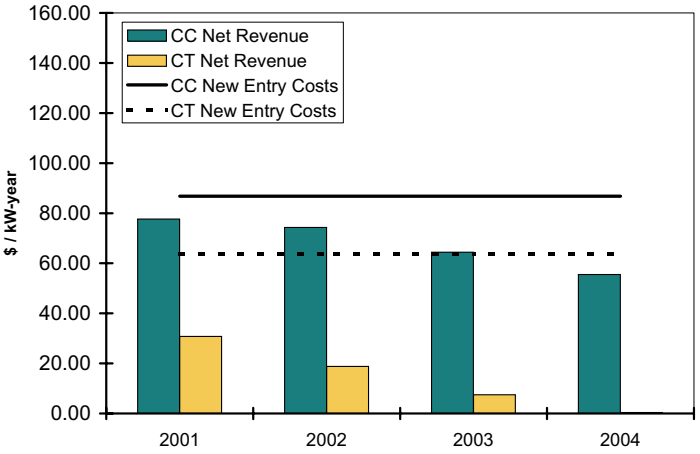
Using estimates based on Energy Information Administration (EIA) data, new gas-fired combustion turbines in New York would require an estimated $63.53/kW-year, and gas-fired combined cycle plants require about $86.76/kW-year to meet debt and equity requirements. Others' estimates of entry costs in New York vary. Levitan & Associates, Inc., in an independent study for the NYISO, estimated that the new entry cost in New York City was $87/kW-year for combustion turbines and $176/kW-year for combined cycles.[4]

Regional Net Revenues from Energy and Capacity

	Net Energy $/kW-yr	Net Capacity $/kW-yr	Total Revenue $/kW-yr
Upstate			
CC	55.49	16.65	72.14
CT	0.38	16.65	17.03
NYC			
CC	112.12	135.25	247.37
CT	20.75	135.25	156.00

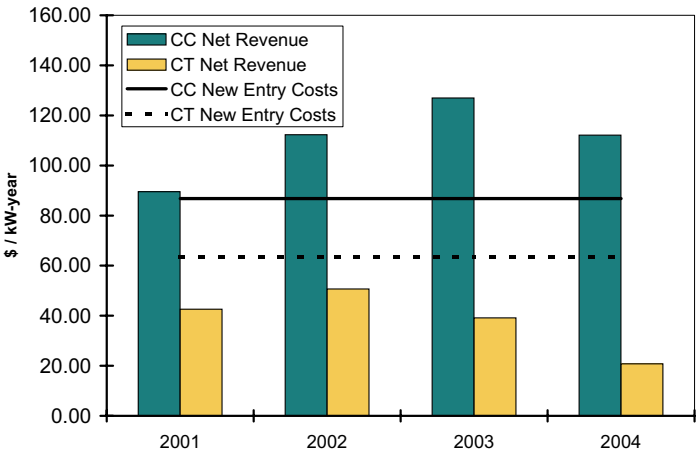
Source: Derived from NYISO data. See "Analytic Note on Net Revenue Calculations" in the Other Material section for details. See source note 8.

Zone G Net Revenue from Energy



Source: Derived from Platts data. See "Analytic Note on Net Revenue Calculations" in the Other Material section for details. See source note 8.

Zone J Net Revenue from Energy



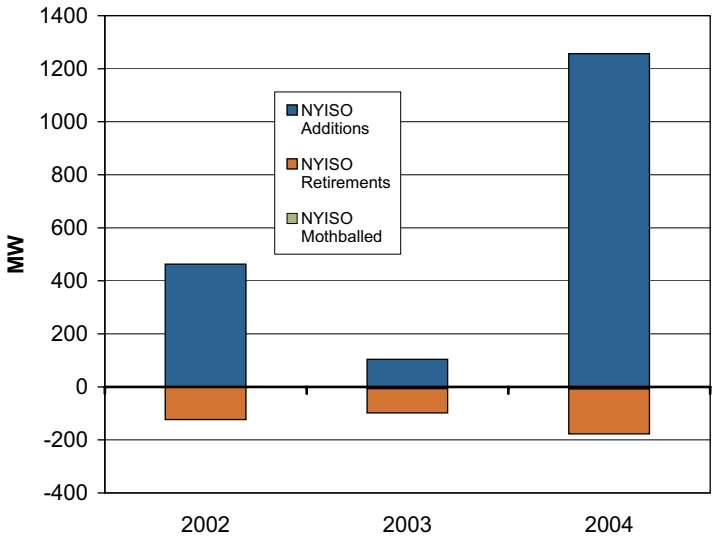
Source: Derived fromPlatts data. See "Analytic Note on Net Revenue Calculations" in the Other Material section for details. See source note 8.

GENERATION AND TRANSMISSION ADDITIONS AND RETIREMENTS

Generation Additions. Three generating plants with a total summer capacity of 1,258 MW came on line in 2004. The largest is Athens, a 938-MW combined-cycle plant in Zone F (Capital) near Albany. The project cost for this independent power plant was $815 million. KeySpan Ravenswood, a 222-MW combined-cycle plant, is located in NYC (Zone J) and also came on line in 2004. All of the new generation is gas-fired; Ravenswood can also burn oil. Three plants totaling 170 MW retired in 2004. Nine proposed projects totaling 5,030 MW were scheduled to be added between 2005 and 2007.[5]

Transmission Additions. No substantial transmission additions were completed during 2004. The previously completed Cross Sound Cable Interconnector, a privately owned, 330-MW high voltage, direct current (HVDC) line between Long Island and Connecticut, resumed operation in 2004. The proposed constellation project (HVDC) from Albany to New York City failed. Four transmission projects were proposed to enter service in 2005–07, including a 36-mile HVDC line from Sayerville, N.J., to W. 49th Street in Manhattan. A proposed seven-mile HVDC line from Bergen, N.J., to W. 49th Street was withdrawn by PSEG after its proposed merger with Exelon was announced.[6]

Capacity Additions



Source: Derived from NYISO, EIA , and Platts data. See source note 9.

Power Authorities Boost Private Investment in New York Power Market

The New York Power Authority (NYPA) and Long Island Power Authority (LIPA) actively solicited private power investment in New York. In June 2004, NYPA released a request for proposals (RFP) seeking as much as 500 MW of New York City capacity and energy supplies. NYPA expects that it will need the additional supplies once its Charles Poletti Power Project, an 875-MW, oil- and natural-gas-fueled facility, is shut down, likely in 2008, to meet a regulatory agreement to reduce emissions in the city. The June RFP drew more than 30 bids from market participants, including bids based on generation and also on proposed transmission projects such as PSEG Cross Hudson, Conjunction, and Astoria Energy. PSEG withdrew after the Exelon-PSEG merger was announced. Entergy, Morgan Stanley Capital Group, and Zilkha Renewable Energy (now owned by Goldman Sachs) were selected to provide energy under the RFP for NYPA's governmental customers in New York City. Because the recent awards only included energy, NYPA announced a new RFP seeking as much as 500 MW of in-city capacity. In addition to RFPs, NYPA was apparently willing to review offers to purchase the small clean power plants that NYPA built in 2002 as part of the Power NOW! program. NYPA has privatized assets in the past; in 2000, it sold two nuclear plants in the largest sale of a public asset to a private company in state history.

In January 2004, LIPA solicited bids for combined-cycle generators to be in service in summer 2005, citing growth in peak demand. Two 79.9-MW units were selected, one each by Calpine and Pinelawn Power. In September 2004, the LIPA board approved a 20-year agreement for transmission capacity on the proposed Neptune Cable, a 660-MW HVDC underwater cable between Long Island and New Jersey. The cable will be privately financed and owned. A 20-year contract from LIPA underwrote another merchant transmission project, the Cross Sound Cable, which resumed operation in 2004 after permitting delays.

Endnotes

[1] NYISO monthly reports, December 2003 and December 2004. All prices are in nominal dollars unless noted.

[2] FERC Order Accepting Filing and Accepting Tariff Revisions, Docket No. EL04-110-000 and others (July 22, 2004); NYISO.

[3] NYISO Market Administration and Control area tariff, attachment H; NYISO Technical Bulletin 67; http://www.nyiso.com/markets/mktmon.html; NYISO December 2004 monthly report.

[4] Levitan & Associates Inc. letter to NYISO Re: ICAP Demand Curve – Capital Cost Details and Update, September 1, 2004.

[5] EIA Form 860 and NEWGen and consulting sources, NYISO 2004 load and capacity data. Capacity Additions and Retirements are for calendar year 2004, based on Platts and EIA net summer capacity estimates and FERC staff research. They may differ from the Summer Generating Capacity in the Supply Demand Statistics table. Summer Generating Capacity may be projected for the summer peak, may omit some calendar year additions, and may reflect actual demonstrated capacity and deratings.

[6] NYISO load and capacity data 2003 and 2004; press reports.

Source notes

1. Platts *Megawatt Daily* and NYISO prices are day-ahead on-peak for NYISO Zone G. For NYISO prices see http://www.nyiso.com/oasis/index.html?wp=damlbmpzonal.

2. Data are from NYISO's monthly reports, summer 2003 Operating Study, 2005 NYCA Forecasted Peak Load, and preliminary data. Summer reserves and summer reserve margins are derived. Generation capacity excludes all derates of resources and imports.

3. Platts *Megawatt Daily* prices are day-ahead on-peak for Zone J. ICE prices are day-ahead on-peak for Zone A. NYISO prices include day-ahead and real-time on-peak for zones A, G and J. NYISO day-ahead prices are located at http://www.nyiso.com/oasis/index.html?wp=damlbmpzonal and real-time prices at http://www.nyiso.com/oasis/index.html?wp=rttwilbmpzonal.

4. ICE on-peak forward and swap prices and volumes are for zones A, G and J and include monthly, dual monthly, quarterly, and calendar year contracts traded for 2004. New York Mercantile Exchange (Nymex) ClearPort on-peak swaps volumes are for zones A, G and J and are traded by month.

5. NYISO capacity price and volume information is located at http://www.nyiso.com/markets/icapinfo.html.

6. Data from Platts PowerDat, RDI Modeled Production Costs dataset for calendar year 2003, reflecting self-reporting from all utility and non-utility electric power generating facilities with nameplate capacity of 50 MW or more and NYISO 2004 load and capacity information.

7. Average hourly net interchange data are from the NYISO.

8. The analysis is based on Platts *Megawatt Daily's* day-ahead on-peak electric prices for NYISO's Zones G or J as applicable and from Platts *Gas Daily's* day-ahead natural gas prices from Transco Zone 6 (NY). The figure does not include revenue from capacity or ancillary services. For a detailed discussion of the calculation method, see "Analytic Note on Net Revenue Calculations" in the Other Material section of the Report.

9. Data from NYISO, Energy Information Administration (EIA) Form 860, Platts NewGen and Platts PowerDat. All generation is summer capacity unless otherwise indicated.

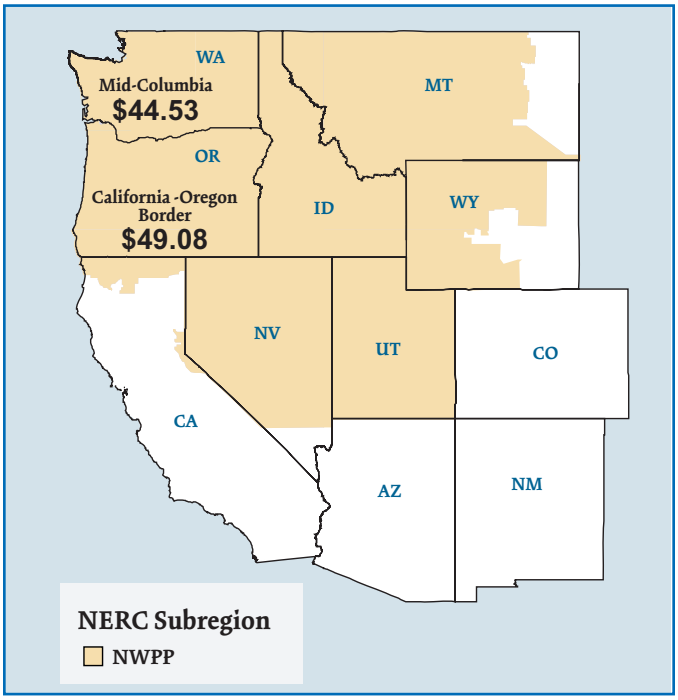
Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Northwest Electric Market Profile

The Northwest electric market encompasses the Northwest Power Pool Area (NWPP) subregion of the Western Electricity Coordinating Council (WECC) as designated by the North American Electric Reliability Council (NERC). The electric grid is dispatched by 16 control areas in coordination with the WECC's Pacific Northwest Reliability Coordinator. No markets are administered by independent system operators (ISOs) or by regional transmission organizations (RTOs). Wholesale market participants, however, utilize physical trades at the California-Oregon Border (COB) Hub and both physical and financial trades at the Mid-Columbia Hub. Average 2004 peak prices for the Mid-Columbia Hub increased 10% from 2003.

The region relies on hydroelectric production for approximately two-thirds of its electricity needs. In most years, the Northwest sells surplus power into California and the Southwest. The largest seller of wholesale power is the Bonneville Power Administration (BPA), which meets approximately 44% of the region's firm energy supply from resources under its control, primarily the federal hydroelectric dams in the Northwest.[1] In 2004, the Northwest received below-normal precipitation. Accordingly, Northwest utilities reported reduced hydro generation and reduced surplus power sales.[2] Nonetheless, when taken together, hydro, fossil fuels, nuclear energy, and renewable resources, were adequate to provide electricity in excess of in-region needs. The Northwest exported electrical energy to California and the Southwest in all 12 months of 2004.[3]

2004 Average Hub Prices for On-peak Hours ($ per MWh)



Source: Derived from Dow Jones data. See source note 1.

Mid-Columbia Hub Prices

	2003	2004	5-Year
Platts	$40.73	$44.54	$75.59
ICE	$40.42	$44.54	NA
Dow Jones	$40.74	$44.53	NA

Source: Derived from Dow Jones, IntercontinentalExchange (ICE), and Platts data. See source note 2.

Supply Demand Statistics

	2003	2004	Exp. 2005
Winter Generating Capacity MW	54,802	57,101	54,645
Winter Peak Demand MW	35,456	39,710	38,804
Winter Reserves MW	19,346	17,391	15,841
Winter Reserve Margin	55%	44%	41%
Annual Load GWh	219,582	223,148	226,744

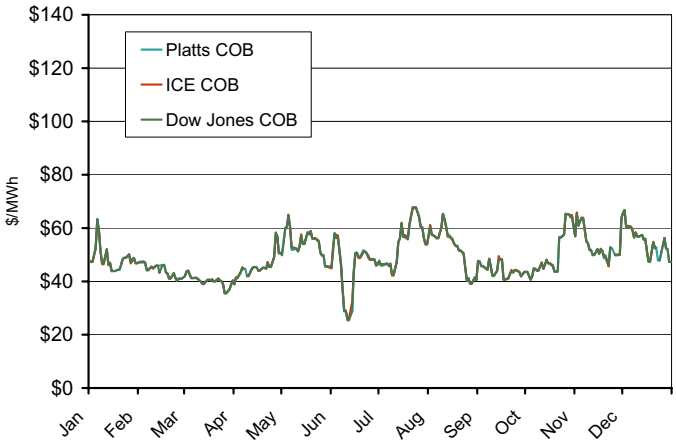
Source: Derived from WECC data. See source note 3.

Focal Points for 2004

- **The driest five-year stretch** since 1929, according to the BPA, occurred in the Northwest as it experienced its fifth consecutive year of below-normal water supplies. The below-average water conditions made it difficult for Northwest utilities to meet revenue projections from hydroelectric power sales. Utility production and market purchasers relied on increased generation from coal and natural gas to make up for the reduced hydro production.
- **Surplus generation** was forecast for the region through 2010 as the Northwest Power and Conservation Council (NWPCC) released its draft "Fifth Power Plan." The forecast was based on several factors including a reduction in demand that started in 2001 (see "Aluminum smelter demand for electricity remained low in 2004"), modest load growth, and more than 4,500 MW of new generation since 2000.
- **Regulatory uncertainties** have made industry participants reluctant to build new transmission facilities, according to a Rocky Mountain Area Transmission Study (RMATS). RMATS stakeholders and the governors of Wyoming and Utah expressed interest in building transmission to use regional coal and wind power resources for local power needs and for sale to other parts of the western interconnection.
- **Independent transmission.** In December, Grid West participants adopted developmental bylaws. Northwestern transmission stakeholders, including nine utilities, negotiated a proposal to develop an independent transmission provider for much of the region. Grid West would succeed the previous RTO West effort and encompass the transmission systems of utilities in Washington, Oregon, Idaho, Montana, Nevada, Utah, and Wyoming. Membership in the new organization would be voluntary to plan and manage key operational and selected commercial functions of the regional grid.
- **PGE sale issues.** Oregon Electric LLC (a holding company consisting of Texas Pacific Group, a private investment firm, and three northwest business leaders) applied at the Oregon PUC (OPUC) to purchase Portland General Electric (PGE) for $1.4 billion and to assume existing PGE debt of $1.1 billion. (OPUC approved the sale of PGE to Enron in 1997 with ring fencing restrictions that helped keep PGE from forced bankruptcy in 2001.)[4] OPUC denied the application in March 2005.

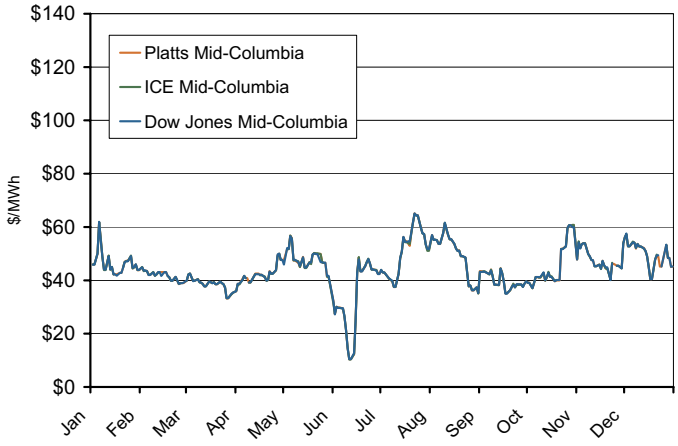
SPOT MARKETS: PRICES AND VOLUMES

CA-OR Border Daily Average of On-Peak Prices



Source: Derived from Platts, ICE and Dow Jones data. See source note 4.

Mid-Columbia Daily Average of On-Peak Prices



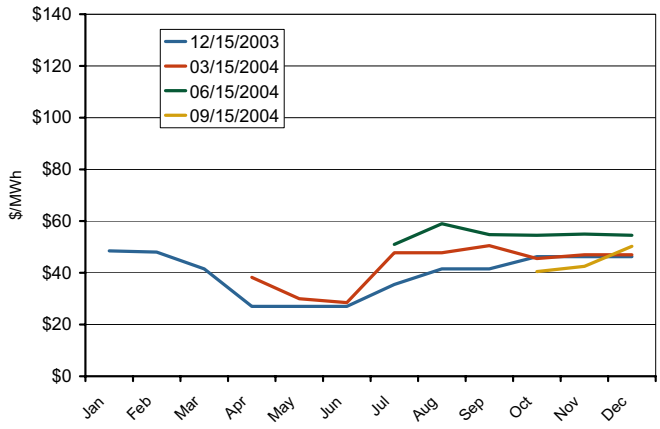
Source: Derived from Platts, ICE and Dow Jones data. See source note 4.

Day-ahead peak bilateral prices are illustrated from Dow Jones, IntercontinentalExchange (ICE), and Platts. Northwest prices followed the annual pattern of decrease in price with increased streamflow and hydro production during the spring runoff season (normally the highest runoff occurs in May and June). During this period substantial surplus power was available to the western market.

In bilateral trading for the California-Oregon Border (COB), ICE volumes averaged 8,156 MW and peaked for December 17 and 18 at 30,400 MW; Platts-reported volumes averaged 591 MW and peaked on December 7 at 1,825 MW. In bilateral trading for Mid-Columbia, ICE volumes averaged 23,626 MW and peaked for June 11 and 12, and for October 19 through 21, at 72,000 MW; Platts-reported volumes averaged 2,079 MW and peaked on July 2 and 3 at 4,250 MW.

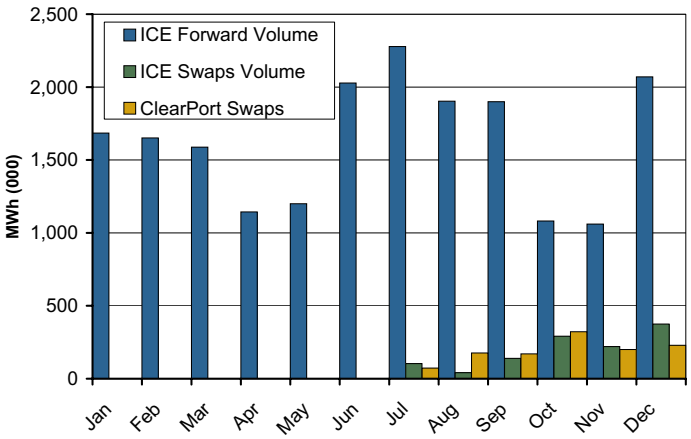
FINANCIAL MARKETS: PRICES AND VOLUMES

Mid-Columbia Forward Prices from Trade Date



Source: Derived from ICE data. See source note 5.

Mid-Columbia Forward and Swaps Volume



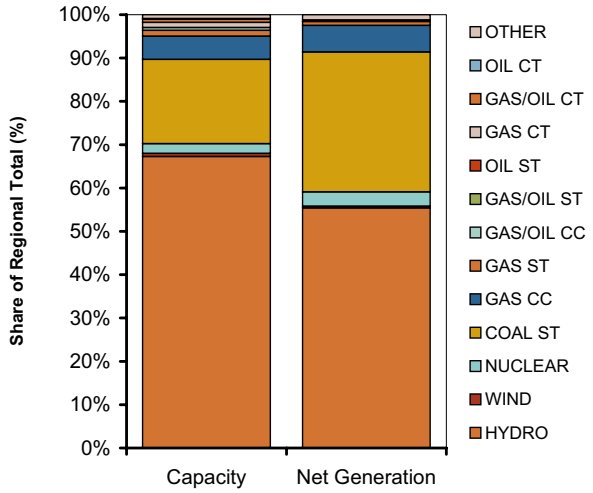
Source: Derived from ICE and Nymex data. See source note 5.

For the Northwest, financial markets consist of both physical forwards and financial swaps. ICE began clearing Mid-Columbia financial swaps in August. The New York Mercantile Exchange (Nymex) ClearPort began trading Mid-Columbia financial swaps in June for July and future months.

Although ICE and Nymex ClearPort both traded Mid-Columbia financial swaps, the volumes of financial trading of these products remained low as compared with the ICE physical Mid-Columbia product. Physical trading on ICE was highest for the third-quarter products. The trading of physical products for the fourth quarter was 15% lower than for the first quarter and more than 30% lower than for the third quarter.

2003 RESOURCE MIX

Capacity and Generation by Fuel and Prime Mover

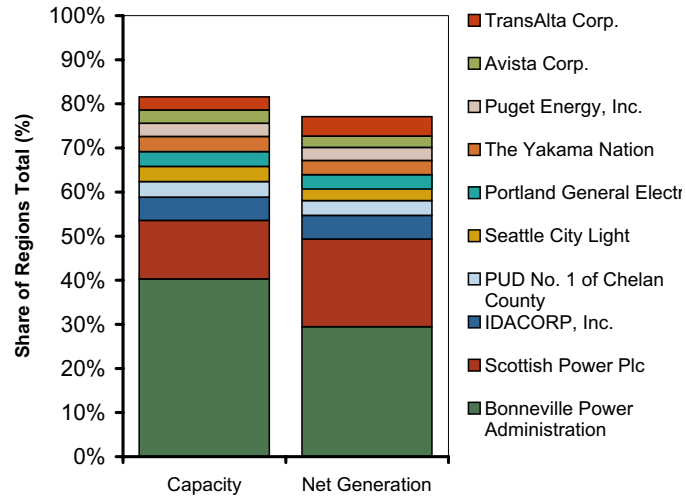


In 2003, hydro, wind, nuclear, and coal totaled 90% of total Northwest capacity and provided 91% of net generation. The region depends primarily on hydro resources, which made up more than two-thirds of total capacity and provided more than half of the annual generation in 2003.

Source: Derived from Platts data. See source note 6.

2003 MARKET CONCENTRATION

Capacity and Generation of Top 10 Companies



The top 10 owners provided 82% of capacity and 77% of generation in the Northwest in 2003.[5] Nine of the top 10 generation owners were regional utilities, their affiliates, or large municipals and cooperatives. Many of the largest suppliers of retail load were also the largest owners of generation and thus able to cover much of their load through self-supply. In 2004, capacity concentration was little changed as three, large (greater than 25 MW) power plants came on line: Plant capacity totaled approximately 341 MW, or less than 1% of the region's total capacity.

Source: Derived from Platts data. See source note 6.

Northwest Transmission Issues Revisited in 2004

In December, the Northwest Power and Conservation Council (NWPCC) released its draft of the "Fifth Power Plan." In its review, the NWPCC recounted regional transmission issues that have been identified since their "1996 Comprehensive Review of the Northwest Energy System." These issues include the need for better management of power flows and available transmission capacity, for improved grid planning and expansion, and the need to address the competitive advantages that various control area operators possess over competing generation owners. Such large issues support regional coordination efforts, the NWPCC concluded.[6] The Regional Representative Group of Grid West laid out other Northwest transmission problems including difficulty managing unscheduled flow; inability to monitor wholesale electricity markets, and transaction and rate pancaking (i.e., contracting, scheduling, and paying for the fixed costs of multiple transmission segments on a volumetric basis to complete a sale); and complexity and potential reliability concerns as a consequence of the proliferation of control areas.[7]

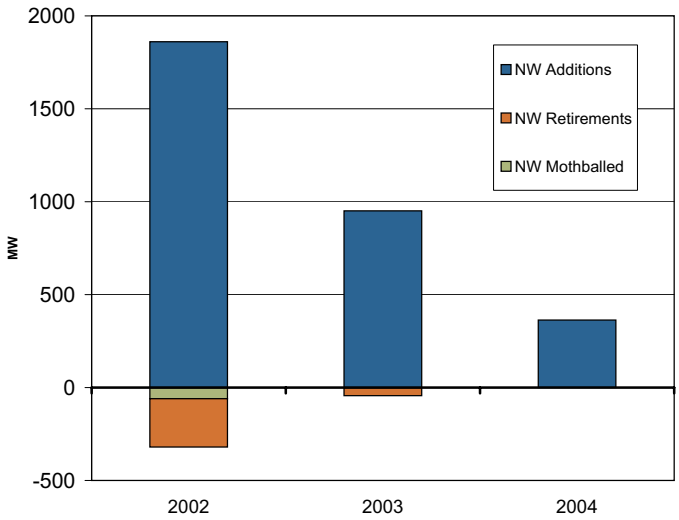
GENERATION AND TRANSMISSION ADDITIONS AND RETIREMENTS

In 2004, 363 MW of generation (all gas-fired) and five new transmission projects were added in the Northwest region.[8]

Generation Additions. In the Northwest region, three, large generation projects came on line. Two were independent power producer projects with a combined generating capacity of 342 MW. In Utah, the Nebo Power Station (a 121 MW Combined Cycle plant) began operation in June 2004. In August 2004, the Goldendale Energy Center (a 221 MW combined cycle plant) came on line. No retirements were reported.[9] Capacity additions in 2004 were less than in the two previous years.

Transmission Additions. Five major transmission projects were completed in the Northwest, representing approximately 309 miles of transmission line. In May, the Falcon to Gondor 345 kV transmission project was completed in Sierra Pacific Power's service area– a 180-mile line across northeastern Nevada. The 84-mile Grand Coulee-Bell 500 kV transmission line also was completed, BPA's largest transmission project in the past 20 years. The three other projects were completed in PacifiCorp's service territory.[10]

Capacity Additions



Source: Derived from EIA and Platts data. See source note 7.

Aluminum Smelter Demand for Electricity Remained low in 2004

Electricity demand from aluminum smelting plants, which historically consumed up to 15% of the region's electricity demand, remained modest in 2004. Cost pressures on aluminum production from world-wide competition and older, less efficient smelters in the Northwest kept production low. Aluminum smelting in the United States is one of the industries most sensitive to electricity prices, as electricity makes up approximately one-third of the production cost.

During the early 1980s, 10 aluminum plants accounted for up to approximately 3,100 average megawatts of the region's load. Northwest aluminum production decreased in the late 1980s and 1990s, with electricity needs decreasing from approximately 2,500 average megawatts down to 2,000 average megawatts, as Northwest power prices rose and more efficient aluminum plants came on line throughout the world. The Northwest smelters became "swing" plants, increasing production when aluminum commodity prices were favorable in world markets.

During the western energy crisis in 2000 and 2001, the region faced tight electricity supplies triggered by load growth, "under-investment in generation and conservation resources," and poor hydroelectric conditions starting in the spring of 2000. To help lower electricity demand, and to avoid purchasing high-priced electricity from the wholesale markets, BPA renegotiated its contracts and was able to buy back power from the aluminum smelters. All the smelters either reduced or ceased production. Electricity demand from the aluminum smelters decreased during 2001 to fewer than 500 average megawatts.

Seven of the region's 10 aluminum smelters remained closed; the rest operated at reduced levels. During 2004, electricity demand for aluminum remained at approximately 500 average megawatts.

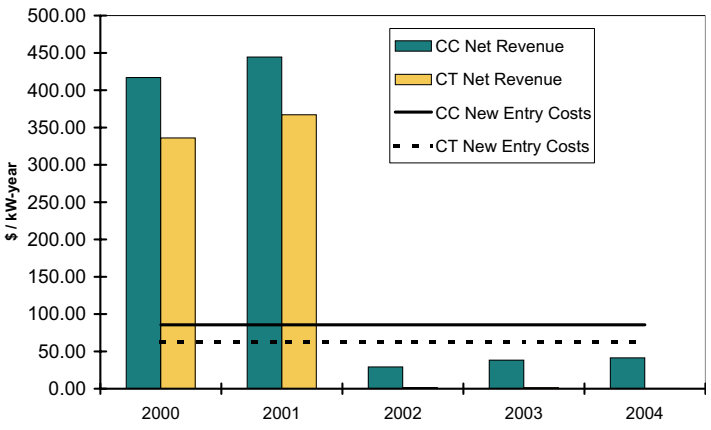
World aluminum prices rose 18% in 2004, but Northwest stakeholders expected electricity prices to stay higher than what Northwest aluminum plants require to operate profitably. Industry analysts believed that electricity use in the region for aluminum smelters would remain low in the coming years.[11]

NET REVENUE

Annual net revenues in 2004 from energy for gas-fired technologies were below the five-year average for the third consecutive year, in part because of relatively large net revenues in 2000 and 2001. Annual net revenues from energy for a combined cycle increased 8% from 2003. Revenues from energy for a combustion turbine declined 73% from 2003.

We estimate that new gas-fired combustion turbine plants in the Northwest require $62.67/kW-yr, and gas-fired combined cycle plants require $85.53/kW-yr, to meet debt and equity requirements. The five-year average net revenue estimates for both gas-fired combined cycle and combustion turbine plants exceeded these levels only because of the exceptionally high-priced periods during 2000 and 2001. In 2002, 2003, and 2004, estimated net revenue for gas-fired combined cycle and combustion turbine plants in the Northwest were below these thresholds.

COB Net Revenue from Energy



Source: Derived fromPlatts day-ahead gas prices for Malin and Platts day-ahead power prices for COB. See "Analytic Note on Net Revenue Calculations" in the Other Material section for details.

Endnotes

[1] BPA was initially formed to sell power from federal hydropower generation in the Northwest. Subsequently, BPA has also signed agreements to sell power from certain nonfederal power plants in the Northwest such as Energy Northwest's nuclear plant, Columbia Generating Station. BPA sells most of its power at cost-based rates to Northwest public utilities and direct service industries such as aluminum smelters. When surplus power is available, BPA also sells power to the western market that it has in excess of its existing firm contractual commitments. This surplus power is sold at market prices. http://www.bpa.gov/corporate/about_BPA/facts/index.cfm, and Bonneville Power Administration News, September 23, 2004.

[2] Bonneville Power Administration 2004 Annual Report, 27.

[3] From October 2000 through September 2001 the Northwest experienced below-normal precipitation and streamflows and, hence, below-normal hydroelectric production (2001 streamflow, as measured at The Dalles Dam, was 58 million acre-feet, which was 56% of the 70-year average of 104 million acre-feet). The Northwest exported electrical energy to the combined regions of California and the Southwest in ten months of 2001. Northwest Power Pool data downloaded from http://www.nwpp.org/pdf/historical_data.pdf, on April 12, 2005.

[4] Oregon Public Utilities Commission, Order Number 05-114, 24. http://www.puc.state.or.us/orders/2005ords/05-114.pdf.

[5] BPA does not own generation, but markets the output of the federal hydropower facilities in the Northwest and that of a few nonfederal power plants.

[6] NWPCC (http://www.nwcouncil.org/energy/powerplan/draftplan/(09)%20Transmission%20(PP).pdf).

[7] Grid West http://www.rtowest.com/Doc/TSLG_RRGUpdateReport_Oct272004.pdf.

[8] Capacity Additions and Retirements are for calendar year 2004, based on Platts and EIA net summer capacity estimates and FERC staff research. They may differ from the Summer Generating Capacity in the Supply Demand Statistics table. Summer Generating Capacity may be projected for the summer peak, may omit some calendar year additions, and may reflect actual demonstrated capacity and deratings.

[9] Platts PowerDAT, NEWGen as of March 1, 2005, EIA Form 860, FERC Staff Research. Data are summer capacity unless otherwise indicated.

[10] WECC 10-Year Coordinated Plan Summary (September 2004), NERC Energy Supply and Demand database, FERC analysis. Data are for new transmission lines 230kV and above unless otherwise indicated.

[11] See "BPA Comments on the Council's draft Fifth Power Plan"; "The Demand Wild Card: Pacific Northwest Aluminum," Cambridge Research Associates, July 2003, 1–6; "Fifth Power Plan: Pre-publication draft," Northwest Power and Conservation Council, A–15, A-23–A-27, 1–3. Northwest Aluminum Industry Study Group, January 26, 2001; OMOI conversation with BPA, April 7, 2005; At the London Metals Exchange, cash market prices for aluminum started in 2004 at $1,460 per ton and ended the year at $1,721 per ton (Bloomberg, March 23, 2005); "2003 Pacific Northwest Loads and Resources Study: The White Book," BPA, July 15, 2004, 48.

Source notes

1. Prices are Dow Jones firm day-ahead on-peak prices for the locations identified.
2. Platts *Megawatt Daily*, IntercontinentalExchange (ICE) and Dow Jones prices are firm day-ahead on-peak for the Mid-Columbia Hub.
3. Data are from WECC, "Summary of Estimated Loads and Resources," as of July 2004 and May 2005. WECC data reflects certain hydroelectric facility derates and limitations as reported by Northwest control area operators. The Northwest is a winter peaking area, generally energy-constrained and not capacity-constrained.
4. Platts *Megawatt Daily*, ICE and Dow Jones prices are for firm day-ahead on-peak delivery to the California/Oregon Border (COB).
5. ICE on-peak forward and swap prices and volumes are for Mid-Columbia and include monthly, dual monthly, quarterly, and calendar year contracts traded for 2004. New York Mercantile Exchange (Nymex) ClearPort on-peak swaps volumes are for Mid-Columbia and are traded by month.
6. Data from Platts PowerDat, RDI Modeled Production Costs dataset for calendar year 2003 reflecting self-reporting from all utility and nonutility electric power generating facilities with nameplate capacity of 50 MW or more.
7. Data from Energy Information Administration (EIA) Form 860, Platts NewGen and Platts PowerDat. All generation is summer capacity unless otherwise indicated.

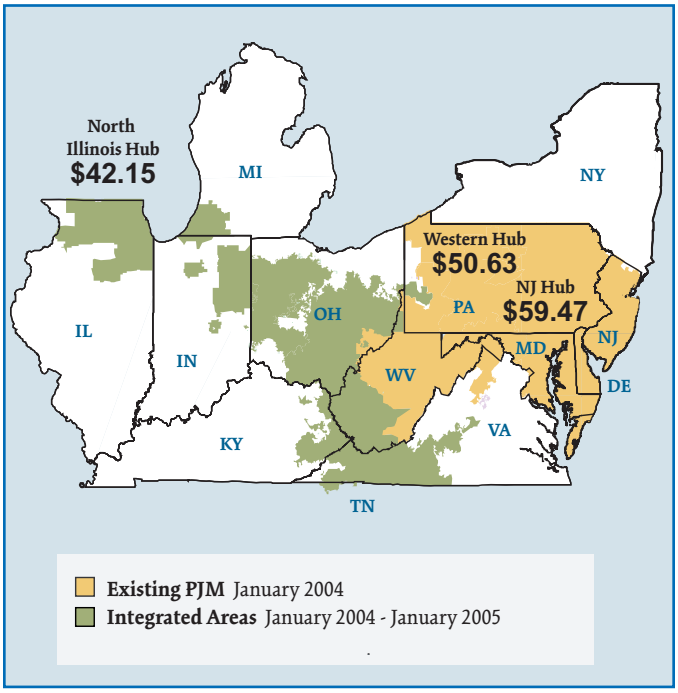
Disclaimer: This report contains analyses, presentations and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

PJM Electric Market Profile

By January 1, 2005, the PJM Interconnection LLC (PJM) electric market stretched from the Atlantic Coast to the Midwest and included all or part of the high-voltage electric system in 12 states and the District of Columbia.[1] Thus, PJM includes all or portions of the North American Electric Reliability Council (NERC) regions of the Mid-Atlantic Area Council (MAAC), the East Central Area Reliability Coordination Agreement (ECAR), and the Mid-America Interconnected Network (MAIN). In 1998, PJM, as independent system operator (ISO), began centrally dispatching the region's power grid and operating a spot energy market. The energy market is now an RTO with a two-settlement market (day-ahead and real-time) using locational marginal pricing (LMP).

PJM also operates a regional capacity market, a financial transmission rights market, and markets for some ancillary services. Market participants also actively trade electricity bilaterally through brokers and the IntercontinentalExchange (ICE), often using the PJM Western Hub as the pricing point. Average 2004 peak prices for the PJM Western Hub increased 5%–6% from 2003.

2004 Average Hub Prices for On-Peak Hours ($ per MWh)



Source: Derived from PJM data. See source note 1.

PJM Western Hub Prices

	2003	2004	5-Year
Platts	$48.49	$51.10	$40.77
ICE	$48.39	$51.10	NA
RTO	$47.71	$50.63	$41.40

Source: Derived from PJM, ICE and Platts data. See source note 2.

Supply Demand Statistics

	2003	2004	Exp. 2005
Summer Generating Capacity MW	140,498	140,855	143,620
Summer Peak Demand MW	112,355	105,541	115,166
Summer Reserves MW	28,143	35,314	28,454
Summer Reserve Margin	25%	33.5%	24.7%
Annual Energy Gwh		598,452	605,432

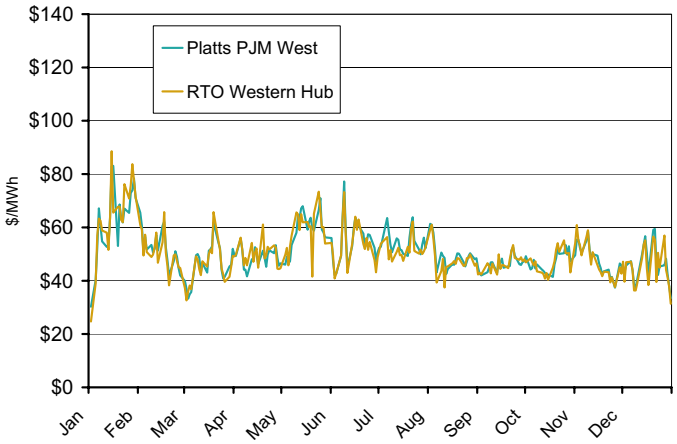
Source: Derived from PJM, Platts and Energy Information Administration (EIA) data. See source note 3.

Focal Points for 2004

- **Control Area Integration.** The integration of the Commonwealth Edison (ComEd), American Electric Power (AEP), and Dayton Light and Power control areas in 2004 increased PJM's peak load approximately 70%. PJM also added the Duquesne Light Co.'s area on January 1, 2005.
- **Joint Operating Agreement.** PJM and the Midwest Independent Transmission System Operator (MISO) initiated a Joint Operating Agreement (JOA) on December 31, 2003, to formalize the seams arrangements between the two regional transmission organizations (RTOs.) For 2004, the JOA set procedures for the market (PJM) to nonmarket (MISO) interface. With MISO's central dispatch market start-up in 2005, the JOA will foster an efficient procedure for management of congestion through re-dispatch based on market prices. PJM and MISO formulated the JOA in partial compliance with the Commission's directive to design a seamless market between the two RTOs.[2]
- **Moderate weather** kept PJM from setting new peaks and moderated prices during the past two summers. However, a combination of cold weather and high natural gas prices caused price spikes of limited duration in winter 2003–04.

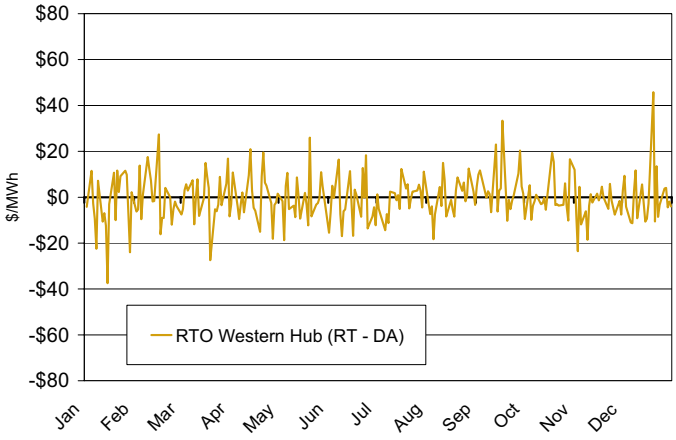
SPOT MARKETS: PRICES AND VOLUMES

Daily Average of On-Peak Prices



Source: Derived from PJM and Platts data. See source note 4.

Daily Average RT vs. DA On-Peak Prices



Source: Derived from PJM data. See source note 5.

Day-ahead, peak bilateral prices from Platts and ICE are illustrated as well as RTO day-ahead and real-time locational marginal prices. Prices in PJM were higher in 2004 than in the previous year largely due to higher fuel costs. However, as a result of the integration of areas with lower cost generation and moderate temperatures, average spot prices in PJM actually declined after adjustment for fuel costs.[3]

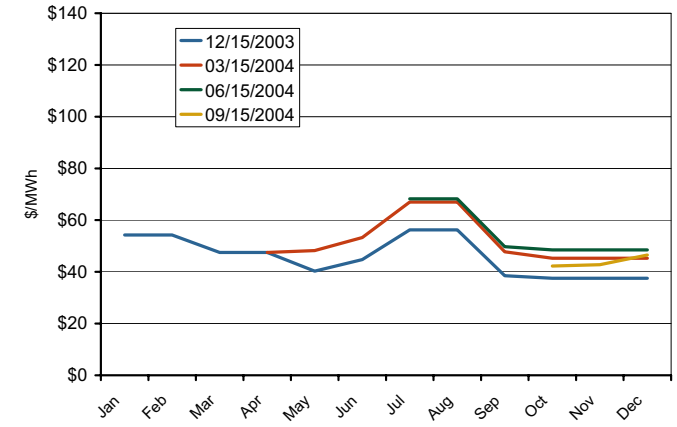
The integration during 2004 of major service areas into PJM markedly increased the load served. Before the ComEd integration, the average daily peak load was 41,753 MW. After the ComEd integration, but before the AEP and Dayton integrations, the average daily peak load was 58,661 MW. From the time of the AEP and Dayton integrations to the end of the year, the average daily peak load was 70,595 MW.

Platts volume reports of bilateral trading for the PJM Western Hub peaked on July 23 at 4,650 MW and averaged 1,996 MW. ICE volume peaked on May 5 at 84,000 MW and averaged 28,314 MW. In reports of bilateral trading for Northern Illinois, Platts volume peaked on February 9 at 3,575 MW and averaged 913 MW; ICE volume peaked on November 11 at 31,200 MW and averaged 7,450 MW.

The differences are also shown between the average peak-hour, day-ahead price and average peak-hour, real-time price. These differentials center around zero with a small bias toward a higher day-ahead price in peak hours.

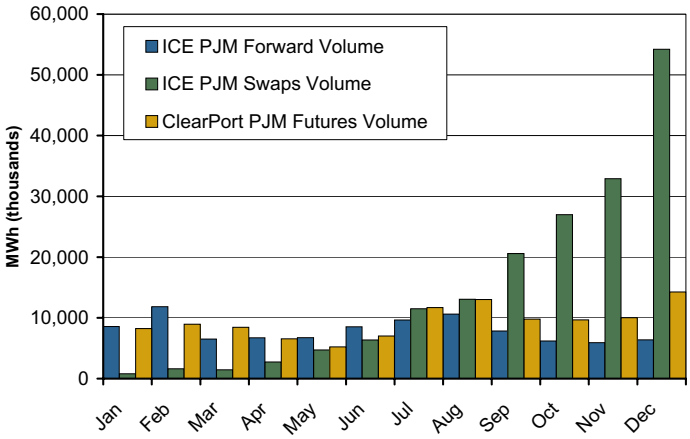
FINANCIAL MARKETS: PRICES AND VOLUMES

Swaps Prices from Trade Date



Source: Derived from ICE data. See source note 6.

Forward and Swaps Volume



Source: Derived from ICE and Nymex data. See source note 6.

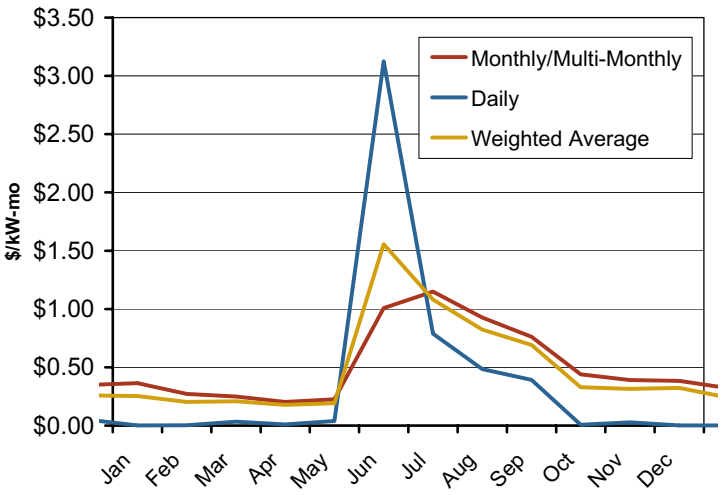
For PJM, financial markets consist of both physical forward and financial swaps. Market participants use many platforms for their financial transactions. Data are available for ICE and Nymex only.

Financial trading increased on both the Nymex ClearPort and ICE trading platforms. Trading of PJM financial products on Nymex ClearPort for the fourth quarter was 30% higher than for the first quarter. Trading of financial products on ICE for the fourth quarter was 29 times higher than the first quarter. Trading of ICE PJM physical volumes outweighed financial volumes until July. By the fourth quarter, financial trading volumes on ICE outweighed the physical volumes by more than six-fold.

The increase in trading of PJM financial products is consistent with the general trend in electricity trading as more nontraditional electricity trading entities (hedge funds and banks) have become active in financial markets, as industry credit has improved, and as platforms like ICE and Nymex have begun to offer clearing of trades. Trading of PJM financial products on ICE and Nymex ClearPort outweighed trading for other regions and hubs significantly.

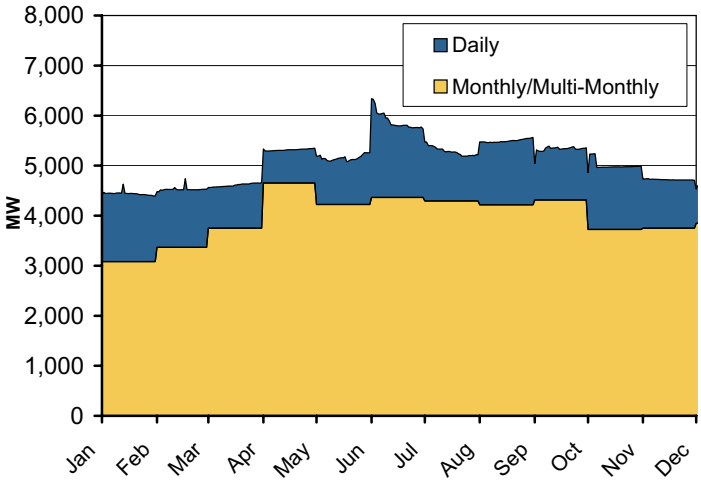
CAPACITY AUCTIONS

PJM Capacity Auction Prices



Source: FERC/OMOI analysis of PJM data. See source note 7.

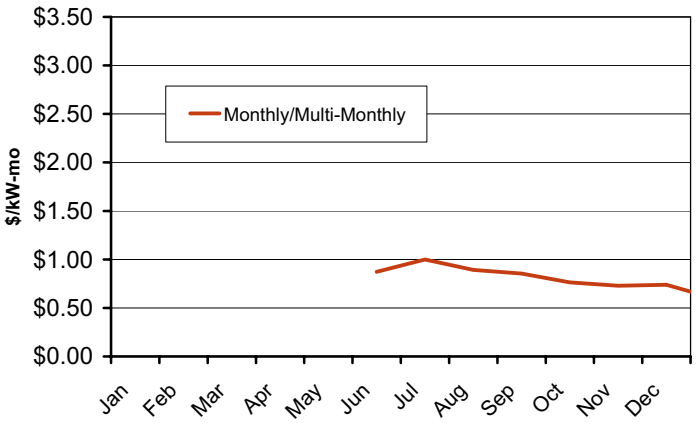
PJM Capacity Auction Volume



Source: Derived from PJM data. See source note 7.

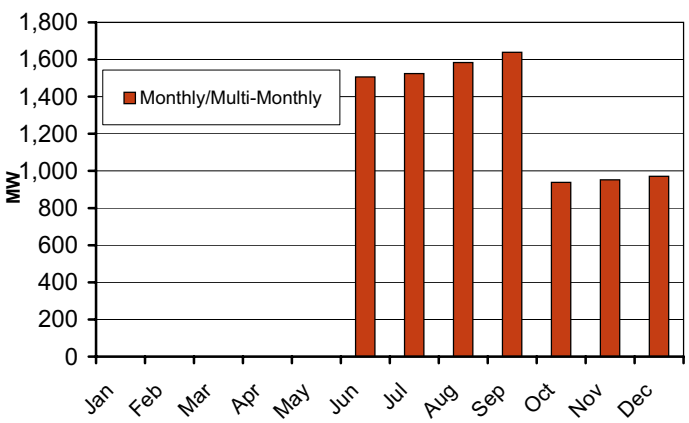
PJM requires that all load-serving entities in PJM maintain contracted or owned capacity equal to their load, plus a specified reserve (15% of forecasted peak in 2004). They may purchase capacity bilaterally, own the capacity, or transact through the PJM capacity market. With the integration of the northern Illinois control area, PJM started a second, parallel capacity auction for the northern Illinois control area. All other areas use the original capacity auction process. Capacity for the northern Illinois control area is procured in a separate auction with different rules and capacity requirements. A single PJM-wide process took effect June 1, 2005, when differences between PJM capacity requirements and MAIN capacity requirements were reconciled.

Northern Illinois Capacity Auction Prices



Source: Derived from PJM data. See source note 8.

Northern Illinois Capacity Auction Volume



Source: Derived from PJM data. See source note 8.

The PJM capacity markets consist of monthly and multi-monthly auctions and also a daily auction, each auctioning unforced capacity (UCAP), that is, generators' demonstrated capacity adjusted for forced outage history. Capacity can be purchased in any of these auctions, with monthly and multi-monthly auctions occurring at frequent intervals through PJM's website. Load-serving entities that do not procure enough resources to meet their capacity obligations must pay a deficiency payment to PJM.

Capacity prices were highest in the summer months, particularly June. A drop in capacity imports, adjustments to forced outage rates, and generator retirements decreased UCAP supply by 1,400 MW. The PJM market monitor noted a change in capacity bidding patterns: Supply offers were higher than in previous months, and load purchased more capacity in the daily auction.[4]

The northern Illinois capacity markets consist of monthly and multi-monthly auctions, auctioning installed capacity (ICAP). Capacity can be purchased in monthly and multi-monthly auctions, which PJM conducts at frequent intervals. Load-serving entities that do not procure enough resources to meet their capacity obligation must make deficiency payments.

Capacity in the northern Illinois control area was highly concentrated: nearly two-thirds was owned or controlled by one entity.[5] Auction volumes fell in October after a change in seasonal obligations on October 1.

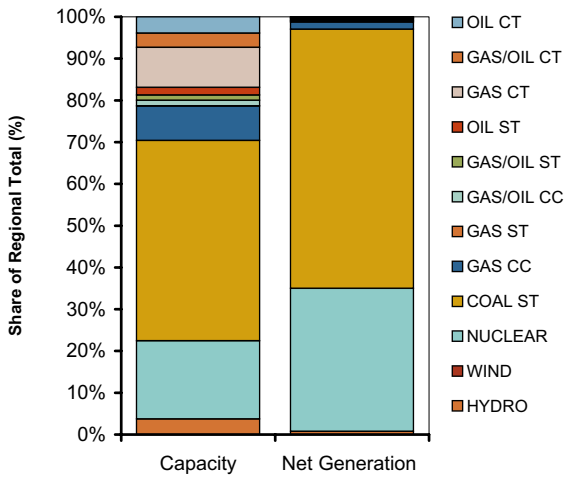
Offer Mitigation

PJM mitigates generator offers when units are in a transmission-constrained area and are needed for reliability. Units in PJM Mid-Atlantic whose construction started between July 9, 1996 and September 30, 2003 are exempted. Also, if the relevant constraint is either the eastern or western interface, mitigation is not imposed. When a unit is mitigated, its offer is generally restricted to its variable cost (on file with PJM), plus 10%. Some frequently mitigated units are allowed an adder on top of the normal mitigated offer through a negotiated option.

The mitigation experience for 2004 was slightly higher than the previous year. The share of total unit run hours under mitigation was 1.3% in 2004 (1.1% in 2003). The trend had been declining mitigation since 2001, when 2.8% of the unit run hours were under mitigation.

2003 RESOURCE MIX

Capacity and Generation by Fuel and Prime Mover

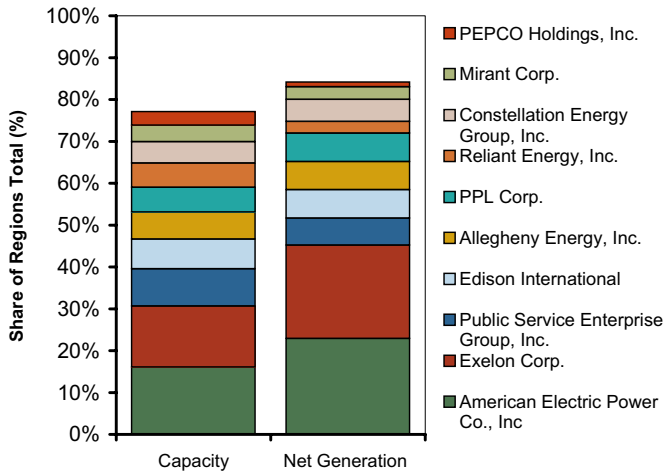


In 2003, hydroelectricity, wind, nuclear energy, and coal constituted 70% of the total PJM capacity and provided almost all net generation. By comparison, gas-fired capacity was 18% of the total and contributed 2% of annual net generation in 2003; dual-fuel (gas/oil) generators constituted 6% of capacity and contributed 1% of annual net generation.

Source: Derived from Platts data. See source note 9.

2003 MARKET CONCENTRATION

Capacity and Generation of Top 10 Companies



The top 10 owners provided 77% of capacity and 84% of generation in PJM in 2003. Seven of the top 10 generation owners in PJM were regional utilities or their affiliates. Three of the top 10 providers were independent power producers or utility affiliates that built or acquired generating assets outside of their traditional service territories.

The top 10 major utilities supported 91% of peak load and 93% of total retail sales in the region. Many of the largest suppliers of retail load in PJM were also the largest owners of generation and were able to cover much of their load through self-supply.

Source: Derived from Platts data. See source note 9.

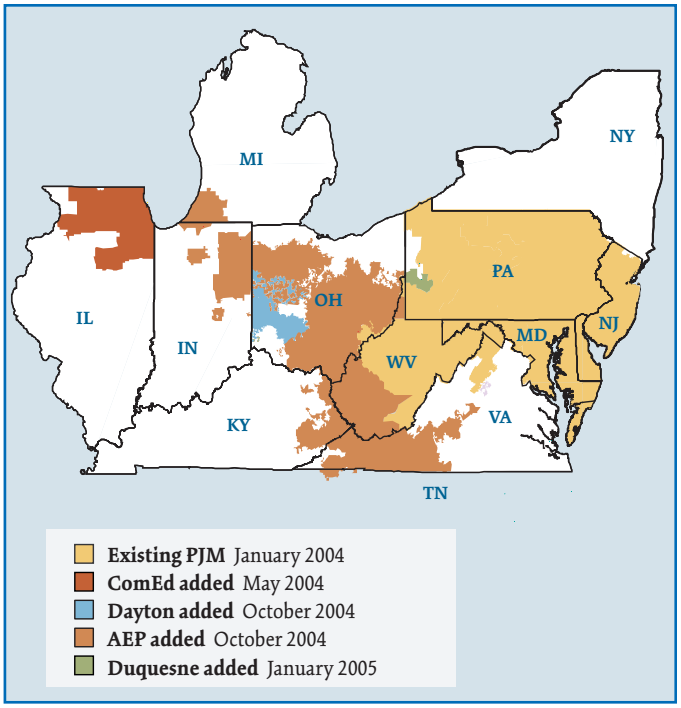
PJM EXPANSION

In 2004, ComEd, Dayton, and AEP control areas integrated into the area for which PJM controls the transmission service and operates a centralized spot energy market. PJM also added the Duquesne Light Company area on January 1, 2005.

ComEd joined the RTO on May 1, 2004. Because ComEd did not have a direct electrical connection to PJM at the time, PJM devised a temporary 500 MW pathway of transmission reservations through AEP to connect the two areas. From May to October, PJM centrally dispatched the ComEd control area, along with the rest of PJM, but the limited capacity of the pathway often prevented full economic use of capacity in northern Illinois. On October 1, AEP and Dayton joined PJM and became part of PJM's central dispatch and spot market. With AEP in PJM, the pathway was no longer necessary, and transactions between the far-western reaches of PJM and the Mid-Atlantic portion ran smoother.

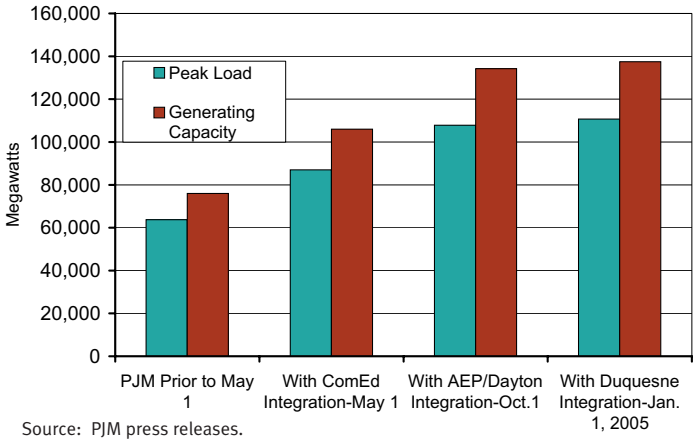
For each integration phase, PJM and the participants conducted two, full-scale market trials. PJM also held numerous simulation and training exercises to prepare its own operations and to help participants learn to take part in the new markets. PJM also had to allocate Financial Transmission Rights for each new area and prepare its Open Access Same Time Information System (OASIS) to provide transmission service in the expanded configurations.

Operation of an LMP system in these new areas has presented challenges for PJM and its neighbors, particularly MISO, in dealing with inadvertent energy movement across new borders. As discussed above, PJM and MISO formulated a joint operating agreement for solutions to these seams situations, and the integrations have proceeded without major problems. PJM added the Dominion-Virginia Power service territory on May 1, 2005.



Source: PJM press releases.

Expansion



Source: PJM press releases.

Recent Increase in Generation Retirements

After years with practically no generation retirements in the PJM Mid-Atlantic region, late 2003 and 2004 saw an upsurge in notifications to PJM from owners that planned to retire units. Owners removed more than 2,000 MW of generation from service in 2004. Before this activity, PJM did not have a formal policy for coordinating retirements between the generator owners and the RTO. PJM placed an informal policy in effect until the Commission approved the elements of what is now PJM's formal retirement policy.[6] The current policy requires generators to notify PJM of planned retirements 90 days before they take effect and requires PJM to respond with an estimate of effects on reliability within 30 days of the notification. If the retirement does pose a reliability risk, the policy provides for a mechanism to reimburse the owner for the cost expended to continue operation. PJM received 58 requests to deactivate units during 2004.

NET REVENUE

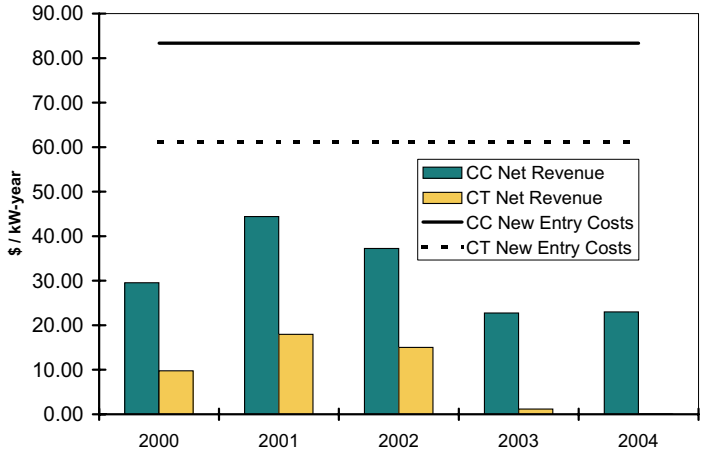
Annual net revenue from energy for gas-fired technologies in 2004 was below the five-year average for the second consecutive year. For a combined cycle, revenue from energy increased 1.1% from 2003 but was still 26.7% below the five-year average. For a combustion turbine, revenue from energy reached a five-year low, declining from $9.76/kW-year in 2000 to $0.05/kW-year in 2004.

FERC estimated cumulative annual net revenue for sale of energy at the PJM western trading hub.

Estimates of the cost of new entry in PJM vary. For example, PJM estimates were higher than the EIA-based estimates above: $93.50/kW-year for a new combined cycle and $72.20/kW-year for a new combustion turbine.[7] In addition, the EIA-based cost estimates do not provide a detailed picture of intrastate cost divergence. According to a Strategic Energy Services Inc. report, new-entry costs for a combustion turbine (CT) in New Jersey are estimated at $72.21/KW-year, slightly lower than for a CT in Maryland or Illinois at $74.12/kW-year and $73.84/kW-year, respectively.[8]

Estimated PJM 2004 net energy revenues fell below all of these thresholds. The addition of estimated net revenue from capacity made little difference. Without significant net revenue from energy, capacity, and ancillary services, market-based investment was not signaled.

PJM Western Hub Net Revenue from Energy



Source: Derived from Platts and EIA data. See "Analytic Note on Net Revenue Calculations" in the Other Material section for details. See also source note 10.

Regional Net Revenues from Energy and Capacity

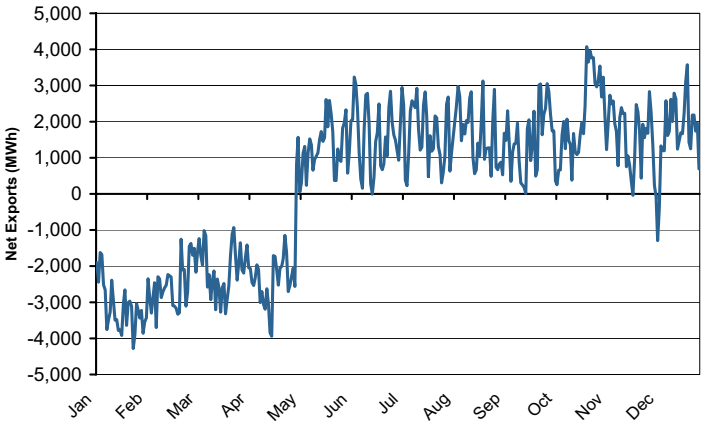
	Net Energy $/kW - yr	Net Capacity $/kW - yr	Net Revenues $/kW - yr
CC	$23.00	$5.24	$28.24
CT	$0.04	$5.38	$5.42

Source: Derived from FERC/OMOI analysis of Energy Revenues; PJM MMU estimates of capacity revenues as presented in May 4, 2005 State of the Markets.

REGIONAL EXPORTS AND IMPORTS

Before integration, PJM was a net importer of energy. After integration of the northern Illinois control area and continuing with the integration of AEP and Dayton, PJM became a net exporter. PJM was a net importer on five days after May 1 (June 16, November 21, December 5, December 6, and December 7). Before ComEd integration on May 1, average net imports were 2,539 MW. May through September average net exports were 1,529 MW. After the AEP and Dayton integrations on October 1, average net exports were 1,811 MW.

Average Daily Net Interchange



Source: Derived from PJM data. See source note 11.

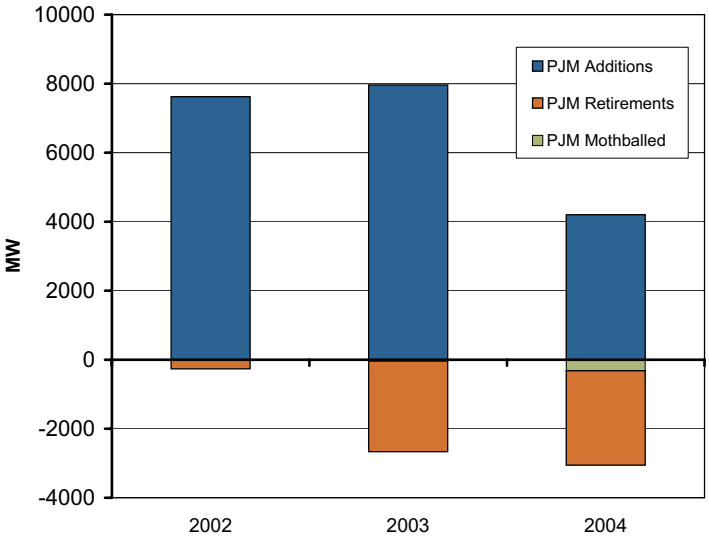
GENERATION AND TRANSMISSION ADDITIONS AND RETIREMENTS

In 2004, 4,202 MW of new generation and five major transmission projects were completed in PJM. During the year, 78 MW of generation was mothballed and 2,742 MW was retired.[9]

Generation Additions. In the PJM region, 10 generation projects came on line. All, except for one 10-MW plant, are fueled by natural gas. The five largest plants total 3,800 MW and are independent power producer projects, including the PSEG Lawrenceburg Energy Facility (1,062 MW at a cost of $600 million) and the Fairless Energy Center (1,150 MW). Capacity additions in 2004 were lower than in the two previous years. In 2004, 2,740 MW of generation were retired, most of which were owned by Reliant, Edison Mission Energy (EME), and PSEG Power. This total included the Collins plant, owned and retired by EME.

Transmission Additions. Five major transmission projects were completed in PJM, totaling 6.4 miles.[10] Three of the new projects were completed by AEP in the ECAR region.

Capacity Additions



Source: Derived from PJM, EIA and Platts data. See source note 12.

Endnotes

1 This section includes all PJM regions existing or integrated through January 1, 2005.

2 Commission Order Providing Guidance on Midwest ISO and PJM Structure, 100 FERC 61,137 (2002), paragraph 48.

3 PJM, 2004 State of the Market (PJM SOM), (March 8, 2005), 48.

4 PJM SOM, 164–166.

5 PJM SOM, 170.

6 PJM Open Access Transmission Tariff, Section V.

7 PJM, 2004 State of the Market (March 8, 2005). Cost of new entry levelized over the 20-year life of a project.

8 "Reconciliation of Initial to Final Revenue Requirements, Final Revenue Requirements Region," Ray Pasteris, President, Strategic Energy Services Inc., February 4, 2005. See http://www.pjm.com/committees/workinggroups/pjmramwg/downloads/20050209-cone-ct-reconciliation.pdf.

9 Platts PowerDAT, NEWGen as of March 1, 2005. EIA Form 860, FERC Staff Research, PJM Market Monitor Unit. Data are for summer capacity, unless otherwise indicated. Capacity Additions and Retirements are for calendar year 2004, based on Platts and EIA net summer capacity estimates and FERC staff research. They may differ from the Summer Generating Capacity in the Supply Demand Statistics table. Summer Generating Capacity may be projected for the summer peak, may omit some calendar year additions, and may reflect actual demonstrated capacity and deratings.

10 NERC ES&D Database 2004. Updates from NERC as of April 19, 2005. Data are for new transmission lines 230 kV and above, unless otherwise indicated.

Source notes

1. Prices are PJM's day-ahead locational marginal prices for the hubs identified. Data located at http://www.pjm.com/markets/energy-market/day-ahead.html. On-peak hours are from 7:00 a.m. to 11:00 p.m. Monday through Friday excluding NERC holidays. Northern Illinois Hub price series began May 1, 2004.

2. Platts *Megawatt Daily* and IntercontinentalExchange (ICE) prices are day-ahead on-peak for "PJM West." PJM prices are day-ahead locational marginal prices for the Western Hub, data located at http://www.pjm.com/markets/ energy-market/day-ahead.html.

3. Data from PJM's 2005 Load Forecast Report, February 2005; Platts NewGen, Platts PowerDat, and EIA. Summer generating capacity is that capacity available each summer at summer rating. Summer peak demand in 2003 did not reflect diversity between Mid-Atlantic and West peaks.

4. Platts *Megawatt Daily* prices are day-ahead on-peak for the "PJM West." PJM prices are day-ahead locational marginal prices for the internal Hub, data located at http://www.pjm.com/markets/energy-market/day-ahead.html.

5. PJM prices include real-time and day-ahead locational marginal prices for the internal Hub. PJM real-time price data located at http://www.pjm.com/markets/jsp/lmp.jsp. PJM day-ahead price data located at http://www.pjm.com/markets/energy-market/day-ahead.html.

6. ICE on-peak forward and swap prices and volumes are for PJM's Western Hub and include monthly, dual monthly, quarterly, and calendar year contracts traded for 2004. New York Mercantile Exchange (Nymex) ClearPort on-peak swaps volumes are for PJM's Western Hub traded by month.

7. PJM capacity price and volume information is located at http://www.pjm.com/pub/capacity_credit_market/ downloads/daily.csv for daily and http://www.pjm.com/pub/capacity_credit_market/downloads/stat.csv for longer terms.

8. PJM capacity price and volume information for Northern Illinois is located at ftp://ftp.pjm.com/pub/capacity_credit_market/results/ nica/ccmmonthly-nica.csv.

9. Data from Platts PowerDat, RDI Modeled Production Costs dataset for calendar year 2003 reflecting self-reporting from all utility and non-utility electric power generating facilities with nameplate capacity of 50 MW or more.

10. The analysis is based on Platts Megawatt Daily's day-ahead on-peak electric prices for the Western Hub and from Platts Gas Daily's day ahead natural gas prices from Transco Zone 6 (non-New York). The figure does not include revenue from capacity or ancillary services. For a detailed discussion of the calculation method, see "Analytic Note on Net Revenue Calculations" in the Other Material section of the Report.

11. Average hourly net interchange data are from PJM real-time tie schedules and can be found at http://www.pjm.com/markets/jsp/nts.jsp.

12. Data from PJM, Energy Information Administration (EIA) Form 860, Platts NewGen and Platts PowerDat. All generation is summer capacity unless otherwise indicated.

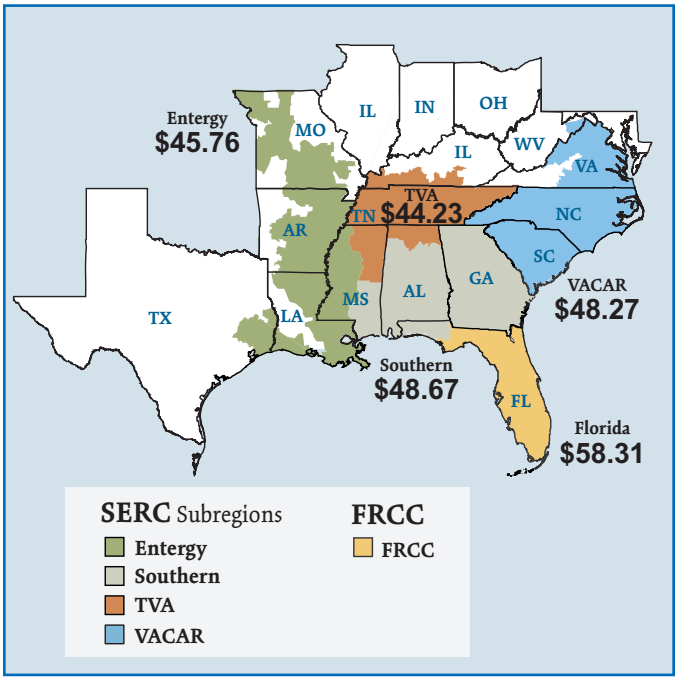
Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Southeast Electric Market Profile

The Southeast electric market is composed of two regions designated by the North American Electric Reliability Council (NERC): the Florida Reliability Coordinating Council (FRCC) of peninsular Florida, and the Southeastern Electric Reliability Council (SERC), which includes the Southern, Entergy, Tennessee Valley Authority (TVA), and VACAR (Virginia-Carolinas) subregions. Eleven control areas dispatch in coordination with FRCC's Reliability Coordinator and 22 control areas dispatch in coordination with SERC's Reliability Coordinator. Physical and financial electricity products are traded using Entergy, Southern, TVA, VACAR, and Florida price points. Volumes for these products remain low, especially in Florida where merchant power plant development is restricted by a state statute. In addition, there is trading on IntercontinentalExchange (ICE) for the Entergy Hub, Southern and TVA. Average 2004 peak prices for the Entergy Hub increased about 10% over 2003. Average prices were similar in Entergy, Southern, TVA, and VACAR, and slightly higher in Florida.

The SERC region had a large pool of interconnected generation capacity that was designated "noncommitted." The deliverability of output from these facilities is not assured because they lacked firm transmission capacity or agreements to serve load; yet they often sold power into the spot market. These plants are primarily located in the Entergy and Southern subregions and totaled 45,579 MW. They were not included in the EIA-411 SERC regional capacity of 180,038 MW, or in the reserve margin of 16.6%. If included, capacity would have increased to 225,617 MW with a reserve margin of 42.4%.[1]

2004 Average Regional Prices for On-Peak Hours ($ per MWh)



Source: Derived from Platts data. See source note 1.

Entergy Prices

	2003	2004	5-Year
Platts	$41.47	$45.76	$41.10
ICE	$41.45	$45.86	NA

Source: Derived from Platts and IntercontinentalExchange (ICE) data. All prices are in nominal dollars. See source note 2.

Supply Demand Statistics

	2003	2004	Exp. 2005
Summer Generating Capacity MW	214,207	218,438	223,029
Summer Peak Demand MW	193,585	200,666	205,387
Summer Reserves MW	20,622	17,772	17,642
Summer Reserve Margin	11%	9%	9%
Annual Load GWh	1,045,985	1,088,336	1,114,169

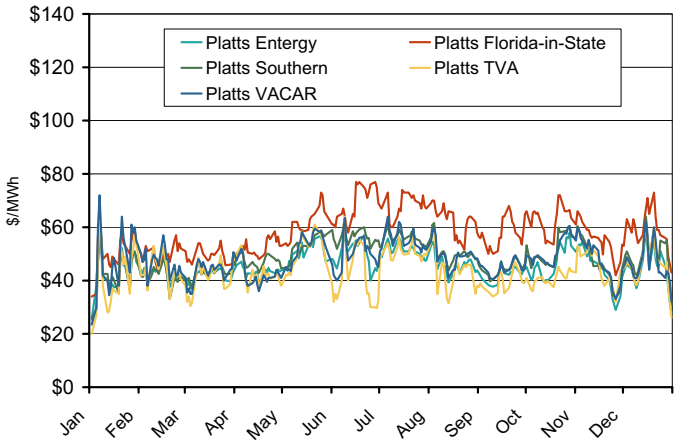
Source: Derived from NERC and SERC data. See source note 3.

Focal Points for 2004

- **Hurricanes battered Florida** during summer 2004. Four major storms caused widespread damage and loss of service to customers. Hurricane Frances disrupted operations affecting four million end-users. The repeated storms strained utility recovery operations because of widespread damage to the local distribution systems from downed wires. Despite this, there was only minor damage to generation and transmission assets. Nuclear and fossil power plants were shut down as a precaution, and there were fuel disruptions because of damage to the gas system, wet coal stockpiles, and some fuel oil delivery interruptions. In spite of such problems, power prices remained stable as supply and demand fell simultaneously in roughly equal proportions.
- **Southeast utilities** organizing the SeTrans RTO suspended a 2-year effort in December 2003 to create a regional transmission organization. They stated that "the retail commissions in the region have expressed significant concerns about the role of an RTO and its effects on matters subject to their jurisdiction, including concerns about native load protection and cost impacts." The SeTrans members were City of Dalton (Ga.) Utilities, City of Tallahassee (Fla.), Cleco Corp. Entergy Services, Georgia Transmission Corp., Jacksonville (Fla.) Electric Authority, the Municipal Electric Authority of Georgia, Sam Rayburn Electric Cooperative, Santee Cooper, Southern Co., and South Mississippi Electric Power Association.
- **New investment** in the SERC region's transmission system totaled $1.13 billion in 2004.[2] Based on a survey of the capital investment plans of the regional utilities, this level is expected to remain consistent each year through 2010.

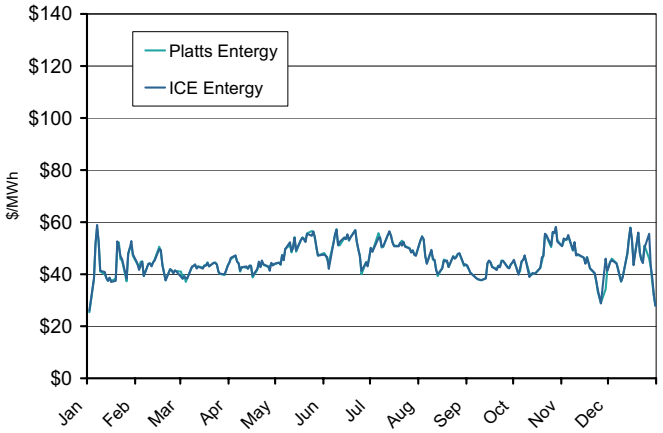
SPOT MARKETS: PRICES AND VOLUMES

Daily Average of On-Peak Prices



Source: Derived from Platts data. See source note 4.

Comparison of On-Peak Prices between Platts and ICE



Source: Derived from Platts and ICE data. See source note 5.

Southern and TVA prices peaked in the mid-$60s per MWh, Southern on December 15 and TVA on June 9. Florida and VACAR peaked in the lower $70s, Florida on various dates in June and VACAR on January 7. Entergy peaked in the high $50s on December 15. All prices in the Southeast were the lowest on January 2; Florida was in the mid-$30s, whereas all others areas were in the mid to lower $20s.

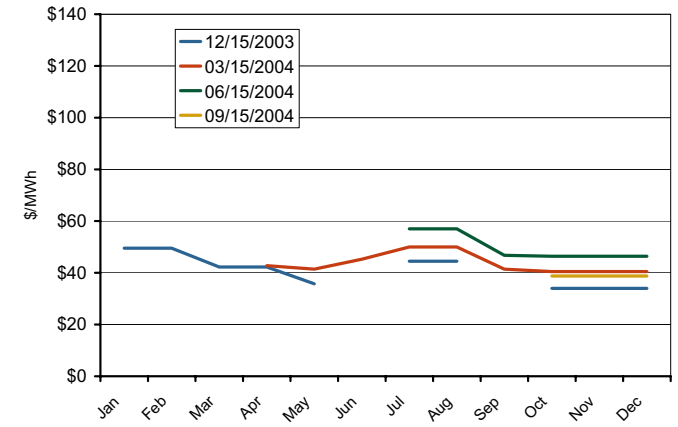
In bilateral trading reporting by Platts, Entergy volumes averaged 1,000 MW, peaking at 3,000 MW on May 24; Florida volumes averaged 50 MW, peaking at 50 MW on August 19; Southern volumes averaged 721 MW, peaking at 1,800 MW on August 19; TVA volumes averaged 438 MW, peaking at 600 MW for August 4; and VACAR volumes were not reported by Platts for 2004.

Prices in the Southeast were stable in 2004, which is typical for the region. Two factors contributed to this: first, there was a general level of generation overbuild, minimizing supply constraints. Second, the generation mix in the region has a high proportion of coal and nuclear plants, which have lower fuel price volatility than gas-fired units.

The pricing basis differential between the adjacent Southern SERC subregion and the FRCC region of peninsular Florida averaged $8.39 in 2004. The regions' generation plant mix differs—86% of the output is from coal and nuclear in Southern, and 48% in the FRCC.[3] Limited transmission interconnection between the regions tends to prevent the local prices in the areas from converging.

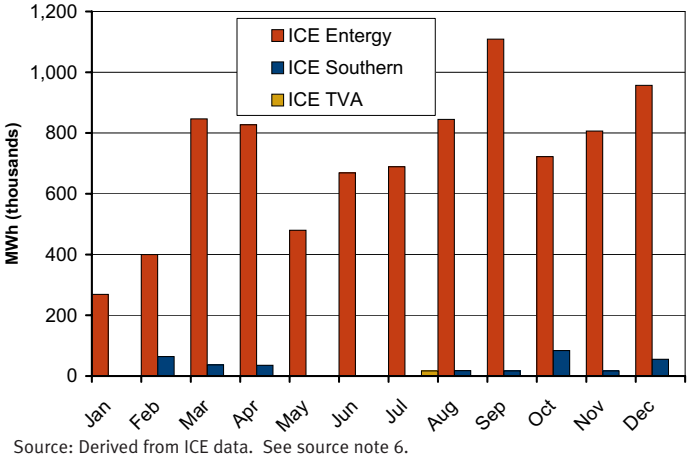
FINANCIAL MARKETS: PRICES AND VOLUMES

Entergy Forward Prices from Trade Date



Source: Derived from ICE data. See source note 6.

Southeast Forward Volume



Source: Derived from ICE data. See source note 6.

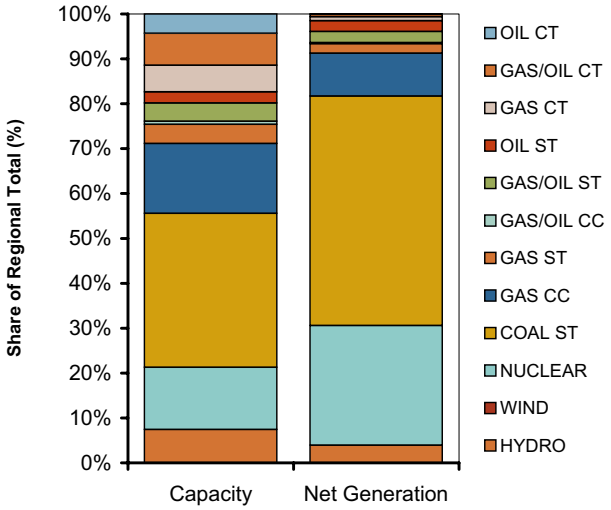
In the Southeast, financial markets consist of physical forwards. ICE clears physical trading into Entergy, Southern, and TVA.

Entergy is the most actively traded Southeastern product on ICE.

For 2004, Entergy trading was highest for the third quarter. At the end of the year, trading of the fourth quarter products was more than 60% higher than for the first quarter.

2003 RESOURCE MIX

Capacity and Generation by Fuel and Prime Mover



Source: Derived from Platts data. See source note 7.

In 2003, nuclear and coal totaled 48% of total Southeast capacity and provided 78% of net generation. The region depends on natural gas for intermediate and peak loads with gas-fired combined cycle capacity that provided 16% of the capacity in 2003 and contributed 10% of annual net generation.

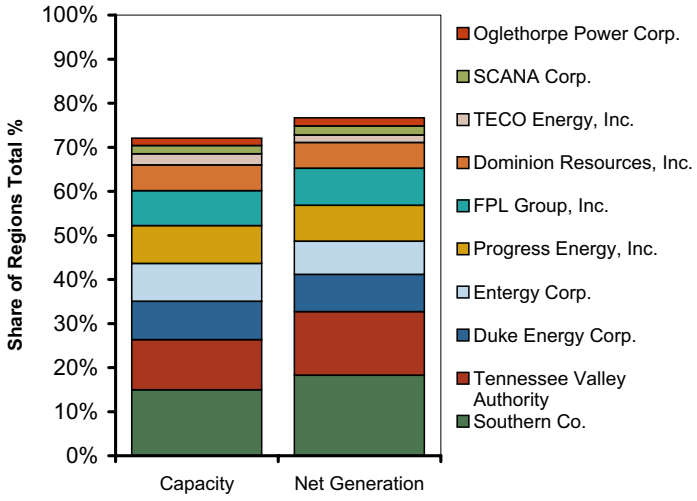
Within the Southeast, the resource mix varies between NERC regions and subregions. The FRCC has a much greater utilization of gas and oil than the rest of the Southeast and is notable as the only area where oil is significantly employed. Gas is the marginal fuel in almost all hours in the FRCC. Within SERC, the Southern subregion generates over 85% of electricity from baseload coal and nuclear plants, yet still has gas as the marginal fuel more than 50% of the time. The Entergy subregion uses gas to a much greater extent than the regional average; it is the marginal fuel more than 70% of the time. The TVA subregion has a significant amount of hydro capacity and output, and very little dependence on gas. The VACAR subregion has the highest utilization of nuclear generation in the Southeast: 94% of its output was from baseload coal and nuclear facilities.[4]

2003 MARKET CONCENTRATION

The top 10 owners provided 72% of capacity and 77% of generation in the Southeast in 2003. All of the top 10 generation owners in the Southeast are regional utilities, their affiliates, or large municipals and cooperatives; the largest independent power producer in the region owns less than 2% of Southeast capacity.

In 2004, capacity concentration remained virtually unchanged from 2003; however, there were several large asset sales to financial firms. Duke Energy North America, Duke's merchant generation company, sold a pool of 8 plants with 5,325 MW of capacity to MatlinPaterson. Goldman Sachs purchased Cogentrix, with 3,300 MW of capacity, and other plants were purchased by AIG and Bear Stearns. In total, these transactions represent approximately 4% of the region's capacity.

Capacity and Generation of Top 10 Companies



Source: Derived from Platts data. See source note 7.

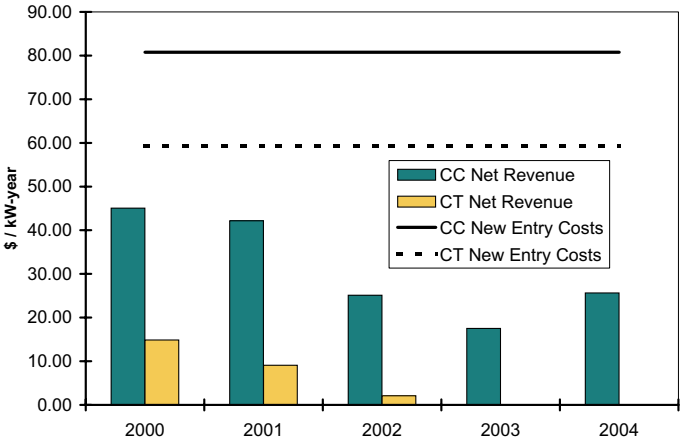
The top 10 major utilities supported 88% of peak load and 60% of total retail sales in the region. Many of the largest suppliers of retail load in the Southeast are also the largest owners of generation and cover much of their load through self-supply. Tennessee Valley Authority, a federal power authority, is the primary source of generation and transmission services in the TVA subregion. The Authority provides wholesale power to 158 municipal and cooperative power distributors, and direct service to 62 large industries and government installations. In the TVA area, the Authority operates 80% of the generation capacity, which produced 92% of the subregion's electrical output in 2003. The Tennessee Valley Authority, Georgia Transmission Corp., and Oglethorpe Power include sales-for-resale to municipal and cooperative power distributors in their peak load calculations, but these values are not included in their retail sales figures.

NET REVENUE

Annual net energy revenue for gas-fired technologies in 2004 were below the five-year average for the third consecutive year. Annual net energy revenue for a combined cycle increased 46% from 2003. For a combustion turbine, energy revenue reached a five-year low, declining from $14.86/kW-year in 2000 to $0/kW-year in 2004.

We estimate that new gas-fired combustion turbine plants in the Southeast require $59.35/kW-yr, and gas-fired combined cycle plants require $80.75/kW-yr, to meet debt and equity requirements. Southeast 2004 net energy revenue estimates are well below this threshold, which suggests that market-based investments in new generation were not attractive.

Southern Net Revenue from Energy



Source: Derived from Platts day-ahead prices for Transco 85 and day-ahead power prices for Southern. See "Analytic Note on Net Revenue Calculations" in the Other Material section for details.

Southeast Merchant Generation Sector Struggles with Overcapacity

The SERC region experienced a dramatic wave of merchant generation construction from 1999 to 2003. Almost all of the plants were gas-fired and in most cases built without the surety of a specific customer or a contractual sales agreement. Those not included as a network resource or contracted to receive firm point-to-point transmission service were designated "noncommitted" by the regional grid coordinator and were not included in the official EIA-411 Capacity calculations—even though these units often participate in the spot market. When included in the overall regional supply calculations, the SERC had a capacity margin that exceeded 40% in the summer of 2004.

A significant portion of these units remain idle or underused several years after completion and their financial outlook remains difficult. Several factors have contributed to this: the demand for electricity will take many years before it reaches the level of overbuild, these gas-fired plants cannot compete with the large base of coal- and nuclear-fueled plants in the region, and, in many cases, these facilities have had problems accessing the transmission grid to sell their output.

At year-end 2004, almost 19,000 MW of new generation had signed or filed agreements to connect to the SERC transmission system within the next 5 years. For the entire Southeast, including both the SERC and FRCC, the 2004 reserve margin was expected to increase slightly from 2003 as supply additions outpaced demand growth.[5]

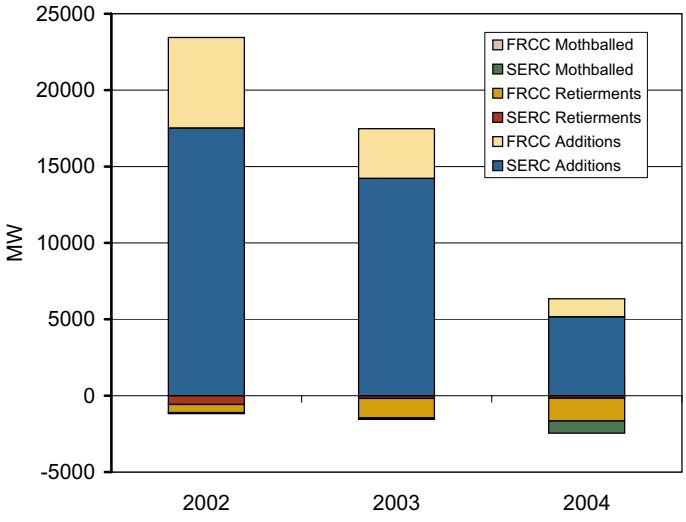
GENERATION AND TRANSMISSION ADDITIONS AND RETIREMENTS

In 2004, 6,342 MW of generation were added (all gas-fired except 55 MW) and 2,546 MW were retired or mothballed. Thirteen new transmission projects were connected in the Southeast region.[6]

Generation Additions: In the Southeast/Florida region, 16 generation projects came on line with a total cost of about $3.5 billion. The largest was the 900 MW Tenaska Virginia Generation Station, an independent power producer (IPP) plant in central Virginia. Bayside and Osprey Energy Center are new plants in Florida's FRCC region (1,182 MW). The remaining plants are in the SERC region. One of the few wind plants to come on line in 2004 was an 18 MW expansion of the Buffalo Mountain Wind project in Tennessee. The level of capacity additions in 2004 declined from the previous two years. There were two generation retirements in FRCC: the Gannon Plant, a 1,171 MW coal facility, and the Brandy Branch Generating Facility, a 317 MW natural gas facility. In SERC, 172 MW of generation retired, 85 MW of which was mobile cogeneration units. In SERC, 801 MW of capacity was mothballed, of which 726 MW were at Reliant Energy's Choctaw County facility.[7]

Transmission Additions: In 2004, 11 transmission projects were completed and an additional 2 were scheduled to be completed in the Southeast region, representing about 149 miles of new lines. The longest was a 31-mile line west of Atlanta in the Georgia Power territory (Yellow Dirt to Hickory Level). Florida Power and Light had six projects, totaling 74 miles in length. Significant areas of constraint remain at the SERC-FRCC interface, in the greater Atlanta area and in southwest Louisiana. There are 16 projects totaling 248 miles scheduled to become active in SERC in 2005 and one 54-mile line in the FRCC.[8]

Capacity Additions



Source: Derived from EIA form 860 and Platts (summer capacity).

Florida Generation Resource Mix at a Crossroad

In 1973, oil-fired plants constituted 55% of Florida's generation mix, and the foreign embargo that year caused oil prices to quickly triple. The economics of oil plants were severely affected, and Florida's utilities began to change their resource planning to reach a more balanced generation mix. By 2004, the generation mix became more diversified, with coal units accounting for 32% of output, "gas only" plants 29%, nuclear 16%, gas/oil dual fuel 13%, and "oil only" 9%. However, the state's utilities' planning documents forecast a return to an imbalanced mix, with natural gas-fired generation rising to more than half the output over ten years.

According to a study by the Florida Public Service Commission's (PSC) Economic Division, the state's anticipated reliance on gas generation may force the utilities to again reconsider their plans. Recent price increases and supply insecurity are sources of concern regarding gas, despite potential new capacity from proposed LNG facilities and increased use of the Gulfstream pipeline. However, the Florida utilities don't have many easy alternatives and the study's outlook on other technologies highlights these concerns. Nuclear power plants are not currently an option. Florida has few potential renewable resources, with no significant capability for hydro or wind generation, and prospects for immediate development of landfill gas and solar installations also are substantially limited. The question facing planners is: Do they continue down the current path or is it time to change strategy again?

The PSC report suggests coal as a possible answer, despite high capital costs, emissions, and siting problems. An example of one facility is the Orlando Utilities Commission's announced plans to build a 285 MW advanced coal gasification facility in central Florida, in partnership with Southern Company, which will cost $557 million. This facility is part of the U.S. Department of Energy's Clean Coal Power Initiative and is to receive $235 million of federal funding. FPL is also considering use of clean coal technology as it looks to meet its future development needs.[9]

Subregional Capacity and Generation

		Coal	Nuclear	Hydro	Gas - CC	Gas - Steam	Oil/Gas - Steam	Oil - Steam	CT - all fuel	Hours of 'Gas on Margin'
FRCC	Capacity	23%	8%	0%	24%	1%	12%	9%	23%	Over 90%
	Net Gen	32%	16%	0%	28%	0%	11%	9%	3%	
Southern	Capacity	41%	9%	9%	18%	1%	0%	2%	20%	50% to 70%
	Net Gen	67%	19%	4%	7%	1%	0%	2%	1%	
Entergy	Capacity	19%	11%	1%	28%	22%	10%	1%	8%	70% to 90%
	Net Gen	35%	28%	1%	17%	13%	3%	1%	2%	
TVA	Capacity	42%	18%	17%	8%	0%	0%	0%	14%	25% to 50%
	Net Gen	59%	26%	14%	1%	0%	0%	0%	0%	
VACAR	Capacity	42%	22%	11%	4%	0%	0%	1%	19%	25% to 50%
	Net Gen	54%	40%	2%	1%	0%	0%	1%	1%	
Total Southeast	**Capacity**	**35%**	**14%**	**7%**	**16%**	**4%**	**4%**	**2%**	**17%**	
	Net Gen	**51%**	**27%**	**4%**	**10%**	**2%**	**2%**	**2%**	**1%**	

Source: Derived from Platts and CERA. See source note 8.

Endnotes

[1] Southeastern Electric Reliability Council, Reliability Review Committee, 2004 Report to the SERC Engineering Committee, Information Summary, August 2004.

[2] SERC, "SERC Generation & Transmission Development Survey Results" presentation to the SERC Spring 2005 Joint Meeting, March 10, 2005.

[3] POWERdat, System Version 8.0.3, Release Date, September 22, 2004; Data Version 8.1.0804, January 2005.

[4] CERA, "Company Structure Reflecting the Hybrid Industry Landscape," Figure 13.

[5] SERC, Reliability Review Subcommittee, 2004 Report to the SERC Engineering Committee, June 2004.

[6] Capacity Additions and Retirements are for calendar year 2004, based on Platts and EIA net summer capacity estimates and FERC staff research. They may differ from the Summer Generating Capacity in the Supply Demand Statistics table. Summer Generating Capacity may be projected for the summer peak, may omit some calendar year additions, and may reflect actual demonstrated capacity and deratings.

[7] Platts PowerDat, EIA Form 860, NEWGen as of March 24, 2005. All generation data is in summer capacity unless otherwise indicated.

[8] NERC Energy Supply and Demand database, SERC reliability Review Subcommittee's 2004 report to the SERC Engineering Committee, and FERC analysis. All transmission data is for lines 230 kV and above unless otherwise indicated.

[9] Florida PSC Division of Economic Regulation, A Review of Florida Electric Utility 2004 Ten-Year Site Plans, December 2004, Orlando Utilities Commission website; PowerDat; FERC/OMOI analysis.

Source notes

1. Prices are from Platts *Megawatt Daily* for day-ahead on-peak delivery at the identified pricing locations.

2. Platts *Megawatt Daily* and IntercontinentalExchange (ICE) prices are for day-ahead on-peak delivery at the Entergy Hub.

3. Data are from NERC's 2004 ES&D Database and SERC, "Reliability Review Subcommittee's 2004 Report to the SERC Engineering Committee" (June 2004). Summer generating capacity, summer reserve and summer reserve margin values do not include "Non-committed" generation resources in SERC. Generation capacity excludes all derates of resources and imports.

4. Prices are from Platts *Megawatt Daily* for day-ahead on-peak delivery at the identified pricing locations.

5. Platts Megawatt Daily and IntercontinentalExchange (ICE) prices are for day-ahead on-peak delivery at the Entergy Hub.

6. ICE on-peak forward and swap prices and volumes are for Entergy, Southern and TVA as identified and include monthly, dual monthly, quarterly, and calendar year contracts traded for 2004. Gaps in the December 15, 2004 forward prices are due to insufficient trading volumes.

7. Data from Platts PowerDat, RDI Modeled Production Costs dataset for calendar year 2003 reflecting self-reporting from all utility and nonutility electric power generating facilities with nameplate capacity of 50 MW or more.

8. Data from Platts PowerDat (System Version 8.0.3, release Date September 22, 2004, data version 8.1.0804, January 2005) and from CERA, "Company Structure Reflecting the Hybrid Industry Landscape," April 16, 2006, Figure 13.

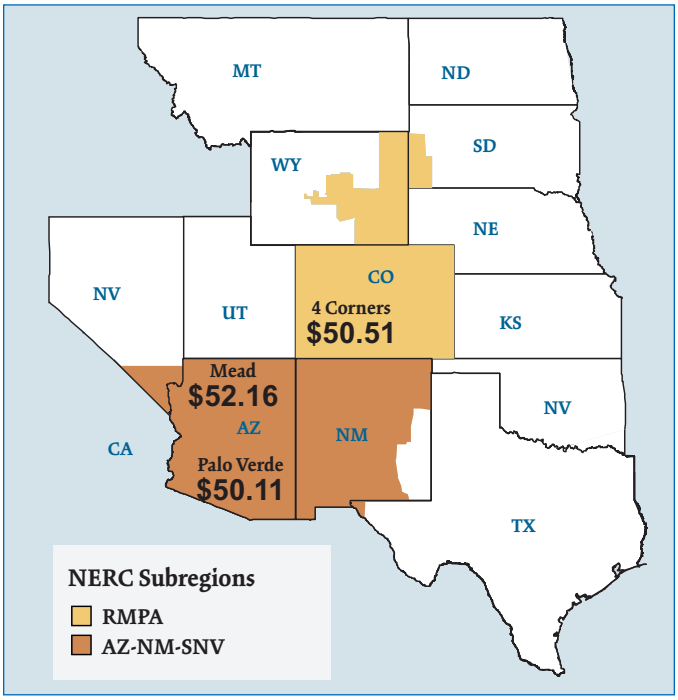
Disclaimer: This report contains analyses, presentations and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Southwest Electric Market Profile

The Southwest electric market encompasses the Arizona-New Mexico-Southern Nevada (AZNMSNV) and the Rocky Mountain Power Area (RMPA) subregions of the Western Electric Coordinating Council (WECC) as designated by the North American Electric Reliability Council (NERC). Twelve control areas dispatch the Southwest electric grid in coordination with the WECC's Rocky Mountain/Desert Southwest Reliability Coordinator. Physical and financial electricity products are actively traded through brokers with the Palo Verde, Four Corners, and Mead hubs as price points. Average 2004 peak prices for the Palo Verde Hub increased 2%–3% over 2003 prices. Average prices for the year were similar at Palo Verde and Four Corners, and slightly higher at Mead. There are no RTO/ISO administered markets in the region.

The region has a surplus of generating capacity, notably in Arizona, where transmission access to California markets is limited (see Palo Verde Transmission Development Lags Generation Growth, below). In 2004, the regional reserve margin increased slightly from 2003 as supply additions outpaced demand growth.

2004 Average Hub Prices for On-peak Hours ($ per MWh)



Source: FERC/OMOI analysis of Dow Jones data. See source note 1.

Palo Verde Hub Prices

	2003	2004	5-Year
Platts	$49.10	$50.09	$70.39
ICE	$49.04	$50.42	NA
Dow Jones	$48.88	$50.11	$68.25

Source: Derived from Platts, IntercontinentalExchange (ICE) and Dow Jones data. See source note 2.

Supply Demand Statistics

	2003	2004	Exp. 2005
Summer Generating Capacity MW	41,646	45,588	45,726
Summer Peak Demand MW	35,815	35,280	37,826
Summer Reserves MW	5,831	10,308	7,900
Summer Reserve Margin	16%	29%	21%
Annual Load GWh	177,401	180,154	187,128

Source: Derived from WECC data. See source note 3.

Focal Points for 2004

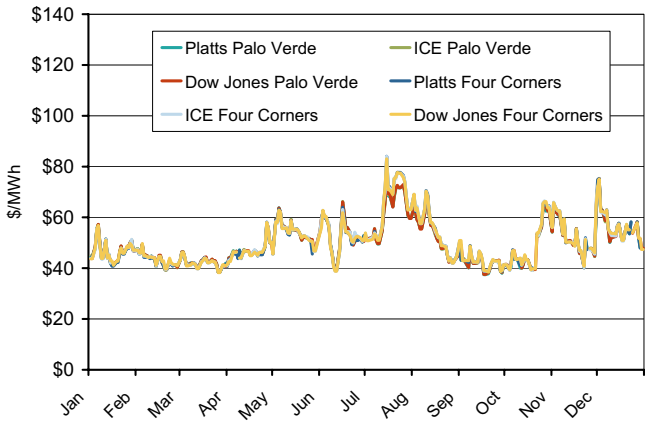
- **Transmission events** in Arizona led to a review of system reliability measures. On June 14, a disturbance on a 230-kV line west of Phoenix tripped several transmission lines near Palo Verde and caused load-shedding in Arizona and surrounding states. More than 4,500 MW of generation, including all three nuclear units at Palo Verde, were lost for periods from a few minutes to a few days. On July 4, a fire at the West Wing substation northwest of Phoenix reduced the city's power supply, forcing conservation during July and August. A July 20 fire near the Deer Valley substation northwest of Phoenix caused local outages. Consulting studies found that the June 14 disturbance weakened a transformer at West Wing, which contributed to the July 4 fire. The studies recommended several system and procedure improvements.

- **Regional transmission planning groups.** Regional utilities, state regulators and agencies, transmission users, owners, operators, and environmental groups have been engaged in coordinated transmission planning. In Arizona, southern California, southern Nevada, and Mexico, the ad hoc Southwest Transmission Expansion Planning Group looked at increasing the transfer capability into California. The Southwest Area Transmission Group (SWAT) worked on transmission project analysis for the Palo Verde and the Four Corners areas. Others involved included the Central Arizona Transmission Study Group and the Colorado Coordinated Planning Group (CCPG), which analyzed new transmission to support proposed generation such as Xcel Energy's coal-fired generation at the Comanche Station in Pueblo.

- **Financial health of utilities.** New projects were slowed by questions about the creditworthiness of regional utilities. Of seven long-term renewable projects intended to start in 2004, financing for five was hampered by prospective lender's skepticism of power purchase agreements with Nevada Power due to the poor financial condition of parent company Sierra Pacific Resources.[1] Southern Nevada depends on imports for more than half of its energy; the remainder is purchased from nonutility or out-of-state resources. Demand continued to grow in southern Nevada.[2]

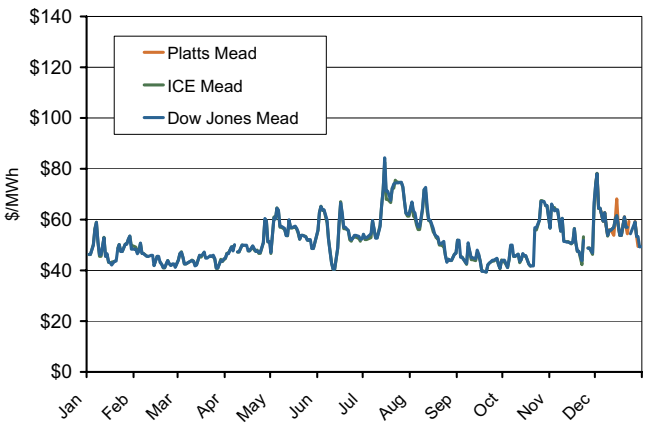
SPOT MARKETS: PRICES AND VOLUMES

Daily Avg of Four Corners and Palo Verde On-Peak Prices



Source: Derived from Platts, ICE, and Dow Jones data. See source note 4.

Daily Average of Mead On-Peak Prices



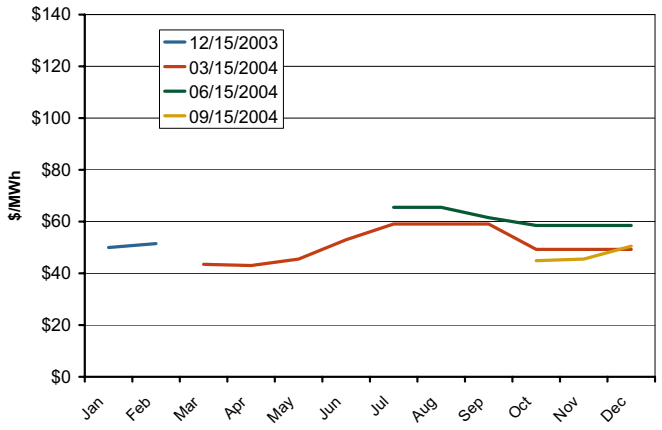
Source: Derived from Platts, ICE, and Dow Jones data. See source note 4.

The figures above illustrate day-ahead peak bilateral prices from Platts, ICE, and Dow Jones for Palo Verde, Four Corners, and Mead trading hubs for peak hours and days. Southwest prices peaked on July 15, from the upper $70s/MWh at Palo Verde to the lower $80s at Four Corners and Mead. The lowest prices occurred in late September and in March. Prices on the IntercontinentalExchange (ICE) for Four Corners were lowest on March 26 and 27, whereas ICE Palo Verde prices were lowest on September 17 and ICE Mead prices were lowest on September 20.

Palo Verde appeared more actively traded than Four Corners or Mead. On ICE, Palo Verde volumes averaged 20,953 MW, peaking at 49,600 MW for December 23 and 24. Four Corners ICE volumes averaged 3,800 MW, peaking at 14,400 MW for May 28 and 29. Mead ICE volume averaged 7,116 MW, peaking at 22,400 MW for December 3 and 4.

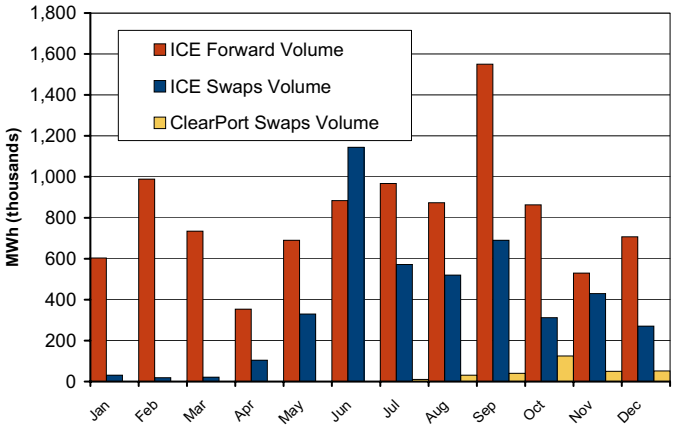
FINANCIAL MARKETS: PRICES AND VOLUMES

Palo Verde Swaps Prices from Trade Date



Source: Derived from ICE data. See source note 5.

Palo Verde Forward and Swaps Volume



Source: Derived from ICE and Nymex data. See source note 5.

For the Southwest, financial markets consist of both physical forwards and financial swaps.

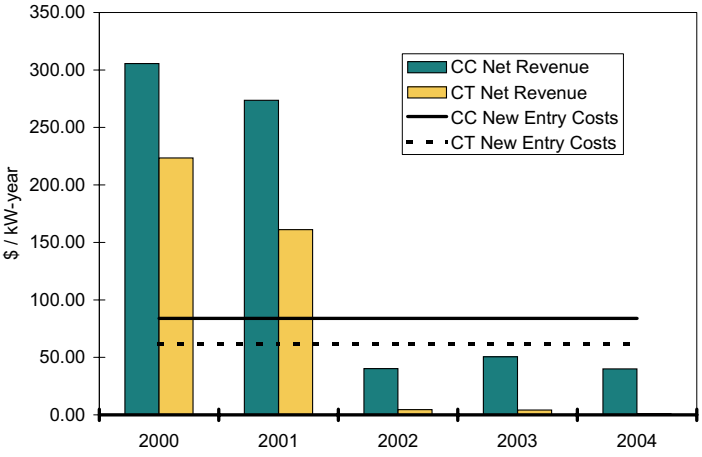
Though ICE financial swap volumes increased in 2004 at Palo Verde, physical trading remained greater. Over the year, ICE physical forwards volumes were more than two times greater than financial swaps volumes. Only in June was ICE swaps trading greater than the physical trading volume.

NET REVENUE

Cumulative annual net revenue from energy for gas-fired technologies in 2004 declined from 2003. For a combined cycle plant, revenue from energy declined 20% from 2003 and 88% from 2000. For a combustion turbine, revenue from energy declined 67% from 2003 and 99% from 2000. See figure this page.

We estimate that new gas-fired combustion turbine plants in the Southwest require $61.52 per kW per year, and gas-fired combined cycle plants require $83.87 per kW per year, to meet debt and equity requirements. The five-year average net revenue estimates for both gas-fired combined cycle and combustion turbine plants exceeded these levels only due to the exceptionally large revenue extracted from high-priced periods during 2000 and 2001. In 2003 and 2004, estimated net revenue for gas-fired combined cycle and combustion turbine plants in the Southwest was below these thresholds, which suggests that market-based investment was not attractive.

Palo Verde Net Revenue from Energy



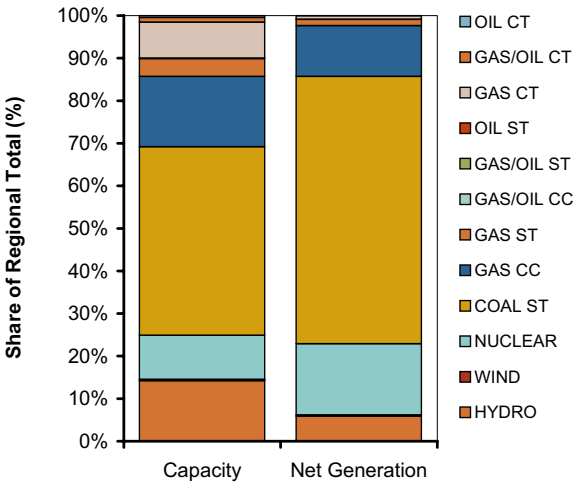
Source: Derived from Platts day-ahead gas prices for Socal Gas Large Packages and day-ahead power prices for the Palo Verde Hub. See "Analytic Note on Net Revenue Calculations" in the Other Material section for details.

Palo Verde Transmission Development Lags Generation Growth

During 2002 and 2003, more than 6,000 MW of new merchant generation was connected to the transmission grid near the Palo Verde Hub in Arizona. By the end of 2003, grid upgrades had increased the maximum power flow from Palo Verde eastward (towards Phoenix) to 6,970 MW from 3,810 MW. The westbound transfer capability of 2,800 MW (from Phoenix into California) has not grown since the new merchant generation was built. Westbound transfer capability was enough to support historical levels of peak hour power exports to California, but not more. The Arizona Corporation Commission (ACC) reported in 2004 that merchant generators may find themselves "stranded at the hub due to transmission limitations into California." At least three proposals for transmission upgrades were under review in 2004: a second transmission line from Palo Verde to the Devers substation in California, a new 500-kV line into San Diego, and a series of short-term upgrades such as new capacitors and transformers. In its transmission assessment, ACC staff raised reliability concerns about the large amounts of generation built near the Palo Verde transmission hub. Noting the extreme (but low probability) transmission disruption that occurred at Palo Verde in 2004 (see major topics discussion above), ACC suggested bolstering transmission standards for future generators built near Palo Verde. [3]

2003 RESOURCE MIX

Capacity and Generation by Fuel and Prime Mover

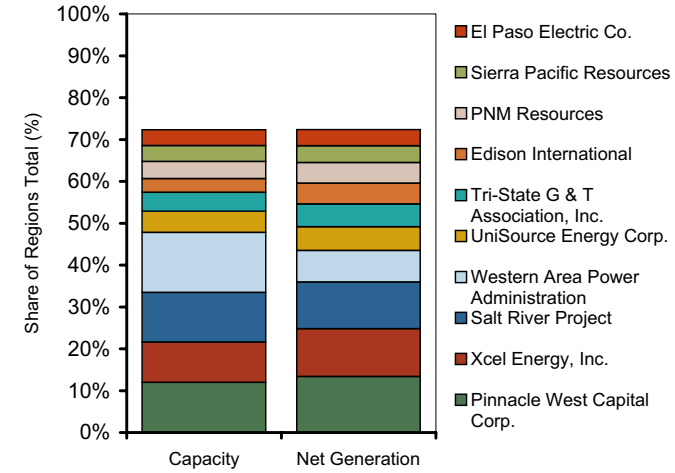


In 2003, hydro, wind, nuclear, and coal totaled 69% of total Southwest capacity and provided 86% of net generation. The region depends on natural gas for intermediate loads. Gas-fired generation provided 29% of the capacity in 2003 and 14% of annual generation.

Source: Derived from Platts data. See source note 6.

2003 MARKET CONCENTRATION

Capacity and Generation of Top 10 Companies



Source: Derived from Platts data. See source note 6.

The top 10 owners provided 72% of capacity and 72% of generation in the Southwest in 2003. All of the top 10 generation owners in the Southwest are regional utilities, their affiliates, or large municipals and cooperatives; the largest independent power producer in the region owns less than 2% of Southwest capacity. The largest suppliers of load in the Southwest are predominantly the largest owners of generation and are able to cover much of their load through self-supply.

In 2004, capacity concentration was reduced slightly as new units at the 1,240-MW Harquahala plant entered service. Although a few generating facilities were transferred to lenders from their independent owners, most notably the 2,200-MW Gila River power station and the Harquahala facility, the transfers had little impact on ownership concentration in 2004.

2003 REGIONAL EXPORTS AND IMPORTS

The Southwest region was a net exporter of electricity with an average of 4,080 MW in 2003. It exported 4,511 MW on average to the California-Mexico subregion, while importing an average of 431 MW from the Northwest subregion and the Southwest Power Pool.

Average Hourly Net Interchange

External Interface	Avg Exports - MW	Avg Imports - MW	Avg Net Exports (Imports) MW
California-Mexico Subregion	4,763	252	4,511
Northwest Subregion	283	455	(172)
Southwest Power Pool	1	260	(259)

Source: Derived from Platts data. See source note 7.

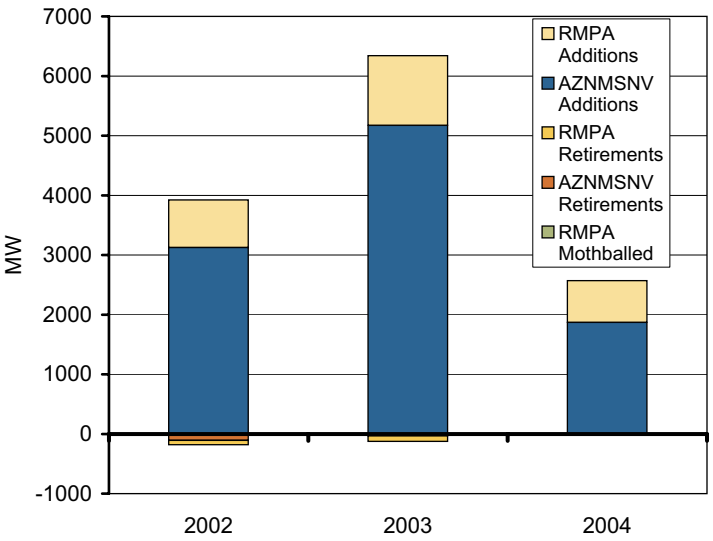
GENERATION AND TRANSMISSION ADDITIONS AND RETIREMENTS

In 2004, 2,570 MW of generation (all gas-fired) and five new transmission projects were added in the Southwest and Rocky Mountain region.[4]

Generation Additions: In the Southwest/Rocky Mountain region, five generation projects came on line and one project that was started in 2003 received an additional two units. The four largest generation additions cost roughly $1.5 billion. In southern Nevada two combustion turbine plants, Silverhawk and Bighorn, came on line. Both Silverhawk and Bighorn are located in Power's Service territory and together provide 1,046 MW of summer capacity. The Rocky Mountain Energy Center, a 516-MW plant, came on line in Xcel Energy's service territory to serve wholesale energy markets in Colorado. Units 2 and 3 at the Harquahala plant came on line, adding another 825 MW of capacity in Arizona. Capacity additions in 2004 were less than in each of the two previous years.[5]

Transmission Additions: Five transmission projects were completed, three in the Southwest and two in the Rocky Mountain region. The largest transmission expansion was Tucson Electric Power Co.'s 31-mile 354-kV line from Winchester, Ariz., to Vail, Ariz., that was completed in June 2004. In the Rocky Mountains, the Lamar, Colo., 210-MW DC tie line connects Xcel Energy's Southwestern Public Service Co. (SPS) in the eastern interconnection with Xcel's Public Service Co. of Colorado system in the west, adding 210 MW of power transfer capability in both directions.

Capacity Additions



Source: Derived from Platts, EIA, and Nevada State Office of Energy and Arizona Corporation Commission (Summer capacity).

The Green Valley-Spruce 230-kV line came on line in May 2004. Six projects are under construction and expected to become active in 2005. Two of these are in the AZNMSNV area, one of which is from Palo Verde to Pinal West (in the Phoenix region). The other four projects are in the Rocky Mountain region.[6]

Increasing Market Power, Arizona Public Service Acquires Local Assets

Arizona Public Service (APS) continued efforts to transfer merchant power plants to its utility rate base. In 2004, APS reached a settlement with intervenors in its proposal to acquire from an affiliated company five Arizona merchant power plants, totaling 1,790 MW. It also announced the intent to purchase the 450 MW Sundance Generating Station from PPL Corporation. The Arizona Corporation Commission (ACC) stated it would address the implications of the asset transfers on competition in workshops to discuss resource planning and acquisition issues.

In its 2003 general rate case filing with the ACC, APS proposed to acquire five merchant plants built by its affiliate, Pinnacle West Energy Corporation (PWEC). The five plants totaled approximately 1,790 MW including the 1,060 MW Redhawk Units 1 and 2, the 650 MW West Phoenix Units 4 and 5, and the 80 MW Saguaro Unit 3. On August 18, 2004, APS entered into a settlement with 21 parties–including ACC staff, customer groups, and merchant generators. Under the settlement, APS would recover $700 million in its rates as the cost for the power plants (a discount of $148 million from book value), issue a request for proposal for an additional 1,000 MW in 2005 to meet electricity demand growth, and not build any power plants that went into service before 2015 (subject to a "safety mechanism" where it must prove to the ACC that it cannot obtain needed resources on acceptable terms in the wholesale market). The third provision, a so-called "self-build moratorium," did not preclude APS from buying generating plants from other, unaffiliated companies.

In November 2003, APS issued a request for proposal for long-term power supply resources and selected PPL Corporation's Sundance offer. In mid-2004, APS said the utility would face a 1,000 MW shortfall in 2007, even after the Sundance acquisition. In June, APS entered a $190 million purchase agreement with PPL and filed an application with the ACC to finance the costs.[7] APS announced its intention to include Sundance acquisition costs in its next rate case, to be filed in late 2005.

Endnotes

[1] Nevada State Office of Energy.

[2] The electric utility for most of southern Nevada, Nevada Power, experienced peak demand growth of 3.3% in 2004 and customer growth of 5%. Sierra Pacific Resources Annual Report 2004, Nevada Power Facts, http//www.nevadapower.com/company/facts.

[3] *Third Biennial Transmission Assessment,* Arizona Corporation Commission, Nov. 30, 2004, 54.

[4] Capacity Additions and Retirements are for calendar year 2004, based on Platts and EIA net summer capacity estimates and FERC staff research. They may differ from the Summer Generating Capacity in the Supply Demand Statistics table. Summer Generating Capacity may be projected for the summer peak, may omit some calendar year additions, and may reflect actual demonstrated capacity and deratings.

[5] Platts PowerDAT, NEWGen as of March 1, 2005; EIA Form 860; 2005 Status of Energy in Nevada Report; ACC *Third Annual Biennial Transmission Assessment*; FERC staff research. Data are for summer capacity unless otherwise indicated.

[6] NERC Electricity Supply & Demand database 2004, updates from NERC as of April 19, 2005; WEstern Electricity Coordinating Council, summary of "10-Year Coordinated Plan," September 2004, which involved the following groups in planning transmission for the Southwest: Southwest Area Transmission Planning group (SWAT), SOuthwest Transmission Expansion Planning (STEP), and Colorado Coordinated Planning Group (CCPG). Data are for new transmission lines 230 kV and above unless otherwise indicated.

[7] Although the costs of Sundance Acquisition were not included in the 2003 general rate case, analysts have noted that a Power Supply Adjustor (PSA) proposed in the rate case may provide APS ability to collect some fuel and purchased power costs related to the purchase agreement before the next general rate case decision.

Source notes

1. Prices are Dow Jones firm day-ahead on-peak prices for the locations identified.
2. Platts Megawatt Daily, IntercontinentalExchange (ICE) and Dow Jones prices are firm day-ahead on-peak for the Palo Verde Hub.
3. Data are from WECC, "Summary of Estimated Loads and Resources," July 2004 and May 2005.
4. Platts Megawatt Daily, ICE and Dow Jones prices are for firm day-ahead on-peak delivery to identified locations.
5. ICE on-peak forward and swap prices and volumes are for Palo Verde and include monthly, dual monthly, quarterly, and calendar year contracts traded for 2004. New York Mercantile Exchange (Nymex) ClearPort on-peak swaps volumes are for Palo Verde and are traded by month.
6. Data from Platts PowerDat, RDI Modeled Production Costs dataset for calendar year 2003 reflecting self-reporting from all utility and nonutility electric power generating facilities with nameplate capacity of 50 MW or more.
7. Average hourly interchange data derived from Platts PowerDat reporting of FERC Form 714 data.

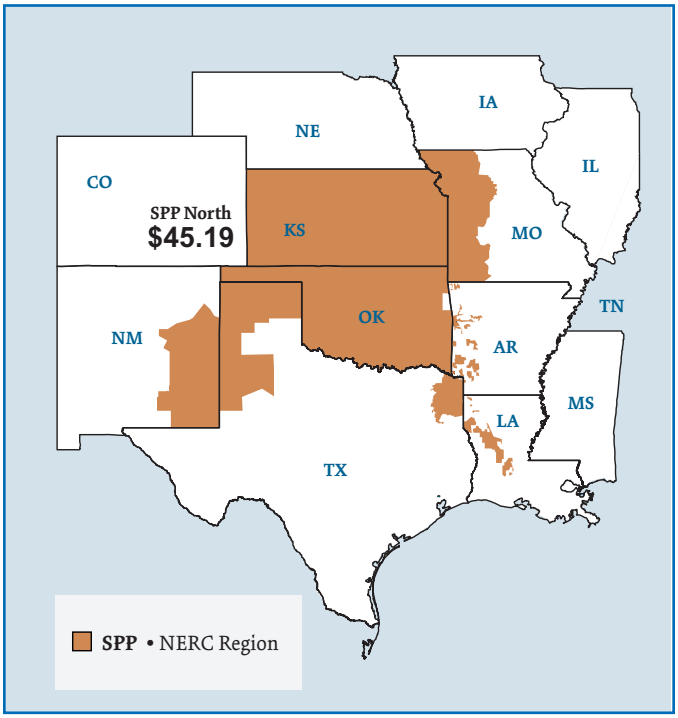
Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Southwest Power Pool (SPP) Electric Market Profile

The Southwest Power Pool (SPP) electric market comprises the SPP reliability region, as designated by the North American Electric Reliability Council (NERC). Working in concert with the region's reliability coordinator, 15 control areas dispatch generation on the SPP electric grid. Market participants also trade physical electricity bilaterally, either directly or through brokers. Average 2004 peak prices were 8% higher than in 2003, according to Platts, which publishes energy figures for an SPP North pricing point.

NERC statistics indicate that the region has adequate capacity reserves.

2004 Average Regional Prices for On-peak Hours ($ per MWh)



Source: Derived from Platts data. See source note 1.

Supply Demand Statistics

	2003	2004	Exp. 2005
Summer Generating Capacity MW	45,929	45,242	45,937
Summer Peak Demand MW	40,214	39,893	40,906
Summer Reserves MW	5,715	5,349	5,031
Summer Reserve Margin	21%	20%	19%
Annual Load GWh	185,574	191,829	194,180

Source: Derived from SPP data. See source note 2.

SPP North Prices

	2003	2004	5-Year
Platts	$41.66	$45.19	$38.70

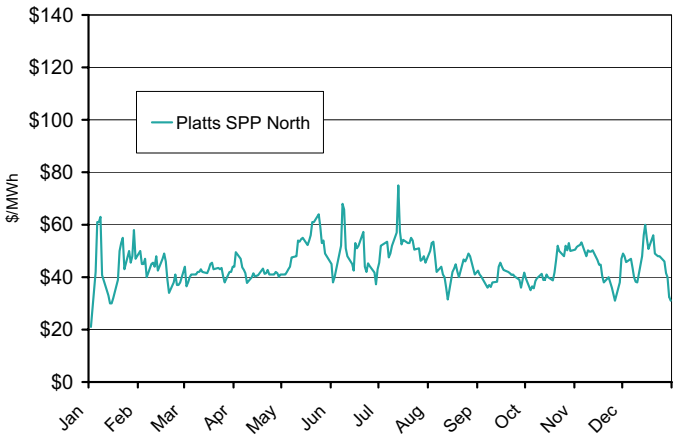
Source: Derived from Platts data. See source note 1.

Focal Points for 2004

- **Work continues** on the SPP regional transmission organization (RTO), approved by FERC on October 1, 2004. SPP has completed its market design and protocols, along with the system design. Market applications are being worked on. SPP is set to file a new tariff with FERC in June 2005 and plans to go live March 1, 2006.
- **Gearing for a push.** SPP named a new CEO, Nick Brown, in February 2004 and seated an independent (all nonstakeholder) board in May. SPP also hired 27 people, boosting the staff to 131. SPP doubled its assets in 2004 by floating $25 million in senior notes.
- **Locational price signals** could spur transmission investment in the region. SPP control areas called 317 transmission loading relief (TLR) events level 3 or above in 2004. Eleven of these TLRs reached level 5, which led to curtailment of firm point-to-point and network transmission service and suggests that several significant constrained flowgates exist in SPP. Better locational price information and enhanced regional planning through the RTO and Regional State Committee is expected to encourage transmission investment.

SPOT MARKETS: PRICES AND VOLUMES

Daily Average of On-Peak Prices



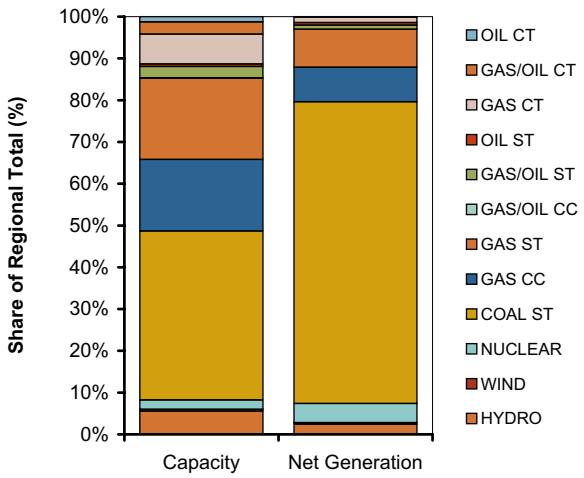
Source: Derived from Platts data. See source note 1.

Day-ahead peak bilateral prices peaked on July 13 at $75 per MWh, as forecast temperatures were expected to break 100 degrees in Oklahoma and the mid-90s in many areas throughout the region, according to figures drawn from Platts *Megawatt Daily*. Prices were lowest on January 2, at $21 per MWh, as temperatures were unseasonably warm for that period. No major pricing events occurred in SPP in 2004.

Platts SPP North pricing point is not actually traded. Platts reported only one day, October 29, with bilateral trading volume. The SPP North Hub does not appear as the pricing location for any transactions reported to FERC in the Electric Quarterly Report in 2004.

2003 RESOURCE MIX AND IMPORTS

Capacity and Generation by Fuel and Prime Mover



Source: Derived from Platts data. See source note 3.

In 2003, hydro, wind, nuclear, and coal totaled 49% of total SPP capacity and provided 80% of net generation. The region depends on gas-fired, combined-cycle capacity to meet intermediate and peak loads, providing 17% of the capacity in 2003 and contributing 8% of annual net generation.

SPP is interconnected with ERCOT, WECC, SERC, MAPP and MAIN and was a net importer of energy in 2004.

Average Hourly Net Interchange

Avg. Exports MW	Avg. Imports MW	Avg. Net Exports(Imports)
2,200	4,958	(2,758)

Source: Derived from SPP data.

SPP Regional State Committee Hits the Ground Running in 2004

The SPP Regional State Committee (RSC) was formed in April 2004 to provide input from state regulators on regional issues. The committee, which is funded by the SPP, is made up of public utility commissioners from Arkansas, Kansas, Missouri, Texas, and Oklahoma. A member from New Mexico resigned based on concerns of his state's Attorney General. The chairman of the RSC is Denise Bode, who also chaired the Oklahoma Corporation Commission.

The costs and benefits of SPP's transition to a regional transmission organization, including implementation of an imbalance market, have been studied by a working group of RSC staff and SPP stakeholders. They also looked at ways to make cost-benefit regulatory filings by SPP utilities easier. A final report was completed in May 2005.

In addition, an RSC working group developed options for allocating the costs of transmission upgrades for designated resources. A funding policy they recommended was adopted by the SPP board in January 2005. The new policy allocates 33% of base plan upgrade costs to region-wide transmission rates. The remainder is recovered in zonal rates for areas benefiting from the upgrade. SPP filed tariff revisions to implement the transmission cost allocation policy with FERC on February 28, 2005.[1] The commission approved the policy in May 2005.

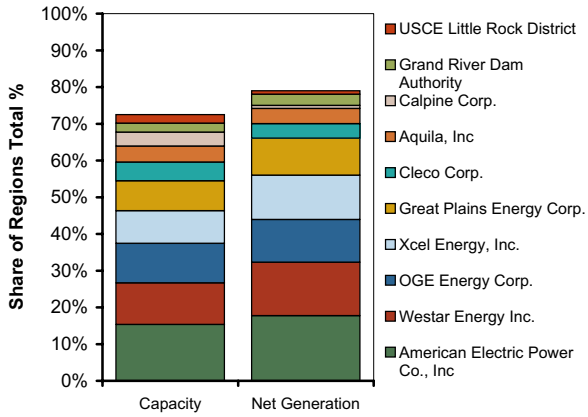
2003 MARKET CONCENTRATION

The top ten owners provided 73% of capacity and 79% of generation in SPP in 2003. Nine of the top ten generation owners in SPP were regional utilities, their affiliates, or large municipals and cooperatives. In 2004, capacity concentration changed little because very few plants were added or retired.

The largest load-serving entities in SPP were also the largest owners of generation and covered much of their load through self-supply.

Source: Derived from Platts data. See source note 3.

Capacity and Generation of Top 10 Companies



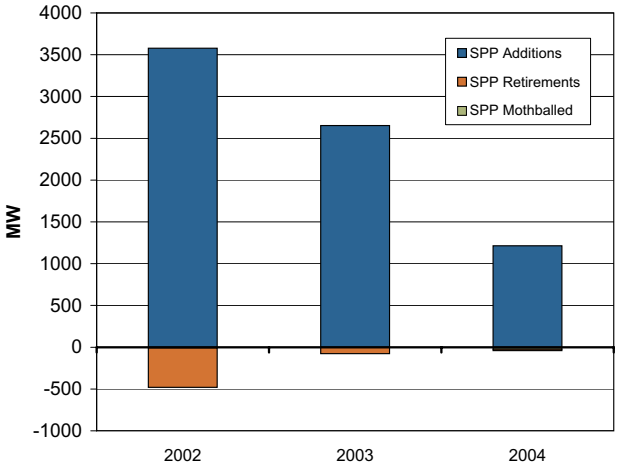
GENERATION AND TRANSMISSION ADDITIONS AND RETIREMENTS

Generation Additions. Three generation projects, totaling 1,214 MW of capacity, came on line in SPP. The largest is the 1,144 MW natural gas Redbud Power Plant, which cost about $856 million to build. The other plants are a 60 MW wind project and a 10 MW oil plant. The capacity additions in 2004 were fewer than in the two previous years. Twenty-three MW of generation were mothballed and 20 MW retired.[2]

Fifteen projects in SPP totaling 1,155 MW were under construction or development and expected to be on line between 2005 and 2007. About 1,060 MW of wind projects were due to be completed in 2005. The remaining capacity additions are gas-fired.

Transmission Additions. Two new transmission projects, totaling 131 miles, were completed in 2004. Both projects were built by Southwestern Public Service Co.[3]

Capacity Additions



Source: Derived from EIA and Platts data. See source note 4.

Wind Power Developers Find SPP Fertile Ground

SPP had 432 MW of wind capacity operating in 2004. Most of the capacity came on line in the last three years. FPL Energy Inc. is the largest owner and operator, with 214 MW. The developers of other major wind farms are Cielo Wind Power, LLC (140 MW) and Zilkha Renewable Energy (74 MW). Aquila, Oklahoma Municipal Power Authority, Southwestern Public Service, and Western Farmers Electric Cooperative have signed power purchase agreements to buy power from these wind farms. In November 2004, Public Service of Oklahoma (PSO) and sister company Southwestern Electric Power issued a solicitation for up to 250 MW of renewable resources.

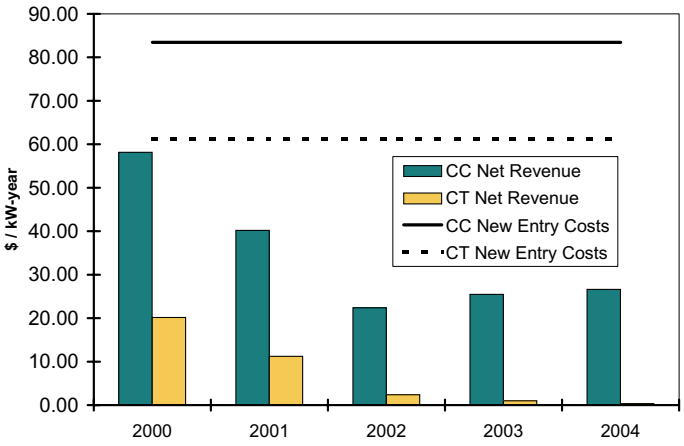
In 2005, wind generating capacity in SPP is expected to triple. FPL Energy Inc. is adding 107 MW, while Cielo Wind Power LLC will add an additional 180 MW, and Zilkha Renewable Energy is building 120 MW. Newcomers include Great Plains Windpower LLC (320 MW), Elk River Windfarm LLC (150 MW), Chermac Energy Group (137 MW), Padoma Wind Power LLC (120 MW), enXco Inc. (100 MW), Central Plains Power LLC (100 MW), and Grand Vent Wind Systems (50 MW). Southwestern Public Service leads the list of utilities signing power purchase agreements with projects coming on line in 2005, with 360 MW. Other major buyers of wind power are Westar in Kansas (200 MW), Empire District Electric in Missouri (150 MW), and Kansas City Power & Light in Missouri (100 MW). By the end of the year, American Electric Power's subsidiary, Public Service of Oklahoma, is expected to be the largest buyer of wind power in Oklahoma, with 227 MW under 10- and 20-year contracts.[4]

NET REVENUE

Annual net revenues from energy for gas-fired technologies were below the five-year average for the third consecutive year. For a combined cycle, revenues from energy increased 4% from 2003 and 54% from 2000. For a combustion turbine, revenues from energy declined 67% from 2003 and 98% from 2000.

We estimate that new gas-fired, combustion-turbine plants in SPP require $61.21/kW-yr, and gas-fired, combined-cycle plants require $83.43/kW-yr, to meet debt and equity requirements. SPP 2004 net energy revenue estimates were well below these thresholds. This suggests that market-based investments in new generation were not attractive.

SPP Net Revenue from Energy



Source: FERC/OMOI analysis of Platts day-ahead gas parices for NGPL (Midcont.) and day-ahead power prices for SPP. See "Analytic Note on Net Revenue Calculations" in the Other Material section for details.

Endnotes

[1] SPP, SPP Regional State Committee minutes, SPP Filing in ER05-652, February, 28, 2005.

[2] Platts PowerDAT, NewGen as of March 1, 2005, EIA Form 860. Data are for summer capacity unless otherwise indicated. Capacity Additions and Retirements are for calendar year 2004, based on Platts and EIA net summer capacity estimates and FERC staff research. They may differ from the Summer Generating Capacity in the Supply Demand Statistics table. Summer Generating Capacity may be projected for the summer peak, may omit some calendar year additions, and may reflect actual demonstrated capacity and deratings.

[3] NERC ES&D Database 2004; Updates from NERC as of April 19, 2005. Transmission data are for new transmission lines 230kV and above unless otherwise indicated.

[4] Platts NewGen, Amercian Wind Energy Association, *Megawatt Daily* March 8, 2005.

Source notes

1. Prices are from Platts *Megawatt Daily* for day-ahead on-peak delivery at the identified pricing locations.

2. Data are from NERC's 2004 ES&D Database and Platts PowerDat (annual net generation). Generation capacity excludes all derates of resources and imports.

3. Data from Platts PowerDat, RDI Modeled Production Costs dataset for calendar year 2003 reflecting self-reporting from all utility and nonutility electric power generating facilities with nameplate capacity of 50 MW or more.

4. Data from Energy Information Administration (EIA) Form 860, Platts NewGen and Platts PowerDat. All generation is summer capacity unless otherwise indicated.

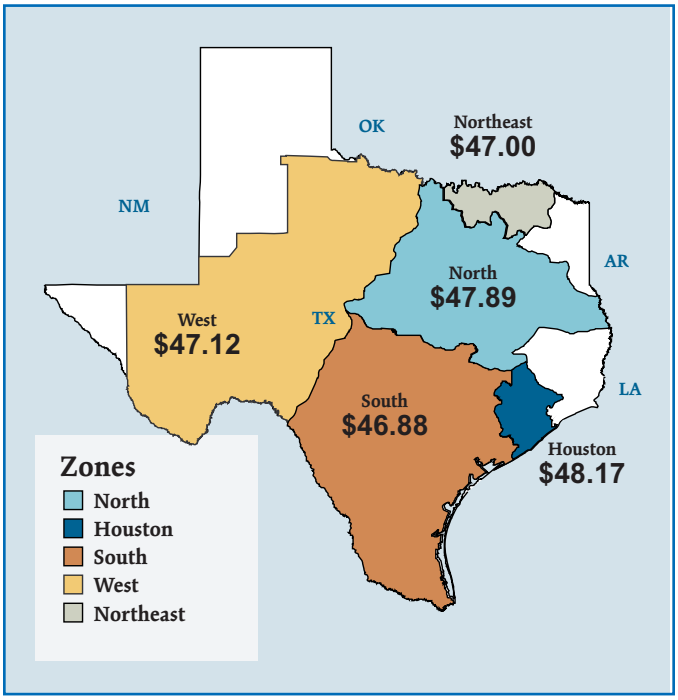
Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Texas (ERCOT) Electric Market Profile

The Energy Reliability Council of Texas (ERCOT), as designated by the North American Electric Reliability Council (NERC), constitutes the ERCOT electric market. In 2002, ERCOT expanded its role of central dispatch within a single control area, ensuring transmission reliability and open wholesale access, to oversee the ongoing restructuring of the Texas electric industry—including the development and operation of most of the Texas competitive retail market. ERCOT runs balancing energy and ancillary service markets with zonal congestion management. Market participants trade electricity bilaterally either directly or through brokers and the IntercontinentalExchange (ICE), generally using the ERCOT Hub as the pricing point. Average 2004 peak prices for the ERCOT zones have changed little from 2003.

The region currently has excess capacity. In 2004, the regional reserve margin increased from 2003 as new plants entered commercial operation. Several companies are seeking permission from ERCOT to retire older, inefficient generating plants. The small differences in average zonal prices indicate some congestion among zones. What is not shown is much more significant intra-zonal congestion.

2004 Average Zonal Prices for On-Peak Hours ($ per MWh)



Source: Derived from ERCOT data. See source note 1.

ERCOT Prices

	2003	2004	5-Year
Platts	$46.49	$47.32	$41.08
ICE	$46.78	$47.55	NA
ERCOT North	$48.16	$47.89	NA

Source: Derived from ERCOT, Platts and IntercontinentalExchange (ICE) data. See source note 2.

Supply Demand Statistics

	2003	2004	Exp. 2005
Summer Generating Capacity MW	73,882	73,855	70,639
Summer Peak Demand MW	59,996	58,531	59,702
Summer Reserves MW	13,886	15,324	10,937
Summer Reserve Margin	23%	26%	18%
Annual Load GWh	283,868	289,146	294,928

Source: Derived from ERCOT and NERC data. See source note 3.

Focal Points for 2004

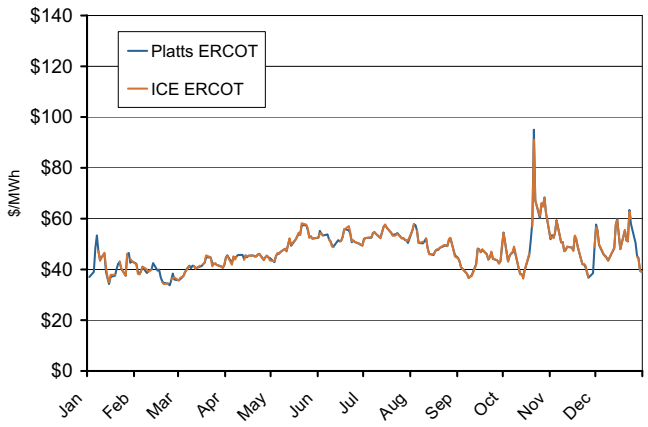
- **Competitive electricity markets** in Texas are maturing. The Public Utility Commission of Texas (PUCT) described the current state of electric market competition in a statutorily mandated biannual report to the Texas legislature. The PUCT claimed that Texas has the most robust, well-functioning retail market in the United States. Texas has seen healthy investment in new generation and entry of retail providers offering electricity at competitive prices. The report noted that electricity prices have increased because of higher natural gas prices.

- **An independent market monitor** for the ERCOT market was proposed by the PUCT in June, but dropped from a final rule issued in December 2004 because the issue was expected to be taken up by the Texas Legislature in its current session. A Senate bill laying out provisions for developing an independent market monitor for ERCOT passed the Texas Senate on April 14, 2005.

- **PUCT is investigating** bidding practices after off-peak prices jumped to $400/MWh on November 29, 2004. TXU Corp. is the subject of several investigations and lawsuits about its marketing practices and bidding in ERCOT's balancing energy market. Texas Commercial Energy, a retail electric supplier, sued, claiming that TXU and other suppliers drove up prices during severely cold weather in February 2003, bankrupting the company. An interim report of the Market Oversight Division of the Public Utility Commission of Texas (PUCT) did not find evidence of wrongdoing. The inquiry remains open. In a related development, two Texas retail providers sued several electricity suppliers in February 2005, alleging price fixing and collusion.

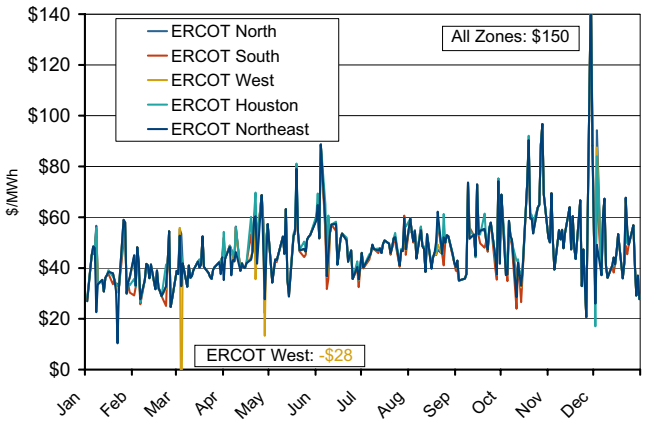
SPOT MARKETS: PRICES AND VOLUMES

Daily Average of On-Peak Prices



Source: Derived from Platts and ICE data. See source note 4.

Daily Average of Balancing Energy On-Peak Prices



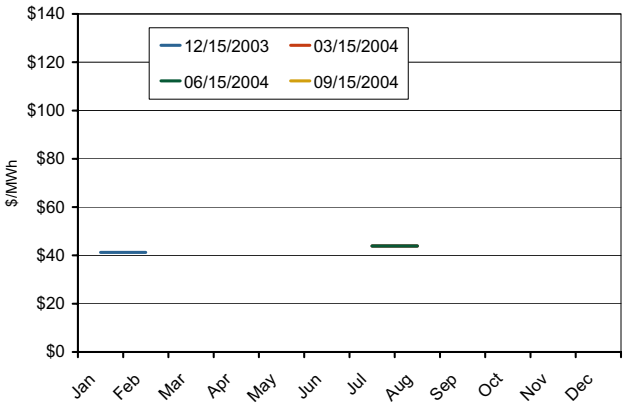
Source: Derived from ERCOT data. See source note 1.

The graphs illustrate day-ahead peak bilateral prices from Platts and ICE as well as ERCOT's real-time balancing energy prices. ERCOT's major 2004 pricing event was on November 29, when 15-minute, on-peak prices rose to almost $140/MWh and off-peak prices jumped to more than $400/MWh. The PUCT initiated an investigation of this price spike, focusing on the bidding behavior of TXU. In early March 2004, congestion on the ERCOT grid prompted operators to re-dispatch generation in the ERCOT west zone. The balancing energy price in the west zone went negative because some generators that were re-dispatched submitted negative-price bids to avoid having their output reduced.

ERCOT reached its 2004 peak hourly load of 58,531 MW on August 3. In 2004, the daily peak-load hours averaged 36,355 MW. In bilateral trading, Platts reported that volume for the ERCOT market averaged 1,794 MW and peaked on July 29 at 4,600 MW; ICE said the trading volume averaged 6,193 MW and peaked on December 10 at 31,200 MW.

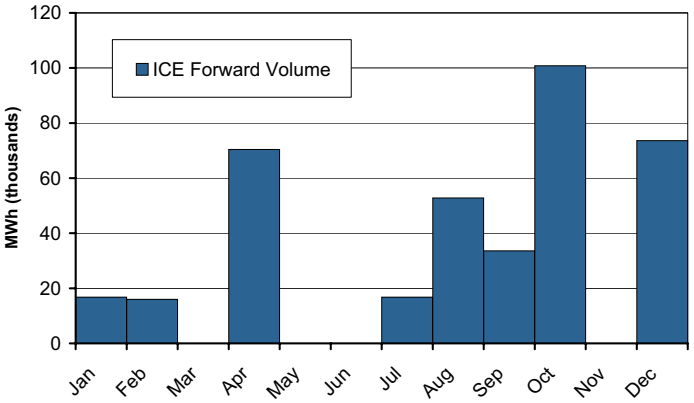
FINANCIAL MARKETS: PRICES AND VOLUMES

Forward Prices from Trade Date



Source: Dervied from ICE data. See source note 5.

Forward Volume

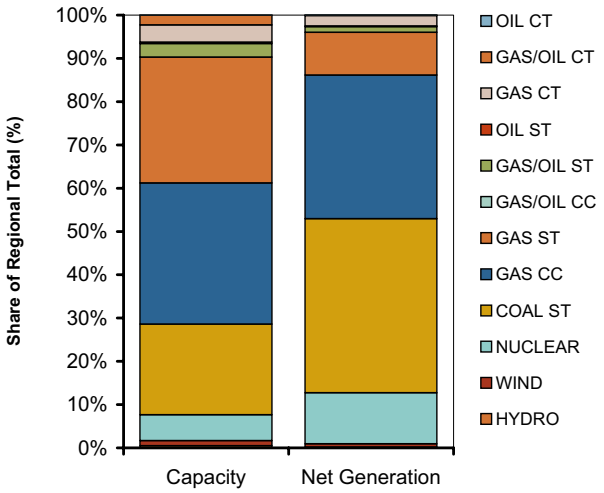


Source: Derived from ICE data. See source note 5.

For ERCOT, financial markets consist of physical forwards. In 2004, trading of ICE ERCOT monthly products amounted to 330 GWh, which was 20% of the 1,475 GWh that was traded on a next-day basis.

2003 RESOURCE MIX

Capacity and Generation by Fuel and Prime Mover

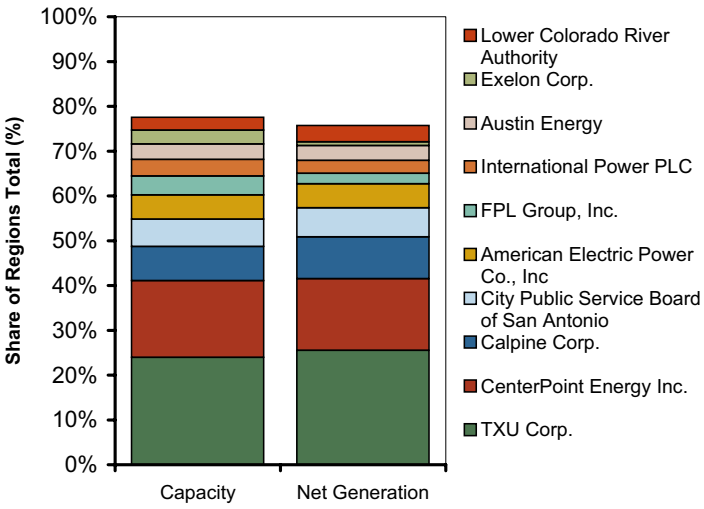


In 2003, hydro, wind, nuclear, and coal represented 29% of total ERCOT capacity and provided 53% of net generation. The region depends on gas-fired capacity to meet intermediate and peak loads, providing 66% of the capacity in 2003 and contributing 45% of annual net generation. The remainder is served by generators that can switch between gas and oil.

Source: Derived from Platts data. See source note 6.

2003 MARKET CONCENTRATION

Capacity and Generation of Top 10 Companies



Source: Derived from Platts data. See source note 6.

As this graph shows, the top 10 owners provided 78% of capacity and 76% of generation in ERCOT in 2003. Six of the top 10 generation owners in ERCOT are regional utilities, their affiliates, or large municipals and cooperatives. The other four are independent power producers or utility affiliates that have built or acquired generating assets outside of their traditional service territories.

Capacity concentration declined in 2004 as a number of asset sales closed. Although some sales were one-asset deals, two large portfolios were transferred to private equity owners. In July, AEP sold the majority of its Texas Central Portfolio to a joint venture of Sempra Energy Partners and Carlyle/Riverstone Global Energy and Power Fund. In December, CenterPoint Energy Inc. sold the majority of its Texas Genco assets to GC Power Acquisition LLC, an entity owned in equal parts by affiliates of The Blackstone Group, Hellman & Friedman LLC, Kohlberg Kravis Roberts & Co. L.P., and Texas Pacific Group. Both AEP and CenterPoint recently received regulatory approval to close the sale of their ownership shares in the South Texas Project Electric Generating Station, which has two nuclear reactors producing 2,500 MW of power.

Offer Mitigation

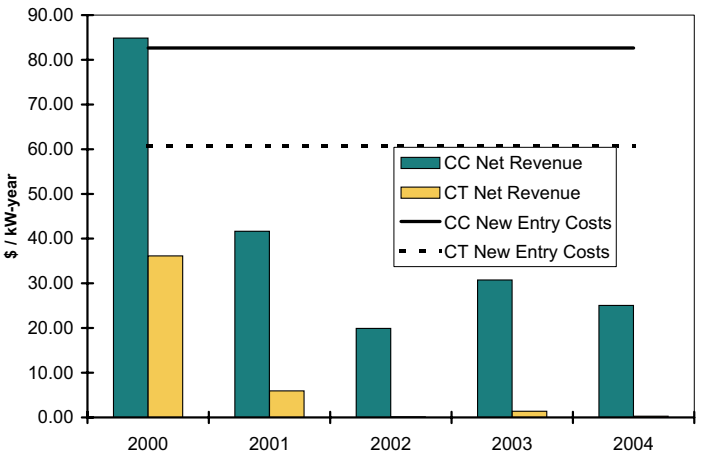
The ERCOT market has a supply offer cap of $1,000/MWh as well as a $1000/MWh cap for ancillary services. Although ERCOT does not mitigate supply offers, the market clearing price for energy is adjusted when balancing energy bids are exhausted, and there is no zonal congestion. The clearing price is recalculated after removing the highest priced 5% of the power in the bid stack. The resulting price is then multiplied by 1.5 to account for scarcity. Suppliers with offers above the adjusted price are paid as bid. The clearing price adjustment occurred infrequently from its inception in June 2003 until fall 2004. Price adjustments have become more frequent since October 2004 because of changes in bidding strategies. This trend is part of the PUCT's ongoing investigation of TXU bidding practices.

NET REVENUE

Estimated annual net revenue from energy for gas-fired technologies in 2004 was below the five-year average for the third consecutive year. For combined-cycle plants, revenue from energy declined 18% from 2003 and 71% from 2000. For combustion turbine plants, revenue from energy declined 81% from 2003 and 99% from 2000.

We estimate that new gas-fired combustion turbine plants in ERCOT require $60.66/kW-year, and gas-fired combined cycle plants require $82.64/kW-year, to meet debt and equity requirements. Estimated ERCOT 2004 net energy revenue did not meet these requirements, which suggests that market-based investments in new generation were not attractive.

ERCOT Net Revenue from Energy



Source: FERC/OMOI analysis of Platts data. See "Analytic Note on Net Revenue Calculations" in the Other Material section for details.

REGIONAL EXPORTS AND IMPORTS

ERCOT is linked with the Southwest Power Pool (SPP) in the Eastern Interconnection by two AC-DC-AC ties, with a total transfer capability of 860 MW. In addition, Tenaska has 1,800 MW of generating capacity that can be electrically connected with either ERCOT or SPP. ERCOT was a net importer of energy in 2004 with average imports of 449 MW over the DC ties with SPP.

Hourly Net Interchange

-External Interface	Max Exports - MW	Max Imports - MW	Avg. Net Exports (Imports) MW
DC ties to SPP	898	755	(449)

Source: Derived from ERCOT data.

Nodal Market Design in the Works

The Texas Nodal Team (TNT) of ERCOT stakeholders spent 2004 developing a major redesign of the wholesale market. In September 2003, the Public Utility Commission of Texas had ordered them to design sweeping wholesale-market revisions.[1] Major enhancements include a day-ahead market, resource-specific (instead of portfolio) bid curves, assignment of congestion cost to specific resources causing congestion, nodal energy prices for resources, zonal energy prices for loads, tradable financial congestion rights, and pricing safeguards. In November 2004, a PUCT-ordered cost-benefit study found potential benefits to market redesign.[2] ERCOT filed a redesign proposal in March 2005.[3] Also in November 2004, an assessment of ERCOT market operations by market adviser Potomac Economics documented inefficiencies in ERCOT's current zonal congestion-management system and real-time operations.[4] The report suggested that the inefficiencies will be significantly reduced and real-time operations improved with a move from a zonal to a nodal system.

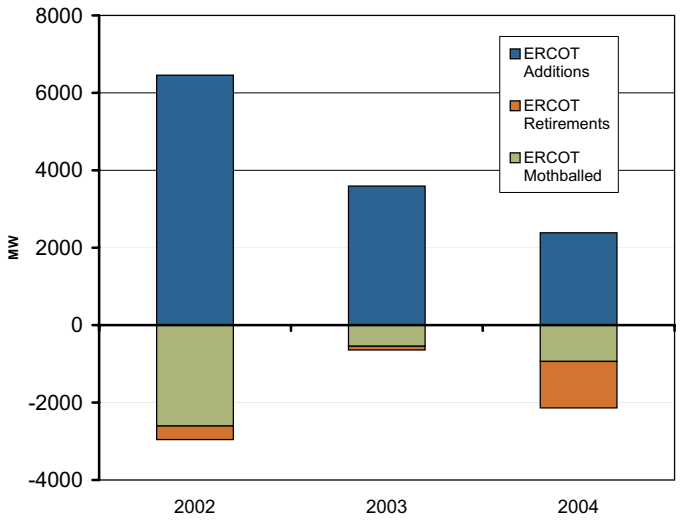
GENERATION AND TRANSMISSION ADDITIONS AND RETIREMENTS

In 2004, ERCOT utilities added 2,358 MW of generating capacity, mothballed 937 MW, and retired 1,204 MW.[5]

Generation Additions. In ERCOT, seven generation projects came on line in 2004. The two largest plants were both independent power producers (IPPs). The Wise County Power plant (675 MW) and the Deer Park Energy Center (568 MW) are both gas-turbine plants. The largest utility plant is San Antonio's Leon Creek gas-turbine plant, with a capacity of 298 MW. The Parkdale plant, a 330-MW natural gas plant owned by TXU, was the largest single retirement. TXU also mothballed 814 MW of generation. Capacity additions in 2004 were less than in the two previous years.

Transmission Additions. ERCOT utilities were expected to add 1,000 circuit miles of transmission lines in 2004. This number includes 158 miles of 345-kV lines, 809 miles of 138-kV lines and 33 miles of 69-kV lines. ERCOT claims that this is a far greater expansion of the transmission infrastructure than in any other region in North America.[6]

Capacity Additions



Source: Derived from EIA and Platts data. See source note 7.

Centerpoint Asset Sales and Retirements

CenterPoint sold Texas Genco Holdings, its wholesale power generation unit, to a joint venture owned by four private equity firms in 2004. Originally, Reliant Energy was expected to execute first-right-of-refusal to purchase the assets, but Reliant had too much debt on its books. Because the sale was required as part of deregulation agreements in Texas, CenterPoint sought another buyer.

GC Power Acquisition, a partnership of Texas Pacific Group, Hellman & Friedman, the Blackstone Group, and Kohlberg Kravis Roberts & Co., won over other bidders including another private equity consortium, with a $3.65 billion bid, making it the largest U.S. power deal by a financial buyer.

The deal closed in December, completing the acquisition of 11 power plants with a generating capacity of more than 13,000 MW. The next step, approval by the Nuclear Regulatory Commission in 2005, completed the acquisition of CenterPoint's share of the South Texas Project nuclear facility.

In the meantime, GC Power Acquisition, known as Texas Genco LLC, announced plans to retire six plants in its portfolio that have been mothballed or used minimally in the past couple of years. ERCOT approved the plan for most of the units but is discussing reliability must run (RMR) status for continued operation of a single unit in the portfolio accounting for 740 MW.[7]

Endnotes

[1] PUCT, Project No. 26376, Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas, September 22, 2003.

[2] Tabors Caramanis & Associates and KEMA Consulting Inc., Market Restructuring Cost-Benefit Analysis: Final Report, November 30, 2004.

[3] Texas Nodal Team, filing before the PUCT, March 18, 2005.

[4] Potomac Economics Ltd., Adviser to the Market Oversight Division, Public Utility Commission of Texas, 2004 Assessment of the Operation of the ERCOT Wholesale Electricity Market, November 2004.

[5] Capacity Additions and Retirements are for calendar year 2004, based on Platts and EIA net summer capacity estimates and FERC staff research. They may differ from the Summer Generating Capacity in the Supply Demand Statistics table. Summer Generating Capacity may be projected for the summer peak, may omit some calendar year additions, and may reflect actual demonstrated capacity and deratings.

[6] ERCOT, Report on Existing and Potential Electric System Constraints and Needs Within the ERCOT Region, October 1, 2004.

[7] Trade press reports.

Source notes

1. Prices are ERCOT on-peak balancing prices for the zones identified. Data located at http://www.ercot.com/ercotPublicWeb/PublicMarketInformation/FileSystem.cfm?SubDir=mos/Operating_Day_Report&Title=Operating%20Day%20Reports.

2. Platts *Megawatt Daily* and IntercontinentalExchange (ICE) prices are day-ahead on-peak for the ERCOT Hub. ERCOT on-peak balancing prices are for ERCOT North.

3. Data are from NERC's 2004 ES&D Database and Platts PowerDat (annual net generation). 2004 data are from ERCOT. Generation capacity excludes all derates of resources and imports.

4. Platts *Megawatt Daily* and ICE prices are day-ahead on-peak for ERCOT.

5. ICE on-peak forward and swap prices and volumes are for ERCOT and include monthly, dual monthly, quarterly, and calendar year contracts traded for 2004. Omission of the March 15 and September 15, 2004 curves is due to insufficient trading volumes.

6. Data from Platts PowerDat, RDI Modeled Production Costs dataset for calendar year 2003 reflecting self-reporting from all utility and nonutility electric power generating facilities with nameplate capacity of 50 MW or more.

7. Data from Energy Information Administration (EIA) Form 860, Platts NewGen and Platts PowerDat. All generation is summer capacity unless otherwise indicated.

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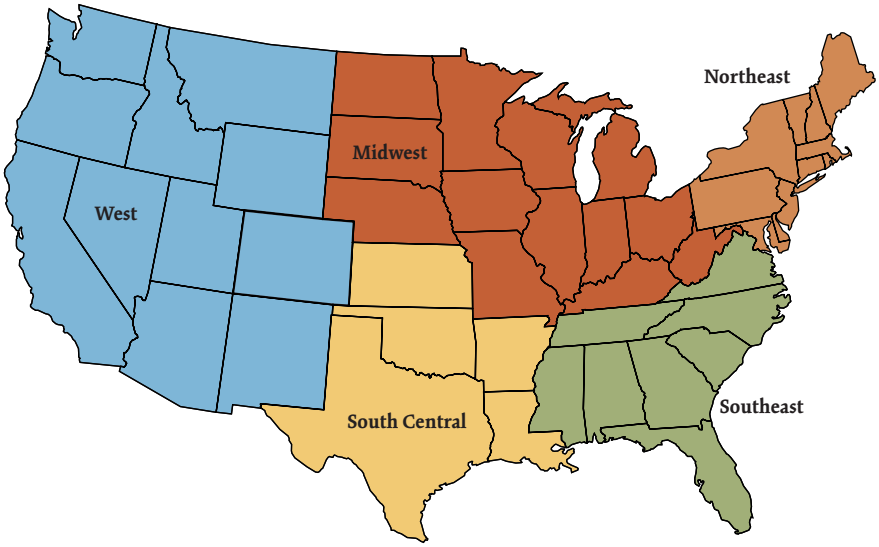
Natural Gas Markets in 2004

The *State of the Markets Report* contains individual profiles on natural gas trading at the Henry Hub and five major regions: Northeast, Southeast, Midwest, South Central, and the West.

National Overview



Nationally, five keys to understanding U.S. natural gas markets in 2004 were:

Natural gas prices rose 7 percent in 2004, following an increase of 63 percent in 2003.
This price rise came during a year of increasing oil prices and mild weather.

Natural gas suppliers responded to higher prices by increasing efforts to find new supplies.
Suppliers increased exploration, developed sources previously deemed too expensive, and increased imports, especially of liquefied natural gas (LNG). Exploration and development expenditures were 45 percent higher in 2004 than the average in 2001 and 2002.

The natural gas industry continued to build its infrastructure.
Investment in interstate pipeline transmission capacity in 2004 was $2.1 billion, down from $3.5 billion in 2003. Most of the difference was due to completion of the Kern River expansion in 2003.

Financial gas markets grew.
During the year, financial platforms offered a wide range of new products, both attracting financially oriented traders and allowing companies to hedge geographic and seasonal risk more robustly than before.

Information issues remained important.
Natural gas price indices improved, but markets remained sensitive to key supply indicators, especially the Energy Information Administration (EIA) storage report.

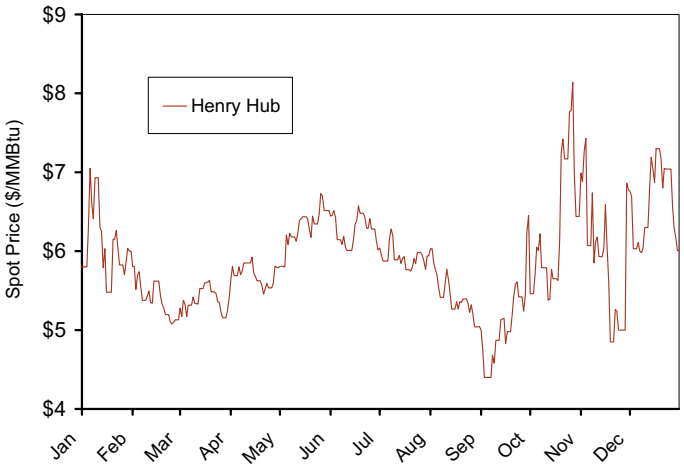
Natural Gas Prices

Henry Hub Prices

Natural gas prices in 2004 averaged $5.86 per million British thermal units (MMBtu) at the Henry Hub. This was 7 percent higher than the 2003 average of $5.47 per MMBtu, which in turn was 63 percent higher than in 2002 (see Figure 1).

Henry Hub prices remained stable during cold weather in the Northeast in January. Local prices rose, but national prices did not. This pattern occurs when downstream buyers face limited transportation capacity from producing regions, but there is no national shortage of supply. In that case, prices in the production area remain stable and the value of transportation (basis) rises.

Fig 1: Henry Hub Prices



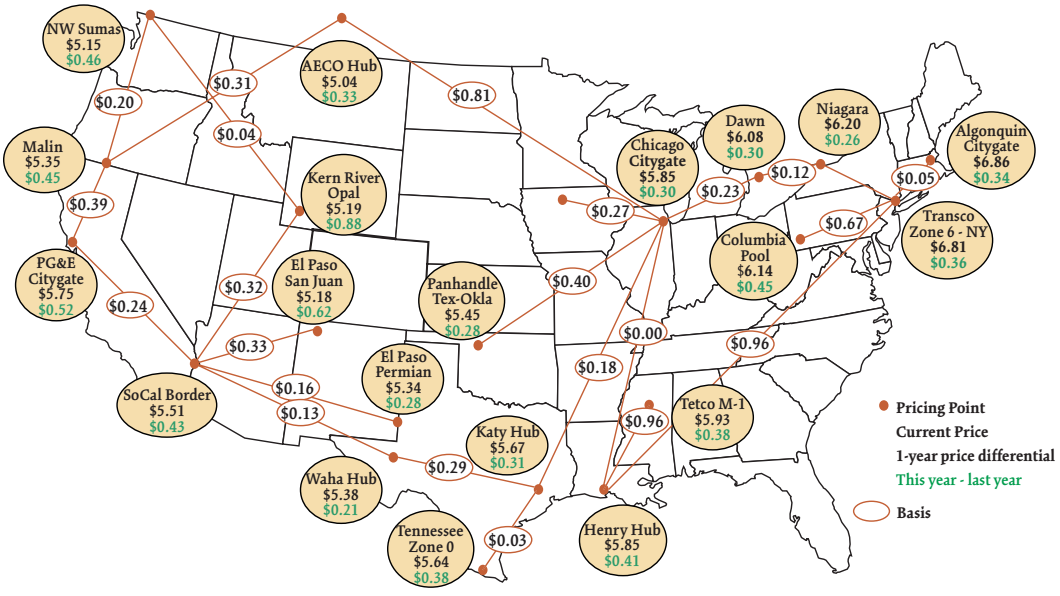
Source: Derived from Platts data.

Regional Variations

Although gas prices overall increased in 2004, the differences in price among regions remained similar (see Figure 2). Compared with Henry Hub:

- **Prices in the Northeast were higher.** This difference is long-standing. It reflects limits on pipeline and storage capacity. The difference is higher in the winter.
- **Prices in the West were lower.** This reflects overall limitations in moving gas between eastern and western halves of the continent. Western gas has been lower-priced than eastern gas in most years—but not always. During the western energy crisis of 2000–2001, the pattern reversed and western prices were higher.

Fig 2: Locational Gas Prices 2004



Source: Derived from Platts data.

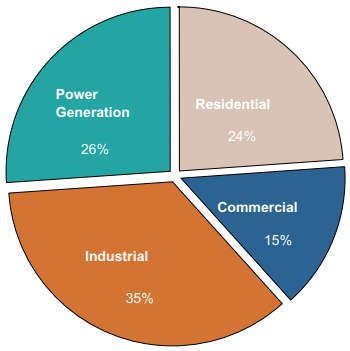
Weather and its Effects on Consumption

Weather was mild in 2004, reducing stress on the natural gas system. Winter of 2003–2004 was 6 percent warmer than the previous winter, and the 2004 summer (June through August) was the ninth coolest on record, reducing electric demand and allowing market participants to fill storage early. The major weather events that affected gas markets were:

Hurricane Ivan. Ivan struck the Gulf Coast September 16, 2004, disrupting both production and pipeline transportation in the gulf. At the height of the disruption, about 6.5 billion cubic feet (Bcf) were unavailable. Of this amount, 0.6 Bcf remained off line at the end of the year. In total, Ivan reduced U.S. gas production by 0.7 percent for 2004. The loss of production may have been responsible for a price surge through October.

January cold snap in New England. A short period of cold weather hit New England on January 14–16. The cold weather stressed both the natural gas and electric power industries, and market participants found it difficult to coordinate their activities across the two markets (see separate essay). Still, overall, the markets worked successfully during the event. Both power and gas markets cleared without curtailments, and prices returned to normal levels when the severe weather passed.

Fig 3: Demand shares in 2004



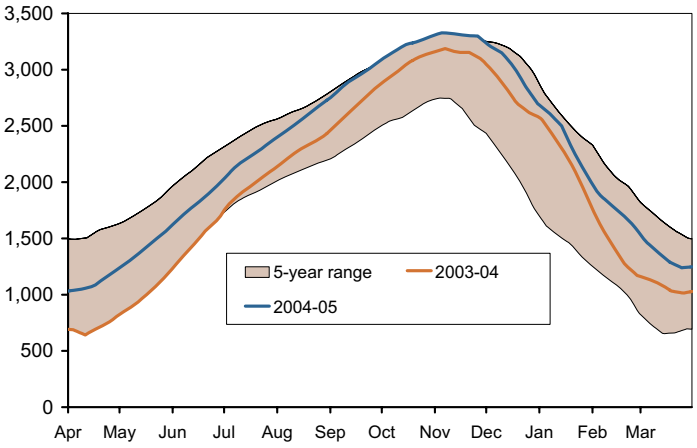
Source: Derived from EIA data.

Consumption. Traditional weather-sensitive load fell for the year by 3.9 percent for residential customers and 6.7 percent for commercial customers (see Figure 3). The decline reflected the warmer winter (6 percent warmer than the year before). Industrial and power generation load increased 2.2 and 4.2 percent, respectively. The increase in electric load is particularly significant. It came despite a cool summer and reflected the large amount of combined-cycle natural gas generation that has come on line in the last five years. The increase is likely to continue, and the mild weather may have masked its significance for the future.

Natural Gas Prices, Storage, and Oil Prices

Over time, two major factors have affected natural gas prices: the size of storage inventories and the price of oil. When storage is low compared with historical experience, gas prices tend to rise, sometimes sharply. Other things being equal, gas prices also roughly track the price of oil.

Fig 4: Storage Levels



Source: Derived from EIA Weekly Storage Report.

Storage Issues

Natural gas storage inventories started at low levels, but rose rapidly through the spring (See Figure 4). Inventories reached the highest levels ever recorded by the end of the 2004 injection season.

Storage affected gas prices most directly during the fall. Taking advantage of a mild summer, market participants filled storage to higher levels earlier than usual. During the fall, before winter weather arrived, additional gas supplies could not be forced into storage and faced relatively low shoulder-month demand in other markets. As a result, prices fell, then recovered as winter set in.

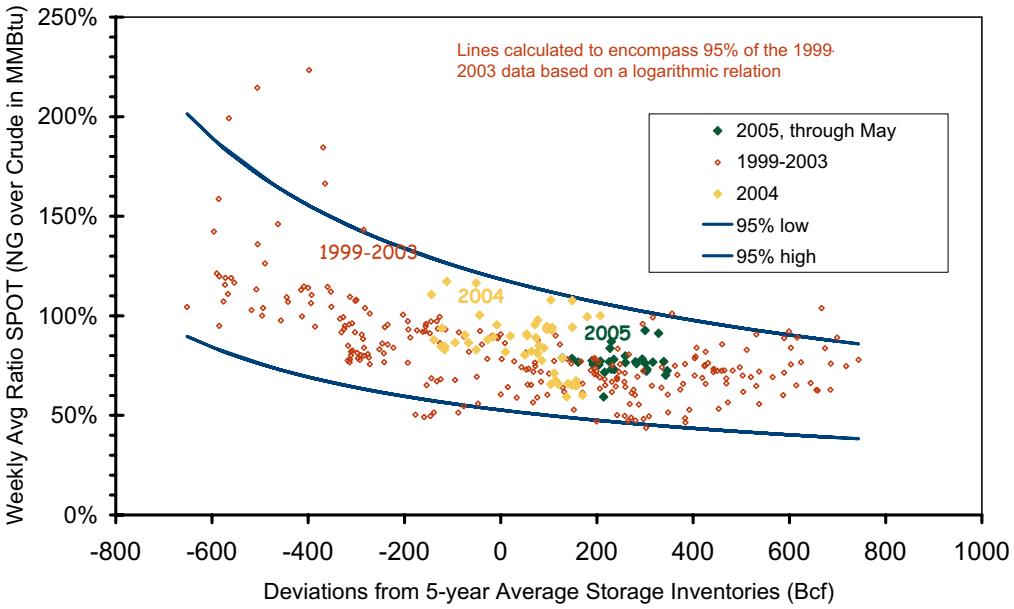
Longer-term Relationship and Oil Prices

When storage inventories are significantly lower than normal for a given time of year, gas prices tend to rise. This is a market response to concerns that supplies may not be sufficient for the coming peak season, and a resulting desire to buy more gas to fill storage more quickly.

Storage inventories do not completely explain natural gas prices. More recently—starting in 2004—the effects of oil prices on gas prices have been more prominent.

Prevailing gas prices when storage is normal have risen over the past few years. Figure 5 plots gas prices against storage levels, with gas prices controlled for oil prices. The result shows that the change in gas prices when there is no shortage of storage is primarily the result of rising oil prices.

Fig 5: Henry Hub Storage Concentration Correlated for Oil Price



Source: Derived from Platts and EIA data.

Supply Responses to High Natural Gas Prices

In 2004, domestic gas production declined by 1.4 percent as output from some key traditional basins declined. Figure 6 shows the major sources of U.S. natural gas supply.

Natural gas suppliers responded to declining production and high prices by increasing:

- Imports into the United States, both from Canada and, as LNG, from other countries.
- Efforts to improve traditional production.
- Deployment of technologies that were sometimes too costly in previous years.

Table 1: LNG Deliveries

	2003	2004
Cove Point	66.1	209.2
Elba Island	43.9	105.3
Everett	158.3	173.7
Lake Charles	238.2	163.8

Source: Derived from EIA *Natural Gas Monthly* data.

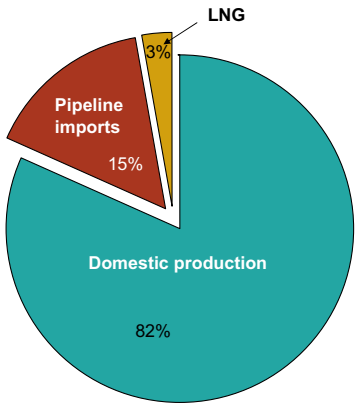
Imports. Canadian imports increased by 0.5 percent in 2004 to 3.2 Tcf, after a larger decrease in 2003 (see Figure 7). Canadian imports have not recovered to levels seen in the early 2000s.

LNG imports rose by almost 29 percent, to 0.65 Tcf. Most LNG imports came from Trinidad and Tobago (71 percent – see Figure 8) and Algeria (19 percent). All of the LNG terminals in the United States saw increased deliveries during the year except Lake Charles, which was down for maintenance during the last part of the year (see Table 1). Lake Charles is also farther from load centers than the other terminals, receives a lower netback, and is most likely to be the "swing terminal" for LNG.

Increased Drilling Activity

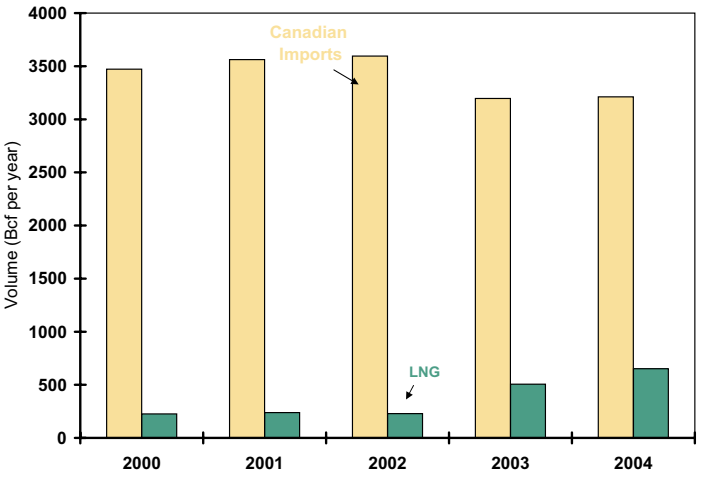
Natural gas producers in the United States increased their efforts to find natural gas during 2004. Expenditures on exploration and production rose by 11 percent over 2003, 45 percent over the average at 2001 and 2002 (see figure 9). The number of drilling rigs dedicated to finding natural gas increased throughout the year and averaged 15 percent higher than in 2003. This increased activity did not lead to increased production overall—though in some basins it did reduce or prevent declines that had been expected.

Fig 6: Supply shares 2004



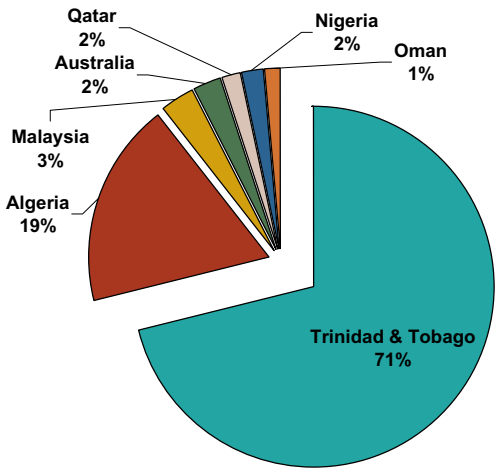
Source: Derived from EIA data.

Fig 7: Natural Gas Imports



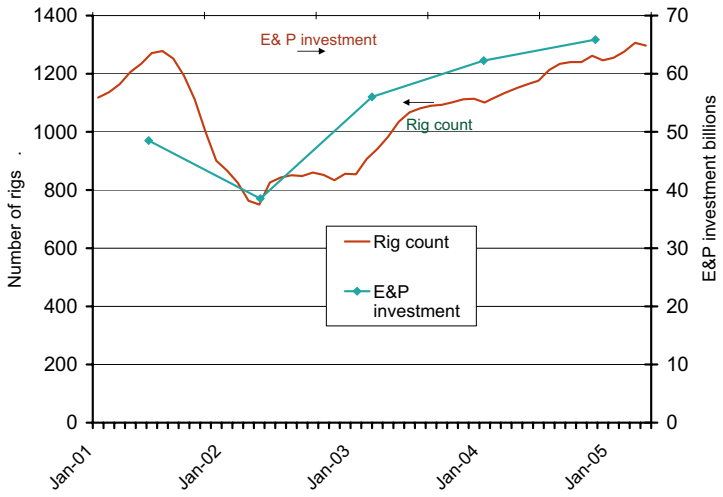
Source: Derived from EIA *Natural Gas Monthly* data.

Fig 8: 2004 LNG Source Countries



Source: Derived from EIA data.

Fig 9: Rig Counts and E&P Investments



Source: Derived from Baker, Hughes, and *Oil and Gas Journal* data.

Increased Penetration of Unconventional Technology

Producers have turned to new production plays in recent years to stem the decline in domestic production. These include tight formations in Texas' Barnett Shale, deep gas and deepwater gas, and coalbed methane.

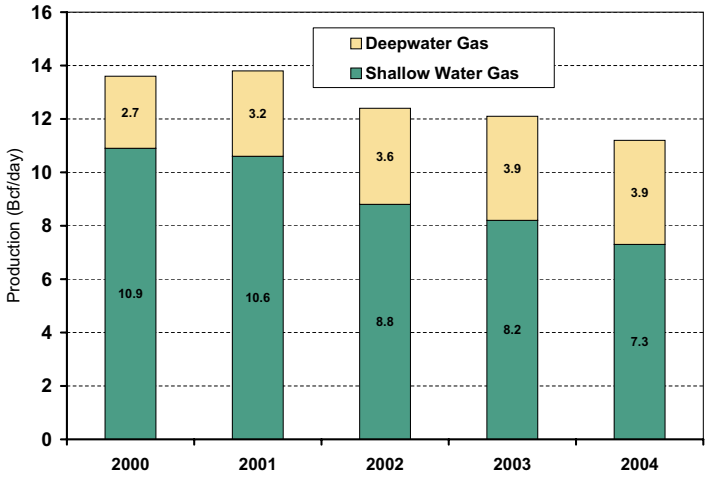
- **Barnett Shale.** The Barnett Shale is a tight formation in Texas. During 2004, production from the Barnett Shale increased by 22 percent, to 520 Bcf for the year. This helped ensure that overall production in Texas grew during the year.

- **Deep gas.** Shallow water production in the Gulf of Mexico has been declining rapidly since 2001 (see Figure 10). Producers responded by increasing deep drilling—both drilling in deep water and to greater depths in shallow water. Increases in deep drilling alleviated some of the decline in output from shallow water drilling between 2000 and 2003. Deep gas production remained constant between 2003 and 2004.

- **Coalbed methane.** This technology has been in widespread use in the San Juan Basin and onshore Gulf Coast since the early 1990s. In recent years, those sources have declined, but a rapid increase in coalbed methane in the Rocky Mountains has increased overall production from this source, about 2 percent in 2004.

Taken together, these technologies have helped slow the decline in production in recent years. Except for the Barnett Shale, however, increases in 2004 were marginal at best.

Fig 10: Gulf of Mexico Production



Source: Derived from EIA *Natural Gas Monthly* data.

Infrastructure Investment

During 2004, the natural gas industry continued to invest in upgrading its infrastructure for transmission and storage. Total investment in interstate pipeline transportation projects that came on line in 2004 was $2.18 billion, compared with $3.75 billion in 2003 (EIA). Completion of the Kern River expansion in 2003 ($1.26 billion) represents most of the difference. Most of the new construction went to strengthen the existing grid, and there were few major long-distance projects. Investment in storage fell to $159 million in 2004 from $253 million in 2003.

Table 2: Major Pipeline Projects Certificated in 2004

Company	Project Name	Docket	Date	Capacity MMcfd	Miles	Hp	Cost $Million	States
AES Ocean Express	Ocean Express Pipeline	CP02-90	1/29/04	842	53.6		$264.2	FL
Northwest Pipeline Corp	Everett Delta Lateral Project	CP01-49	2/18/04	113	9.2		$24.1	WA
Cheyenne Plains Gas Pipeline Co		CP03-302	3/24/04	560	387.2	20620	$410.1	CO,KS
TransColorado Gas Transmission Corp		CP04-12	3/24/04	1125	0.1	20120	$28.6	CO
Tractebel Calypso Pipeline	Calypso Pipeline Project	CP01-409	3/24/04	832	41.8		$144.3	FL
Transwestern Pipeline Co	San Juan Lateral Expansion	CP04-104	8/5/04	375	72.6	20000	$138.4	NM
Trunkline Gas Company	LNG Loop Project	CP04-64	9/17/04	1500	22.8		$ 50.0	LA
Cheniere Sabine Pass Pipeline Co.		CP04-38	12/21/04	2600	16		$ 90.0	LA

Source: FERC, Office of Energy Projects.

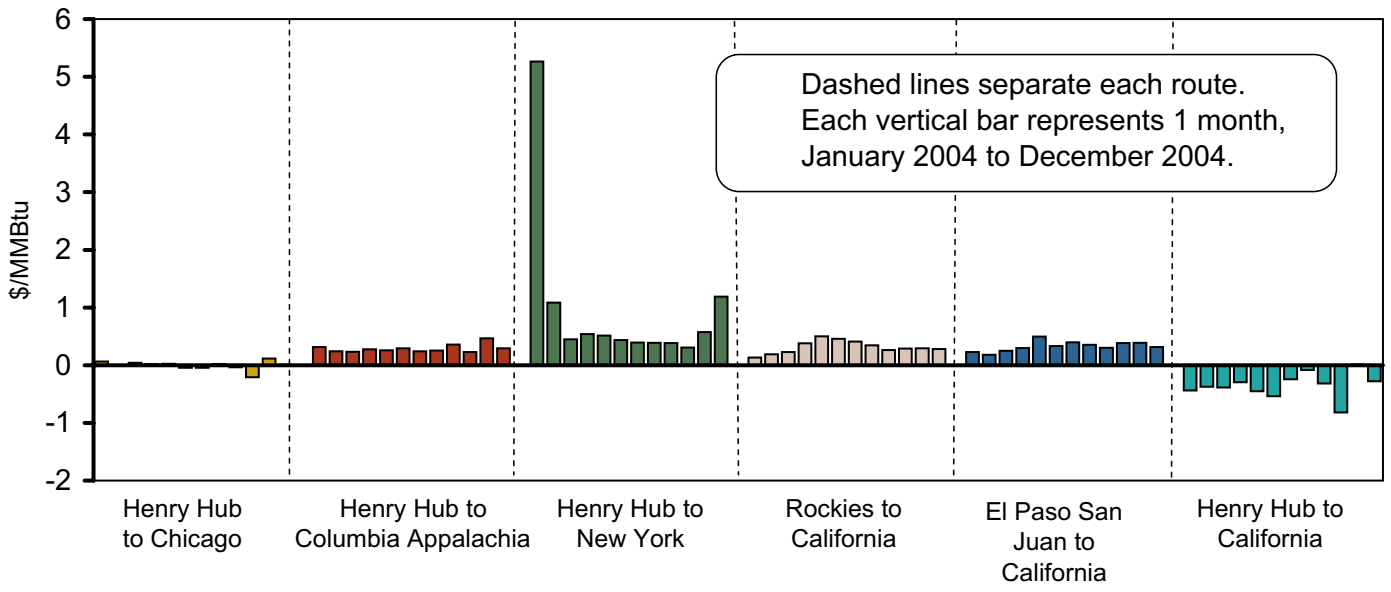
Table 3: Major Pipeline Projects Completed in 2004

Company	Project Name	Docket	Date	Capacity MMcfd	Miles	Hp	Cost $Million	States
El Paso Natural Gas Company	Line No. 2000 Power Up Phase I	CP03-1	2/04	120	0	73720	$81.0	AZ, NM, TX
El Paso Natural Gas Company	Line No. 2000 Power Up Phase II	CP03-1	4/04	100	0	45000	$54.0	AZ, NM, TX
Texas Eastern Transmission LP	M-1 Expansion Project	CP02-381	5/04	197	32	28000	$66.0	AL, MS, TN
El Paso Natural Gas Company	Line No. 2000 Power Up Phase III	CP03-1	6/04	100	0	32880	$39.0	AZ, TX
TransColorado Gas Transmission Corp		CP04-12	8/04	125	0.1	20120	$28.6	CO
Texas Eastern Transmission, LP	Mid-Atlantic Expansion Project	CP03-43	10/04	223	35	0	$83.0	PA
ANR Pipeline Company	West Leg Expansion	CP02-434	10/04	220	33	0	$42.0	IL, WI
Northwest Pipeline Corp	Everett Delta Lateral Project	CP01-49	11/04	113	9.2	0	$24.1	WA
Cheyenne Plains Gas Pipeline Co		CP03-302	12/04	560	387.2	20620	$410.1	CO, KS

Source: FERC, Office of Energy Projects.

The lack of long-distance projects reflected market realities in the industry. To justify construction of a new long-haul pipeline, the price difference (basis) between two regions must be high enough on average to pay for the cost of additional pipeline capacity. Figure 11 shows basis differentials among key regions in 2004.

Fig 11: Monthly Basis Differentials for Major Transport Routes



Source: Derived from Platts data.

The largest basis differentials were between producing areas and the Northeast (Transco Zone 6–New York). Although the basis was high for short periods in the winter, it was low for most of the year. Averaged across the year, the basis to the Northeast was about equal to current pipeline tariffs. The tariffs, however, represent cost-of-service rates for pipelines that companies built in the past and have depreciated. The tariff rate is likely to be high enough to justify some incremental upgrades (for example, compression, when possible) but not to pay for more costly expansions. In addition, it may be less costly to develop or increase LNG terminal capacity.

The 2004 basis from Opal (in Wyoming) to California was about the same as from the San Juan Basin. This represented a major change from 2002 when there was not enough pipeline capacity and much Wyoming gas was trapped locally and sold at lower prices than other western gas. In 2003, Kern River opened its expansion to California, removing the bottleneck and allowing Wyoming gas to receive prices prevailing in the West.

Overall, gas infrastructure investment in North America has been an important market success story for many years. Over time, natural gas supplies have constantly shifted, as have markets. Companies have sponsored and built pipelines to meet the changing needs so that market dislocations, like the Wyoming production pocket, have generally been short-lived.

Financial Gas Market Growth

Financial services available to the natural gas industry increased in 2004. These improvements included both new financial products (swaps, for example) and more widely used clearing services.

New Products

Financial natural gas markets have been growing in importance since 1990, and new financial products have recently become available to customers. Nymex added a wide range of financial natural gas products to its electronic ClearPort trading system. All of the products settle financially; there is no physical delivery. The products offer natural gas buyers and sellers a variety of tools to hedge many different price risks. These and similar products are also available on the IntercontinentalExchange (ICE) and through voice brokers and bilateral contacts. The Nymex listing makes them easier to trade, and gives daily published settlement prices for the contracts with open interest. In 2004, Nymex's new natural gas products included:

Basis swaps. These products let market participants hedge the basis difference from Henry Hub to a given location for some time in the future. For example, a buyer could lock in a basis difference between the Henry Hub and Transco Zone 6–New York for the month of January. Such a buyer would no longer be vulnerable to changes in the basis value between New York and the Gulf Coast for that month. Basis swaps give market participants price discovery at points other than Henry Hub. Nymex offered 12 additional delivery points for basis swaps in 2004 (in addition to 29 pre-existing points).[1]

Index and swing swaps. Index swaps let a market participant hedge exposure to daily price changes by locking in a monthly index at a given physical point. Swing swaps let customers hedge against changes in daily price changes, without being tied to a monthly index. Both products are hedges against daily price volatility. Nymex added six locations for index swaps and daily swing futures.[2]

Penultimate swaps are the purchase or sale of a fixed quantity at a fixed price in exchange for the settlement price of the underlying futures contract on the day prior to its expiration. They protect customers against last-day changes in futures prices. Nymex added this product for its basic natural gas futures contract.

Calendar spread options are options on the price spread between two specified months. Market participants can use calendar spread options to hedge the value of storage. Nymex added spread options between the months of April and October and the months of October and January,

Taken together, this array of hedging tools gives customers great latitude to shape their risk management strategies. To the extent that the hedging instruments trade in a liquid market, market participants can adjust their risk management strategies as needed.

Clearing Services

Clearing services enhance the liquidity of markets by giving customers a convenient way to address credit risk and to net credit exposures. During 2004, both ICE and Nymex saw the volumes in their clearing services rise rapidly. For ICE, the volumes increased almost four fold, from 4.5 million contracts to 17.0 million contracts. (Each contract covers 2,500 MMBtu). For Nymex, clearing volumes for both swaps and options increased more than five fold, from 2.4 million contracts to 13.4 million contracts.

Overall

Development of these financial products represents significant innovation for the industry. Their demonstrated market viability shows that customers are using the services. Together the innovation and market diffusion of these services indicates a healthy market. Customers have more risk management options, which is important in an industry with high capital costs and volatile prices. They also see a market that can create services (like clearing) that can be used to respond to problems that would otherwise undermine liquidity.

Information Issues Remained Important

Natural gas markets depend on having reliable information about prices and basic demand and supply conditions.

Price Indices

Participation in gas price indices increased in 2004, signalling increased confidence. During the early years of the decade, some market participants manipulated the price indices that many participants use for basic price discovery and often include in contractual pricing terms.

During 2003 and 2004, the Commission encouraged the industry to improve index reporting. By 2004, companies reporting to the index publishers had better procedures for ensuring honest reports. The index publishers reported far more details (such as the number of transactions and total volumes being reported for a given price). The Commission issued a rule laying out requirements for indexes referenced in contracts under the Commission's jurisdiction. By 2004, many market participants expressed greater confidence in using the indexes.

Nonetheless, popular confidence in natural gas pricing remains uncertain. With rapid price increases in 2003 and 2004, pricing mechanisms remain under close scrutiny by policy makers in Congress and elsewhere.

EIA Storage Report

Basic information about supply and demand remained scarce, so that EIA's weekly storage reports retained disproportionate influence over the market. The United States has no timely and reliable reports on current gas production. As a result, EIA's storage estimate has become the most available indicator of the overall balance of supply and demand—despite the fact that it represents a tiny proportion of gas being produced or consumed at any given time.

Late in November, one company's clerical error led EIA to underestimate storage injections for the previous week. During the rest of the trading day, gas prices rose by 15 percent. Because the reporting also happened to be the close for the Nymex December futures contract and for bid week for monthly physical deliveries in December, the overall effects on the market were large.

In the absence of better information on supply, natural gas markets will remain vulnerable to errors or aberrations in the few reports that are available.

Conclusion

The natural gas industry faced a declining traditional resource base in 2004, at the same time that gas usage in electric generation increased. Mild weather helped avert any significant disruptions, and natural gas markets responded largely as expected. Tight supplies (and rising oil prices) led to higher gas prices. In turn, the industry increased gas imports from Canada and, as LNG, from other countries; increased drilling for new reserves; and increased efforts to produce natural gas from less traditional supply sources, such as tight formations. Nonetheless, overall supply remained about the same.

Going forward, the natural gas industry faces several crucial market questions including:

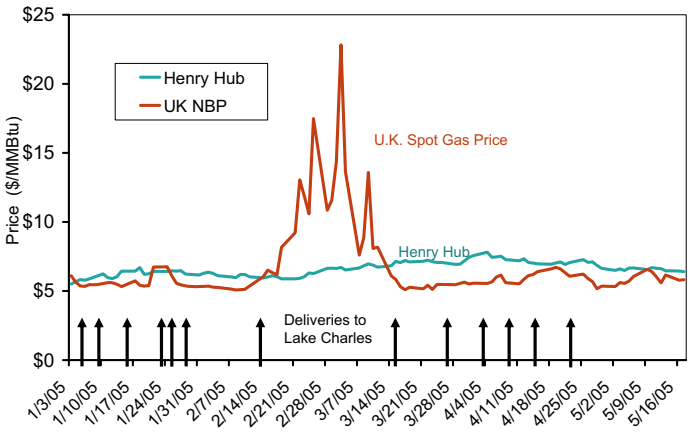
How will gas markets respond to more severe weather? In 2004, natural gas supply and demand balanced closely, largely because of a decline in residential and commercial demand occasioned by relatively mild weather. More severe weather would impose significantly greater stresses on the natural gas system, leading at least to higher prices.

A shift in demand for gas is likely to exacerbate any weather-related problems. Price spikes occur because many or most customers are unwilling or unable to reduce their demand. Traditional industrial demand served to limit the severity of natural gas price spikes because customers bought less gas if the price went too high. In today's natural gas industry, the electric generation sector is growing most rapidly. Its demand for gas tends to be unusually inelastic because there is little price-responsive demand for electric power. As a result, electric demand is unlikely to serve as the same sort of shock absorber for severe weather as traditional industrial demand.

Will innovations help improve natural gas supplies? One response to high prices is to devote resources to finding and deploying new approaches. In natural gas, current high prices have led the industry to work at developing some less conventional supply sources, to limited effect so far. More changes are likely. For example, early in 2005, EnergyBridge introduced an LNG tanker with onboard liquefaction. Such a ship takes significantly longer to offload than LNG tankers at terminals, but incurs much less capital cost (and environmental dispute), and so can deliver gas more flexibly to more points. The first deliveries were to the Gulf Coast, but proposals are already on the table for two potential delivery points in New England, and such technology could eventually help a company arbitrage gas prices in widely dispersed areas.

How will global markets for natural gas develop? The United States has long experience with spot markets for natural gas that allow arbitrage among different parts of the grid. The beginning of 2005 saw early signs that a North Atlantic spot market is developing between the United States and Western Europe, especially Great Britain. British gas prices spiked in late January and February (see Figure 12) in response to cold weather. Simultaneously, Spain was short of gas to fuel combined-cycle electric generation. LNG deliveries to Lake Charles stopped, and there were reports that shippers diverted cargos destined for the United States to Europe. (Shippers have diverted some cargos from Europe to the United States for several years.)

Fig 12: Henry Hub and European Gas Prices



Source: Derived from Bloomberg and U.S. Waterborne LNG data.

Development of more flexible North Atlantic LNG deliveries could have significant effects for both Europe and North America in the future—mostly positive ones, because gas will flow to areas with the greatest willingness to pay, which probably correspond to the areas with the greatest need.

Market Profiles

The first profile is on trading (especially financial) at the Henry Hub, because the Henry Hub market forms the basis that market participants use to measure all other natural gas markets. The regional profiles cover five regions: Northeast, Southeast, Midwest, South Central, and the West. Each regional profile can stand alone as a summary of the region's natural gas markets in 2004. The profiles are as standard as possible but vary somewhat because of differences in the nature of the regions themselves. The regional profiles generally include the following sections:

Market Description. The opening section of each profile includes:

- A brief description of the region and important factors affecting its natural gas market,
- A map with average prices for 2004 for available pricing points and key entry or exit points for natural gas supply,
- A summary price table,
- A brief description of major issues that affected the region in 2004,
- Overall statistics for supply and demand.

Spot Market Prices and Volumes. This section includes:

- A graph of daily prices for major pricing points during the year. It is especially useful for identifying price spikes and seeing the overall range and volatility of prices through the year. Basis values for the region (differences in prices between key regional points and the Henry Hub), are included where relevant.
- Forward prices and volumes traded, as reported several times during the year. This information shows how trader expectations of coming seasonal prices evolved during the year.
- Volumes traded, as reported by ICE and *Gas Daily*.

Infrastructure Development. This section contains a table of major construction projects for pipelines, storage, and LNG in the region. The table includes information on the size, cost, location, and status of each project.

Regional Gas Supply. This section describes where the gas comes from to serve a given region. This source information includes local production, but in most consuming regions, the bulk of supply comes from outside by pipeline or from LNG terminals. The section also describes gas storage facilities and usage in the region, because these can supply winter or peaking demand.

Regional Market Shares. This section shows the relative market shares for capacity of the major pipeline companies that serve a region. It also shows the largest holders of pipeline capacity rights, usually large downstream customers.

Selected Topics. Each regional profile includes at least one short article that highlights an important event or development during the year in greater detail than is possible in the standard sections.

Endnotes

[1] New points include ANR Pipeline Louisiana, Upper Midwest, (Dawn, Ontario), Florida Gas Transmission—Zone 3, East Texas, Katy, Kern River Gas Transmission—Wyoming, Niagara, Questar Pipeline—Rocky Mountains, Tennessee Gas—Louisiana, Tennessee Gas—Zone 0, Texas Gas— Zone SL, Trunkline Gas—Louisiana, and Williams Gas Central (Texas, Oklahoma, and Kansas).

[2] New swap locations include Henry Hub, Houston Ship Channel, Panhandle Eastern—Texas, Oklahoma, El Paso—Permian Basin, Waha, and Chicago citygates.

Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Natural Gas Trading

Henry Hub, La., serves as the primary U.S. pricing reference point for buying and selling natural gas because it is the delivery point for the New York Mercantile Exchange (Nymex) natural gas futures contract.[1] Nymex chose Henry Hub about 15 years ago because it connects with nine interstate and four intrastate pipelines with access to markets in the Gulf Coast, Southeast, Northeast, and Midwest.[2] Consequently, Henry Hub serves as the key link between natural gas financial and physical markets. Market participants in these regions and across the United States can price their physical and financial natural gas contracts based on the price of the Henry Hub futures contract, plus or minus a differential to their delivery points.

Futures contracts constitute the purchase or sale of a standardized product—set volume, delivery location, delivery period—with the obligation to take or make delivery. Some futures contracts do not extend to physical delivery and include a specified financial settlement. The specifications for the Nymex Henry Hub natural gas futures contract are for physical delivery, unless the original contract purchased or sold is sold or bought back prior to the contract's expiration. Nevertheless, the majority of Henry Hub natural gas futures do not go to delivery because in a straightforward strategy (hedge or speculation), buyers sell contracts and sellers buy them prior to expiration to keep the effects financial rather then physical.

Futures contracts serve two primary purposes:

- As a pricing mechanism for purchases and sales of a given contract's underlying physical commodities in order to hedge against price changes.
- As a means of price discovery.

Henry Hub Prices ($ per MMBtu)

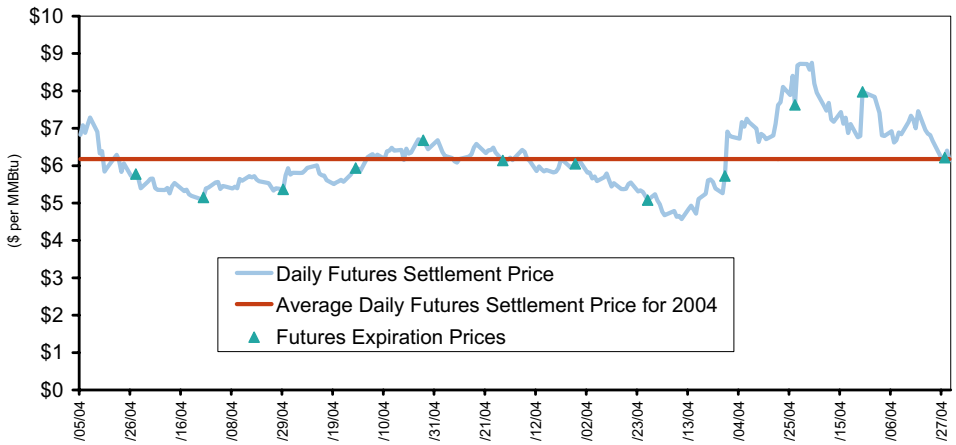
Year	Avg Daily Futures Settlement Price	Percent Change from Prior Year
1995	$1.688	
1996	$2.506	44%
1997	$2.476	-1%
1998	$2.158	-13%
1999	$2.320	8%
2000	$4.315	86%
2001	$4.054	-6%
2002	$3.367	-17%
2003	$5.492	63%
2004	$6.177	12%

Source: Derived from Bloomberg and Platts *Gas Daily* data.

Published prices for a natural gas contract occur via daily settlement by Nymex for 72 consecutive forward months and through monthly futures expiration prices. On the third business day prior to the end of each month, trading stops for the prompt month natural gas futures contract (the first forward-month traded), and the contract expires. Physical natural gas contracts often use the natural gas futures expiration price in their pricing terms. The expiration price also provides a reference point for physical trading during the natural gas market's bidweek, when the next month's physical transactions are commonly transacted.

In 2004, Henry Hub futures prices reached the highest average nominal levels since natural gas futures trading began in 1990. Natural gas futures prices for the prompt month settled on a

2004 Futures Settlement Prices

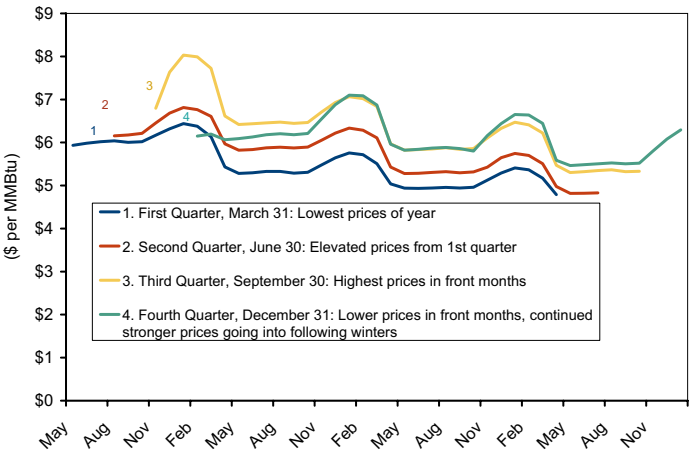


Source: Derived from Platts *Gas Daily* data.

daily average of $6.177 per MMBtu for 2004, an increase of 12.5% from 2003 in contrast to next-day Henry Hub physical prices which increased by 7%. For January through August, prompt-month futures traded in a range between $5.00 and $7.00 per MMBtu. Starting in September, next-day Henry Hub physical prices and prompt-month futures prices rose steadily from the sub $5.00 per MMBtu level (low futures price of $4.57 per MMBtu on September 10) to above $8.00 per MMBtu range (high futures price of $8.75 per MMBtu on November 3).

Forward futures settlement prices are shown going 3 years beyond the prompt month as of the end of each quarter during 2004. At the end of the first three quarters of the year, the market expressed concern over natural gas prices for the winter of 2004–2005. As the figure shows, the shape of the forward curve—higher prices for the coming winter, as compared with the subsequent two winters (referred to as "backwardation")—conveyed market expectations that the supply-demand balance would be tight and that winter weather would be cold in 2004–2005. Backwardation expressed expected price relief later. High price expectations are most apparent in the forward curve at the end of the third quarter 2004. By the end of the year, when part of the heating season was already over, the market adjusted its views, and the price curve for the balance of the winter season, February to March, declined from the third quarter.

Forward Futures Settlement Prices



Source: Derived from Platts *Gas Daily* data.

Factors Affecting Henry Hub Physical and Financial Trading in the Fourth Quarter

Fundamental market factors influenced both natural gas physical prices and financial product prices during the latter part of 2004.

Production curtailments related to Hurricane Ivan. In mid-September 2004, Hurricane Ivan caused a reduction in natural gas supply from the Gulf of Mexico. Natural gas production saw peak shut-ins of 6.5 Bcfd,[8] greater than expected damage to platforms, and extended curtailments through the balance of 2004. In reaction to this hurricane, next-day Henry Hub physical prices and futures prices for the prompt month, which had been declining into the mid-$4.50s per MMBtu (the low prices for the year), rose sharply to over $6.00 per MMBtu by the end of September.

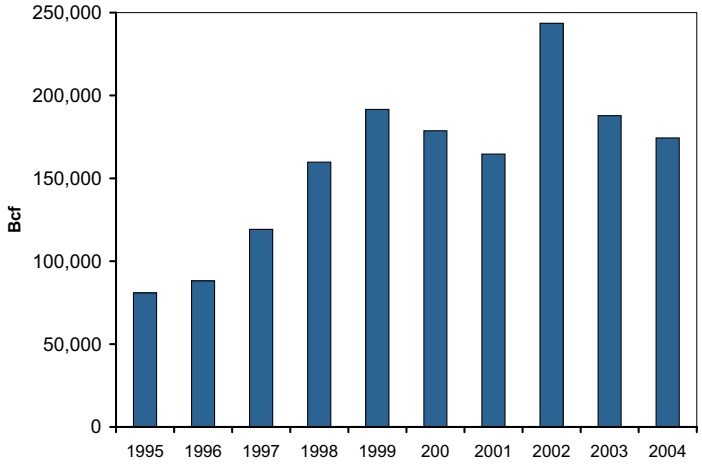
Crude oil market strength. From January through July 2004, crude oil futures traded, on average, below $40 per barrel. In August, prices began to increase steadily to reach a high settlement price for the year of $55.17 per barrel in late October. The continued strength of crude oil prices supported the natural gas futures market and also contributed to natural gas volatility.

Actual and expected winter weather. By early November, natural gas prices held firm in response to the extended effects of Hurricane Ivan and a strong crude oil market. Thus when certain sections of the country experienced early winter weather, prices moved upward. The next-day Henry Hub physical price increased almost $1.00 per MMBtu to trade above $7.00 per MMBtu from late October to early November. Actual and expected winter weather pushed the futures market even higher with prices above $8.00 per MMBtu.

Storage reporting issues during late November (for December delivery). On November 24, the Energy Information Administration (EIA) issued its natural gas storage report for the week ending November 19. The report indicated a withdrawal of 49 Bcf, in sharp contrast to market expectations, which were in the 13–25 Bcf range. The same day (November 24) marked the expiration of the December 2004 futures contracts, when futures prices settled up by $1.183 per MMBtu to $7.976 per MMBtu. The following week, EIA issued a 32 Bcf correction to the prior week's storage report. Commission staff issued its final report on this matter in February 2005.[9]

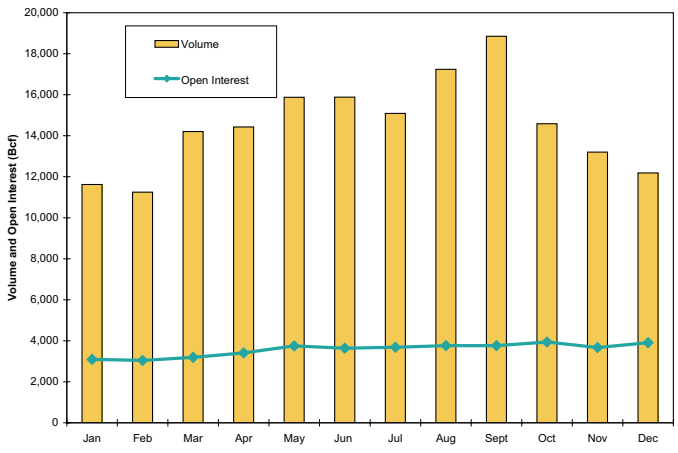
FINANCIAL MARKETS: FUTURES VOLUMES

Henry Hub 10-Year Annual Trading Volume



Source: Derived from Nymex data.

Monthly Volume and Open Interest

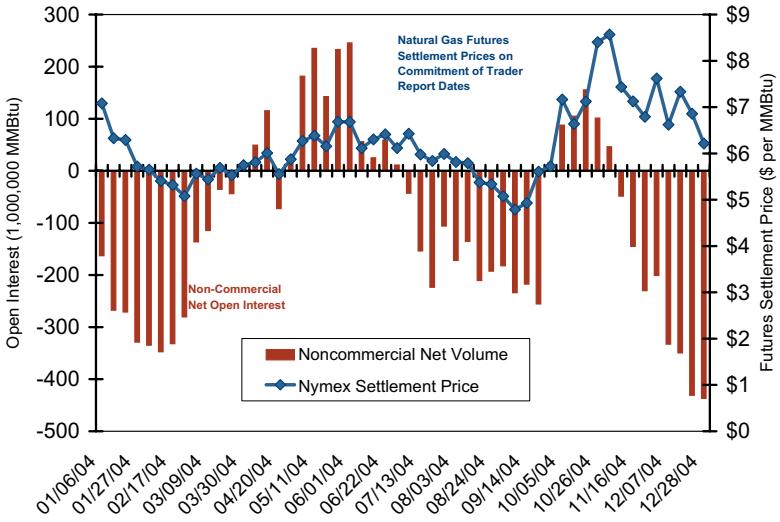


Source: Derived from Nymex data.

Henry Hub natural gas futures volume traded for 2004 dropped for the second year in a row, but was higher than average volume traded over the past 10 years. Volume is the total number of contracts traded for a single time period, such as daily volume or monthly volume. It also can be measured in volumetric units. Despite the higher price levels and news articles suggesting the entrance of new participants into the natural gas market, the natural gas futures contract did not set any volume records, unlike the crude oil futures contract. The total natural gas futures volume traded in 2004 amounted to 17.4 million contracts,[2] which was lower than it had been during the prior 2 years. Total monthly volume and end-of-month open interest for 2004 are shown. The largest natural gas futures volume transacted for the year occurred during September, due in part to the active hurricane season.

Open interest is the total number of outstanding contracts where an offsetting sale (or purchase) has not been made; it is indicative of future activity in the contract. Futures open interest of the noncommercial sector by net long (purchases) and net short (sales) position are delineated in relation to the futures settlement price (see figure). Noncommercials are trading entities that do not use the futures contract to hedge their business activities;[3] they are commonly referred to as speculators. Traders in the noncommercial classification include hedge funds, also known as managed money traders.[4]

Noncommercial Net Open Interest



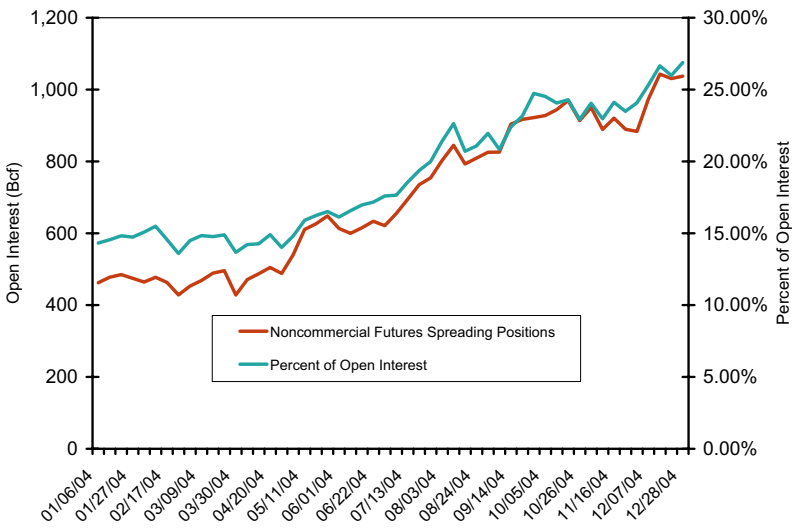
Source: Derived from Platts *Gas Daily*, and CFTC's *Commitment of Traders Report* data.

Open interest in 2004 provides some evidence to support the widespread observation that financial players have become more active in natural gas markets. Another category of noncommercial futures open interest is known as "spreading open interest." Spreading indicates the extent to which the trading entity holds equal long and short positions for the same commodity, but for different time periods. For example, an entity might be long for January and short for February, in which case, it would benefit if the January price rose compared to the February price (i.e., the "spread" between the months changed). A company with a large spreading open interest is betting that the difference between two time periods will change, not that forward prices will generally go up or down.

Spreading open interest for noncommercials increased over 2004, both in absolute volume and as a percent of total open interest. From the beginning of the year to its end, spreading open interest increased almost 125 percent from just under 500 Bcf to over one trillion cubic feet or almost 27 percent of open interest. The noncommercial spreading open interest for 2004 exceeded all prior years for the natural gas futures contract.

Both Nymex and the Commodities Futures Trading Commission (CFTC) examined open interest in 2004 to determine if the noncommercial sector, specifically hedge funds, created greater price volatility.[5] Recent anecdotal evidence points to the evolving interest of hedge funds in the energy sector. Prior to 2004, hedge funds traded energy products. During the past year, there were reports of significant new hedge fund entry into the energy trading space. In 2004, Utilipoint International Inc. identified 300 energy-focused hedge funds.[6] The FERC Office of Market Oversight and Investigations cannot verify the exact number of hedge funds trading natural gas and other energy commodities.

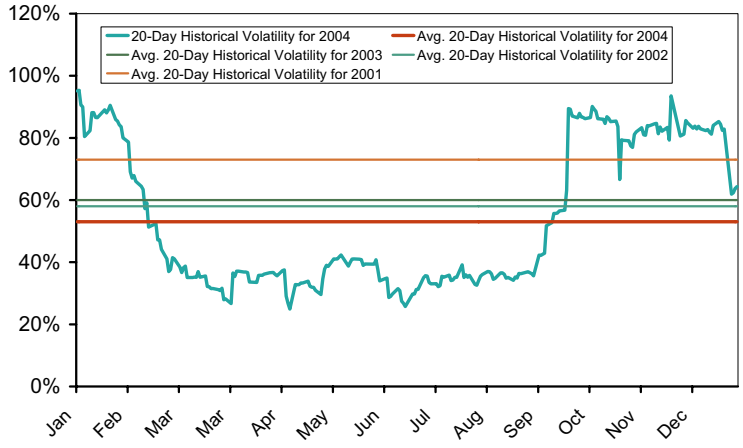
Spreading Open Interest in Gas Futures



Source: Derived from CFTC's *Commitment of Traders Report* data.

FINANCIAL MARKETS: HISTORICAL VOLATILITY

20 Day Historical Volatility



Source: Derived from Platts *Gas Daily* data.

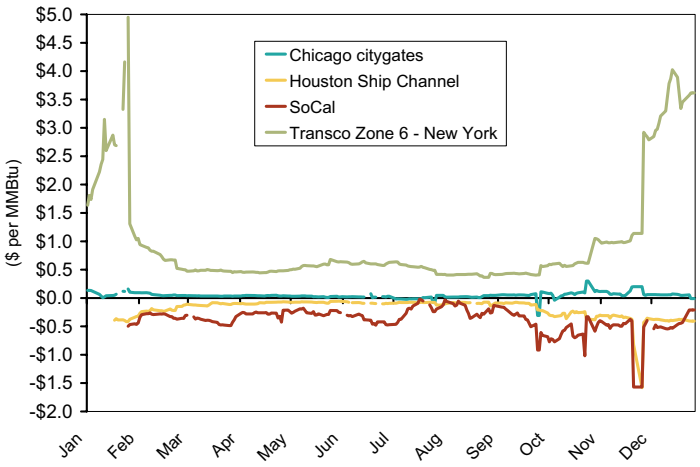
Historical volatility, as measured using futures settlement prices, was lower than it had been over the previous 3 years. Historical volatility is the annualized standard deviation of past price changes measured in percentage terms. The measurement of historical volatility shows what actually happened in the market as opposed to what is expected to occur in the future. Historical volatility measures the degree to which the market price moved up and down, and disregards the absolute price levels. Compared with the 2004 average, volatility was higher during two periods: winter 2003–2004, specifically January; and the onset of winter 2004–2005, specifically the fourth quarter of 2004.

OTHER FINANCIAL PRODUCTS

In addition to natural gas futures, other products were available to hedge natural gas prices during 2004. Basis swaps hedge the pricing differential between Henry Hub and specified delivery points. Basis swaps can have a physical or a financial settlement. Financial basis swaps settle on the difference between a monthly physical index and the Nymex expiration price. Trading for basis swaps takes place on a variety of platforms, including Nymex and IntercontinentalExchange (ICE), and through voice brokers and direct bilateral transactions. Financial basis swaps price on Nymex are shown for four select points over 2004; the prices are for the prompt month (see figure).

Source for chart at right: Derived from Bloomberg L.L.C data.

Swap Prices

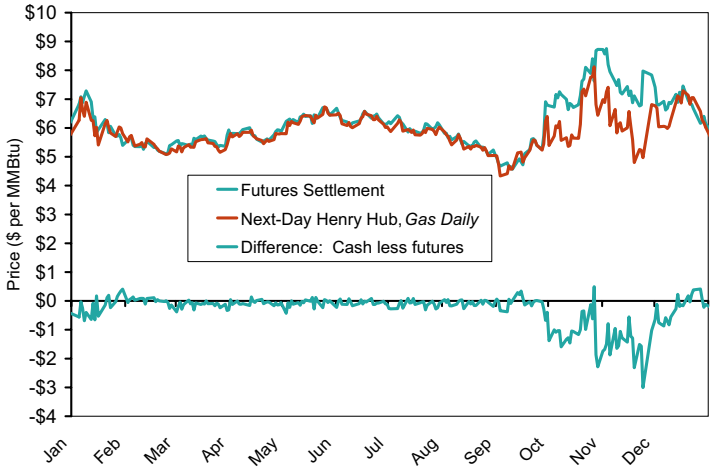


PHYSICAL TRADING

Physical trading of natural gas is related to financial trading for several reasons:

- Fundamental factors that influence the physical market, such as weather, supply, and demand, also affect financial product prices.
- Many physical purchase and sale contracts have pricing terms based on financial prices, the most prominent being the monthly Nymex natural gas futures expiration price. Correspondingly, many financial purchase and sales contracts have financial settlements linked to the physical monthly and daily indices. For example, monthly physical indices form part of the financial basis swap settlements.
- Nymex's natural gas futures contract has a physical delivery mechanism. If a market participant does not close out an open futures contract, then the participant must make or take delivery of the natural gas product at Henry Hub. The delivery mechanism helps to ensure that physical and futures prices converge at futures expiration. When physical and futures prices do not converge, market participants trade various physical and financial products in order to arbitrage the difference in the prices.

Next-Day Henry Hub Physical Prices



Source: Derived from Platts data.

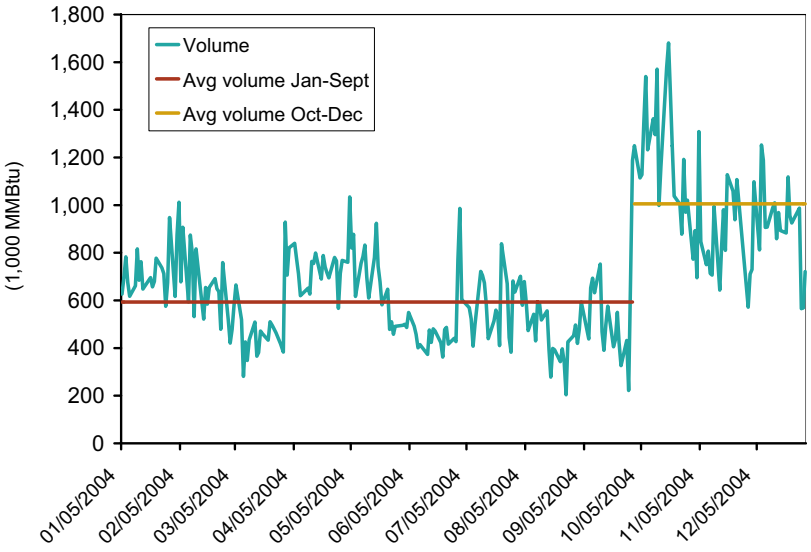
Physical natural gas trading experienced two trends in 2004: divergence of physical and financial prices at Henry Hub, and a rise in next-day Henry Hub physical volumes.

For most of the year, even during a period of relatively high volatility in January, the next-day physical prices at Henry Hub and the futures prompt-month prices corresponded closely. From January through September, an average difference of -$0.08 per MMBtu existed between next-day physical prices at Henry Hub and futures prompt-month settlement prices.[7] From October through December, the average difference jumped to -$.89 per MMBtu (see figure). Futures for most of the fourth quarter were trading at a premium to the next-day prices at Henry Hub. The difference between the prices was the largest average for a fourth quarter. The physical market may have been reacting to short-term, then-current fundamentals, such as weather that was not as cold as expected. The futures market was looking forward toward broader winter expectations.

Monthly physical indices at Henry Hub and the futures expiration price for 2004 settled at almost the same prices for most of 2004, the exception being for December when prices did not converge. From January through November 2004, there was an average difference of $0.006 between the monthly Platts *Gas Daily* Henry Hub index and the futures expiration price. In December 2004, a difference of -$0.196 per MMBtu occurred. This was the same bidweek when the EIA storage misreporting error of 32 Bcf occurred.

Volumes transacted for Henry Hub next-day physical rose during the fourth quarter of 2004. From January through September, total volume transacted per day averaged 500,000 MMBtu on ICE. (ICE volumes represent sell-side only.) From October through December, average total volume per day doubled to 1,006,000 MMBtu (see figure). The 2004 volumes are in relation to an average volume of 604,000 MMBtu on ICE during 2003.

Next-Day Henry Hub Physical Volumes



Source: Derived from ICE data.

Endnotes

[1] For specifications for the natural gas futures contract, see www.nymex.com.

[2] One futures contract is equivalent to 10,000 MMBtu.

[3] CFTC, "The Commitments of Traders Report" CFTC Backgrounders Number 4-91, July 2004. See http://www.cftc.gov/opa/backgrounder/opacot596.htm.

[4] Haigh, Michael S., Hranaiova, Jana, and Overdahl, James A., "Price Dynamics, Price Discovery and Large Futures Trader Interactions in the Energy Comples," Office of the Chief Economist, CFTC. See http://www.cftc.gov/files/opa/press05/opacftc-managed-money-trader-study.pdf.

[5] A Nymex March 2005 report, entitled "A Review of Recent Hedge Fund Participation in NYMEX Natural Gas and Crude Oil Futures Markets," states that hedge funds comprised 9.05% of trading volume and 20.4% of open interest for January through August 2004. A CFTC April 2005 report, entitled "Price Dynamics, Price Discovery and Large Futures Trader Interactions in the Energy Complex," examines open interest for August 2003 through August 2004.

[6] "Energy Comes into Focus for Hedge Funds," UtiliPoint International Inc., Analysts Corner, December 17, 2004, www.globalchange.com/articles/IA_December_17_2004_Reprint.pdf.

[7] The 2004 fourth-quarter difference between next-day physical prices at Henry Hub and futures prompt-month settlement compares to a more narrow difference in 2003. The difference for October through December 2003 was -$0.339 per MMBtu.

[8] Minerals Management Service, Hurricane Ivan evacuation and production shut-in statistics as of Friday, September 16, 2004.

[9] Summary of the FERC OMOI investigation of events related to the EIA Weekly Natural Gas Storage Report for November 24, 2004, http://www.ferc.gov/whats-new/hd-current/02-10-05.asp.

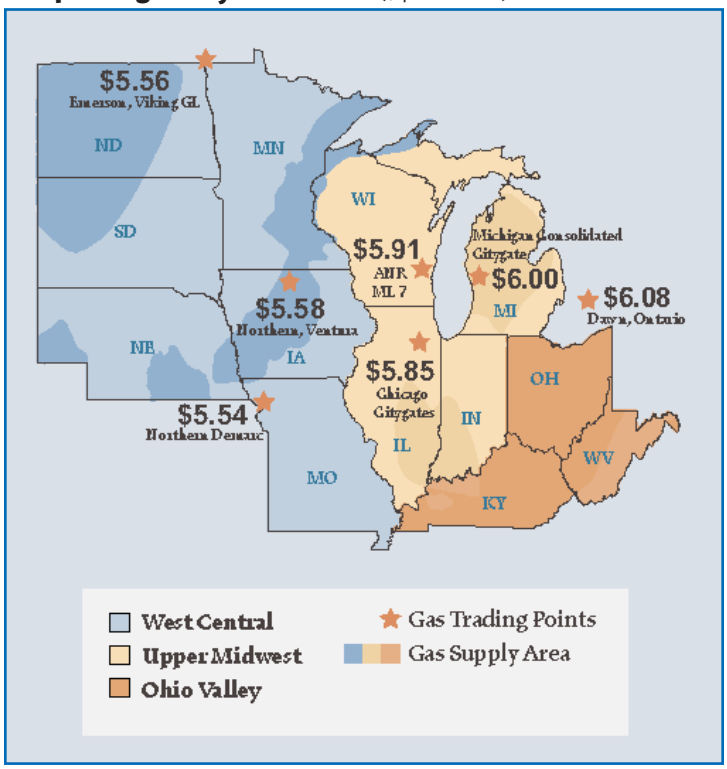
Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Midwest Natural Gas Market Profile

The Midwest market[1] has access to natural gas supply from throughout North America—British Columbia, the Western Canadian Sedimentary Basin, Appalachia, the Midcontinent, the Gulf Coast, and the Rocky Mountains. Regional natural gas production declined 2%, or by 14 Bcf in 2004. In 2004, the Midwest consumed 27% of total Lower 48 natural gas production, while accounting for 3% of total Lower 48 gas production. Imports to the region are critical. Estimated net Midwest imports of Canadian gas averaged 2.3 Bcfd.[2] Estimated net inter-regional firm gas interstate gas pipeline deliveries into the Midwest totaled 3.1 Tcf, or nearly 152 Bcfd.

The region had the highest share of residential and commercial gas use (57%).[3] Gas-fired power generators consumed 5% of gas in the Midwest in 2004, the least of any region, because of the large base of coal-fired power generating capacity. Approximately 4 Tcf of mostly underground, market-area storage supplements long-haul pipe deliveries during peak periods. Midwest market hubs at Chicago and Dawn linked gas resources from multiple production basins throughout North America to customers in eastern Canada and northeast United States.

2004 Average Daily Hub Prices ($ per MMBtu)



Source: Derived from Platts data.

Hub Prices ($ per MMBtu)

	2003	2004	5-Year
ANR ML7	$5.56	$5.91	$4.74
Chicago Citygates	$5.55	$5.85	$4.64
Dawn, Ontario	$5.78	$6.08	$4.74
Mich Consolidated Citygate	$5.68	$6.00	$4.70
Northern, Demarc	$5.28	$5.54	$4.44
Northern, Ventura	$5.32	$5.58	$4.45
AECO-C	$4.71	$5.04	$3.93
Emerson Viking GL	$5.20	$5.56	$4.20

Source: Derived from Platts data.

Focal Points for 2004

- **Higher hub prices.** Annual gas price differences between Louisiana's Henry Hub and Chicago averaged less than 1¢/MMBtu because of continued excess pipeline capacity. Prices at Alberta's AECO-C Hub[4] mirrored gas price increases at Henry Hub; both were up 7%.
- **Varied load factors.** Load factors on pipelines delivering gas from the Gulf Coast averaged 55%; load factors on pipelines delivering gas into the Midwest from western Canada and the Rocky Mountains generally exceeded 80%.
- **Successful sales of capacity rights.** Several Midwest gas pipelines vulnerable to firm contract expirations—Natural Gas Pipeline Co. of America (NGPL), Northern Border Pipeline, and Viking Gas Transmission—were successful, at least temporarily, in selling expiring firm capacity rights to various customers into 2005.
- **Lower gas consumption.** Estimated Midwest gas consumption declined 155 Bcf (3%) because of mild weather and higher natural gas prices that were up by 7%.

Midwest Supply Demand Statistics

Supply Disposition	2004 (Bcf)	2003 (Bcf)
Total Dry Production	585	599
Production by Region		
Michigan	186	195
Williston Basin	41	41
Other	358	363

Other Sources of Supply (2004 Bcf)

International Supply

	Imports	Exports	Net Imports
Canada	3,145	2,310	835
Mexico	0	0	0
LNG	0	0	0
Total	**3,145**	**2,310**	**835**

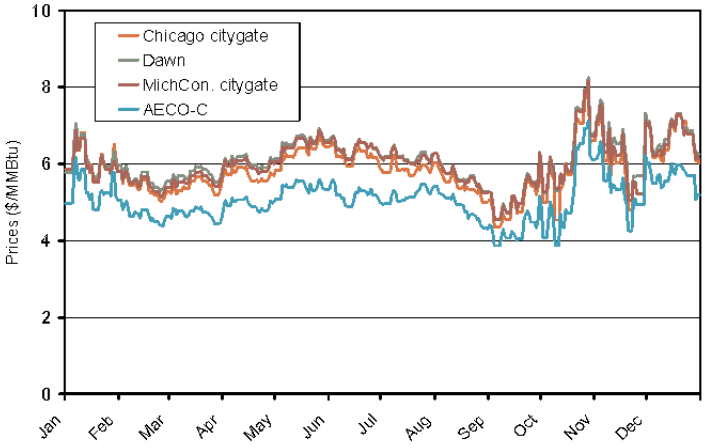
Source: Derived from Bentek Energy, LLC data. Note: Negative net imports are net exports.

Interregional Pipeline Flows	Net Imports
to Northeast	(1,366)
to Southeast	2,535
to South Central	1,706
to West	397
Total	**3,272**

Demand Disposition	2004 (Bcf)	2003 (Bcf)
Residential	1,871	1,990
Commercial	1,034	1,078
Industrial	1,638	1,618
Power	257	260
Losses and Other	288	297
Total	**5,088**	**5,243**
Key End Use Markets		
West Central - IA,NE,SD,MN,MO,ND	1,082	1,106
Upper Midwest - MI,WI,IL,IN	2,820	2,909
Ohio Valley - OH,WV,KY	1,185	1,227

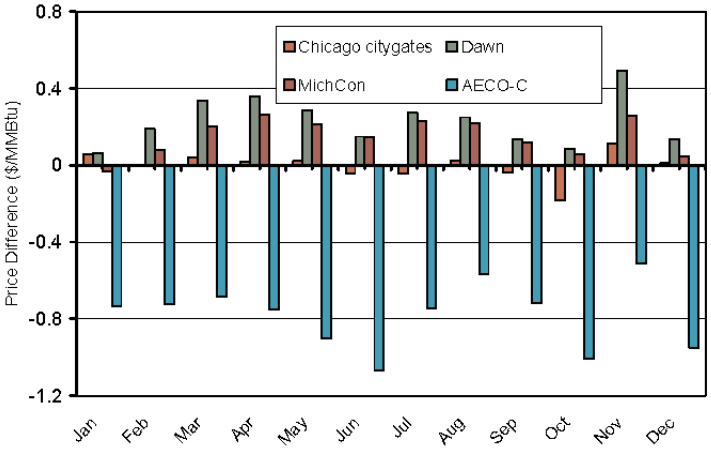
SPOT MARKETS: PRICES AND VOLUMES

Day-Ahead Spot Prices



Source: Derived from Platts data. See source note 1.

Monthly Average Basis Value to Henry Hub

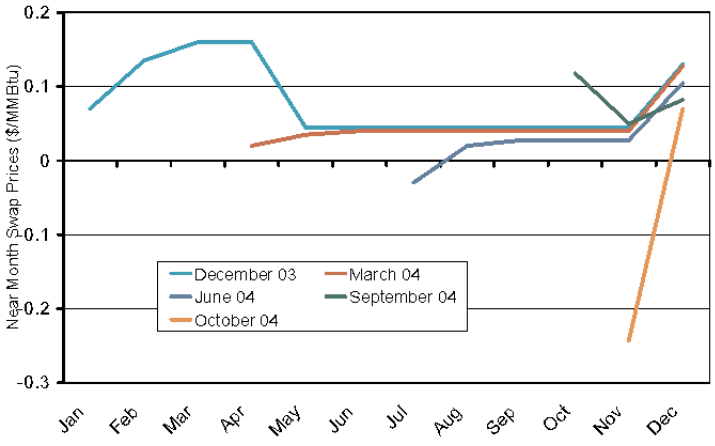


Source: Derived from Platts data. See source note 2.

Annual spot gas prices at key Midwest trading points—the Chicago citygates, Dawn,[5] and Michigan Consolidated Gas Co.[6] citygate—averaged $5.98/MMBtu in 2004, approximately $0.30/MMBtu higher than 2003 prices. During 2004, daily prices at these points ranged between $4.36/MMBtu and $8.25/MMBtu. Chicago gas typically traded lower than MichCon (by $0.08/MMBtu) and Dawn prices (by $0.23/MMBtu). The basis between the Henry Hub and Chicago averaged less than $0.01/MMBtu in 2004 because of excess regional pipeline capacity and mild weather. In fact, Chicago gas was less expensive than gas at the Henry Hub throughout much of June, July, September, and October. For the first time, AECO gas prices averaged more than $5.00/MMBtu (U.S.) in 2004. The basis between AECO and Midwest market points varied between $0.94/MMBtu for downstream points (Chicago, Dawn, and Michigan) and about $0.50/MMBtu for more upstream Midwest points (Demarcation and Ventura).

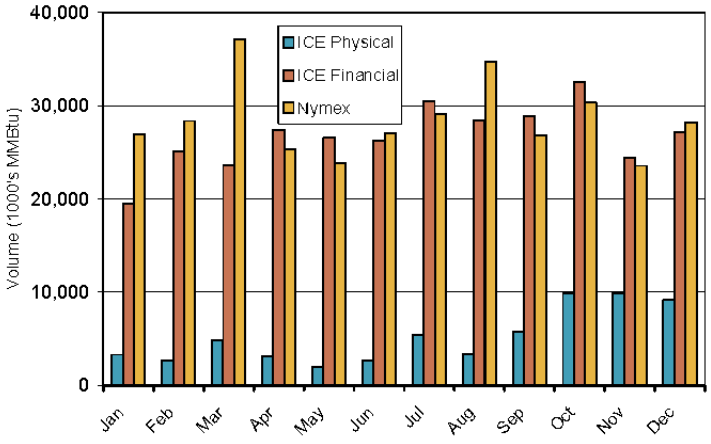
FINANCIAL MARKETS: PRICES AND VOLUMES

Chicago Citygate Swaps Prices from Trade Date



Source: Derived from Bloomberg L.P. and Nymex data. See source note 3.

Chicago Citygates Forward and Swaps Volume



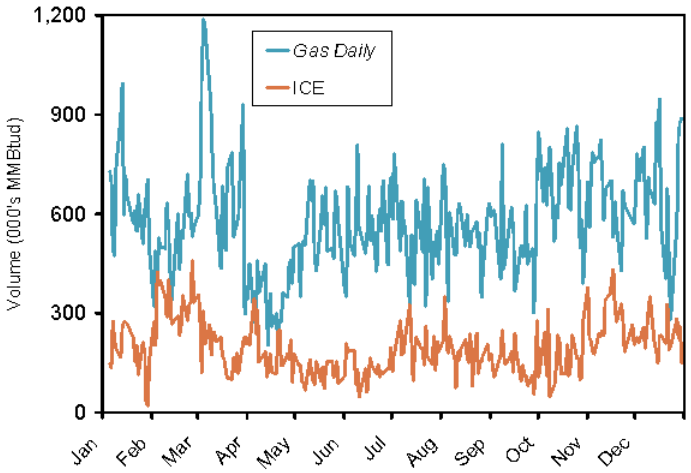
Source: Derived from ICE, Bloomberg, L.P. and Nymex data.

Expectations for end-of-year (November and December) basis swaps in the Chicago market were consistent throughout much of 2004. Through September, swap transactions reported by New York Mercantile Exchange's (Nymex) ClearPort indicated narrow trading ranges for basis between Henry Hub and Chicago—just $0.02–$0.05/MMBtu for November and $0.08–$0.13/MMBtu for December. Except in October, actual basis values for the Chicago citygate point approximated average forward expectations. The Henry Hub futures price increased from $5.11/MMBtu in mid-September (for October delivery) to $8.40/MMBtu by the end of October (for November delivery) because of gas production shortfalls in the Hurricane Ivan aftermath and an escalation in crude oil prices. As a result, the Henry Hub price rose significantly in relation to the Chicago price, leading to a negative $0.23/MMBtu basis in November.

The monthly volume of financial basis swaps for the Chicago market gas traded between 20 and 40 million MMBtu on IntercontinentalExchange (ICE) and Nymex ClearPort. Physical market trades reported on ICE accounted for 20%–35% of financial product volume.[7]

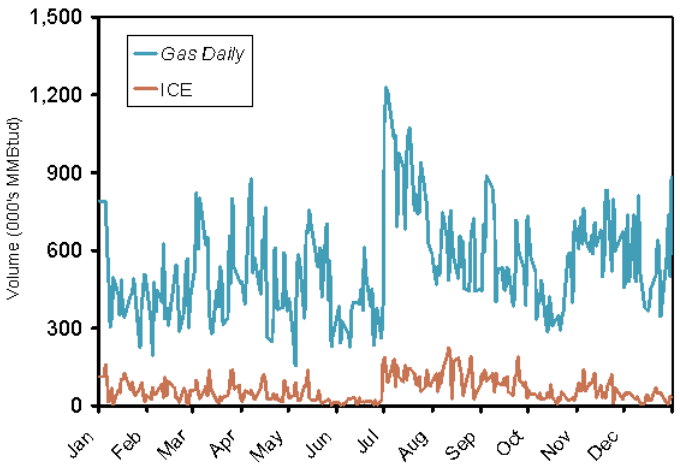
HUB POINTS: VOLUMES

Chicago Citygates Reported Volumes



Source: Derived from Platts and ICE data. See source note 4.

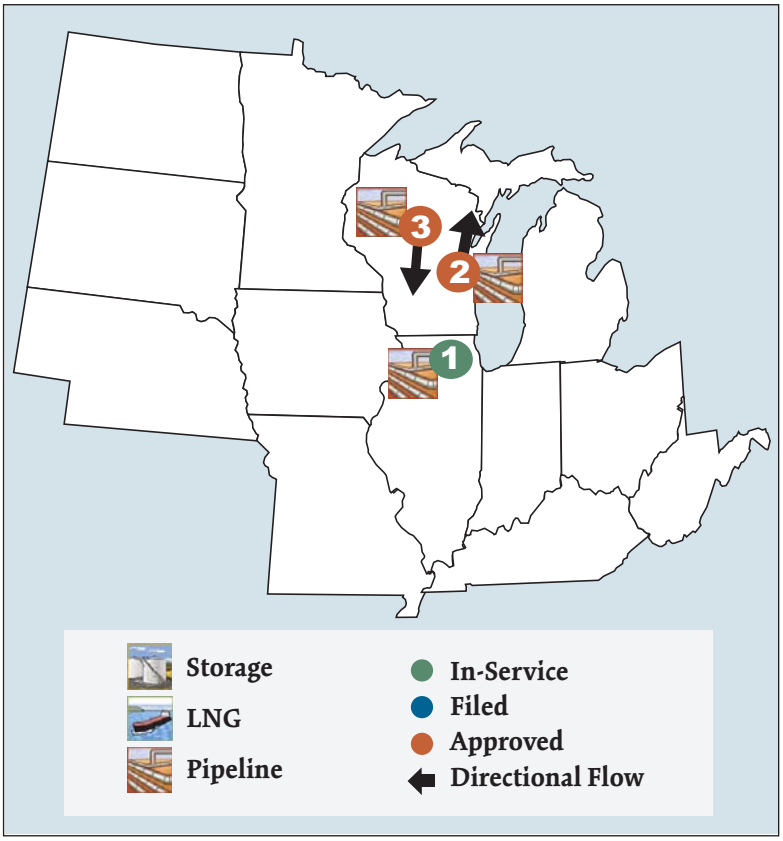
Dawn Ontario Reported Volumes



Source: Derived from Platts and ICE data. See source note 4.

Daily gas trading at Midwest hubs was mixed in 2004. During 2004, Chicago citygate trading averaged between 579,000 MMBtu (*Gas Daily*) and 207,000 MMBtu (ICE). Between 2003 and 2004, average trading volumes reported by *Gas Daily* increased 14% whereas ICE trading declined 28%. The highest reported single-day Chicago citygate trading volume occurred on March 3 (*Gas Daily*) and December 21 (ICE). *Gas Daily* and ICE trading differed by nearly a 0.5 Bcfd at Dawn. According to *Gas Daily*, trading was robust and averaged 538,000 MMBtu whereas ICE trading averaged only 63,000 MMBtu.

NATURAL GAS INFRASTRUCTURE DEVELOPMENTS



PROJECT DEVELOPMENT

1. West Leg Expansion Project
2. East Leg Expansion Project
3. North Leg Project

This map numbering system corresponds to the chart below on Pipeline Projects.

Only 220 MMcfd of new interstate gas pipeline capacity started commercial service in 2004. The ANR Storage Co.'s West Leg project serving Wisconsin entered commercial service in phases between January and October. The Midwest continued to benefit from the nearly 7.3 Bcfd of gas pipeline capacity added between 1999 and 2003, including 2.9 Bcfd of long-haul pipeline from Rocky Mountain and western Canadian production areas to markets in the Midwest.[8] Kinder Morgan Interstate Transmission added 3 Bcf of working gas capacity and 169 MMcfd of deliverability to its Huntsman Storage facility in Cheyenne County, Neb., in 2004. New facilities included 4 new compressor units, 10 new injection/withdrawal wells, 2 new storage field pipelines, construction of a new compressor station, and certain auxiliary or appurtenant facilities.

FERC approved construction of another 250 MMcfd of ANR capacity in Wisconsin. Northern Border Pipeline announced commitments from shippers to support a proposed expansion in the Chicago market area. The $20 million Chicago Expansion III project (130 MMcfd) requires new compressor station construction and modifications to existing compressor stations. The projected in-service date is April 2006; Northern Border Pipeline filed a certificate application with FERC in January 2005.

Pipeline Projects

Company	Project Name	Capacity (MMcfd)	Capital Cost (Millions)+	Status	Year Certificated	From-To State
1-ANR Pipeline Company	West Leg Expansion Project	220	$42	In-Service 01/04 & 10/04	2003	WI-WI
2-ANR Pipeline Company	East Leg Expansion Project	143	$19	Approved	2004	WI-WI
3-ANR Pipeline Company	North Leg Project	107	$14	Approved	2004	WI-WI
Total		**470**	**$75**			

Source: FERC Office of Energy Projects. + Capital cost figures are estimates.

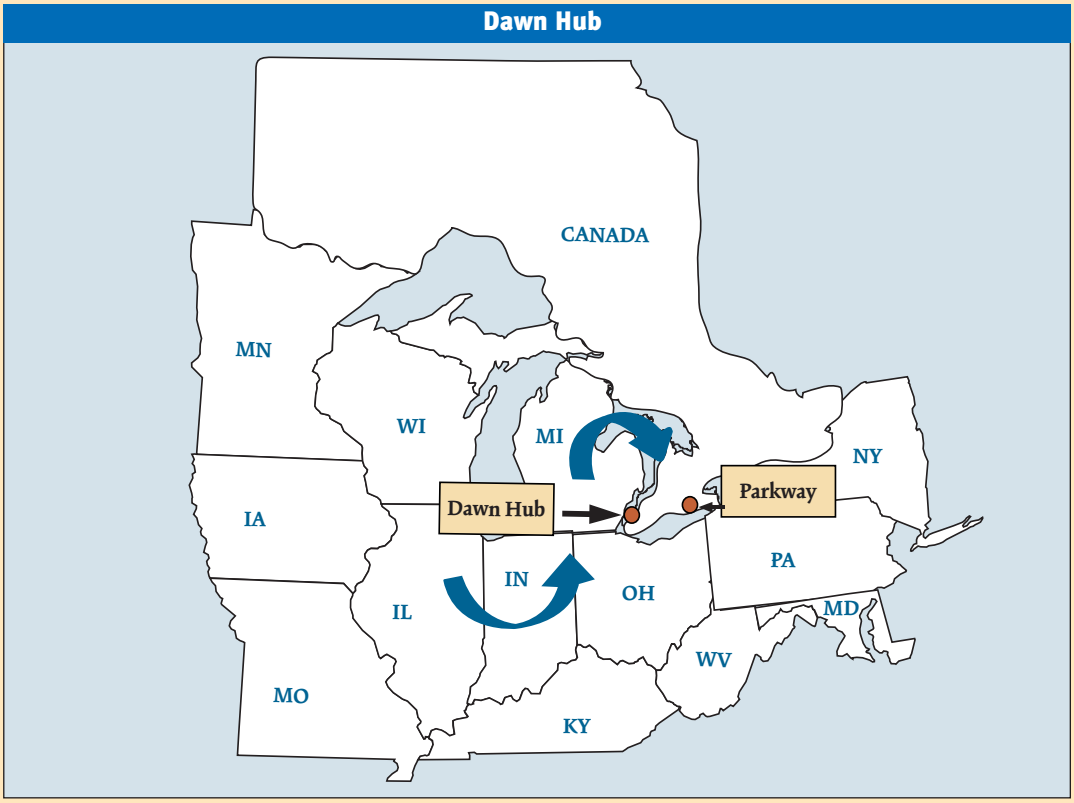
Dawn Links Midwestern and Northeastern Gas Markets

The Dawn Hub is an increasingly important link that integrates gas produced from multiple basins for delivery to customers in the Midwest and Northeast. Union Gas Ltd, an affiliate of Duke Energy Corp, operates the hub.[9] Trading activity at Dawn increased 0.7 Bcfd, or 11%, in 2004 over 2003, to 6.8 Bcfd. The principal participants trading at Dawn include U.S. Northeast and Ontario local distribution companies, retail energy marketers, traditional marketers, and financial institutions. Estimated peak-day throughput was 2.6 Bcfd at Dawn, which includes 20 depleted reservoirs with 150 Bcf of storage capacity.[10]

Dawn has many of the attributes that customers seek as they structure gas transactions at the Chicago Hub: access to diverse sources of gas production; interconnection to multiple pipelines; proximity to market area storage; choice of seasonal and daily park and loan storage services;[11] liquid trade markets and transparent pricing; and opportunities to reduce long-haul pipeline capacity ownership by purchasing gas at downstream liquid hubs.

Interest in gas service at Dawn is growing. Union Gas concluded a binding open season for incremental transportation service between Dawn and Parkway in December 2004. As a result, Union Gas executed firm contracts for 370 MMcfd of capacity with average terms of 12 years. A consortium of U.S. customers was among the 23 parties that acquired this capacity. The consortium decided to acquire a portion of its gas requirements at Dawn rather than buy gas upstream in Alberta. Union Gas submitted an application for the expansion project to the Ontario Energy Board on March 22, 2005. Vector Pipeline LP, which delivers natural gas from Chicago into the greater Dawn market through a 1-Bcfd pipeline, held an open season in April 2005 to add up to 0.5 Bcfd of new capacity through the construction of additional compressor stations on its system.

Dawn Hub



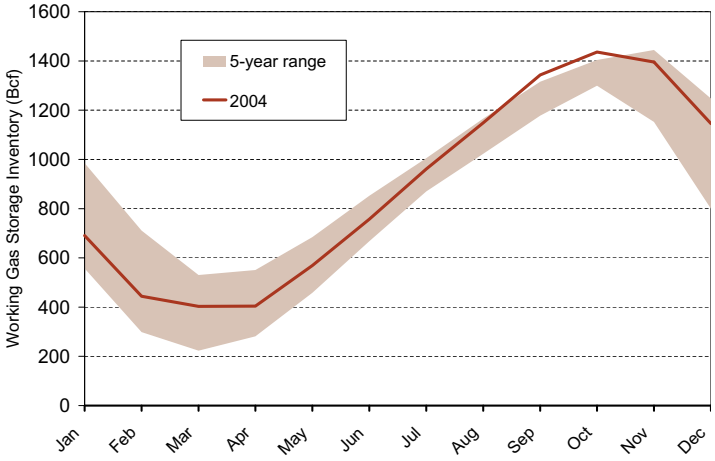
REGIONAL GAS SUPPLY

An extensive network of interstate pipelines gives the Midwest region access to gas supply from western Canada and virtually every producing basin in the United States and offshore Gulf of Mexico. Northern Border and Alliance delivered an estimated 1.4 Tcf (3.8 Bcfd) of western Canadian gas into the Midwest.[12] The region is well supplied, and customers purchase their supplies not only at the regional Chicago and Dawn hubs but also farther upstream at the many production basins. Michigan and West Virginia (375 Bcf) account for almost two-thirds of production within the region. Regional dry proved reserves total 10,200 Bcf.

Approximately 3.7 Tcf (46%) of U.S. gas storage capacity is located in the Midwest market. Customers in the region rely upon market area storage to meet winter peak requirements and to provide no-notice service in support of peaking gas-fired generation. The Midwest has 181 storage sites consisting of depleted field, aquifer, and salt cavern storage capacity. NiSource Inc., ANR,[13] and NGPL own extensive storage facilities in Indiana, Iowa, Illinois, and Michigan. These storage facilities are connected to intrastate pipeline systems and interstate pipeline systems. Columbia Gas Transmission and Dominion Transmission Interstate own significant storage facilities in West Virginia and Ohio connected to their web-like systems.

This network facilitates gas movement from storage within and out of the Midwest region. The Michigan and Chicago markets rely upon ANR and its storage facilities. Meanwhile, states in the Northeast and Mid-Atlantic draw heavily upon storage capacity in West Virginia and Ohio to meet peak-day consumption during the winter.

Regional Storage Inventory Levels



Source: Derived from EIA data. See source note 5.

Midwest regional working gas inventories closely mirrored 5-year averages for the first half of 2004. A relatively mild winter in 2003–04 (heating degree days were about 94% of normal) and a cool summer (cooling degree days averaged 83% of normal[14]) resulted in an exceptionally high working gas inventory, almost 1,400 Bcf, going into the winter withdrawal season.

Storage and Gas Reserves Overview

	Depleted Gas/Oil		Aquifer		Salt Cavern		Total Storage		Dry Proved Reserves
	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	(Bcf)
Illinois	12	206	17	767	0	0	29	972	0
Indiana	11	32	12	81	0	0	23	114	0
Iowa	0	0	4	273	0	0	4	273	0
Kentucky	20	211	3	10	0	0	23	221	1,889
Michigan	42	1,025	0	0	2	4	44	1,028	3,428
Minnesota	0	0	1	7	0	0	1	7	0
Missouri	0	0	1	32	0	0	1	32	0
Nebraska	1	39	0	0	0	0	1	39	0
N. Dakota	0	0	0	0	0	0	0	0	448
Ohio	24	572	0	0	0	0	24	572	1,126
West Virginia	31	511	0	0	0	0	31	511	3,306
Total	**141**	**2,596**	**38**	**1,170**	**2**	**4**	**181**	**3,770**	**10,197**

Source: Derived from EIA data. See source note 6. Note: Totals may not equal sum of components due to rounding.

MARKET CONCENTRATION

Ownership of interstate natural gas transportation rights in the greater Chicago market is not concentrated. Three LDCs—Northern Illinois Gas, Peoples Gas, Light & Coke, Co., and Northern Indiana Public Service Co.—owned about 50% of the firm interstate natural gas pipeline delivery rights in the greater Chicago market in 2004. The top ten shippers in this market owned 69% of aggregate delivery rights. However, excess pipeline capacity rights exist and market-based transportation services reflect steep discounts, especially on U.S. Gulf Coast pipelines.

Greater Chicago Capacity by Holding Company (MMcf)

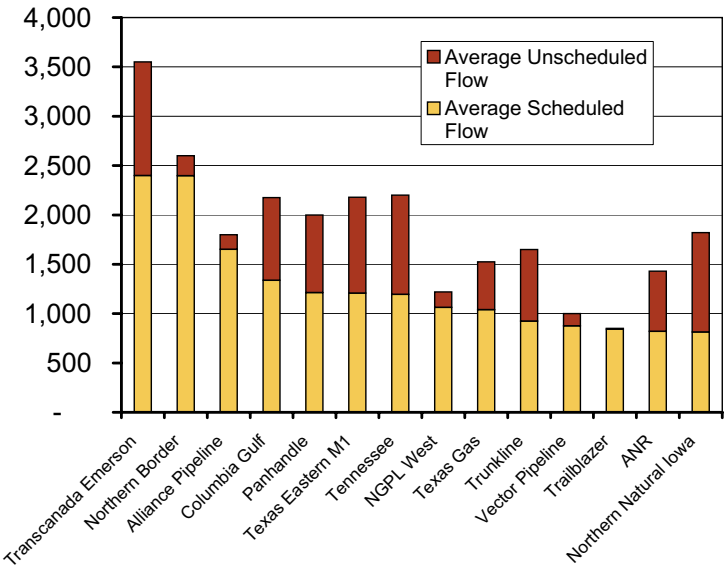
Rank	Customer	Alliance	ANR	Midwestern Gas Pipeline	Natural Gas Pipeline	No. Border Pipeline Co.	Total	Percent of Total
1	Northern Illinois Gas Co.		220	327	1,350		1,897	26%
2	Peoples Gas, Light & Coke Co.		344	96	488	220	1,147	16%
3	Northern Indiana Public Service Co.			70	540		609	8%
4	North Shore Gas Co.		126		123	41	290	4%
5	Wisconsin Gas Co.		228				228	3%
6	BP Canada Energy Co.				125	80	205	3%
7	Wisconsin Electric Power Co.		122		57		179	2%
8	El Paso Merchant Energy, LP	160					160	2%
9	Burlington Resources Canada Energy Ltd	82			25	31	138	2%
10	EnCana Marketing (USA), Inc.	69			26	26	121	2%
	All Others	**1,140**	**174**	**53**	**558**	**278**	**2,203**	**31%**

Source: Derived from Platts data. See source note 7. One million Btu assumed to equal 1 Mcf.

PIPELINE UTILIZATION

A wide variety of pipelines serve the Midwest, the largest of which are TransCanada and Northern Border. In general, pipelines from the Gulf Coast (for example, Panhandle, Texas Eastern, and Tennessee) have lower utilization rates than pipelines from the West. Customers use almost all the capacity available on some of the pipelines from farther west (for example, Trailblazer, Northern Border, and the western leg of Natural Gas Pipeline of America). This usage is consistent with a pattern of lower gas prices in western producing regions.

Average Annual Gas Flows (MMcfd)



Source: Derived from Lippman Consulting Inc., Platts and pipeline company data. See source note 8.

Endnotes

[1] OMOI defines the gas market in the Midwest to include 13 states in 3 sub-regions: West Central (Iowa, Minnesota, Missouri, North Dakota, and South Dakota), the Upper Midwest (Illinois, Indiana, Michigan, and Wisconsin) and the Ohio Valley (Kentucky, Ohio, and West Virginia).

[2] Total imports averaged 6.2 Bcfd but approximately 2.3 Bcfd of Canadian gas was re-exported to Canada. Some of this gas ultimately flows into the northeast U.S. gas market.

[3] Bentek Energy LLC Pipe2Pipe tool natural gas transportation analysis tool.

[4] The AECO-C/Nova Inventory Transfer market center links Canadian natural gas supplies through interconnections with a long-distance gas transportation network to markets in Canada and the U.S. Also, it is the main pricing point for Alberta natural gas and represents the major reference pricing point for Canadian gas. AECO-C prices are determined via the spot market.

[5] Natural gas trading hub located in Ontario, Canada; Dawn is an integral part of the Union Gas system.

[6] According to Nymex ClearPort, MichCon is a natural gas price reporting point that encompasses Michigan Consolidated Gas Co.'s 14,700 square-mile service area and 1.2 million customers. MichCon is an operating subsidiary of DTE Energy Company.

[7] Excludes swap trades executed by voice brokers and other over-the-counter exchanges. OMOI believes trading volume by voice brokers accounts for a sizable share of swap transactions.

[8] Represents capacity expansions on Northern Border in 1999 (0.69 Bcfd), Alliance Pipeline in 2000 (1.6 Bcfd), Trailblazer in 2002 (0.32 Bcfd), and TransCanada (0.23 Bcfd).

[9] Duke Energy Corp, "Union Gas Signs Customer Contracts to Support Natural Gas Infrastructure Expansion in Ontario," news release, March 22, 2005.

[10] Energy Information Administration (EIA), "Natural Gas Market Centers and Hubs," October 2003.

[11] According to EIA, parking refers to a short-term transaction in which the market center holds the shipper's gas for redelivery at a later date. Often storage facilities are used and sometimes displacement or variations in linepack. Loaning refers to a short-term advance of gas to a shipper by a market center that is repaid in kind by the shipper a short time later. Loaning also is referred to as advancing, drafting, reverse parking, and imbalance resolution.

[12] Derived from information provided by Bentek Energy LLC.

[13] Interests in 120 Bcf of storage capacity and peak-day withdrawal capability of 1.5 Bcfd. Partial ownership in more than 60 Bcf of storage capacity in Michigan.

[14] Derived from National Oceanic and Atmospheric Administration data. OMOI analysis.

Source notes

1. Prices reflect the mid-point of day-ahead, spot transactions. All prices reported for flow date.

2. Prices reflect the basis or difference between the delivered price at a downstream market hub and the price of natural gas reported at the Henry Hub for spot, day-ahead transactions. Differences between downstream hub prices reported by *Gas Daily* and the Henry Hub for every calendar flow date in a month are averaged.

3. Reflects near-month natural gas swap price.

4. Trading volumes reported by *Gas Daily* at various market hubs often exceed ICE reported volumes because *Gas Daily* may count the same transaction twice—once from a seller's standpoint and once from a buyer's standpoint. Conversely, as exchange traded products, transactions involving two counterparties are reported only once by ICE.

5. Data for 2003 derived from EIA files entitled "ng_stor_sum_dcu****.xls," where the wild card represents the state designation. Storage activity for 2004 derived from a file provided by EIA, "Working Gas by State and Month – EIA 2004.xls."

6. Storage: "Natural Gas Annual 2003," Movements and Storage – Table 14, EIA. Proved reserves: file "ng_enr_dry_a_EPG0_R11_Bcf_a.xls", Dry Natural Gas Proved Reserves as of December 31, 2003, EIA. File as of April 1, 2005.

7. Uses the first quarter 2005 index of customers. Excludes firm natural gas storage contracts and transportation deliveries to other pipeline companies. Incorporates firm delivery contracts for counties representing the greater Chicago gas market: Cook, DuPage, Grundy, Kane, Kankakee, Kendall, Lake, McHenry, and Will counties.

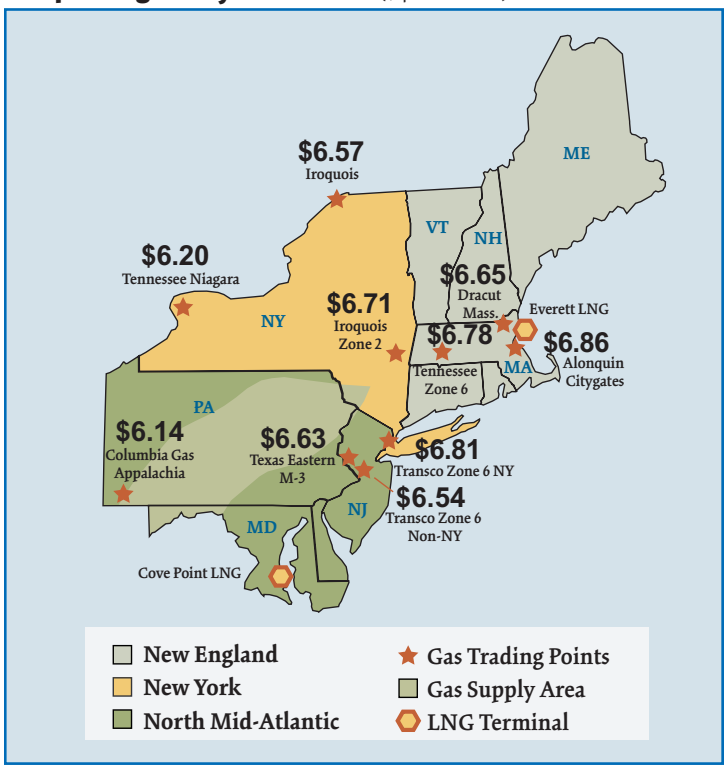
8. Operationally available capacity data bases from Platts GasDat; operationally available capacity information from pipeline company informational postings; "Monthly Pipeline Reports" and "Monthly Regional Capacity Reports" from Lippman Consulting, Inc; and OMOI analysis.

Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Northeast Natural Gas Market Profile

The Northeast[1] is vulnerable to natural gas price spikes. This condition is especially true in winter, when space-heat gas requirements (energy used to heat homes and businesses rather than to power industrial processes) may coincide with the need to run gas-fired power plants. Customers rely on an extensive network of interstate pipelines to obtain gas from various North American basins (e.g., Sable Island, the Western Canadian Sedimentary Basin, Appalachia, the Gulf Coast) because the Northeast has few native gas reserves. Liquefied natural gas (LNG), an increasingly important source of regional supply, accounts for up to 30% of peak-day supply in New England. About 949 Bcf of underground market-area storage, located in Pennsylvania and New York, augments long-haul pipeline deliveries during peak periods. Estimated gas consumption declined 110 Bcf (3%) in 2004 compared with 2003. Mild weather lowered space-heat gas consumption for the residential and commercial sectors by 7%, whereas gas-fired power needs increased 51 Bcf (6%). The Northern Mid-Atlantic subregion accounted for 47% of total regional consumption. Regional dependency on internationally supplied gas increased 19%, from 985 Bcf to 1,176 Bcf, between 2003 and 2004. Estimated dry gas production in the Northeast was unchanged. Estimated daily firm gas deliveries on interstate pipelines to the Northeast from the Midwest and Southeast averaged 3.7 Bcfd and 1.9 Bcfd, respectively.[2]

2004 Average Daily Hub Prices ($ per MMBtu)



Source: Derived from Platts data.

Hub Prices ($ per MMBtu)

	2003	2004	5-Year
Algonquin Citygates	$6.51	$6.86	$5.34
Columbia Gas Appalachia	$5.69	$6.14	$4.80
Dracut Mass.	$6.29	$6.65	$5.13
Iroquois	$6.14	$6.57	$4.98
Tennessee Zone 6	$6.45	$6.78	$5.23
Texas Eastern M3	$6.37	$6.63	$5.20
Transco Zone 6 Non-NY	$6.36	$6.54	$5.23
Transco Zone 6 NY	$6.45	$6.81	$5.43

Source: Derived from Platts *Gas Daily* data.

Focal Points for 2004

- **The New England cold snap** of January 2004 resulted in record gas prices (more than $70/MMBtu) and peak-day send-out records. Market performance during January 14–16 highlighted issues related to the adequacy of existing gas-related infrastructure, the challenges of gas and power coordination, the influence of environmental policies on fuel use, and fuel procurement strategies.
- **Eastern Canadian gas exports** to the Northeast continued to decline in 2004. The Canadian National Energy Board (NEB) estimates that Canadian East Coast offshore production declined from 435 MMcfd in 2003 to 405 MMcfd in 2004 due to unexpectedly high decline rates.[3] Sable gas production may turn out to be one-half of the original estimated reserves of 3.7 Tcf.[4] Exploratory seabed drilling off Nova Scotia was unsuccessful in 2004; wells were abandoned because of the lack of hydrocarbons.[5]
- **Average gas-trading** volumes reported by Platts *Gas Daily* and the IntercontinentalExchange (ICE) in the Northeast increased markedly in 2004. For example, average annual volumes traded at Transco Zone 6 N.Y. rose 78% (*Gas Daily*) and 47% (ICE).

Northeast Supply Demand Statistics

Supply Disposition	2004 (Bcf)	2003 (Bcf)
Total Dry Production	159	159
Production by Region		
Appalachian	159	159

Other Sources of Supply (2004 Bcf)

International Supply

	Imports	Exports	Net Imports
Canada	893	0	893
Mexico	0	0	0
LNG	283	0	283
Total	**1,176**	**0**	**1,176**

Interregional Pipeline Flows

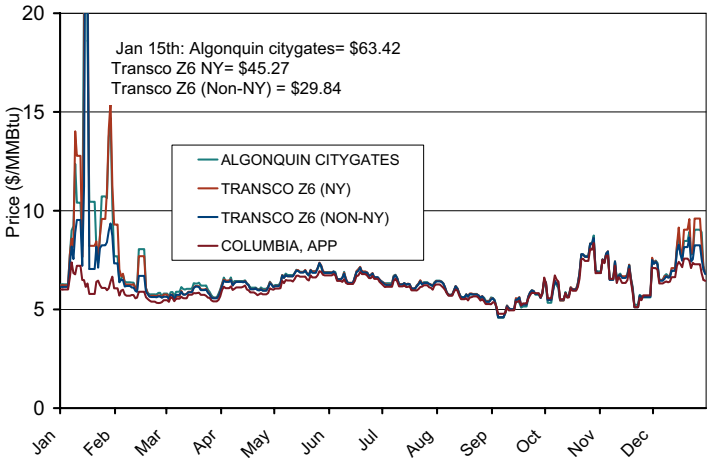
	Imports	Exports	Net Imports
to Midwest	1,366	0	1,366
to Southeast	687	0	687
Total	**2,053**	**0**	**2,053**

Demand Disposition	2004 (Bcf)	2003 (Bcf)
Residential	1,185	1,242
Commercial	779	880
Industrial	518	519
Power	849	798
Losses and other	165	166
Total	**3,495**	**3,605**
Key End Use Markets		
New England - RI,ME,NH,MA,VT,CT	828	824
New York—NY	1,026	1,146
Northern Mid-Atlantic - DC,DE,NJ,PA,MD	1,641	1,636

Source: Derived from Bentek Energy, LLC data.
Negative net imports are net exports.

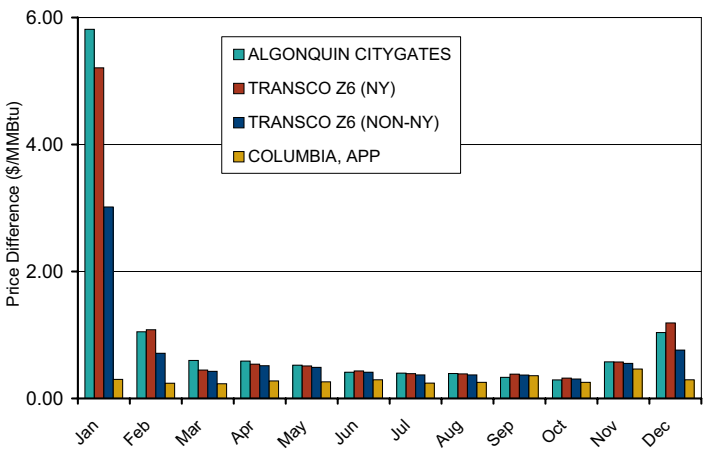
SPOT MARKETS: PRICES AND VOLUMES

Day-ahead Spot Prices



Source: Derived from Platts data. See source note 1.

Monthly Average Basis Value to Henry Hub

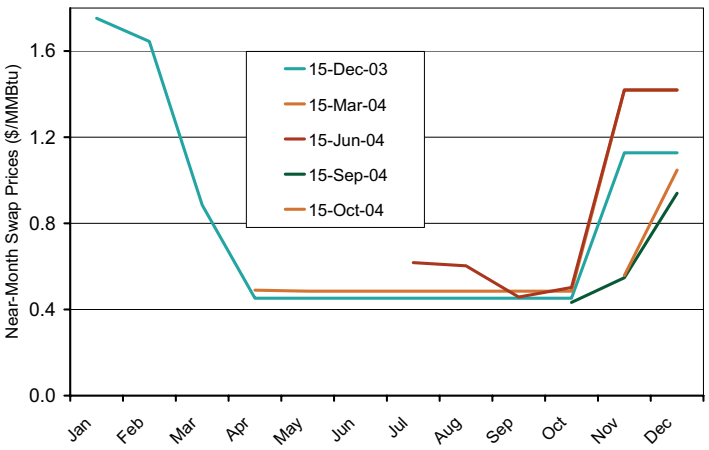


Source: Derived from Platts data. See source note 2.

Daily natural gas spot prices reached record levels during the Northeast cold snap in mid-January. On January 15, gas prices for day-ahead spot gas (*Gas Daily*) climbed to more than $70/MMBtu in New England and New York City. In sharp contrast, the lowest Northeast prices reported during 2004 were about $4.40/MMBtu. Delivered regional prices were about $0.30–$0.40/MMBtu higher in 2004 overall, compared with 2003. Occasionally high basis values reflected pipelines operating at peak conditions with high space-heat demand and coincident gas-driven power load. Transco Zone 6 N.Y. basis averaged $0.96/MMBtu for the year.

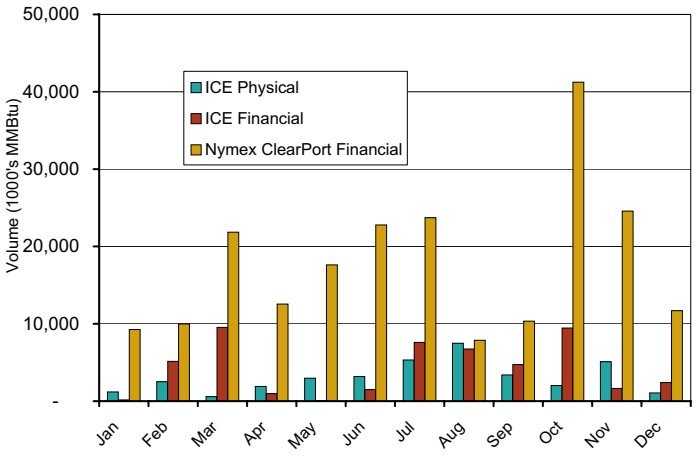
FINANCIAL MARKETS: PRICES AND VOLUMES

Transco Zone 6 NY Swaps Prices from Trade Date



Source: Derived from Bloomberg L.P. and Nymex data. See source note 3.

Transco Zone 6 NY Forward and Swaps Volume

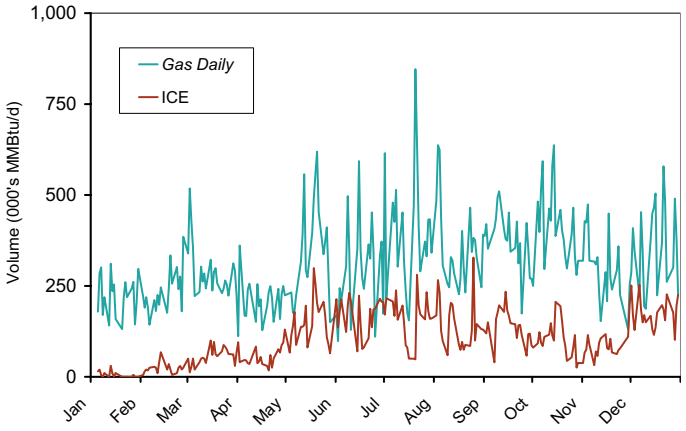


Source: Derived from Bloomberg L.P., ICE and Nymex data.

The value of Transco Zone 6 N.Y. basis-swap contracts for settlement in the winter of 2004–2005 increased between March 2004 and October 2004 despite improving market fundamentals (near-record gas storage inventory levels and mild weather). During this period, Transco Zone 6 swap prices for the 2004–2005 winter strip[6] increased from $1.42/MMBtu to $1.72/MMBtu (21%). The increase was probably due to market participant concerns about winter gas deliverability in light of hurricane-related cumulative gas production shut-ins and markedly higher crude oil futures prices. Transco Zone 6 basis-swap volumes reported by the New York Mercantile Exchange's (Nymex) ClearPort in 2004 were about 2.5 times greater than the combined volumes for ICE physical and financial basis-swap products at Transco Zone 6 N.Y.[7]

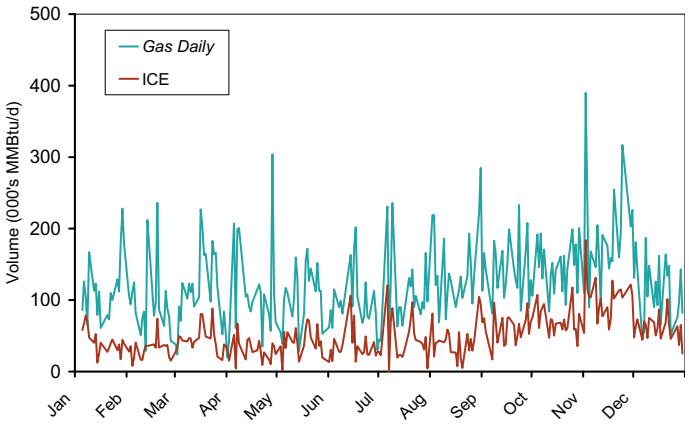
HUB POINTS: VOLUMES

Transco Zone 6-NY Reported Volumes



Source: Derived from Platts and ICE data. See source note 4.

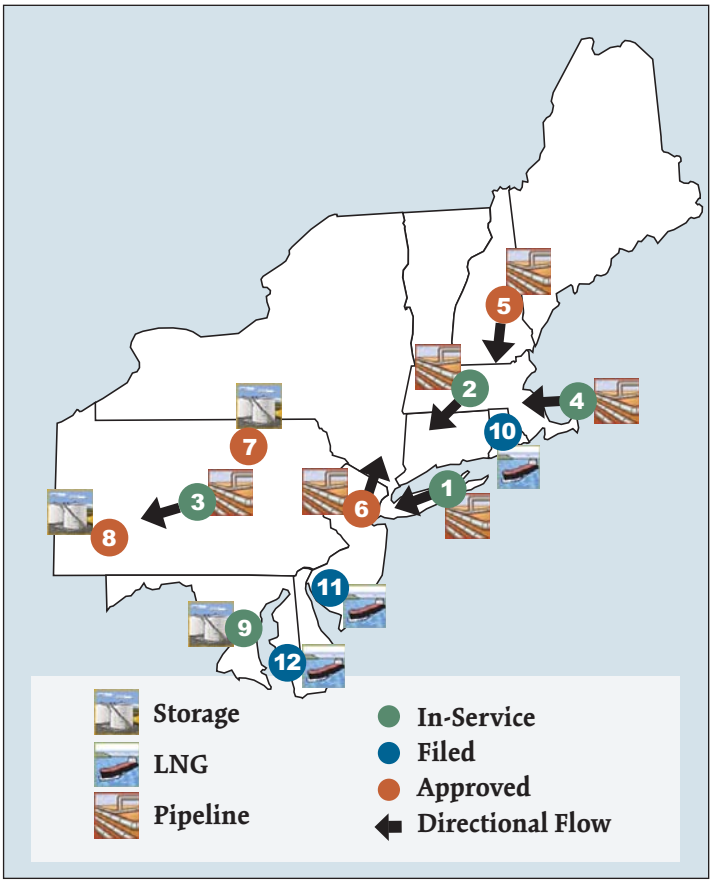
Alonquin Citygates Reported Volumes



Source: Derived from Platts and ICE data. See source note 4.

Average daily trading volumes reported by *Gas Daily* were also greater than volumes reported by ICE at the Transco 6 N.Y. and Algonquin citygates. Trading reported by both *Gas Daily* and ICE at these points increased in 2004 compared with 2003. Average annual volumes reported by *Gas Daily* increased 78% (from 179,000 MMBtu to 319,000 MMBtu) at Transco Zone 6 N.Y. and 50% (from 83,000 MMBtu to 124,000 MMBtu) at Algonquin citygates. Similarly, average annual volumes reported by ICE increased about 47% at Transco Zone 6 N.Y. (from 79,000 MMBtu to 117,000 MMBtu) and 40% (from 36,000 MMBtu to 51,000 MMBtu) at Algonquin citygates.

NATURAL GAS INFRASTRUCTURE DEVELOPMENTS



PROJECT DEVELOPMENT

1. Eastchester Extension
2. Everett Alternative Project
3. Mid-Atlantic Expansion Project
4. I-8 System Uprate Project
5. Tewksbury-Andover Lateral Project
6. Central New Jersey Expansion Project
7. Little Acre Interconnect
8. Mid-Atlantic Expansion Project
9. Cove Point Storage (5th tank)
10. Providence Facility Upgrade Project
11. Crown Landing LNG
12. Cove Point Expansion

This map numbering system corresponds to the following 3 charts on pipelines, storage, and LNG projects.

Northeast gas infrastructure additions in 2004 were limited. Iroquois Gas Transmission System, Texas Eastern Transmission, and Algonquin Gas Transmission added 663 MMcfd of new interstate pipeline capacity in 2004. These mainly short-haul projects fostered greater supply flexibility, improved reliability along existing transportation routes, and brought more gas into the constrained New York market. The Eastchester Project was the most important. Improvements there have enabled Consolidated Edison Inc. (ConEd), to back-haul up to 160,000 MMBtu/d of gas into its distribution system, enhanced linkages between the New England and New York gas markets, and helped ConEd avoid some capital outlays.[8] Also, FERC approved another 130 MMcfd of pipeline capacity and 263 MMcfd in gas storage deliverability in the Northeast. Dominion Cove Point LNG expanded storage capacity by 2.8 Bcfd (56%) and thus increased regional flexibility. Developers submitted applications to FERC and the U.S. Coast Guard to build 3 Bcfd of incremental Northeast LNG send-out capacity.

Pipeline Projects

Company	Project Name	Capacity (MMcfd)	Capital Cost (Millions)+	Status	Year Certificated	From-To State
1. Iroquois Gas	Eastchester Extension	230	$174	In-Service 02/04	2001	NY-NY
2. Algonquin Gas	Everett Alternative	60	$12	In-Service 10/04	2004	CT-MA-RI
3. Texas Eastern	Mid-Atlantic Expansion	223	$83	In-Service 11/04	2003	PA-PA
4. Algonquin Gas	I-8 System Uprate	140	$2	In-Service 12/04	2004	MA-MA
5. Tennessee Gas	Tewksbury Andover Lateral	25	$8	Filed 2004	TBD	MA-MA
6. Transcontinental Gas	Central New Jersey Expansion	105	$13	Filed 2004	TBD	NJ-NJ
Total		**783**	**$292**			

Source: FERC Office of Energy Projects . + Capital cost figures are estimates.

Storage Projects

Company	Project Name	Capacity (Bcf)	Deliverability (MMcfd)	Capital Cost (Millions)+	Status	Year Certificated	State
7. National Fuel	Little Acre Interconnect	0	40	$1	Approved	2004	PA
8. Dominion	Mid-Atlantic Expansion	5.6	223	$78	Approved	2004	PA, VA, WV
Total		**5.6**	**263**	**$79**			

Source: FERC Office of Energy Projects. + Capital cost figures are estimates.

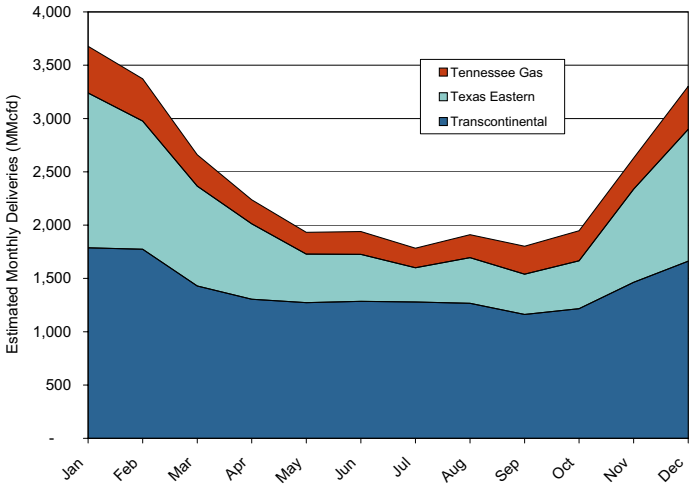
LNG Projects

Company	Project Name	Capacity (Bcf)	Send-Out (Bcfd)	Capital Cost (Millions)+	Status	Year Certificated	State
9. Dominion Cove Point	Cove Point 5th tank	2.8	1.0	$104	In Service 12/04	2004	MD
10. KeySpan	Providence Upgrade	No Change	0.5	$75	Filed 2004	TBD	RI
11. Crown Landing LLC	Crown Landing	9.4	1.2	$500	Filed 2004	TBD	NJ
12. Dominion Cove Point	Cove Point Expansion	7.8	0.8	$160	Filed 2004	TBD	MD
Total		**20**	**3.5**	**$839**			

Source: FERC Office of Energy Projects. + Capital cost figures are estimates.

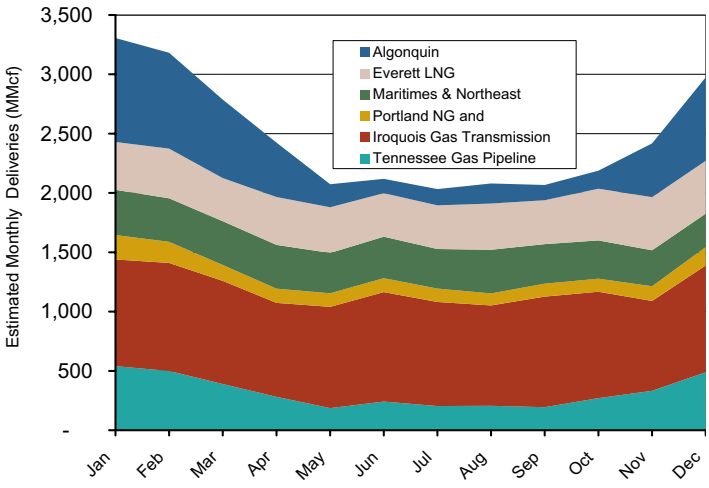
MARKET SHARES

New York City Pipelines



Source: Derived from Platts data. See source note 5.

New England Pipelines



Source: Derived from Platts data. See source note 6.

Average monthly gas deliveries into both the greater New York City market and New England peaked at about 3,500 MMcfd in January 2004. Transcontinental Gas Pipeline and Texas Eastern Gas Transmission delivered more than 80% of New York City's gas in 2004. Pipeline market shares in the broader New England market were divided among a variety of players.

MARKET CONCENTRATION

Most New York City area capacity rights were held by gas and electric distribution utilities. Four companies—Public Service Enterprise Group, KeySpan, New Jersey Resources, and Consolidated Edison—owned nearly 87% of the aggregate firm interstate pipeline capacity rights associated with the greater New York City gas market at the end of 2004. New York City capacity rights were distributed among several pipelines.

Ownership of firm interstate pipeline capacity rights was far less concentrated in New England. The top 5 firm pipeline capacity rights owners controlled about 48% of the delivery rights into New England at the end of 2004. KeySpan was the principal company that owned significant shares of firm transportation service rights in both markets (21% in New York City and 17% in New England). Independent power generators and energy marketers accounted for almost a quarter of firm transportation rights in New England.

Greater NYC Capacity by Holding Company (MMcf)

Holding Company	Iroquois Gas	Tennessee Gas	Texas Eastern	Transcontinental	Total	Est Share Firm Cap
1 Public Service Enterprise Group, Inc		94	633	928	1,654	31%
2 KeySpan Corp	168	74	348	533	1,123	21%
3 New Jersey Resources Corp	40	14	950	24	1,028	20%
4 Consolidated Edison Inc	100	140	128	417	785	15%
All others	233	201	207	39	680	13%

Source: Derived from Platts data. See source note 7. One million Btu assumed to equal 1 Mcf.

New England Capacity by Holding Company (MMcf)

Customer	Algonquin Gas	Iroquois Gas	Maritimes & NE	Portland Natural	Tennessee	Total	Est Share
1 Keyspan Corp	479		86	1	722	1,288	17%
2 Energy East Corp.	173	88			432	693	10%
3 Northeast Utilities	231	105			203	539	8%
4 NSTAR	256				185	441	7%
5 NiSource Inc	106			80	204	390	6%
6 International Power PLC	140	35			72	247	5%
7 Groupe Suez Lyonnaise des Eaux	121			108	229	5%	
8 Dominion Resources, Inc	215					215	5%
9 PG&E Corp	186				25	211	4%
10 Duke Energy Corp		94	105			199	4%
All others	439	30	492	132	708	1,802	29%

Source: Derived from Platts data. See source note 8. One million Btu assumed to equal 1 Mcf.

REGIONAL GAS SUPPLY

Storage and Gas Regional Overview

	Depleted Gas/Oil		Aquifier		Salt Cavern		Total Storage		Dry Proved Reserves
	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	(Bcf)
New York	22	198	0	0	1	2	23	201	365
Pennsylvania	50	748	0	0	0	0	50	748	2,487
Total	**72**	**946**	**0**	**0**	**1**	**2**	**73**	**949**	**2,852**

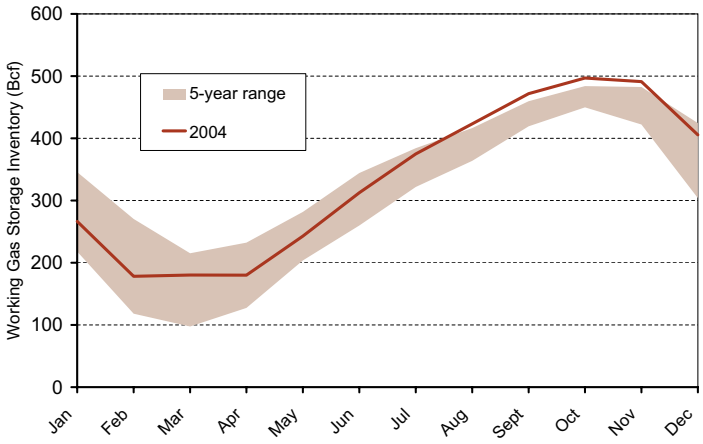
Source: Derived from EIA data. See source note 9.

A modest amount of regional production comes from Pennsylvania and New York and is supplemented with supplies from the Appalachian Basin states of West Virginia, Ohio, and Kentucky. Significant additional amounts of gas come from Sable Island off Nova Scotia, the Western Canadian Sedimentary Basin, and the Gulf Coast, and enter the region by way of an extensive interstate pipeline network. The Northeast imported 893 Bcf of natural gas from Canada in 2004 through the following pipelines: Iroquois Gas Transmission (320 Bcf, or 36%), Tennessee Gas Pipeline (288 Bcf, or 32%), the Maritimes & Northeast Pipeline (131 Bcf, or 15%), TransCanada Gas Pipeline (106 Bcf or 12%), and Portland Natural Gas Transmission System (47 Bcf, or 5%).[9] Regional dry gas proved reserves total about 2,900 Bcf.

The Northeast is highly dependent on stored natural gas, especially during the winter. Customers rely on a mix of regional market area storage assets as well as upstream storage facilities located in Gulf Coast states, the Midwest, and Canada. Conventional storage capacity in the Northeast is located in New York (201 Bcf) and Pennsylvania (748 Bcf). Satellite LNG storage facilities, used to augment retail delivery, are located throughout the Northeast and complement gas delivery from more conventional storage. For example, New England has about 14.9 Bcf of LNG storage capacity; the Distrigas LNG import terminal has another 3.4 Bcf of storage capacity.

Working gas storage inventories in the Northeast totaled

Regional Storage Inventory Levels



Source: Derived from EIA data.See source note 10.

180 Bcf at the start of the 2004 injection season in April, an amount 11 Bcf higher than the most recent 5-year average of 169 Bcf. Working gas storage inventories had been that high in only 2 of the previous 5 years. A combination of economic incentives to inject gas into storage and cool summer weather resulted in robust gas storage injections from April through October.[10] By the onset of the withdrawal season in November, Northeastern storage inventories totaled 497 Bcf, or about 34 Bcf above the 5-year average (463 Bcf).

Northeast Gas Transportation Challenges

Stakeholders continue to examine the adequacy of Northeast natural gas infrastructure because of consecutive winter natural gas price spikes during 2003, 2004, and 2005.[11] A complex set of factors affects decision-making by market participants about firm transportation service requirements: risk preferences; supply reliability needs; near-term and long-term expectations about cumulative pipeline basis values; utilization of existing pipeline capacity; cost of incremental gas infrastructure; and fuel-related, cost pass-through provisions contained in power sales agreements; or local distribution company (LDC) purchased-gas adjustments. Periodic gas and power price spikes during coincidental winter peaks will continue in the Northeast, particularly New England, until additional pipeline capacity and LNG vaporization capacity is added.

Developing new natural gas pipeline capacity in the Northeast remained challenging in 2004 because:

- Developers will not build new pipeline capacity without long-term, firm transportation contracts. It is unclear, however, who will sign up for firm transportation service. Space-heat LDC gas consumption is growing moderately and thus will limit the need for incremental firm service. For several reasons, gas-fired power generators continue to limit their exposure to firm transportation reservation charges by not contracting. Monthly capacity factors for combined-cycle gas plants in 2004 in areas managed by independent system operators (ISOs) in New England and New York averaged between 33% and 50%. ISO-NE capacity payments are insufficient to cover the cost of firm transportation service, and interruptible transportation service remains reliable in the summer and shoulder periods.

- Buying incremental firm transportation service is uneconomical for many market participants. Despite historically high average annual basis at key trading points in the Northeast during 2003 and 2004, the frequency and duration of spikes have not yet justified buying firm transportation on straight economic grounds. Given load factor assumptions, receipt point locations, and the extent of weather-driven price volatility, however, the Northeast gas market is nearing a tipping point: Net-forward transactions involving upstream gas supply purchase, coupled with firm transportation service on some pipelines, may be competitive with buying spot gas at some downstream market hubs.

- New pipeline capacity will cost more than existing capacity. Opportunities to increase gas deliverability into the Northeast through relatively low-cost compression expansions are limited[12]; therefore it is likely that new gas-pipeline capacity will require at least some looping[13] and will result in higher cost-based rates. Increases in current pipeline tariffs might exceed 20%.[14] Further, current tariff rates are based on assets that are significantly depreciated and reflect lower materials costs.

- Local opposition may slow down infrastructure development. Even if developers can construct new facilities economically, infrastructure projects may not get built if developers cannot allay the safety, environmental, and other concerns of regional stakeholders. New LNG projects, if sited, will also require new pipeline infrastructure to get this gas to market. LNG developers unable to secure long-term contracts from gas end-users will have to bear the price risk. They will also have to bear the volume risk, but will do so only if they are assured of access to the pipeline grid.

Recent Basis Trends ($/MMBtu to Henry Hub)

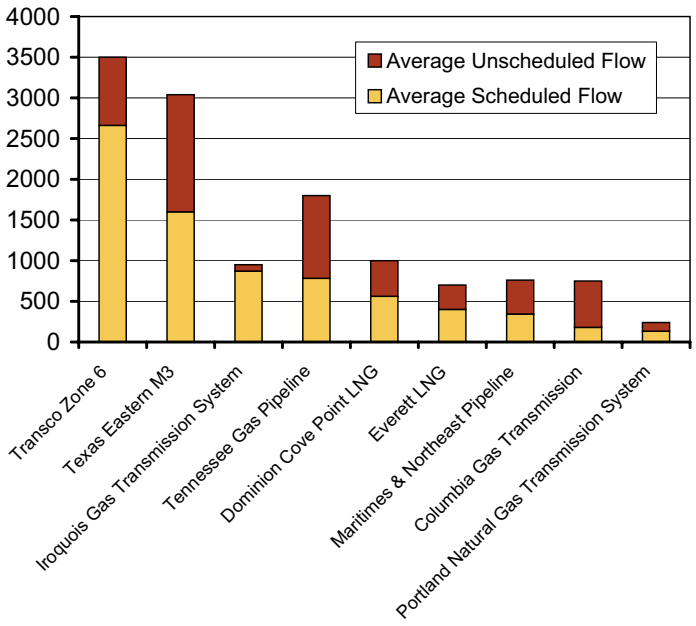
Price Points	2000	2001	2002	2003	2004
Algonquin Citygates	0.77	0.48	0.45	1.07	1.01
Columbia (APP)	0.19	0.20	0.17	0.24	0.29
Dracut (Into Tennessee)	0.74	0.11	0.24	0.84	0.80
Iroquois	0.26	0.18	0.13	0.69	0.72
Niagara (NFG, Tenn.)	0.19	0.23	0.13	0.50	0.35
Tennessee Zone 6	0.56	0.37	0.38	1.00	0.93
Texas Eastern M3	0.16	0.41	0.37	0.92	0.78
Transco Zone 6 (Non-NY)	0.80	0.45	0.37	0.91	0.69
Transco Zone 6 (NY)	1.16	0.63	0.50	1.01	0.96

Source: Derived from Platts data. See source note 11.

PIPELINE UTILIZATION

The principal pipelines delivering gas into the Northeast in 2004 were Transcontinental Gas Pipeline, Texas Eastern Transmission, and Tennessee Gas Pipeline. Transcontinental was the most heavily used; its average daily deliveries exceeded 2,600 MMcfd. Transcontinental's annual system load factor averaged about 76%. Iroquois Gas Transmission System reported the highest average annual load factor of any pipeline in the Northeast (92%). The Maritimes & Northeast Pipeline's load factor, on the other hand, averaged less than 50% due to ongoing productive capacity problems at Sable Island. Overall pipeline use in the Northeast was highly seasonal and averaged about 60% in 2004.

Average Annual Gas Flows (MMcfd)



Source: Derived from Lippman Consulting Inc., Platts , and pipeline company data. See source note 12.

Endnotes

[1] The Northeast gas market includes three principal subregions: New England (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont), New York, and the northern Mid-Atlantic (Delaware, the District of Columbia, Maryland, New Jersey, and Pennsylvania).

[2] Derived from information provided by Bentek Energy LLC.

[3] National Energy Board, "Short-term Canadian Natural Gas Deliverability: 2004-2006," November 2004.

[4] Moody's Investor Service Report, February 18, 2005.

[5] The following exploratory wells drilled in the offshore region of Nova Scotia in 2004 were abandoned: Exxon-Mobil's Cree I-34, EnCana's Weymouth A-45, Canadian Superior's Mariner I-85, and Marathon's Crimson F-81. "New England Natural Gas Supply Assessment," April 1, 2005, Merrimack Energy Group, 11–12.

[6] The simple average of Transco Zone 6 basis prices for November 2004 through March 2005.

[7] Excludes swap trades executed by voice brokers and on other over-the-counter exchanges. OMOI believes trading volume by voice brokers accounts for a sizable share of swap transactions.

[8] Herbert Rakebrand and Associates LLC, "Northeast Natural Gas Infrastructure Assessment," April 1, 2005, 12–13.

[9] Derived from data provided by Bentek Energy LLC.

[10] In 2004, the estimated difference between the daily average cost of buying gas to inject in storage ($5.83/MMBtu at the Henry Hub) versus buying winter natural gas futures contracts ($6.85/MMBtu at the Henry Hub) was $1.02/MMBtu. This amount is more than twice the benchmark ($0.48/MMBtu) assumed to cover customary carrying costs for natural gas stored in depleted field reservoirs. This spread ranged between $0.31/MMBtu and $2.65/MMBtu.

[11] "Northeast Natural Gas Infrastructure Assessment," developed for ISO-NE by Herbert Rakebrand and Associates, April 1, 2005; "New York Markets Lack Key to Avoid Winter Energy Price Spikes," Cambridge Energy Research Associates Decision Brief, July 12, 2004; and "Final Report on Electricity Supply Conditions in New England During the January 14–16, 2004 'Cold Snap'," ISO New England Inc. Market Monitoring Unit, October 12, 2004.

[12] A notable exception entails adding compression to the Maritimes & Northeast Pipeline to deliver potential greenfield LNG from proposed import terminals in eastern Canada. "New England Gas Supply Assessment," developed by Merrimack Energy Group for ISO New England, April 1, 2005, 2.

[13] Construction of new segments of pipe meant to parallel and interconnect with existing infrastructure.

[14] Analysis by Shree Vikas, Science Applications International Corporation.

Source notes

1. Prices reflect the midpoint of day-ahead, spot transactions. All prices reported for flow date.

2. Prices reflect the basis or difference between the delivered price at a downstream market hub and the price of natural gas reported at the Henry Hub for spot, day-ahead transactions. Differences between downstream hub prices reported by *Gas Daily* and the Henry Hub for every calendar flow date in a month are averaged.

3. Reflects near-month natural gas swap price.

4. Trading volumes reported by *Gas Daily* at various market hubs often exceed ICE reported volumes because *Gas Daily* may count the same transaction twice—once from a seller's standpoint and once from a buyer's standpoint. Conversely, as exchange traded products, transactions involving two counterparties are reported only once by ICE.

5. Texas Eastern, Transcontinental Gas Pipeline, and Tennessee Gas Pipeline net natural gas deliveries minus receipts to New York City boroughs plus various New Jersey counties. Transco: deliveries at Linden. Texas Eastern: New York deliveries to Richmond, and New Jersey deliveries to Hunterdon, Middlesex, Morris, Passaic, Somerset, and Union counties. Tennessee: New York deliveries to Kings, Westchester, and Rockland counties plus New Jersey deliveries to Bergen, Passaic, and Sussex counties.

6. Represents natural gas imports into the New England market on interstate natural gas pipelines plus deliveries into Algonquin Gas Transmission and Tennessee Gas Pipeline via the Everett LNG facility. Does not account for LNG delivered by truck to LDCs from Everett.

7. Accounts for firm transportation service right market shares of FERC-jurisdictional pipelines with primary delivery point rights to the greater New York City market. Conversely, excludes firm interstate pipeline transportation rights held by shippers with delivery points designated upstream of the northern New Jersey and New York City markets according to first quarter 2005 index of customers information reported in Platts' GasDat.

8. Accounts for firm transportation service rights on FERC-jurisdictional pipelines with primary delivery point rights to meters located in New England.

9. Gas Annual 2003," Movements and Storage – Table 14. EIA. Proved reserves: file "ng_enr_dry_a_EPG0_R11_Bcf_a.xls", Dry Natural Gas Proved Reserves as of December 31, 2003, EIA. File as of April 1, 2005.

10. "Natural Data for 2003 and prior derived from EIA files entitled "ng_stor_sum_dcu****.xls," where the wild card represents the state designation. Storage activity for 2004 derived from a file provided by EIA, "Working Gas by State and Month – EIA 2004.xls."

11. Basis values represent the average annual difference in market-based transportation costs between various downstream price points and the Henry Hub.

12. Operationally available capacity data bases from Platts GasDat; operationally available capacity information from pipeline company informational postings; "Monthly Pipeline Reports" and "Monthly Regional Capacity Reports" from Lippman Consulting, Inc; and OMOI analysis.

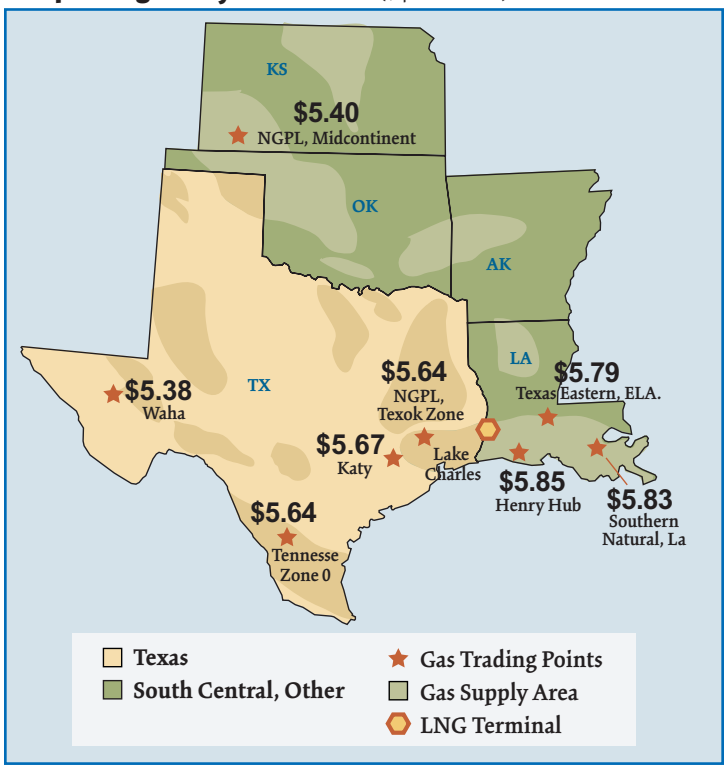
Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

South Central Natural Gas Market Profile

As the key natural gas producing region in the United States, the South Central region accounted for 12.5 Tcf (68%) of dry gas production and nearly 99 Tcf (55%) of proved dry natural gas reserves estimated to exist in the Lower 48 in 2004. Key regional sources of gas production included the federal and state offshore areas, Midcontinent, Permian, East Texas, South Texas, and Arkoma basins. Most of the nation's high deliverability salt cavern storage capacity is located in Texas and Louisiana, and South Central had more than 2.3 Tcf of natural gas storage capacity to augment the region's gas gathering and processing, production, and pipeline networks.

Although a net exporter of natural gas, South Central consumed 27% of total, Lower 48 dry gas production in 2004 and accounted for 35% of total Lower 48 gas consumed by the power generation sector. Total gas consumption declined 1% or 187 Bcf. Estimated firm interstate gas exports to other U.S. regions exceeded 6 Tcf, or 17 Bcfd.[1] Despite historically high natural gas prices in 2004, industrial sector gas use still topped all sectors (51% of total regional consumption). Many of the liquid production area trading points used as benchmarks for pricing natural gas commodity services are located in this region. Trade publications regularly report prices at about 40 locations in this market. Natural gas production in South Central is not concentrated. No company accounted for more than 4% of regional production in 2004.[2] The top 25 exploration and production companies in the region accounted for about 5 Tcf, or 39%, of the 12.5 Tcf of estimated total regional dry production in 2004.

2004 Average Daily Hub Prices ($ per MMBtu)



Source: Derived from Platts data.

Hub Prices ($ per MMBtu)

	2003	2004	5-Year
Henry Hub	$5.44	$5.85	$4.58
Katy	$5.36	$5.67	$4.50
NGPL, Midcontinent	$5.11	$5.40	$4.32
Southern Natural, La	$5.38	$5.83	$4.53
Tennessee Zone 0	$5.26	$5.64	$4.42
Waha	$5.17	$5.38	$4.35
NGPL Texok Zone	$5.31	$5.64	$4.46

Source: Derived from Platts data.

Focal Points for 2004

- **More project investment.** Developers proposed construction of six new liquefied natural gas (LNG) import terminals that could lead to a total average send-out of 8.3 Bcfd. Meanwhile, the U.S. Coast Guard and FERC approved five LNG import projects representing 6.2 Bcfd of send-out in 2004, including the Sabine Pass Project—the largest LNG facility certificated to date in the United States (2.6 Bcfd). Together, send-out from these facilities represented 11% of average daily gas use in the United States in 2004 (59 Bcfd).
- **Increased industrial gas consumption.** Estimated use rose 1% despite high gas prices.
- **Increased trading.** Reported trading volume at Henry Hub increased 16% compared with 2003.
- **Faulty futures price.** The near-month futures contract for December gas at Henry Hub increased $1.18/MMBtu in response to an erroneously reported 49-Bcf gas storage withdrawal on November 24, 2004.
- **Reduced regional production.** Production declined to 12.5 Tcf (-0.5%) despite the addition of 100 operating rigs for a total of 846.[3] Texas was the only state in the region to register a significant production increase (~23 Bcf) from 2003, largely because production from the Barnett Shale fields increased 22% to 368 Bcf.
- **Reduced LNG volume.** Average daily Lake Charles LNG send-out volume declined by 30% (from 656 MMcfd in 2003 to 460 MMcfd in 2004) because of terminal construction, reliance upon spot cargoes, and cargo diversions.

Supply Demand Statistics

Supply Disposition	2004 (Bcf)	2003 (Bcf)
Total Dry Production	12,521	12,587
Production by Region		
Texas Gulf Coast	2,119	2,115
Anadarko	1,432	1,452
Permian-Texas	1,190	1,142
East Texas	1,029	935
Other	6,752	6,943

Other Sources of Supply (2004 Bcf)

International Supply

	Imports	Exports	Net Imports
Mexico	0	153	(153)
LNG	170	0	170
Total	**170**	**153**	**17**

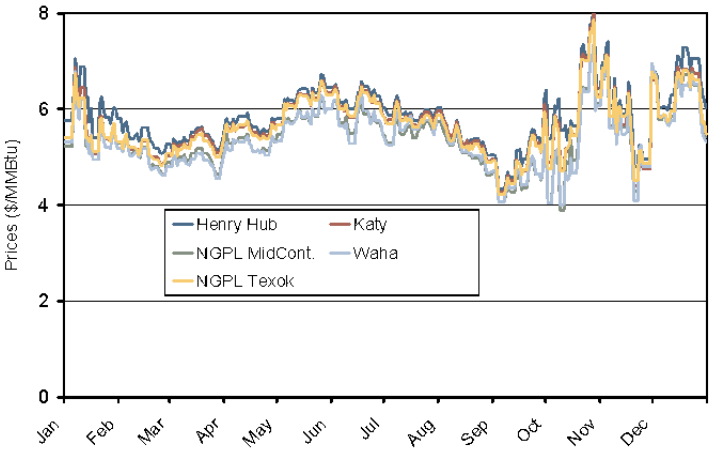
Interregional Pipeline Flows	Net Imports
To Midwest	(1,706)
To Southeast	(4,928)
To West	591
Total	**(6,042)**

Demand Disposition	2004 (Bcf)	2003 (Bcf)
Residential	394	428
Commercial	304	351
Industrial	3,013	2,995
Power	1,844	1,958
Losses and Other	301	310
Total	**5,856**	**6,043**
Key End Use Markets		
Texas	3,756	3,928
Other- AR, KS, LA, OK	2,100	2,115

Source: Derived from Bentek Energy, LLC data. Note: Negative net imports are net exports.

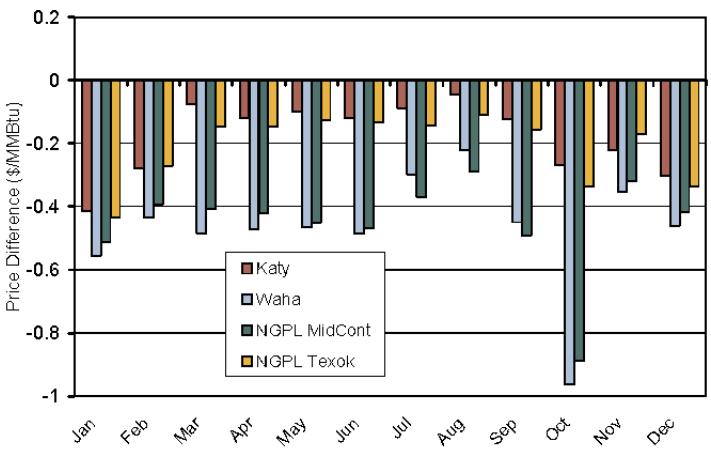
SPOT MARKETS: PRICES AND VOLUMES

Day-ahead Spot Prices



Source: Derived from Platts data. See source note 1.

Monthly Average Basis Value to Henry Hub

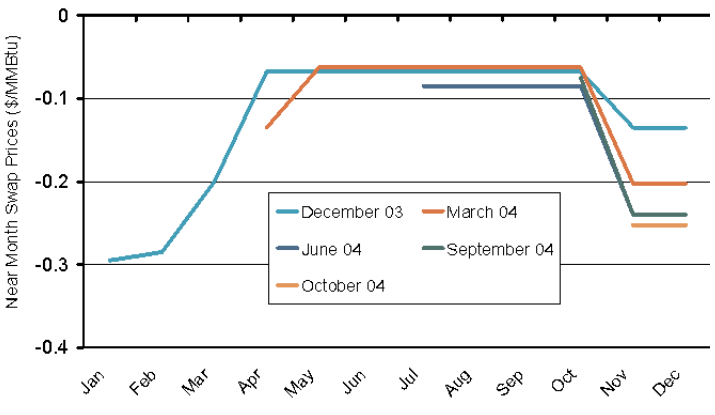


Source: Dervied from Platts data. See source note 2.

The annual average spot gas price at the Henry Hub climbed from $5.44/MMBtu to $5.85/MMBtu or about 7% between 2003 and 2004. Overall, prices throughout the South Central region rose 6% in 2004. Daily prices reported at the Henry Hub ranged between $4.33/MMBtu and $8.12/MMBtu. All pricing points traded at a discount to the Henry Hub on an average monthly basis throughout the year because they are located upstream of the Henry Hub pricing point. Production problems caused by Hurricane Ivan led to historically high negative basis values (up to $1/MMBtu) between the Midcontinent and west Texas markets and gulf-sourced gas in the region.

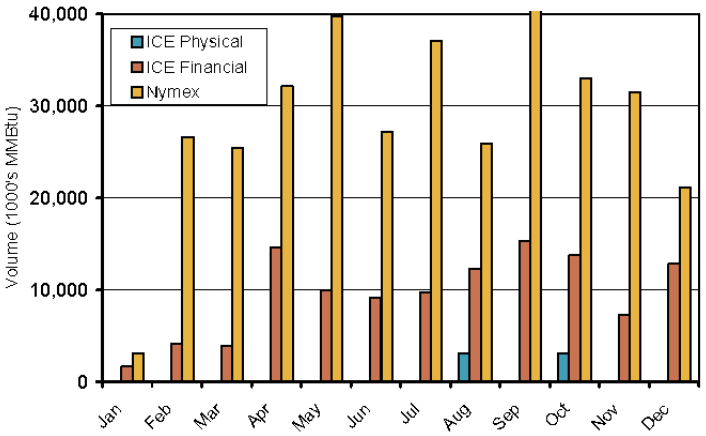
FINANCIAL MARKETS: PRICES AND VOLUMES

Houston Ship Channel Swaps Prices from Trade Date



Source: Derived from Bloomberg, L.P. and Nymex data. See source note 3.

Houston Ship Channel Forward and Swaps Volume

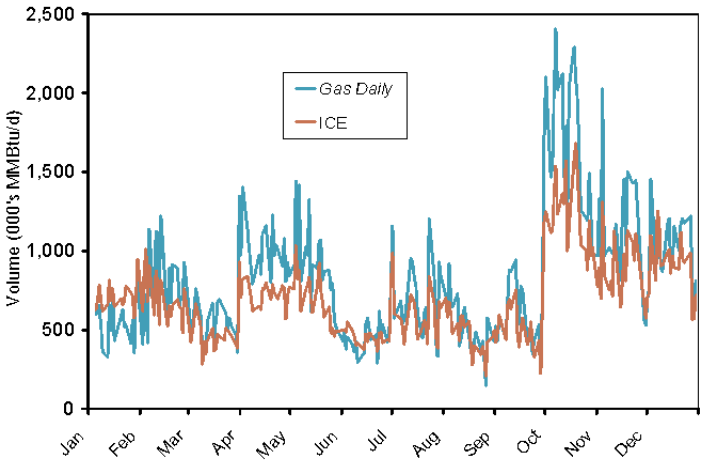


Source: Derived from ICE and Nymex data.

As usual, expectations for summer 2004 basis differentials between the Houston Ship Channel and the Henry Hub narrowed, averaging between -$0.05/MMBtu and -$0.10/MMBtu.[3] The average anticipated basis between Houston Ship Channel and Henry Hub almost doubled, however, from -$0.14/MMBtu to -$0.25/MMBtu, between December 2003 and October 2004, as the market factored in higher gas prices associated with hurricane-related production shortfalls. Traded volumes for Houston Ship Channel financial swaps (47,000,000 MMBtu) on the New York Mercantile Exchange (Nymex) exceeded IntercontinentalExchange (ICE) swaps (9,500,000 MMBtu) by 5-to-1.[4] No physical trades were reported by ICE at the Houston Ship Channel; ICE did report limited trading activity at the nearby Katy storage hub in August and October.

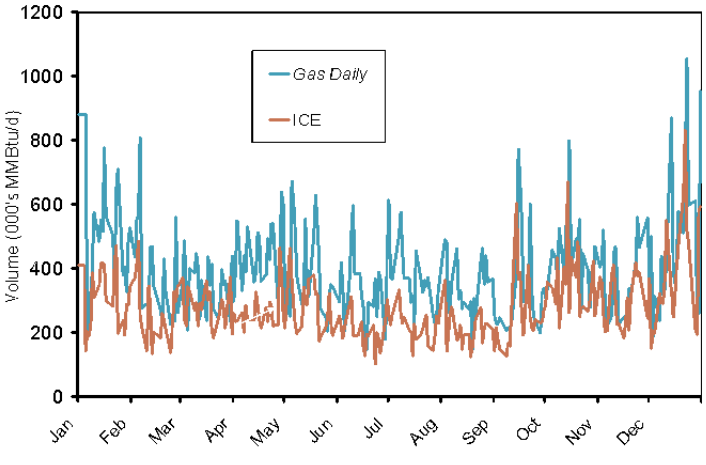
HUB POINTS: VOLUMES

Henry Hub Reported Volumes



Source: Derived from Platts and ICE data. See source note 4.

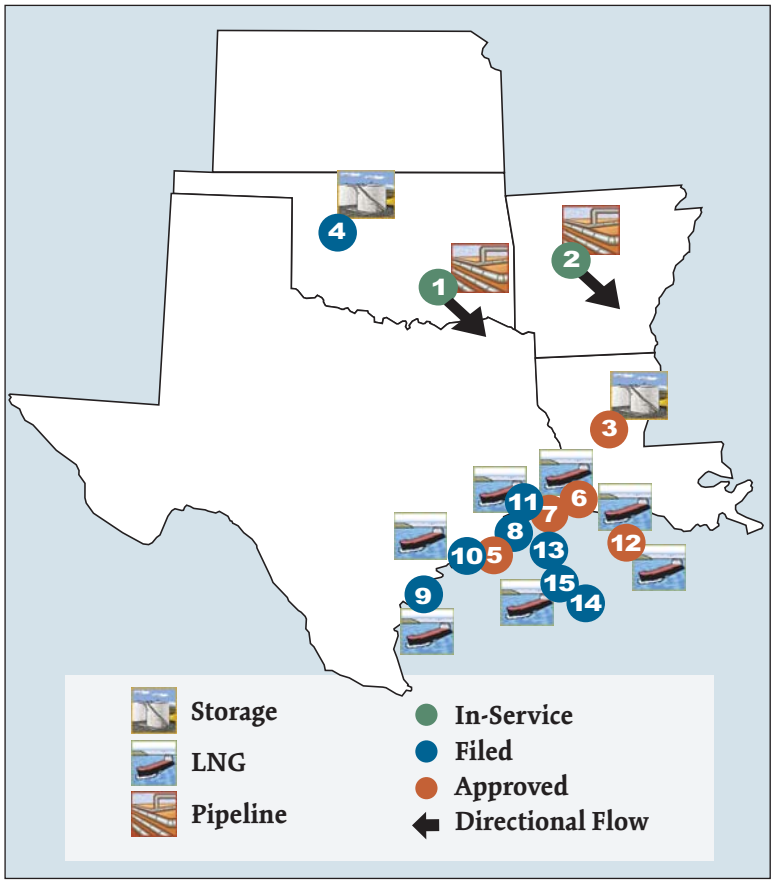
NGPL Texok Reported Volumes



Source: Derived from Platts and ICE data. See source note 4.

Average daily trading volume at Henry Hub grew measurably in 2004. According to *Gas Daily*, average traded volume increased 18%, from 701,000 MMBtu to 831,000 MMBtu. ICE reported a similar percentage increase (16%), as average daily volume grew from 604,000 MMBtu to 698,000 MMBtu. In October, Henry Hub trading activity on Nymex's ClearPort and on ICE doubled that of prior months and continued at robust levels during November and December. Significant trading took place at the Natural Gas Pipeline Co. of America's Texok point in 2004; average daily reported volume ranged between 277,000 MMBtu (ICE) and 400,000 MMBtu (*Gas Daily*).

NATURAL GAS INFRASTRUCTURE DEVELOPMENTS



PROJECT DEVELOPMENT

1. Black Marlin Pipeline Project
2. Round Mountain and Helena Stations
3. Pine Prairie Energy Center Projects
4. Sayre Storage Expansion
5. Freeport LNG
6. Modified Expansion Project
7. Sabine Pass LNG
8. Golden Pass LNG Terminal
9. Vista Del Sol LNG Terminal
10. Ingleside Energy Center LNG Terminal
11. Port Arthur LNG
12. Port Pelican
13. Pearl Crossing
14. Gulf Landing
15. Gulf Gateway

This map numbering system corresponds to the following three charts on pipeline, storage, and LNG projects.

LNG import proposals dominated South Central regional infrastructure activity in 2004. Five LNG import terminal projects with a total send-out of 6.2 Bcfd were approved—three by the Commission and two by the U.S. Coast Guard.[5] Project developers filed applications to construct six more terminals, which could enhance LNG send-out within the region by 8.3 Bcfd. The applicants cited several regional advantages for development, including fuel-blending opportunities, liquid markets, robust existing infrastructure, national market access, deepwater ports, acreage, and proximity to nearby salt storage caverns. Only 0.13 Bcfd of new interstate capacity was brought on line or approved. Intrastate pipelines account for much of the pipeline capacity serving this market.

The Commission approved Sempra Global's multi turn salt cavern project—the Pine Prairie Energy Center—in November. The project is expected to be available for service in fourth quarter 2005. When completed, the facility will provide up to a total of 24 Bcf of storage capacity in three 8 Bcf caverns, with up to 2.4 Bcfd of withdrawal, and up to 1.4 Bcfd of injection capabilities, (6-to-12 turn annual service).

Pipeline Projects

Company	Project Name	Capacity (MMcfd)	Capital Cost (Millions)+	Status	Year Certificated	From-To State
1. NGPL	Black Marlin	60	$1	In-Service 11/04	2004	OK-TX
2. CenterPoint	Round Mountain and Helena Stations	70	$10	Approved	2004	AR-AR
Total		**130**	**$11**			

Source: FERC Office of Energy Projects. + Capital cost figures are estimates.

Storage Projects

Company	Project Name	Capacity (Bcf)	Deliverability	Capital Cost (Millions)+	Status	Year Certificated	State
3. Pine Prairie	Pine Prairie	24	2,400	$180	Approved	2004	LA
4. NGPL	Sayre	10	200	$33	Filed 2004	TBD	OK
Total		**34**	**2,600**	**$213**			

Source: FERC Office of Energy Projects. + Capital cost figures are estimates.

LNG Projects

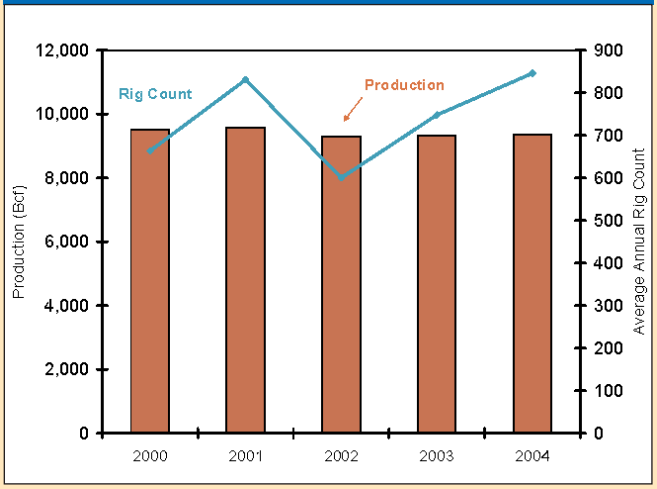
Company	Project Name	Capacity (Bcf)	Send-Out (Bcfd)	Capital Cost (Millions)+	Status	Year Certificated	State
5. Freeport	Freeport	7.0	1.5	$500	Approved	2005	TX
6. Trunkline	Modified Expansion	2.9	1.2	$87	Approved	2004	LA
7. Cheniere	Sabine Pass	10.4	2.6	$450	Approved	2004	TX
8. Golden Pass Terminal LP	Golden Pass LNG Terminal	9.8	1.0	$600	Filed 2004	TBD	TX
9. ExxonMobil	Vista del Sol	9.8	1.0	$600	Filed 2004	TBD	TX
10. Ingleside Energy	Ingleside LNG Terminal	6.8	1.0	$400	Filed 2004	TBD	TX
11. Sempra	Port Arthur LNG	10.1	1.5	$600	Filed 2004	TBD	TX
12. Chevron	Port Pelican *	10.3	1.6	$700	Approved	2004	LA
13. ExxonMobil	Pearl Crossing *	10.6	2.8	$231	Filed 2004	TBD	Gulf of Mexico
14. Shell US Gas & Oil	Gulf Landing *	4.2	1.0	$700	Filed 2004	TBD	Gulf of Mexico
15. Excelerate	Energy Gulf Gateway*	0.5	0.5	$200	Approved	2004	Gulf of Mexico
Total		**79.5**	**14.5**	**$5,068**			

Source: FERC Office of Energy Projects. * Coast Guard Jurisdictional. + Capital cost figures are estimates.

Production Remains Flat Despite Growth in Rig Counts

The average number of rigs operating in the South Central region grew to 846 in 2004 from 736 in 2003. Despite this increase, preliminary estimates indicate that regional dry gas production declined 0.5% to 12.5 Tcf in 2004. Preliminary Texas Railroad Commission data for 2004 show a slight increase (23 Bcf) above 2003 production, with production in Texas accounting for 62% of South Central dry gas production. Oklahoma and Louisiana accounted for 16% and 14%, respectively. Preliminary figures from those two states show slight declines in 2004 production. Accelerated decline rates for existing and newly producing wells continued to plague the industry, as did the lack of trained personnel to operate the rigs. Growing interest in the Barnett Shale in northeast Texas and higher natural gas prices spurred rig activity in 2004.

Rig Count and Production



Source: Derived from Baker, Hughes and Lippman Consulting, Inc. data. See source note 5.

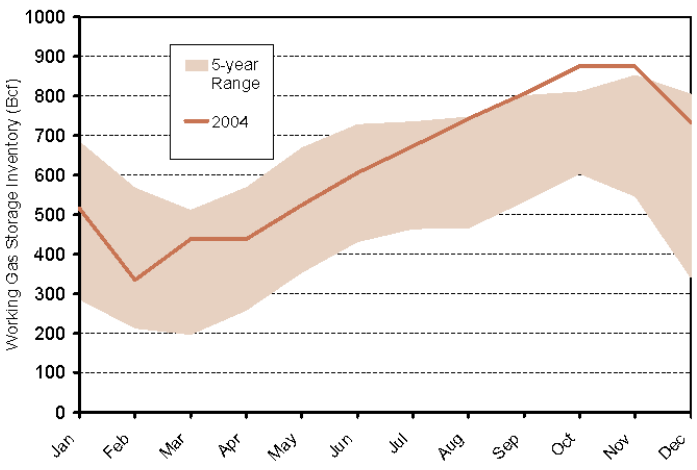
REGIONAL GAS SUPPLY

The South Central region, combined with offshore production in the Gulf of Mexico, accounted for almost 68% of total dry gas production in the Lower 48 states. Although land-based production in the region rose 4% (385 Bcf), offshore production fell 10% (520 Bcf) from 2003 to 2004. According to the Minerals Management Service (MMS), estimated Gulf of Mexico shallow water gas production decreased to 7.3 Bcfd, or by 0.9 Bcfd, in 2004; deepwater gas production remained unchanged at 3.9 Bcfd.[6] Increased production from the Barnett Shale in north Texas offset declining production in the mature shallow water Gulf of Mexico fields. Proved dry reserves amounted to more than 76,900 Bcf.

According to the latest Energy Information Administration (EIA) data, proved dry gas reserves in the Lower 48 increased 1% (2,098 Bcf) to 189,044 Bcf in 2003.[7] Thus, 2003 was the fifth year in a row (and ninth out of the last 10) in which proved gas reserves increased. Most of the increase came from extensions of existing conventional and unconventional gas fields. Gulf of Mexico Federal Offshore proved dry gas reserves, which accounted for 12% of the total, fell 11% (2,825 Bcf) to 22,570 Bcf from 2002. Thus 2003 also was the second year in a row in which a decline in such reserves occurred. By contrast, national coalbed methane reserves, which accounted for 10% of proved dry gas reserves, increased 1% (252 Bcf) to 18,743 Bcf.

As of 2004, more than 2.3 Tcf of storage capacity at 81 sites was distributed throughout the South Central region. Storage operations are well integrated with the interstate and intrastate pipeline network, with enough flowing gas from producing wells to efficiently manage daily fluctuations in production and consumption. Salt cavern storage represented 39% of total regional storage deliverability, even though it accounted for only 8% of regional storage capacity.

Regional Storage Inventory Levels



Source: Derived from EIA data. See source note 6.

On August 19, Cavern 1 at the Moss Bluff storage facility caught fire. Moss Bluff is located about 40 miles northeast of Houston and consists of three salt caverns totaling 16 Bcf of working gas capacity. Rain and cool temperatures in the days that followed minimized the effects of the fire on the market. Before the fire burned itself out on August 25, approximately 6 Bcf of gas was released and burned. As a safety precaution, Caverns 2 and 3 were shut in temporarily; they returned to service in November. Cavern 1 returned to service in April 2005.

Storage and Gas Reserves Overview

	Depleted Gas/Oil		Aquifier		Salt Cavern		Total Storage		Dry Proved Reserves
	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	(Bcf)
Arkansas	2	22	0	0	0	0	2	22	1,663
Kansas	17	287	0	0	1	1	18	288	4,819
Louisiana	8	530	0	0	6	61	14	592	9,325
Oklahoma	13	385	0	0	0	0	13	385	15,401
Texas	20	548	0	0	14	114	34	663	45,730
Total	**60**	**1,772**	**0**	**0**	**21**	**176**	**81**	**1,950**	**76,938**

Source: Derived from EIA data. See source note 7.

PRODUCTION TRENDS

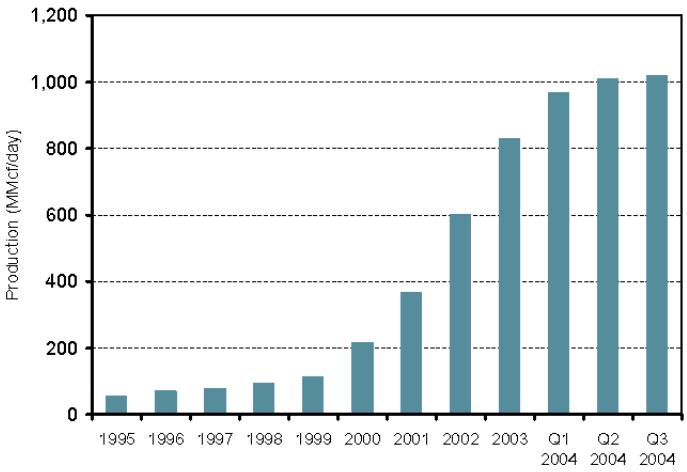
South Central regional production results were mixed in 2004. Generally flat or declining production in many traditional, onshore, and inland conventional gas basins was offset by increased production from unconventional gas basins such as the Barnett Shale deposit in the Fort Worth Basin and the Bossier and Cotton Valley tight sands deposits in the East Texas Basin. In 2004, production from the East Texas Basin increased by almost 94 Bcf (10%) to 1,029 Bcf from 2003. Production from the Barnett Shale was even more successful. According to the Texas Railroad Commission, the Barnett Shale produced 368 Bcf of natural gas in 2004, an increase of more than 170 Bcf (22%) from 2003.[8]

However, those production successes were not enough to offset production declines in the shallow water area of the Gulf of Mexico. Gulf of Mexico production is a major portion of U.S. supply and accounted for 22% of annual Lower 48 natural gas production. Shallow water production has been declining since 1996, when production was more than 4,800 Bcf, and the Minerals Management Service estimates that 2004 production fell by 329 Bcf (11%) to 2,665 Bcf from 2003.[9] Further, deepwater production from the Gulf of Mexico has not been as successful as expected. Production in 2004 was unchanged from 2004; some estimates show that deepwater production may have hit its peak, and will generally decline through 2012, except for a slight increase in 2008 when eight new discoveries are expected to begin production.[10]

Expected production increases from the deepwater portion of the Gulf of Mexico have not occurred due to, among other things, a recent lack of nonassociated gas discoveries, slow company approval of field development, more rapid than expected declines in some existing fields, and the removal of some earlier discoveries from expected development until after 2010 for economic reasons.[11]

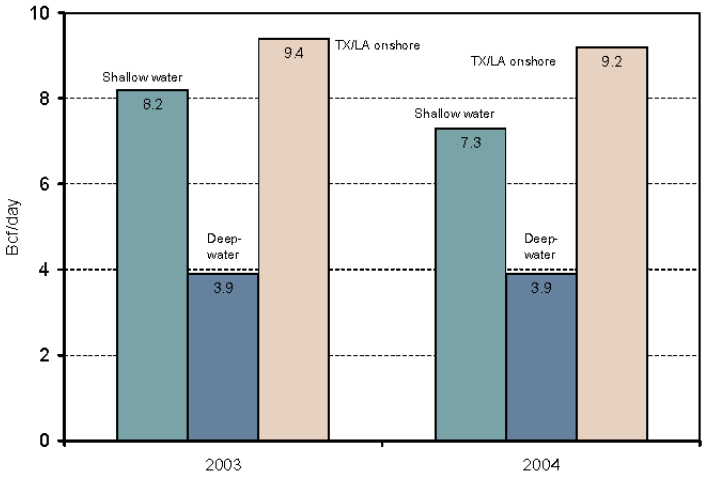
Thus, despite increased drilling and production successes in the Fort Worth and East Texas basins, gas supply from the South Central Region is struggling as production from traditional, conventional shallow water Gulf of Mexico fields continues to decline.

Barnett Shale Production Trends



Source: Derived from Lippman Consulting Inc., Quarterly Regional Production Reports, Report #407, February 22, 2004.

Gulf of Mexico Production

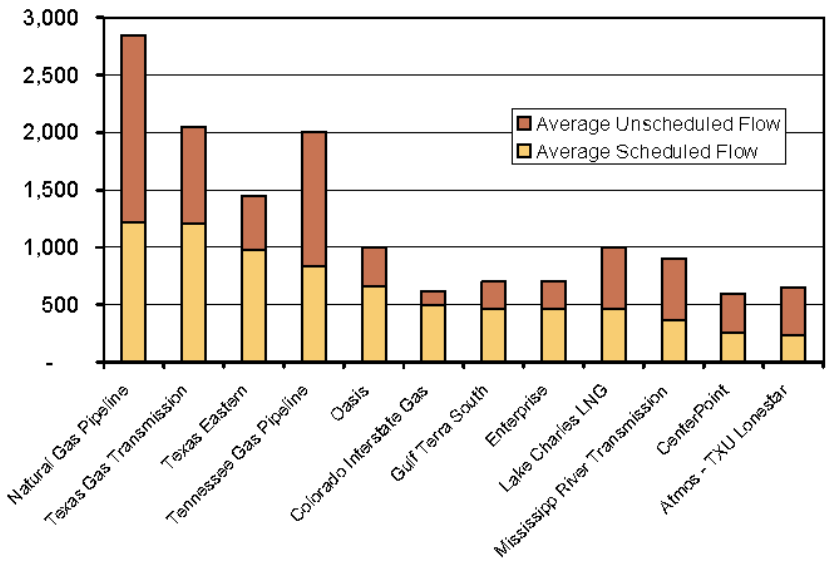


Source: Derived from MMS data. See source note 8.

PIPELINE UTILIZATION

Numerous intrastate and interstate pipelines serve the South Central region, with resulting excess capacity. Almost 17 Bcfd of gas was exported (after removing imports) from the South Central region in 2004. Estimates vary by pipeline, but average pipeline infrastructure usage ranged from about 50% to 55%.

Average Annual Gas Flows (MMcfd)



Source: Derived from Lippman Consulting, Inc., Platts, and pipeline company data. See source note 9.

Endnotes

[1] Derived from information provided by Bentek Energy LLC.

[2] Based on analysis of production trends reported by Lippman Consulting Inc.

[3] Approximately 86% of U.S. operating rigs are gas-directed.

[4] Excludes swap trades executed by voice brokers and other over-the-counter exchanges. OMOI believes trading volume by voice brokers accounts for a sizable share of swap transactions.

[5] The Commission is the lead agency responsible for the preparation of the analysis and decisions required under the National Environmental Policy Act for the approval of new facilities. Under the Natural Gas Act, the Commission has the lead responsibility for authorizing the construction and siting of LNG facilities onshore and within state waters. The U.S. Coast Guard has primary authority over construction and siting of offshore LNG facilities.

[6] Minerals Management Service (MMS), "Deepwater Gulf of Mexico 2005: Interim Report of 2004 Highlights," Outer Continental Shelf (OCS) Report, MMS 2005-023, May 2005.

[7] Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2003 Annual Report, September 2004.

[8] As reported by the *Fort Worth Star-Telegram*, February 22, 2005.

[9] Minerals Management Service, "Deepwater Gulf of Mexico 2005: Interim Report of 2004 Highlights," OCS Report, MMS 2005-023, May 2005, Appendix C.

[10] Cambridge Energy Research Associates, "North American Gas Capacity Race, Can Unconventional Gas Offset the Increased Decline in the Gulf of Mexico?," Robert Esser, May 2005, 17.

[11] Ibid.

Source notes

1. Prices reflect the midpoint of day-ahead, spot transactions. All prices reported for flow date.

2. Prices reflect the basis or difference between the delivered price at a downstream market hub and the price of natural gas reported at the Henry Hub for spot, day-ahead transactions. Differences between downstream hub prices reported by *Gas Daily* and the Henry Hub for every calendar flow date in a month are averaged.

3. Reflects near-month natural gas swap price.

4. Trading volumes reported by *Gas Daily* at various market hubs often exceed ICE reported volumes because *Gas Daily* may count the same transaction twice—once from a seller's standpoint and once from a buyer's standpoint. Conversely, as exchange traded products, transactions involving two counterparties are reported only once by ICE.

5. Rig count based on data reported by Baker Hughes. Production results based on analysis of trends reported by Lippman Consulting, Inc.

6. Data for 2003 derived from EIA files entitled "ng_stor_sum_dcu****.xls," where the wild card represents the state designation. Storage activity for 2004 derived from a MS Excel file provided by EIA, "Working Gas by State and Month – EIA 2004.xls."

7. Storage: "Natural Gas Annual 2003," Movements and Storage – Table 14, EIA. Proved reserves: file "ng_enr_dry_a_EPGo_R11_Bcf_a.xls", Dry Natural Gas Proved Reserves as of December 31, 2003. File as of April 1, 2005. Totals may not equal sum of components due to independent rounding. Proved reserve estimates exclude Federal offshore dry proved reserves, which amount to 22,570 Bcf.

8. "Deepwater Gulf of Mexico 2005: Interim Report of 2004 highlights," OCS Report, MMS 2005-023, May 2005, Appendix C, and Bentek Energy, Bentek Raw Prod Data.xls, April 21, 2005.

9. Operationally available capacity data bases from Platts GasDat; operationally available capacity information from pipeline company informational postings; "Monthly Pipeline Reports" and "Monthly Regional Capacity Reports" from Lippman Consulting, Inc; and OMOI analysis.

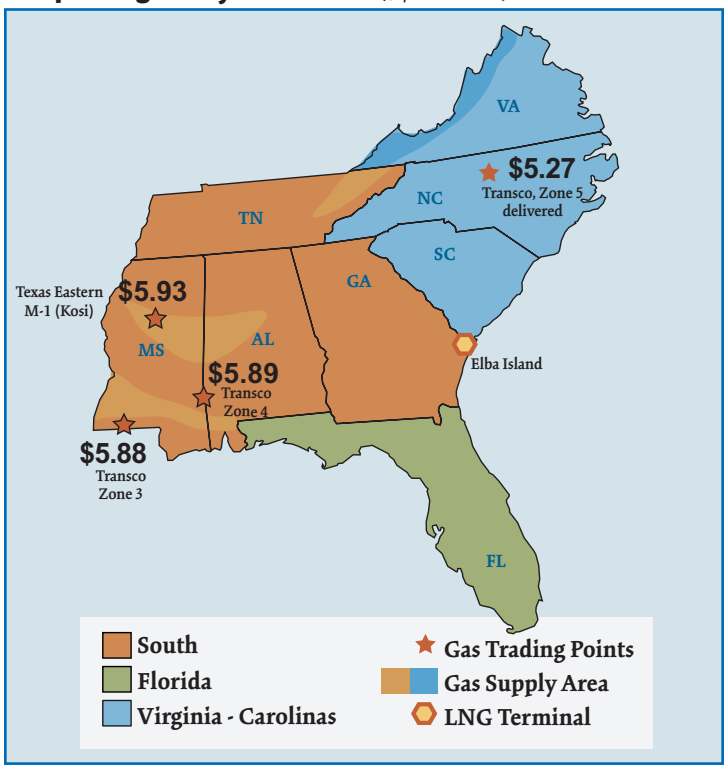
Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Southeast Natural Gas Market Profile

Although the Southeast is the smallest regional end-use gas market in the United States—it consumed only 15% of dry gas produced in the Lower 48 states in 2004—it contains some of the fastest growing gas markets in the country.[1] Overall, estimated gas demand increased 5% in 2004, with the power and industrial sectors accounting for 65% of that demand. The region's principal sources of gas supply include fields in south and east Texas, shallow and deepwater offshore locations, coalbed methane in the Black Warrior Basin, as well as various onshore locations and liquefied natural gas (LNG) terminals. Estimated gas production within the region declined by 12%, or 56 Bcf, in 2004.

Currently, the Southeast has 163 Bcf of storage capacity, much of it located upstream of the fastest growing markets (i.e., Florida, Georgia, and North Carolina). The Southeast depends heavily on natural gas deliveries from the South Central region to meet its fuel requirements. Estimated firm inter-regional gas deliveries from South Central to the Southeast averaged more than 14 Bcfd in 2004.[2] Most of this gas was exported in turn to the Northeast and Midwest. In much of the Southeast market, end-users' gas procurement options have been limited by regional infrastructure and a lack of market liquidity. Proposals to develop gas infrastructure, however, advanced during the year along with improvements in trading liquidity.

2004 Average Daily Hub Prices ($ per MMBtu)



Source: Derived from Platts data.

Hub Prices ($ per MMBtu)

	2003	2004	5-Year
Texas Eastern M-1 (Kosi)	$5.55	$5.93	$4.65
Transco Zone 3	$5.46	$5.88	$4.61
Transco Zone 4	$5.47	$5.89	$4.62
Transco Zone 5, delivered	$5.82	$6.27	$5.35*

Source: Derived from Platts *Gas Daily* data.
* 3 year average available only

Focal Points for 2004

- **Gas supply shut-ins.** Hurricane Ivan shut in 151 Bcf of gas supply in 2004. At one point, the shut-ins temporarily curtailed 6.5 Bcfd, or 13%, of the average Lower 48 gas production. Many of these shut-ins affected the Southeast directly or the gathering lines that deliver gas into Southeast pipelines.
- **Increased demand.** Gas-fired power sector demand increased 142 Bcf (17%). Overall gas demand rose 140 Bcf (5%). Estimated industrial consumption remained unchanged, despite increased gas prices, because of strong economic growth.
- **Increased trading volume.** Transcontinental (Transco) Zone 5 daily trading volume reported by *Gas Daily* increased from 38,200 MMBtu in 2003 to 90,200 MMBtu, in part because of increased deliveries at the Elba Island, Ga., LNG import terminal.
- **Advanced diversification.** Gulfstream Natural Gas increased its pipeline load factor to 29% on an average annual basis. Tractebel, Florida Power & Light, and El Paso Corp. joined forces to establish a prospective project linking re-gasified LNG in the Bahamas to south Florida via a new pipeline. Send-out at the Elba Island terminal doubled to an average annual level of 252 MMcfd.
- **New capacity.** Several major regional pipeline parent companies—El Paso, CrossCountry, Duke, and Williams—brought new capacity on line, submitted applications to build new capacity, and held open seasons for future service commitments.

Southeast Supply Demand Statistics

Supply Disposition	2004 (Bcf)	2003 (Bcf)
Total Dry Production	399	455
Production by Region		
Salt Dome - AL-FL-MS	291	343
Black Warrior	107	111
Other	2	2

Demand Disposition	2004 (Bcf)	2003 (Bcf)
Residential	451	470
Commercial	346	341
Industrial	831	830
Power	960	818
Losses and other	176	166
Total	**2,764**	**2,624**

Other Sources of Supply (2004 Bcf)

International Supply

	Imports	Exports	Net Imports
Canada	0	0	0
Mexico	0	0	0
LNG	96	0	96
Total	**96**	**0**	**96**

Interregional Pipeline Flows

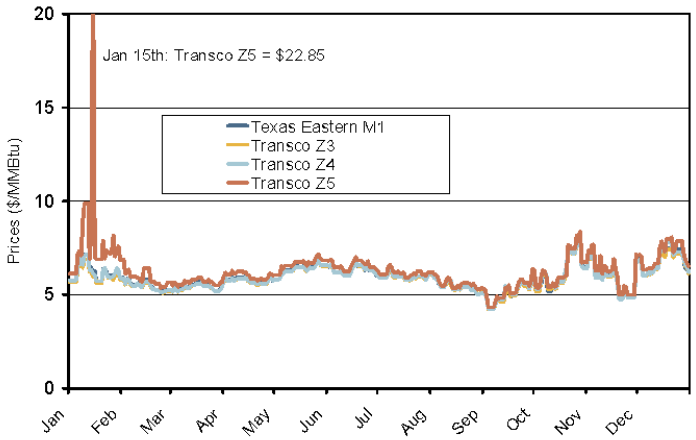
	Net Imports
to Midwest	(2,536)
to South Central	4,928
to Northeast	(687)
Total	**1,704**

Key End Use Markets		
Florida - FL	757	704
Virginia - Carolinas	673	635
South - MS,AL,GA,TN	1,335	1,285

Source: Derived from Bentek Energy, LLC data. Note: Negative net imports are net exports.

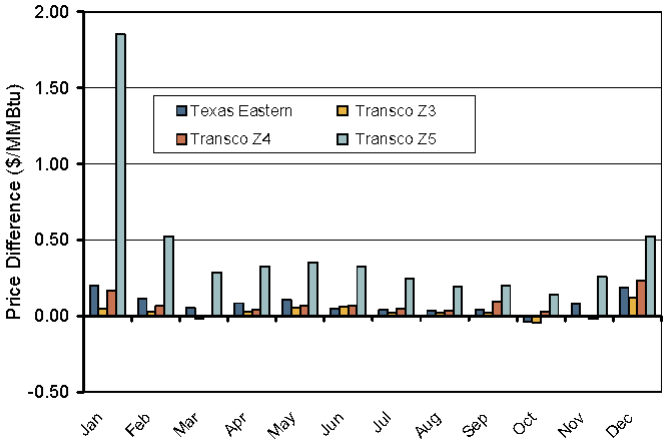
SPOT MARKETS: PRICES AND VOLUMES

Day-ahead Spot Prices



Source: Derived from Platts data. See source note 1.

Monthly Average Basis Value to Henry Hub

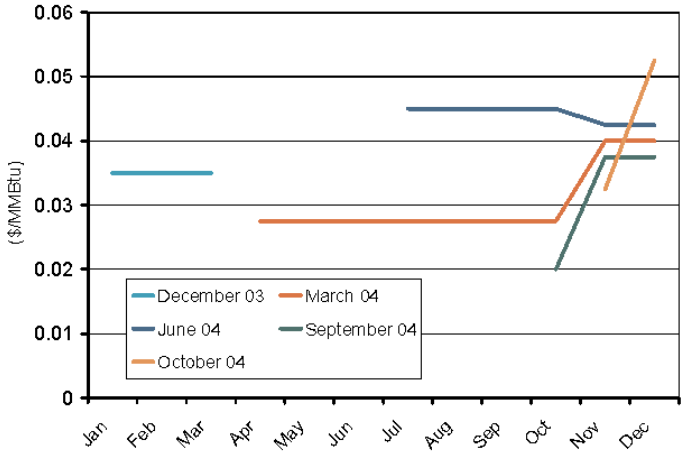


Source: Derived from Platts data. See source note 2.

Annual spot prices at key Southeast trading points—Texas Eastern Transmission Corp. (TETCO) M1, and Transco Zones 3, 4, and 5—averaged $5.99/MMBtu in 2004, approximately $0.41/MMBtu higher than 2003 prices.[3] During 2004, daily prices at Transco Zone 4 ranged between $4.23/MMBtu and $8.11/MMBtu. The basis between the Henry Hub and the Southeast markets varied between $0.08/MMBtu for the upstream Southeast points (Texas Eastern Transmission and East Louisiana) and $0.31/MMBtu for downstream points (Transco Z5). Typically, gas deliveries in Transco Zone 5 reflected congestion at downstream points in the Northeast and therefore traded about $0.20–$0.30/MMBtu above the other points in the Southeast.

FINANCIAL MARKETS: PRICES AND VOLUMES

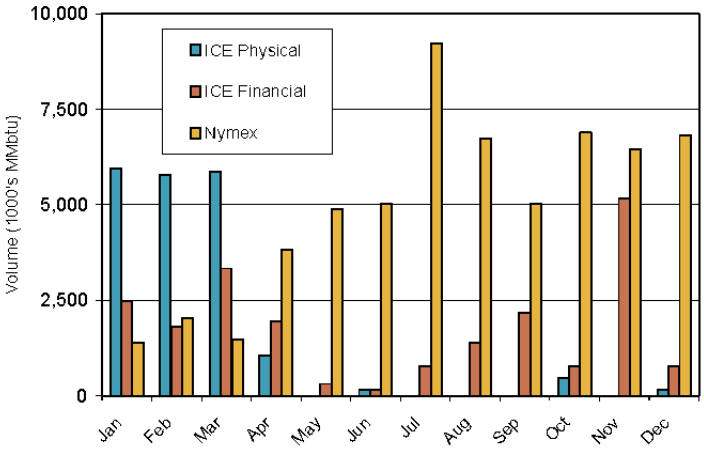
Transco Zone 3 Swaps Prices from Trade Date



Source: Derived from Bloomberg, L.P. and Nymex data. See source note 3.

Forward market expectations of the Transco Zone 3 basis swaps traded within a narrow $0.06/MMBtu premium to the Henry Hub in 2004. Financial swap volumes traded between 1,620,000 MMBtu per day (IntercontinentalExchange (ICE) and 5,000,000 MMBtu er day (*Gas Daily*). The average ICE financial volume traded outstripped physical volume traded by more than 2-to-1.[4]

Transco Zone 3 Forward and Swaps Volume

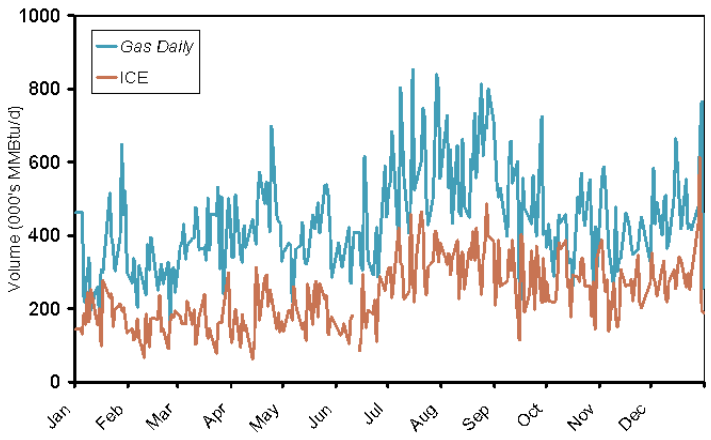


Source: Derived from Bloomberg L.P., ICE, and Nymex data.

Next-month physical trading volume at Transco Zone 3 showed a sharp decline during 2004. Whereas a high volume of front-month gas was often traded during the first few months of the year, beginning in May, physical trading shifted to next-day or intraday deals.

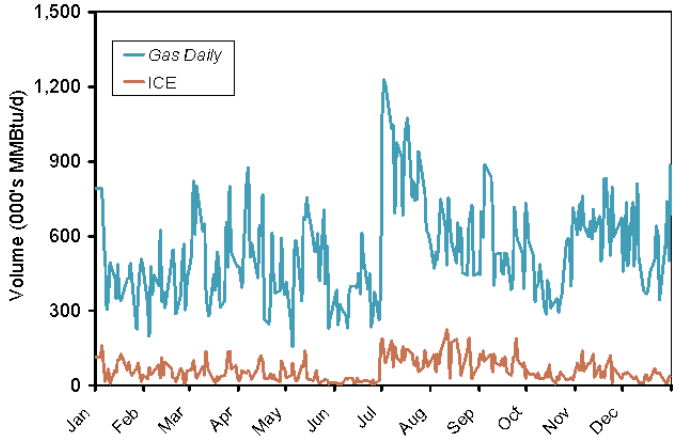
HUB POINTS: VOLUMES

Transco Zone 3 Reported Volumes



Source: Derived from Platts and ICE data. See source note 4.

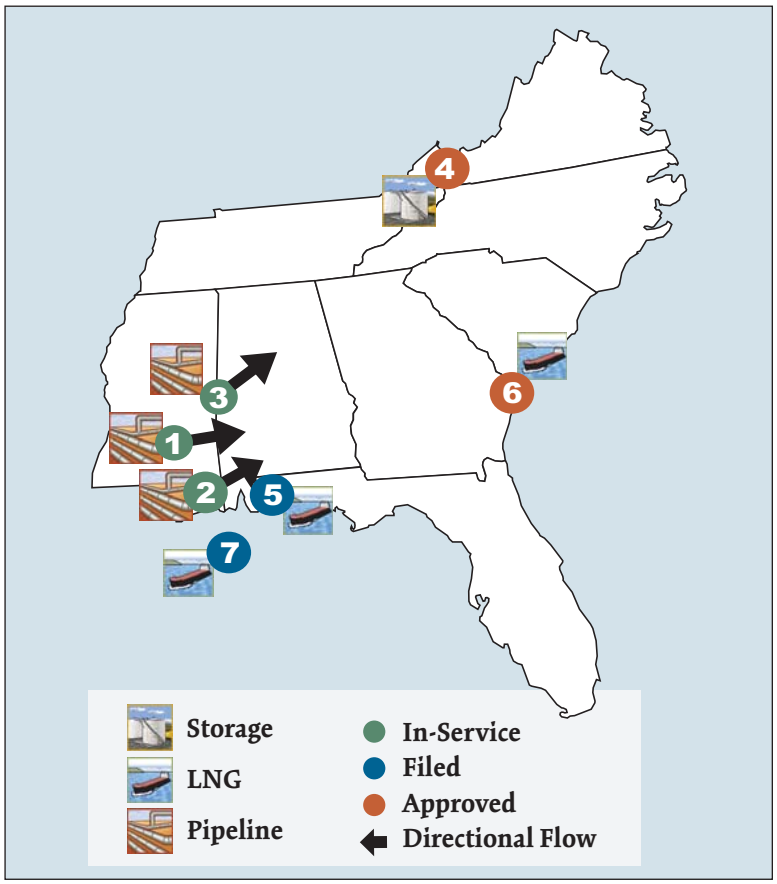
Texas Eastern M1 Kosi Reported Volumes



Source: Derived from Platts and ICE data. See source note 4.

Daily trading volumes at Transco Zone 3 and Texas Eastern Mt Kosi (TETCO M1) increased from 2003. At TETCO M1, *Gas Daily* reported that the average volume increased 31% to 162,000 MMBtu. At Transco Zone 3, *Gas Daily* reported a 21% average volume increase to 442,000 MMBtu, and ICE reported a 31% increase to 238,000 MMBtu. In 2004, highest reported single-day trading volumes at Transco Zone 3 occurred on July 15 (*Gas Daily*) and on December 29 (ICE).

NATURAL GAS INFRASTRUCTURE DEVELOPMENTS



Project Development

1. M-1 Expansion Project
2. South System Expansion Project
3. Phase II Momentum Expansion Project
4. Saltville Storage Project
5. Clean Energy Project
6. Elba Island Georgia Expansion
7. Compass Port

This map numbering system corresponds to the following three charts on pipeline, storage, and LNG projects.

The Southeast added little gas infrastructure in 2004. TETCO's M1 Expansion Project and Southern Natural Gas Co.'s South System Expansion Project added 527 MMcfd of pipeline capacity to the Southeast region. In February, Transco placed into service Phase II of the Momentum pipeline expansion service, increasing firm capacity on its system in Georgia by about 52 MMcfd. FERC approved El Paso's Elba Island LNG expansion plans to increase send-out by 0.5 Bcfd in the first quarter of 2006. During 2004, Gulf LNG Energy LLC filed plans for the Port of Pascagoula LNG Project (1.0 Bcfd) in Mississippi.

FERC issued a certificate to the Saltville Storage project in Smyth County, Va. When completed, the salt cavern facility will have 5.8 Bcf of gas capacity and deliverability of 550 MMcfd. The facility is connected to the East Tennessee Natural Gas Pipeline, and the expansion is expected to improve gas supply flexibility and reliability to customers in eastern Tennessee and southwestern Virginia. AGL Resources bought Saltville from NUI Corp. on November 30.

In July, Gulfstream began construction on its Phase II, 30-inch diameter, 110-mile mainline lateral to eastern Florida. The expansion, completed in February 2005, enables Gulfstream to deliver natural gas to Florida Power & Light's Martin gas-fired power plant in Indiantown, Florida.[5] Florida Gas Transmission (FGT) announced in December its Phase VII Expansion Open Season for service beginning in mid-2007. FGT executed a precedent agreement with Progress Energy to serve Progress Energy's Hines generating facilities near Tampa. On December 21, Southern Natural Gas sought use of the Commission's National Environmental Policy Act Pre-Filing Process for the Cypress Pipeline Project, a proposed 165-mile, 24-inch diameter pipeline that would link LNG gas receipts at Elba Island with end-users in Florida.

Pipeline Projects

Company	Project Name	Capacity (MMcfd)	Capital Cost (Millions)+	Status	Year Certificated	From-To State
1 -Texas Eastern Transmission LP	M-1 Expansion	197	$66	In-Service 05/04	2004	MS-AL
2 -Southern Natural Gas Company	South System Expansion	330	$229	Phase 1 In-Service 11/03 Phase 2 In-Service 07/04	2004	LA-GA
3 -Transcontinental Gas Pipeline	Phase II Momentum Expansion	52	$189	In-Service 02/04	2004	GA-GA
Total		**579**	**$484**			

Source: FERC Office of Energy Projects. +Captial cost figures are estimates.

Storage Projects

Company	Project Name	Capacity (Bcf)	Deliverability (MMcfd)	Capital Cost (Millions)+	Status	Year Certificated	State
4 -Saltville Gas Storage Co, LLC	Saltville Storage	5.8	550	$96	Approved	2004	VA
Total		**5.8**	**550**	**$96**			

Source: FERC Office of Energy Projects. +Captial cost figures are estimates.

LNG Projects

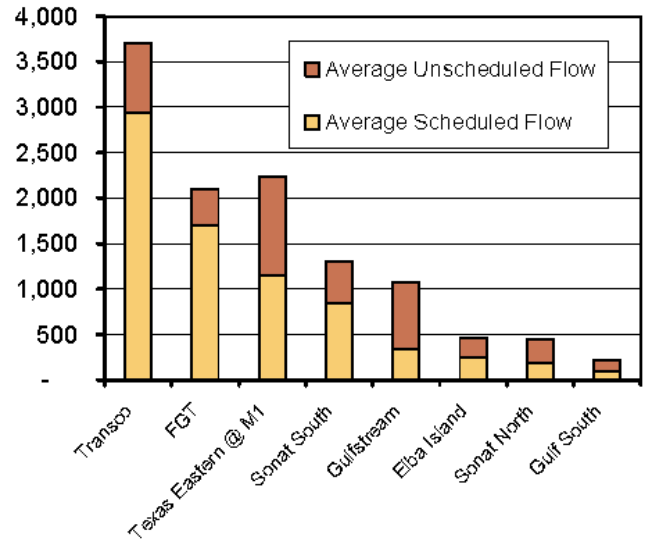
Company	Project Name	Capacity (Bcf)	Send-Out (Bcfd)	Capital Cost (Millions)+	Status	Year Certificated	State
5 -Gulf LNG Energy, LLC	Clean Energy Project	6.8	1.0	$450	Filed 2004	TBD	MS
6-El Paso/ Southern LNG	Elba Island Georgia Expansion	3.3	0.5	$86	Approved	2004	GA
7 -ConocoPhilips	Compass Port*	6.3	1.0	$700	Filed 2004	TBD	AL
Total		**16.4**	**2.5**	**$1,236**			

Source: FERC Office of Energy Projects. *Coast Guard jurisdictional facility. +Captial cost figures are estimates.

PIPELINE UTILIZATION

Transcontinental is the largest pipeline serving the Southeast, both in capacity and in volumes transported, though much of the gas it moves is delivered farther up the East Coast. Southeast pipelines that transport gas on to the Northeast and Midwest averaged 80% and 65% load factors, respectively. Several pipelines serve primarily the Southeast itself (including Alabama, Mississippi, Georgia, and the Florida panhandle)—Southern Natural, Texas Eastern's M1 line, and Gulf South. They all have relatively low load factors, ranging from 42% to 65%. Two pipelines mainly serve peninsular Florida—Florida Gas and Gulfstream. Customers use almost all the capacity on Florida Gas because of its lower rates. They use Gulfstream for supplementary supply, resulting in a much lower load factor.

Average Annual Gas Flows (MMcfd)



Source for chart on right: Derived from Lippman Consulting Inc. and Platts databases.

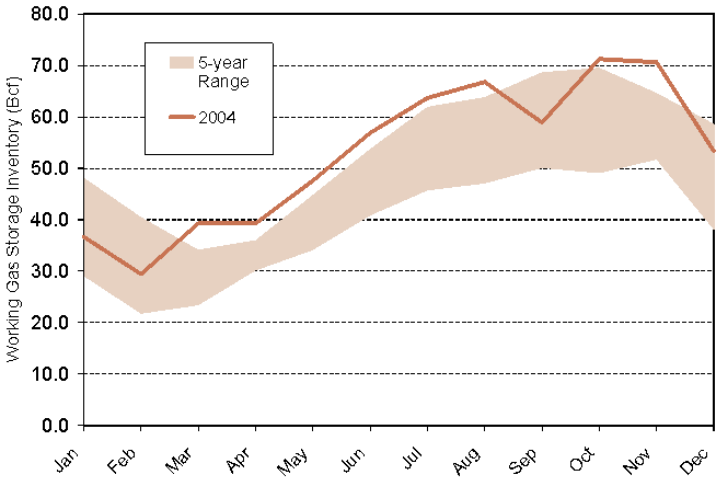
REGIONAL GAS SUPPLY

Gas fields in south and east Texas, in Louisiana, in shallow and deepwater offshore locations, and in the Black Warrior Basin account for much of the region's supply. LNG imports through the Elba Island re-gasification facility more than doubled in 2004 to almost 100 Bcf, and El Paso plans to complete an expansion project in 2005 that will increase capacity to 3.3 Bcf. Transco, TETCO, and Southern Natural interstate pipelines serve the region, but Transco remains the principal transporter for customers located from Georgia to Virginia. Regional dry proved reserves exceed 6,800 Bcf.

In 2004, the Southeast region had 163 Bcf of storage capacity distributed among 13 storage facilities. Mississippi accounted for 144 Bcf, or nearly 88%, of regional gas storage capacity. High-deliverability salt cavern storage represented nearly 32% of total regional capacity. Satellite LNG storage facilities located throughout the Southeast added about 23 Bcf of capacity to the regional storage mix. Salt cavern storage contributed about 3.6 Bcfd to regional gas deliverability.

In February, inventories stood near 30 Bcf, approximately the 5-year average level for that time of year. Robust injections into storage began in March and continued through August. Regional working gas storage levels were high during most of the April–October injection season, averaging 5–10 Bcf above 5-year average levels. Net regional gas storage withdrawals occurred during early to mid-September because Hurricane Ivan temporarily hampered Gulf Coast gas production. Working gas levels recovered, however, quickly reaching almost 71 Bcf on November 1, or about 6 Bcf above the 5-year top of the range for the beginning of the withdrawal season.

Regional Storage Inventory Levels



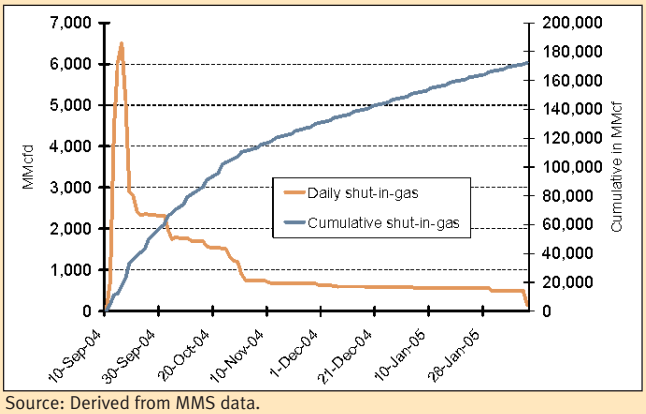
Source: Derived from EIA data. See source note 5.

Hurricane Ivan Shut-ins Compound an Already Tight Supply Market

The Atlantic Basin had a more active season than average with nine hurricanes, six of which were major (Category 3 or above). The hurricanes caused an estimated $42 billion in damage, the most costly U.S. hurricane season on record. Four hurricanes (Ivan, Charley, Frances, and Jeanne) damaged an estimated one in five homes in Florida. Although Ivan did not cause the largest economic damage, it had the greatest effect on Gulf of Mexico production because of its track through the central gulf. The other three hurricanes tracked over the east and west coasts of Florida.

Hurricane Ivan moved through the east-central portion of the Gulf of Mexico, making landfall near Mobile Bay, Ala., on September 16, damaging 24 oil and gas platforms and destroying 7 platforms. Seventeen pipelines were damaged, mostly as a result of mudslides on the Louisiana Shelf. Oil and gas companies started removing personnel from platforms on September 10 and began shutting in production on September 14.

Significant production was shut-in for long periods of time. Among its final Hurricane Ivan statistics, the Minerals Management Service (MMS) reported that cumulative shut-in natural gas production from September 11, 2004, through December 31, 2004 was 151 Bcf, or 3.4% of yearly natural gas production in the Gulf of Mexico. Typically, the gulf accounts for about 22% of total domestic natural gas production.



Source: Derived from MMS data.

Storage and Gas Reserves Overview

	Depleted Gas/Oil		Aquifer		Salt Cavern		Total Storage		Dry Proved Reserves
	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	(Bcf)
Alabama	1	3	0	0	1	82	2	11	4,301
Florida	0	0	0	0	0	0	0	0	79
Mississippi	4	103	0	0	3	41	7	144	746
Tennesse	1	1	0	0	0	0	1	1	0
Virginia	1	4	0	0	2	3	3	7	1,717
Total	**7**	**111**	**0**	**0**	**6**	**52**	**13**	**163**	**6,843**

Source: Derived from EIA data. Note: Totals may not equal sum of components due to independent rounding. See source note 6.

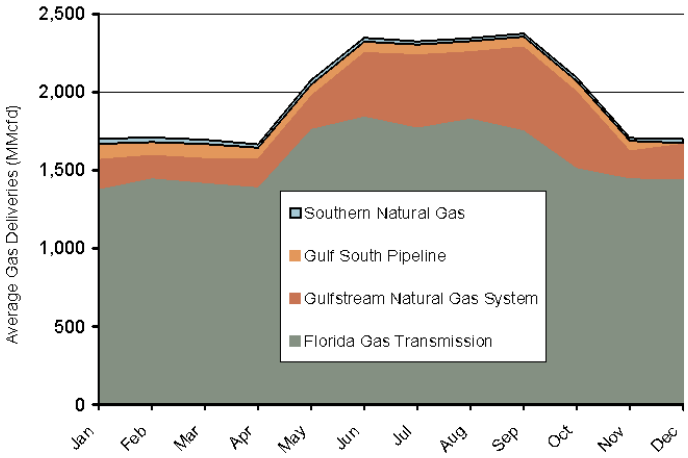
MARKET SHARES AND CONCENTRATION

Monthly gas flows into Florida averaged about 2 Bcfd in 2004. Load factors varied significantly by interstate gas pipeline. FGT accounted for on average about 80% of natural gas delivered to Florida. Throughput on Gulfstream increased nearly 50% and averaged over 300 MMcfd.

Ownership of firm transportation rights on interstate natural gas pipelines delivering gas into Florida remained moderately concentrated. Florida Power & Light, Peoples Gas System, Florida Power Corp, and Tampa Electric owned 58% of the total firm transportation delivery rights. The top 10 firm shippers retained 75% of aggregate capacity rights. Power generators dominated firm transportation rights.

Source for chart on right: Derived from Lippman Consulting Inc., Platts GasDat, and pipeline company data. See source note 7.

Florida Pipelines



Florida Firm Capacity by Holding Company

Rank	Firm Shipper	Firm Capacity Rights Held (MMcf)	Share of Firm Interstate Pipeline Capacity in Florida
1	Florida Power & Light Co.	750	28.2%
2	Peoples Gas System	413	15.5%
3	Florida Power Corp	207	7.8%
4	Tampa Electric Co.	159	6.0%
5	Florida Gas Utility	103	3.9%
6	Calpine Energy Services LP	101	3.8%
7	Southern Co. Services Inc	87	3.3%
8	Tallahassee Electric & Gas Dept.	65	2.5%
9	Orlando Utlities Commission	60	2.3%
10	NUI Utilities	59	2.2%
11	All Others	654	24.6%
Total		**2,659**	**100.0%**

Source: Derived from analysis of Platts GasDat data. See source note 8. One million Btu assumed to equal 1 Mcf.

Endnotes

[1.] OMOI's definition of the Southeast market includes three subregions: the South (Alabama, Georgia, Mississippi, and Tennessee), Florida, and Virginia/Carolinas (North Carolina, South Carolina, and Virginia).

[2.] Bentek estimates that about 10 Bcfd of firm interstate natural gas is exported from the Southeast to the Northeast and the Midwest.

[3.] These trading points are located as follows: Transco Zone 3, sometimes referred to as Station 65, includes the delivery areas between Mississippi and Alabama; Transco Zone 4 includes points downstream of Station 65 to the Georgia/South Carolina border; Transco Zone 5 includes South Carolina, North Carolina, and Virginia; and TETCO M1 is the first market zone on Texas Eastern's system and starts in central Mississippi at Kosciusko, Miss.

[4.] Excludes swap trades executed by voice brokers and other over-the-counter exchanges. OMOI believes trading volume by voice brokers accounts for a sizable share of swap transactions.

[5.] As a result, about two-thirds of Gulfstream's capacity has been sold under long-term firm transportation contracts.

Source notes

1. Prices reflect the midpoint of day-ahead spot transactions. All prices reported for flow date.

2. Prices reflect the basis or difference between the delivered price at a downstream market hub and the price of natural gas reported at the Henry Hub for spot, day-ahead transactions. Differences between downstream hub prices reported by *Gas Daily* and the Henry Hub for every calendar flow date in a month are averaged.

3. Reflects near-month natural gas swap price.

4. Trading volumes reported by *Gas Daily* at various market hubs often exceed ICE reported volumes because *Gas Daily* may count the same transaction twice—once from a seller's standpoint and once from a buyer's standpoint. Conversely, as exchange traded products, transactions involving two counterparties are reported only once by ICE.

5. Data for 2003 derived from EIA files entitled "ng_stor_sum_dcu****.xls," where the wild card represents the state designation. Storage activity for 2004 derived from a MS Excel file provided by EIA, "Working Gas by State and Month – EIA 2004.xls."

6. "Natural Gas Annual 2003," Movements and Storage – Table 14, EIA. Proved reserves: file "ng_enr_dry_a_EPGo_R11_Bcf_a.xls," Dry Natural Gas Proved Reserves as of December 31, 2003, EIA. File as of April 1, 2005.

7. Operationally available capacity data bases from Platts GasDat; operationally available capacity information from pipeline company informational postings; "Monthly Pipeline Reports" and "Monthly Regional Capacity Reports" from Lippman Consulting, Inc; and OMOI analysis.

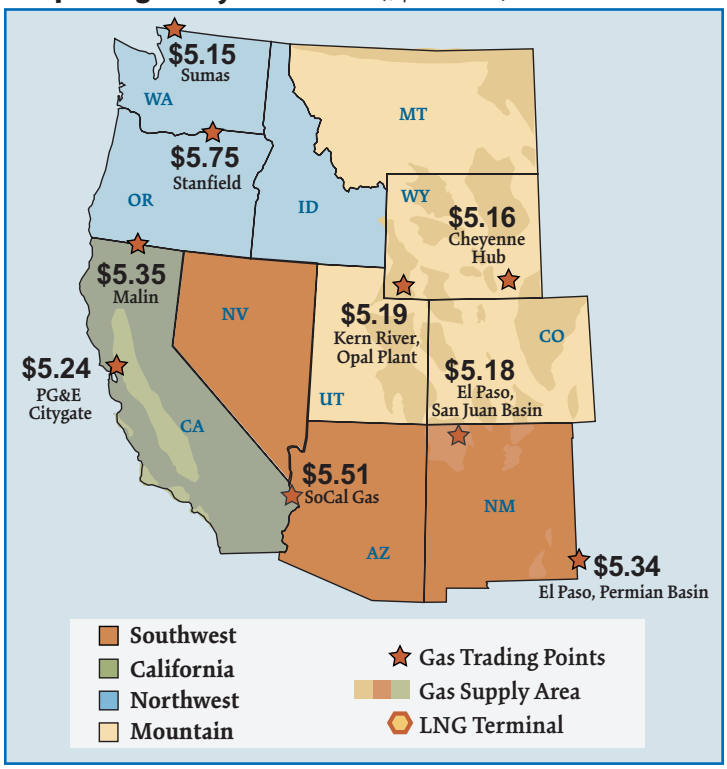
8. Uses the first quarter 2005 index of customers. Excludes firm natural gas storage contracts. Only includes natural gas contracts with firm deliveries into Florida.

Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Western Natural Gas Market Profile

The West[1] was the only regional market that produced and consumed more gas in 2004 than in 2003. Estimated gas consumption grew by 0.2 Tcf, or 5%, to 4 Tcf in 2004 and accounted for 20% of U.S. total consumption in the Lower 48 states. California, the largest market in the West, accounted for 2.4 Tcf (55%) of total estimated consumption. More than half of the estimated growth in regional gas demand came from the power-generation sector. As the leading consuming sector, power accounted for nearly 1.4 Tcf (about a third) of regional gas consumption. Diverse gas resources from western Canada (Alberta and British Columbia), the San Juan Basin, the Permian Basin, the Rocky Mountains, and California supply the region. Estimated gas production in the West increased 62 Bcf (1%) in 2004. So did Canadian gas imports (about 200 MMcfd, or 8%).[2] Record drilling in Colorado and Wyoming in 2004 highlighted the growing role of Rocky Mountain gas in the U.S. production outlook.[3] Developers also are attempting to add liquefied natural gas (LNG) as a substantial component of incremental supply in California and the Southwest (probably via Mexico). The western market contains 1.3 Tcf, or about 16%, of total U.S. storage capacity.

2004 Average Daily Hub Prices ($ per MMBtu)



Source: Derived from Platts data

Hub Prices ($ per MMBtu)

	2003	2004	5-Year		2003	2004	5-Year
Cheyenne Hub	$4.00	$5.16	$3.77	PG&E citygate	$4.83	$5.24	$4.35
El Paso, San Juan Basin	$4.56	$5.18	$3.95	Stanfield	$5.23	$5.75	$5.16
El Paso, Permian Basin	$5.07	$5.34	$4.30	SoCal Gas	$5.08	$5.51	$5.57
Kern River, Opal Plant	$4.31	$5.19	$3.72	Sumas	$4.69	$5.15	$4.24
PG&E Malin	$4.90	$5.35	$4.73				

Source: Derived from Platts data.

Focal Points for 2004

- **Average annual gas prices** at key Rocky Mountain production market hubs rose at least 14%—Cheyenne Hub (29%), Kern River, Opal plant (20%), and El Paso/San Juan Basin (14%). New take-away pipeline capacity was added to the Rocky Mountain region in 2003–04 raising gas prices to regional producers by linking new production fields with growing, downstream markets. Wholesale gas price increases at most downstream end-use markets in the West rose 5%–10%.
- **Interstate pipelines** placed into service provided more than 1.5 Bcfd of new capacity, valued at more than $600 million; incremental pipeline improvements increased access to new gas fields and enhanced the reliability of traditional transportation corridors.
- **Gas production trends** were mixed. Preliminary estimates indicate a 1.3% increase in 2004. New production areas in the Green River and Uinta-Piceance basins spearheaded a 91-Bcf growth in dry gas production, whereas more mature areas, such as the Permian, declined by 9 Bcf.[4] Wyoming and Colorado set drilling records in 2004, according to state-specific records going back to 1987.
- **Commercialization** of LNG moved slowly. Developers filed plans with FERC and the U.S. Coast Guard to build four new LNG import facilities. By year end, Sempra Energy Global Enterprises's LNG project in Ensenada, Mexico—Energia Costa Azul—had met many of the requirements to bring its terminal on line: manage cross-jurisdictional regulatory oversight, obtain financing, acquire liquefaction rights, secure shipping rights, negotiate capacity deals, and obtain permits.
- **An unplanned outage** at the San Onofre nuclear plant on November 19 highlighted the benefits of regional fuel diversity and led to improved gas and electric industry coordination. High, unanticipated gas-fired consumption due to the outage resulted in extremely low line-pack on San Diego Gas & Electric's 30-inch diameter line. However, SDG&E reinforced system pressures by re-importing gas flowing through the North Baja Pipeline and downstream pipelines in Mexico—the Gasoducto Bajanorte and the Transportadora de Gas Natural systems—back into the United States.[5]

Supply Demand Statistics

Supply Disposition	2004 (Bcf)	2003 (Bcf)
Total Dry Production	4,855	4,793
Production by Region		
San Juan	1,386	1,385
Green River	846	799
Permian - New Mexico	520	529
Uinta - Piceance	511	467
Other	1,591	1,523

Other Sources of Supply (2004 Bcf)

International Supply

	Imports	Exports	Net Imports
Canada	1,024	0	1024
Mexico	0	105	(105)
LNG	0	0	0
Total	**1,024**	**105**	**919**

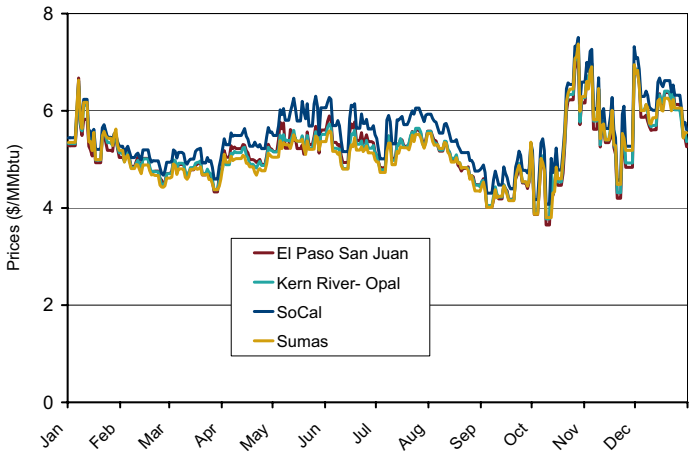
Interregional Pipeline Flows	Net Imports
to Midwest	(398)
to South Central	(591)
Total	**(989)**

Demand Disposition	2004 (Bcf)	2003 (Bcf)
Residential	960	931
Commercial	524	547
Industrial	1,196	1,111
Power	1,393	1,276
Losses and Other	229	219
Total	**4,302**	**4,085**
Key End Use Markets		
California - CA	2,369	2,248
Northwest - WA, OR, ID	570	538
Mountain - CO, UT, WY, MT	667	666
Southwest - NV, AZ, NM	696	634

Source: Derived from Bentek Energy, L.L.C. data. Note: Negative net imports are net exports.

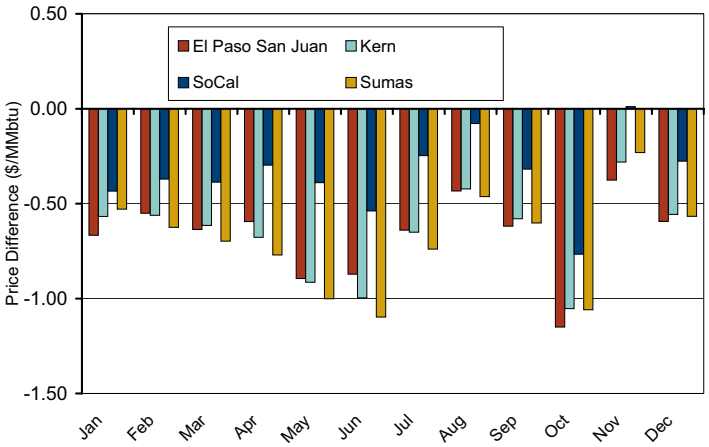
SPOT MARKETS: PRICES AND VOLUMES

Day-ahead Spot Prices



Source: Derived from Platts data. See source note 1.

Monthly Average Basis Value to Henry Hub

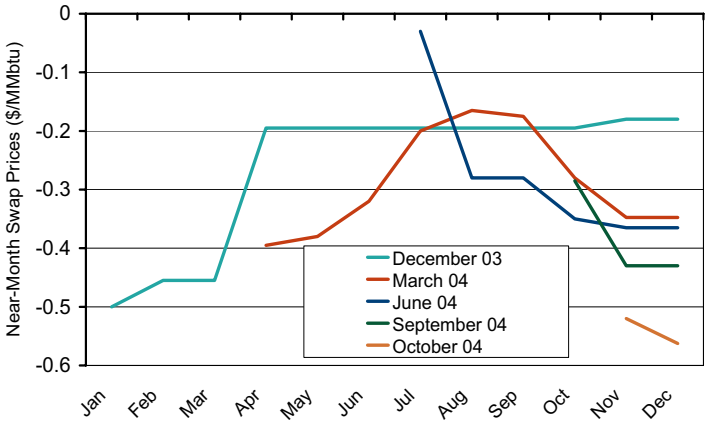


Source: Derived from Platts data. See source note 2.

Spot gas prices generally increased more in the West than in the East, but price changes varied by market. The most significant increases in average annual gas prices were reported in upstream supply basins benefiting from recent pipeline capacity expansions—at the Cheyenne Hub (29% expansion) and at the Kern River/Opal plant (20% expansion). New pipeline capacity enabled more gas from the Rocky Mountains to flow to markets in the West and the Midcontinent, resulting in greater price integration with western and eastern end-use markets. Prices increased more moderately in most other western markets. Average annual gas prices in major western end-use markets—Southern California Gas (SoCal), Pacific Gas and Electric (PG&E) at Malin, and citygates—increased 8%–11%. Western gas prices paralleled Gulf Coast price increases in October caused by hurricane-related production shut-ins and record crude oil price increases.

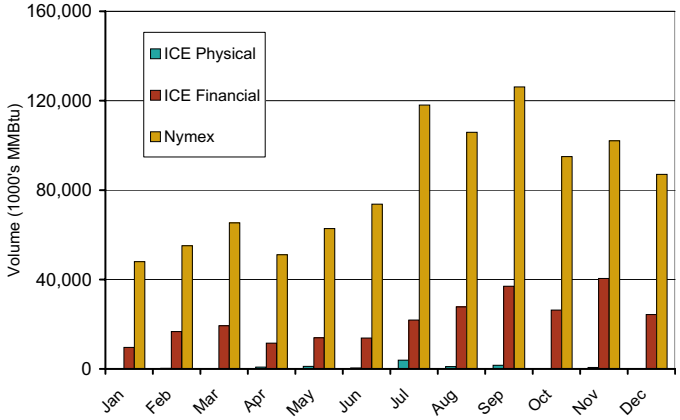
FINANCIAL MARKETS: PRICES AND VOLUMES

SoCal Swaps Prices from Trade Date



Source: Derived from Nymex data. See source note 3.

SoCal Forward and Swaps Volume

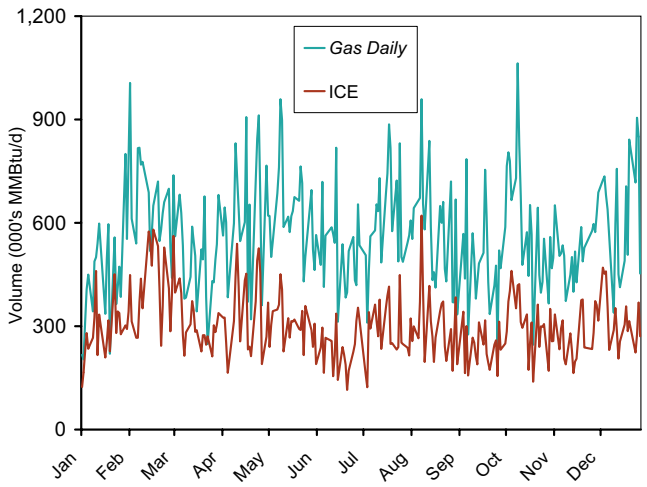


Source: Derived from ICE, Bloomberg, L.P., and Nymex data.

Average annual basis values at liquid trading points throughout the West ranged between -$0.34/MMBtu and -$0.70/MMBtu. Many major western trading points traded at discounts of greater than $1/MMBtu to the Henry Hub during October when Henry's gas prices climbed significantly because of hurricane-related shut-ins and oil market price increases. The SoCal swap prices dropped consistently during the year for trade dates in March, June, September, and October. Actual SoCal basis closely tracked expectations, averaging -$0.36/MMBtu. Trading volumes reported by platform show that New York Mercantile Exchange (Nymex) and IntercontinentalExchange (ICE) financial products ranged from a low of 51,000,000 MMBtu and 10,000,000 MMBtu, respectively, in January to a maximum of 126,000,000 MMBtu (September) and 40,000,000 MMBtu (November), respectively. ICE physical trades were minimal throughout the year.

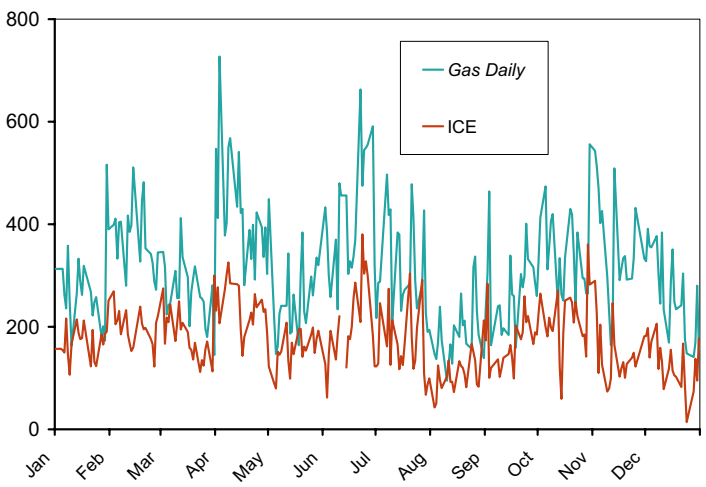
HUB POINTS: VOLUMES

SoCal Reported Volumes



Source: Derived from Platts and ICE data. See source note 4.

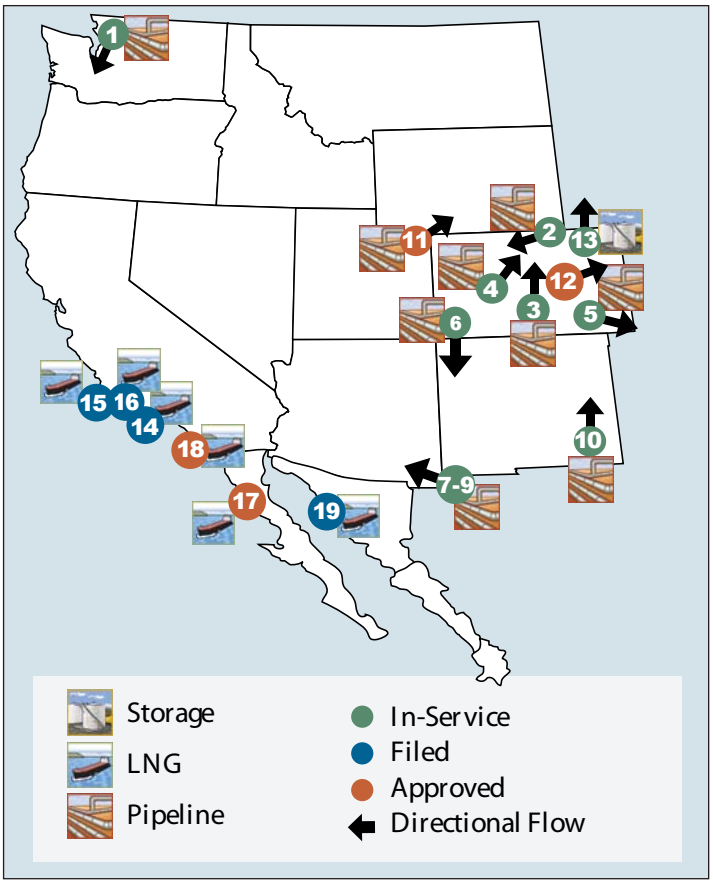
Kern River Reported Volumes



Source: Derived from Platts and ICE data. See source note 4.

Daily trading activity at market hubs in the West rose markedly in 2004. For example, average daily volumes reported by Platts *Gas Daily* at SoCal jumped 96%, from 291,000 MMBtu in 2003 to 570,000 MMBtu in 2004; similarly, ICE-reported volumes at SoCal Gas soared 146%, from 122,000 MMBtu to 302,000 MMBtu. Trading volumes reported at the Kern River/Opal increased 27%, from 66,000 MMBtu to 314,000 MMBtu (*Gas Daily*) and 17%, from 25,000 MMBtu to 173,000 MMBtu (ICE).

NATURAL GAS INFRASTRUCTURE DEVELOPMENTS



Project Development

1. Everett Delta Lateral Project
2. Cheyenne Plains Jumper Compressor
3. TransColorado Expansion Project
4. Echo Springs Project
5. Cheyenne Plains Pipeline Project
6. Bondad Expansion Project
7. Line No. 2000 Power Up Phase I
8. Line No. 2000 Power Up Phase II
9. Line No. 2000 Power Up Phase III
10. Hobbs Lateral Expansion Project
11. Southern System Expansion Project
12. Cheyenne Plains 2005 Expansion
13. Cheyenne Market Center Expansion
14. Long Beach LNG Terminal
15. Clearwater Port
16. Cabrillo Port
17. Energia Costa Azul
18. Terminal GNL Mar Adento de Baja, California
19. Sonora Pacific LNG Project

This map numbering system corresponds to the following three charts on pipeline, storage, and LNG projects.

Pipeline Projects

Company	Project Name	Capacity (MMcf/d)	Capital Cost (Millions)+	Status	Year Certificated	From-To State
1-Northwest	Everett Delta Lateral	113	$24	In-Service 11/04	2004	WA-WA
2-Colorado Interstate	Cheyenne Jumper Compressor	118	$5	In-Service 12/04	2004	CO-CO
3-TransColorado	TransColorado Expansion	125	$29	In-Service 08/04	2004	CO-CO
4- Wyoming Interstate	Echo Springs	116	$12	In-Service 11/04	2004	WY-WY
5- Cheyenne Plains	Cheyenne Plains	560	$410	In-Service 12/04	2004	WY-KY
6- El Paso	Bondad Expansion (Phase 1&2)	140	$7	In-Service 03/04	2003	CO-CO
7-El Paso	Line No. 2000 Power Up Phase I	120	$81	In-Service 02/04	2003	TX-AZ
8-El Paso	Line No. 2000 Power Up Phase II	100	$54	In-Service 04/04	2003	TX-AZ
9-El Paso	Line No. 2000 Power Up Phase III	100	$39	In-Service 06/04	2003	TX-AZ
10- Pinnacle	Hobbs Lateral Expansion	42	$1	In-Service 03/04	2003	NM-NM
11- Questar	Southern System Expansion	102	$55	Filed 2004	2005	UT-UT
12- Cheyenne Plains	Cheyenne Plains 2005 Expansion	170	$8	Approved	2004	CO-CO
Total		**1,806**	**$725**			

Source: FERC Office of Energy Projects. + Capital cost figures are estimates.

Storage Projects

Company	Project Name	Capacity (Bcf)	Deliverability (MMcf/d)	Capital Cost (Millions)+	Status	Year Certificated	State
13 -Kinder Morgan Interstate Gas Transmission	Cheyenne Market Center Expansion Project	6.5	68	$27	In-Service 06/04	2003	CO, NE
Total		**6.5**	**68**	**$27**			

Source: FERC Office of Energy Projects. + Captial cost figures are estimates.

LNG Projects

Company	Project Name	Capacity (Bcf)	Send-Out (Bcf)	Capital Cost (Millions)+	Status (Bcfd)	Year Certificated	State
14 -Sound Energy Solutions	Long Beach	3.5	0.7	$400	Filed 2004	TBD	CA
15 -Crystal Energy	Clearwater Port*	0	0.5	$160	Filed 2004	TBD`	CA
16- BHP Billington	Cabrillo Port*	6.0	1.5	$550	Filed 2004	TBD	CA
17- Sempra & Shell Energía	Costa Azul**	6.8	1.0	$600	Approved	2004	MX
18 -Chevron Texaco	GNL Adentro de Baja***	5.3	1.4	$650	Approved	2004	MX
19 -Sonora Pacific	Sonora Pacific	6.8	1.3	$500	Filed 2004	TBD	MX
Total		**28.4**	**6.4**	**$2,860**			

Source: FERC Office of Energy Projects and California Energy Commission. + Captial cost figures are estimates.
* Coast Guard jurisdictional facilities (all others are FERC jurisdictional). **All major permits obtained in Mexico. *** Environmental permit granted in Mexico.

Ten pipeline projects accounting for 1.5 Bcfd of incremental capacity began commercial service in 2004 in the western market. FERC approved one pipeline expansion adding 170 Mcfd. The Cheyenne Hub added 6.5 Bcf of storage capacity and 66 MMcfd of deliverability.

Developers submitted applications to build four LNG import terminals in the West, totaling four Bcfd in potential send-out. Infrastructure developers held numerous open seasons in 2004 to assess whether shippers wanted access to new conventional and LNG supply sources.

El Paso Capacity Allocation Problem Settled

El Paso Natural Gas Co. and its customers reached a final settlement on reallocation of capacity rights in August 2004. Customers secured firm, point-to-point rights similar to traditional rights available on other pipelines. The reallocation has improved service and affected how customers buy and sell both financial and physical gas in the Southwest market (including California). Responding to FERC's directives, El Paso changed its capacity allocation, requiring full-requirements customers to convert to contract-demand service. This change meant that the same type of tariff was levied on all customers and also required them to switch from systemwide to specific-receipt rights. As a result, firm service on the El Paso system has become more reliable and capacity is allocated to those customers valuing it most.

REGIONAL GAS SUPPLY

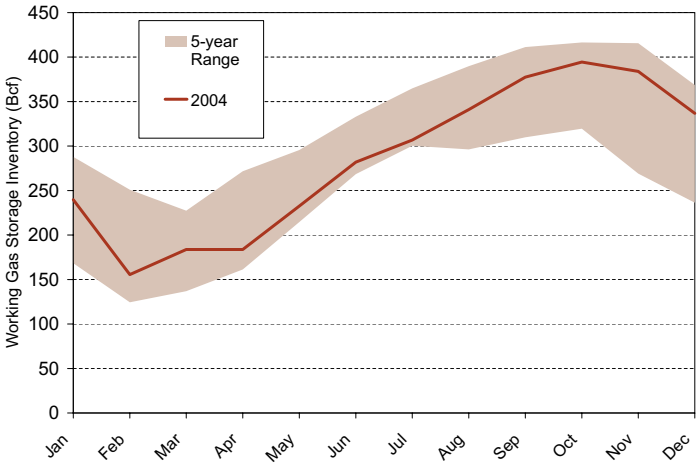
Much of the region's supply originates in the Southwest and in the Rocky Mountains of the United States and Canada. Domestic production of more than 4,800 Bcf accounts for more than 80% of regional supply with the other 20% coming from Canada. Conventional and nonconventional (coalbed methane) gas production comes from California; the western Canadian Sedimentary Basin; the San Juan Basin; the Permian Basin; the Powder River Basin; the Raton Basin; and the Piceance, Uintah, and Green River basins in the central Rocky Mountain area. An increasingly important source of production, coalbed methane from the San Juan Basin and various Rocky Mountain basins, totaled more than 4 Bcfd in third quarter 2003.[6] Proved dry gas reserves in the region total about 61,200 Bcf.

More than 1.3 Tcf of storage capacity at 42 sites is distributed throughout the West. Market participants use a mix of storage facilities located in or near the production basins in the Rocky Mountain and market-area storage in California, Oregon, and Washington. Most of the regional storage capacity (72%) is located in California, Montana, and Utah. Depleted reservoir storage accounts for 1.2 Tcf of the total regional capacity. New techniques enable storage operators to increase the storage capacity, deliverability, and cycling of some new and existing depleted reservoir fields. Examples of multi cycle, high-deliverability storage facilities in the West include the Lodi (17 Bcf) and Wild Goose (17 Bcf) facilities in California and the Mist (14 Bcf) facility in Washington. In addition, the West has 4.5 Bcf of regional, satellite LNG storage capacity to augment retail gas supply flexibility.

Working gas inventory at the start of the injection season was 184 Bcf, nearly 20 Bcf below the 5-year average (214 Bcf), but still within the average inventory range during the previous 5 years. Winter weather in 2003–04 was typical; actual cumulative heating-degree days reflected 96% of normal levels. Warm summer weather, however, resulted in cumulative cooling-degree days that were 111% of normal levels. Increased cooling consumption, however, did not dampen storage injections; working gas inventories equaled the 5-year average (about 384 Bcf) by the start of the withdrawal season.

Aggregate California storage operations in 2004 remained in line with operations in 2003. Systemwide, PG&E and SoCal Gas injected 286 MMcfd of gas into storage from April through October, about 6 MMcfd less in 2004 than in 2003. However, an equivalent 6 MMcfd increase in injections at the independently owned and operated Lodi and Wild Goose facilities offset this decline.

Regional Storage Inventory Levels



Source: Derived from EIA data. See source note 5.

Storage and Gas Reserves Overview

	Depleted Gas/Oil		Aquifer		Salt Cavern		Total Storage		Dry Proved Reserves
	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	Sites	Capacity (Bcf)	(Bcf)
California	8	446	0	0	0	0	8	446	2,450
Colorado	9	101	0	0	0	0	9	101	15,436
Montana	5	374	0	0	0	0	5	374	1,059
New Mexico	2	79	1	5	0	0	3	84	17,020
Oregon	5	24	0	0	0	0	5	24	0
Utah	1	118	2	12	0	0	3	129	3,516
Washington	0	0	1	40	0	0	1	40	0
Wyoming	7	104	1	10	0	0	8	114	21,744
Total	**37**	**1,246**	**5**	**67**	**0**	**0**	**42**	**1,312**	**61,225**

Source: Derived from EIA data. See source note 6.

MARKET CONCENTRATION

Principal Capacity Owners by Pipeline

	Customer	Northwest Pipeline (MMcf)	Questar (MMcf)	Wyoming Interstate (MMcf)	Kern River (MMcf)	Colorado Interstate (MMcf)	Wyoming Pipelines (MMcf)	Est Market Share (%)
1	Questar Corp	3	1790	6	53	0	2,113	15%
2	The Williams Companies Inc	61	30	303	84	235	906	7%
3	Puget Energy Inc	777	0	0	0	0	777	6%
4	Xcel Energy Inc	0	0	40	0	665	711	5%
5	El Paso Corp	0	188	333	79	0	600	4%
6	Encana Corp	0	20	10	0	183	511	4%
7	Northwest Natural Gas Co	500	0	0	0	0	500	4%
8	BP plc	0	35	272	72	25	474	3%
9	Cascade Natural Gas Corp	412	0	0	0	0	412	3%
10	MDU Resources Group, Inc	0	0	0	0	0	404	3%

Source: Derived from Platts data. See source note 7. One Million Btu assumed to equal 1 Mcf.

Top 3 Owners of Wyoming Pipeline Capacity

	Pipeline	Top Customers	Est % of Market share	Top Customers	Est % of Market Share	Top Customers	Est % of Market Share
1	Northwest Pipeline Co	Puget Energy, Inc	25	Northwest Natural	16	Cascade Natural Gas	14
2	Questar Corp	Questar Corp	72	El Paso Corp	8	Dominion Resources	4
3	Wyoming Interstate	El Paso Corp	16	Williams Co	14	BP	13
4	Kern River	Reliant	12	Southwest	11	Los Angeles Dept Water	9
5	Colorado Interstate	Xcel Energy	41	Williams Co	15	Encana Corp	11
6	Southern Star	Southern Union	50	Oneok	16	Duke Energy Corp	10
7	Kinder Morgan	Kinder Morgan	33	Oneok	30	Northwest Corp	12
8	TransColorado	Encana	59	Williams Co	28	Western Gas Resources	10
9	Willston Basin	MDU	96	CHS Inc	1	Covana	1
10	Overthrust	Questar Corp	100				
11	MIGC Inc	Western Gas Resources	100				

Source: Derived from Platts data. See source note 8.

Overall, ownership of firm receipt point capacity rights measured across all interstate pipelines in the Wyoming market was not concentrated. However, ownership of firm transportation capacity rights on individual pipelines in the West was highly concentrated. A single shipper owned 50% or more of firm receipt point rights on the following pipelines: Questar (72%), MIGC (100%), TransColorado (59%), Overthrust (100%), Williston Basin (96%), and Southern Star (50%).

Major Pipeline Capacity Owners in California

Rank	Company	Share	Capacity (MMcf)
1	Sempra Energy Global Enterprises	20.7%	1,721
2	PG&E Corp	11.6%	964
3	Southwest Gas Corp	5.9%	491
4	Chevron Corp	4.2%	347
5	Reliant Energy, Inc	4.6%	300
6	BP plc	3.5%	289
7	Calpine Corp	3.3%	277
8	Sierra Pacific Resources	3.2%	266
9	Duke Energy Corp.	3.0%	251
10	Royal Dutch Petroleum Co	2.1%	174

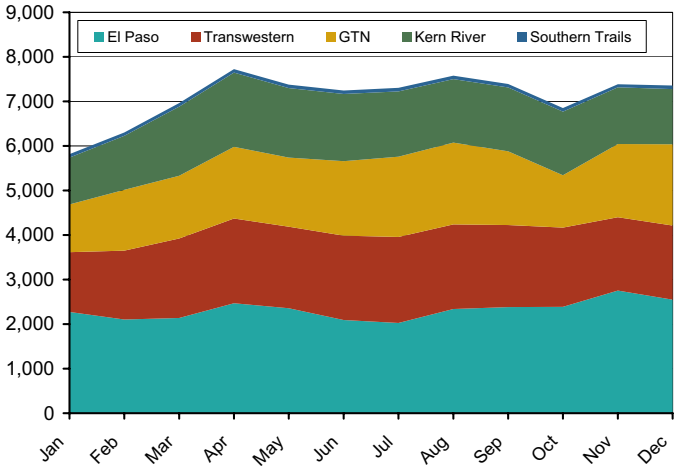
Source: Derived from Platts data. See source note 9. One million Btu assumed to equal 1 Mcf.

MARKET SHARES

Average monthly natural gas deliveries by interstate pipelines into California increased about 590 MMcfd, or 9%, to 7,100 MMcfd in 2004. Pipeline market shares were as follows: El Paso (33%), Transwestern (25%), Gas Transmission Northwest (22%), Kern River (20%), and Southern Trails (1%). Annual California consumption has two peaks, one each in winter and summer. Gas use is somewhat less seasonal than in other markets. Ownership of firm interstate natural gas transportation service rights by end-users in California is not concentrated. The major LDCs—Sempra Utilities Group[7] and PG&E Corp.—owned 33% (2.7 Bcfd) of firm capacity rights on pipelines delivering natural gas into California.

Source: Derived from Lippman Consulting, Inc. data. See source note 10.

Pipeline Deliveries into California (MMcfd)

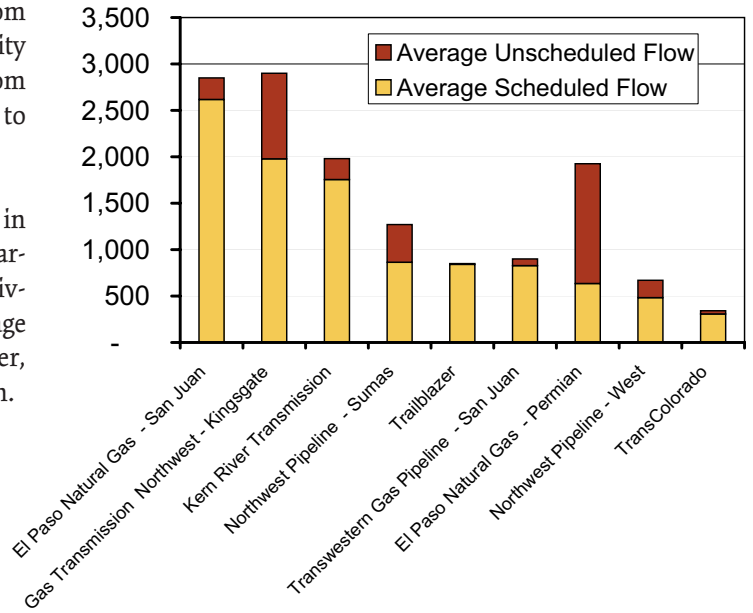


PIPELINE UTILIZATION

The largest pipelines serving major western markets are El Paso (from the San Juan and from the Permian Basin), Northwest (importing from Canada), and Kern River (delivering from southwestern Wyoming). Customers use most of the capacity on most western pipelines. An exception is the El Paso leg from the Permian Basin. Much of the Permian Basin's gas flows to higher-priced regions in the East.

Estimated western gas pipeline utilization averaged 75% in 2004, the highest of any gas region.[8] Customers bought comparatively low-cost gas in the Rocky Mountain region and delivered it through an expanded network of gas pipelines. Average annual load factors were at least 89% on Kern River, TransColorado, Transwestern San Juan, and El Paso San Juan.

Average Annual Gas Flows (MMcfd)



Source: Derived from Lippman Consulting Inc., Platts and pipeline company data. See source note 11.

Endnotes

[1.] OMOI defines the gas market in the West to include 11 states in 4 subregions: California, the Southwest (Arizona, Nevada, and New Mexico), the Pacific Northwest (Washington, Oregon, and Idaho), and the Mountain region (Montana, Wyoming, Colorado, Utah).

[2.] The growth in net imports was only 150 MMcfd (6%) after accounting for increased gas exports to Mexico.

[3.] According to the U.S. Geological Survey, Montana, Wyoming, Colorado, and Utah together account for 26% of total U.S. gas reserves.

[4.] Bentek Energy LLC estimated natural gas consumption data when the Energy Information Administration state-level gas consumption data were unavailable. Also, Bentek estimated natural gas production, international imports and exports, and firm inter-regional interstate gas transfers. Bentek used natural gas production data from state agencies, when available.

[5.] GBN is a 145-mile natural gas transportation pipeline that links gas receipts from the North Baja Pipeline at Ogilby, Calif., with deliveries into the TGN Pipeline near Tijuana in Baja California, Mexico. Sempra Pipelines & Storage built this 30-inch-diameter pipeline with capacity of 500 MMcfd; it began operating in September 2002. TGN is a 23-mile, 30-inch-diameter pipeline that began supplying natural gas from the United States-Mexico border near San Diego to the Presidente Juárez power plant in Rosarito, Baja California, in summer 2000.

[6.] Lippman Consulting, Inc., Lower-48 States Coalbed Methane 3rd Quarter 2004 Production Report, April 19, 2005.

[7.] Sempra is the holding company for SoCal Gas and San Diego Gas & Electric.

[8.] OMOI analysis of average annual deliveries as measured on the following pipelines: El Paso Natural Gas—San Juan, Gas Transmission Northwest—Kingsgate, Kern River Transmission, Northwest Pipeline—Sumas, Trailblazer, Transwestern Gas Pipeline—San Juan, El Paso Natural Gas—Permian, Northwest Pipeline—West, and TransColorado.

Source notes

1. Prices reflect the midpoint of day-ahead, spot transactions. All prices reported for flow date.

2. Prices reflect the basis or difference between the delivered price at a downstream market hub and the price of natural gas reported at the Henry Hub for spot, day-ahead transactions. Differences between downstream hub prices reported by *Gas Daily* and the Henry Hub for every calendar flow date in a month are averaged.

3. Reflects near-month natural gas swap price.

4. Trading volumes reported by *Gas Daily* at various market hubs often exceed ICE reported volumes because *Gas Daily* may count the same transaction twice—once from a seller's standpoint and once from a buyer's standpoint. Conversely, as exchange traded products, transactions involving two counterparties are reported only once by ICE.

5. Data for 2003 derived from EIA files entitled "ng_stor_sum_dcu****.xls," where the wild card represents the state designation. Storage activity for 2004 derived from a MS Excel file provided by EIA, "Working Gas by State and Month – EIA 2004.xls."

6. Storage: "Natural Gas Annual 2003," Movements and Storage – Table 14, EIA. Proved reserves: file "ng_enr_dry_a_EPG0_R11_Bcf_a.xls", Dry Natural Gas Proved Reserves as of December 31, 2003, EIA. File as of April 1, 2005. Totals may not equal sum of components due to independent rounding.

7. Represents the most significant owners of firm interstate natural gas pipeline receipt point rights (as measured in MMcfd) in Wyoming, Northwestern Colorado, and Northeastern Utah across all FERC-jurisdictional pipelines in this market.

8. Comprises the top three customers (as measured in MMcfd) on individual interstate natural gas pipelines with receipts in Wyoming, northwestern Colorado, and northeastern Utah.

9. Represents firm interstate pipeline delivery rights into California by pipeline customer. The following pipelines were included in the analysis: Transwestern, Kern River, El Paso, GTN Northwest, and Tuscarora Gas Transmission and Southern Trails.

10. Average monthly natural gas deliveries into California on interstate natural gas pipelines. Excludes volumes transported on the North Baja Pipeline.

11. Operationally available capacity databases from Platts GasDat; operationally available capacity information from pipeline company informational postings; "Monthly Pipeline Reports" and "Monthly Regional Capacity Reports" from Lippman Consulting, Inc; and OMOI analysis.

Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Other Energy Markets in 2004

This *State of the Markets Report* contains profiles of 7 markets and other related factors that affect electric and natural gas markets: Coal, Demand Response, Emissions Allowances, Energy Debt and Equity, Oil, Weather, and Wind.

Overview

The profiles cover 7 areas that have important implications for natural gas and electric power markets:

Coal. Prices for eastern coal rose by as much as 69 percent during the year and contributed significantly to the regional pattern of electric power price changes.

Demand Response. Electric power markets have little price responsive demand, the lack of which can create price spikes. During 2004, mild summer weather reduced responses in price-sensitive programs, but more sophisticated technologies began to emerge.

Emissions Allowances. During 2004, emissions allowance prices rose rapidly. This added to the upward pressure on electric power prices in regions dependent on coal, especially from the East. Allowances can add as much as about $20 per MWh to the running cost of an unscrubbed coal plant.

Energy Debt and Equity. During 2004, the energy industry recovered a degree of financial health, compared with other years, as the cost of borrowing went down and stock prices rose more than the Standard and Poor's 500 index.

Oil. Global oil markets saw significant price increases in 2004 as well. This put continuing upward pressure on all other energy prices, including natural gas and electric power. The two most obvious factors influencing natural gas prices are gas storage inventories and global oil prices.

Weather. Weather was moderate during 2004. The winter of 2003-2004 was 6 percent warmer than the year before. The summer of 2004 was the ninth coolest on record. Two events affected energy markets during the year: a cold snap in New England in January and Hurricane Ivan in September.

Wind. Wind has become the fastest-growing generation source. But it remains heavily dependent on government policy (such as tax credits) at both state and national levels.

Coal

Coal is the leading fossil fuel used by U.S. power generators, accounting for 1.93 billion MWh, or half of U.S. net generation in 2004. About 30% of U.S. generating capacity is coal-fired. U.S. recoverable coal reserves totaled 271,677 million short tons (mmst) in 2003 or about 25% of worldwide recoverable reserves.[1] Total U.S. coal production increased by 3.7% to 1,112 mmst in 2004. The most prolific U.S. coal supply regions are the Powder River Basin in the west with 38% and the Appalachian Basin in the east with a third of U.S. coal production. Power sector consumption of coal increased slightly in 2004 to 1,015 mmst, reducing end-of-year stockpiles by 12% in 2004. Coal delivery was slowed by some constraints on transloading facilities and on the intermodal network of rail, barges, and trucks. Coal is the lowest-cost fossil fuel for power generation on a dollar per MMBtu basis. Trends in 2004, however, indicated that coal prices may face increased price volatility in the future.[2]

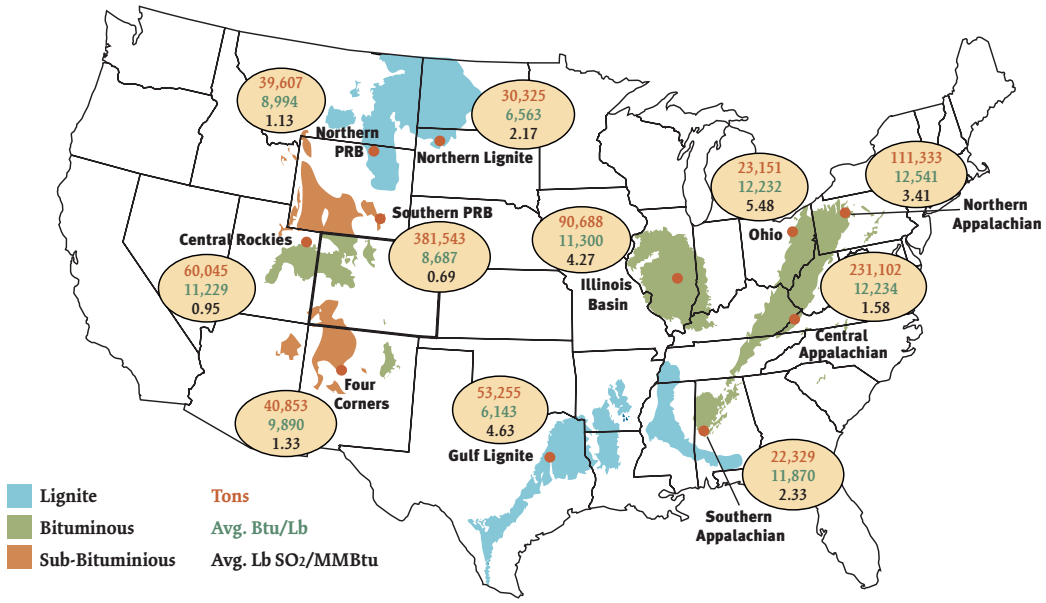
Fewer companies controlled greater shares of total U.S. coal production than a decade ago. The advance in public ownership of coal companies spurred accountability, short-term profitability, and sensitivity to Wall Street.[3] International coal demand growth and a weak dollar during 2004 contributed to a 17% increase in net coal exports.[4]

Coal Spot Prices ($/short ton)

Source	2004	2003	5-Year Avg
Central Appalachia	$54.2	$32.1	$35.6
Colorado/Utah	$22.0	$15.0	$17.3
Illinois Basin—High Sulfur	$29.1	$22.8	$24.2
Illinois Basin—Mid Sulfur	$30.1	$24.8	$25.9
Northern Appalachia	$45.6	$30.9	$31.3
PRB 8800	$6.6	$6.2	$6.4

Source: Derived from Bloomberg, L.P. data.

Coal Production in the U.S.



Source: Derived from Platts data. See source note 1.

Focal Points for 2004

- **Volatile spot prices.** An imbalance between production and consumption combined with a strong international market, triggered a 69% increase in central Appalachian coal prices in 2004.[5] Coal prices increased markedly in most coal supply regions and generally exceeded 2001 levels. National retail prices, however, increased 6%, on average, as customers relied on long-term contracts.
- **Continued price growth expectations.** Futures prices and over-the-counter forward market signals indicated sustained high coal prices.
- **Effects on power prices.** Higher coal prices translated into higher on-peak and off-peak power prices in coal-dominated regions.
- **Coal transportation constraints.** Regional rail and barge bottlenecks reduced coal deliveries to customers and compounded price volatility.

Coal Market Overview (Million Short Tons)

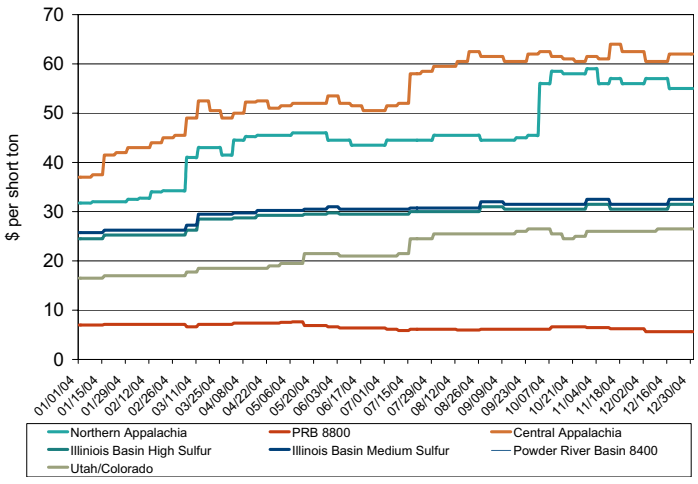
Production by Region	2003	2004	Consumption By Sector	2003	2004
Appalachian	376	389	Electric Power	1,005	1,015
Interior	146	146	Coke Plants	24	24
Western	549	575	Other Industrial Plants	61	61
Coal Refuse Recovery	1	1	Residential/Commercial Users	4	4
Total	1,072	1,112	Total	1,095	1,104
U.S. Coal Trade			**Year-End Coal Stocks**		
Exports	43	48	Electric Power	122	107
Imports	25	27	Other Industrial Plants	44	41
Net Exports	18	21	Total	166	147

Source: Derived from EIA data. See source note 1. Note: Sum of components may not equal total due to independent rounding.

Production

U.S. coal production increased by 3.7% in 2004, despite transportation constraints. The 4.7% coal production increase in the West outpaced a 3.4% increase in the East. Interior regional coal production effectively remained unchanged. As a result, western coal production accounted for a growing share of total U.S. production, slightly more than half in 2004. Appalachian mines produced less than 400 mmst of coal for the third consecutive year—the first time this has happened since the 1970s.[6] The increase in eastern coal production was modest given the material change in eastern coal spot prices.

2004 Coal Prices



Source: Derived from Bloomberg, L.P. data.

Coal Production for 2004

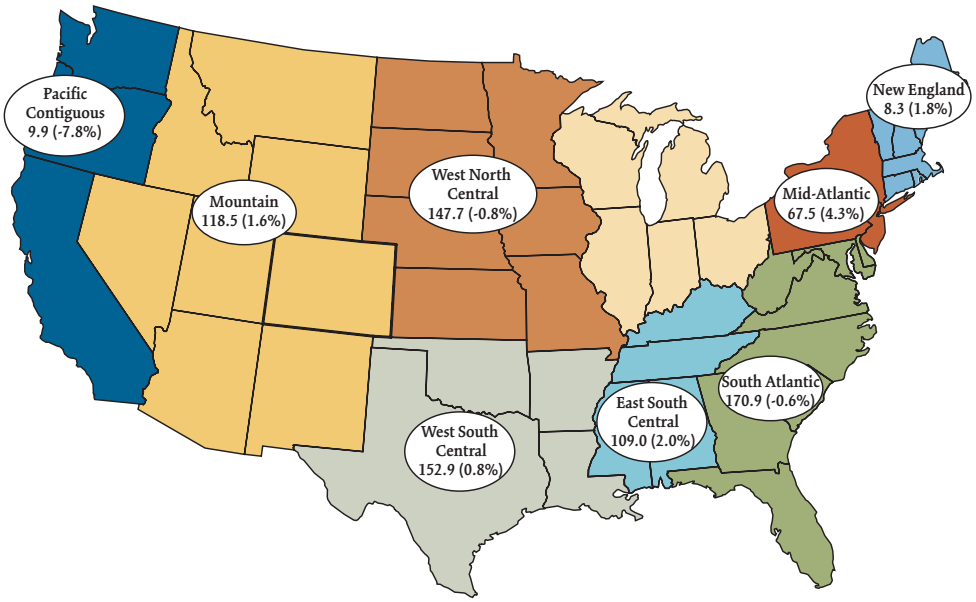
	Tons (Millions)	% of Total
Central Appalachia	231	20.8
Southern Appalachia	22	2.0
Mid-Continent: Gulf Lignite	54	4.8
Mid-Continent: Illinois Basin	91	8.2
Mid-Continent: Interior	2	0.2
Northern Appalachia: Northeast	111	10.0
Northern Appalachia: Ohio	23	2.1
Western: Central Rockies	60	5.4
Western: Four Corners	41	3.7
Western: Northern Lignite	30	2.7
Western: Northern PRB	40	3.6
Western: Raton/Canon City	0	0
Western: Southern PRB	382	34.4
Western: Southern Wyoming	15	1.3
Western: Washington	6	0.5
Total	**1,109**	**100.0**

Source: Derived from Platts data. See source note 2.
Note: Sum of components may not equal total due to independent rounding.

Coal Consumption

Coal consumption grew slightly in 2004, by about 1%. The electric power sector consumed a record amount of coal in 2004 and accounted for 92% of the total, despite the generally mild weather that moderated electric demand. Nevertheless, coal's share of overall net generation declined across the country. About 75% of the national increase in coal consumption occurred in two areas—the East North Central and Mid-Atlantic census regions.

Electric Power Coal Consumption Across the U.S. (Millions of Tons)
U.S. Total = 1,015



Source: Derived from EIA data. See source note 3.

Prices

Estimated average annual spot[7] prices increased markedly for coal purchased in most markets: 69% for central Appalachia, 49% for northern Appalachia, 25% for Illinois Basin and 48% for Colorado.[8] Factors accounting for higher coal prices in 2004 included:

- Structural imbalances in production and consumption.
- High gas prices.
- Higher oil costs which drove up the cost of mining and shipping.
- Net increased exports of bituminous coal as a consequence of high international prices and the comparatively weak dollar.[9]
- Declining mining productivity.
- Ongoing production and productive capacity challenges including reserve degradation, legacies of past lawsuits, bankruptcies, deferred investment in new mines, temporary mine closures due to fires, permitting delays and new regulations affecting coal hauling by truck in West Virginia and Kentucky.

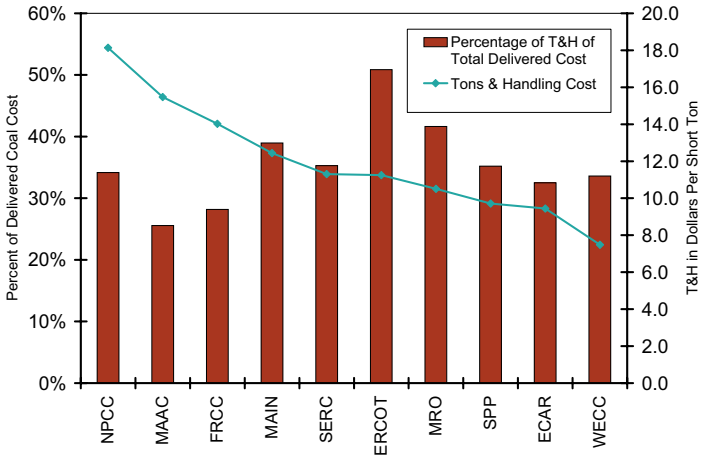
Coal transportation and handling (T&H)[10] charges added between a quarter and a half of the total delivered cost of coal in 2004. Estimated annual costs as a percentage of total delivered costs changed little between 2003 and 2004 in most North American Electric Reliability Council (NERC) regions. Average T&H costs exceeded $14/ton and were generally higher in eastern NERC regions: Northeast Power Coordinating Council, Florida Reliability Regional Council, and the Mid-Atlantic Area Council. In these areas, T&H costs climbed from 18% to 28% of total delivered coal costs. Estimated T&H costs were much lower, on average, in the Western Electric Coordinating Council region because many of its coal-fired plants are situated in close proximity to coal supplies.[11]

Transportation Constraints

Despite numerous constraints along the coal transportation network in 2004, total carloadings of coal increased 3%. Moreover, Energy Information Administration (EIA) analysis of U.S. Army Corps of Engineering data on tonnage indicators for coal and coke suggested that waterborne coal distribution probably increased roughly 4% to 5% in 2004.

Coal distribution networks experienced growing pains in 2004. On many segments, trains rolled 24 hours a day, 7 days a week. Hence, delays on some segments had ripple effects on the distribution network, with few opportunities to accelerate deliveries and compensate for such slowdowns. Increased eastern metallurgical coal exports, most of which were shipped from the Hampton Roads and Baltimore terminals, strained rail deliveries of domestic coal.[12] Lack of spare railroad capacity likely constrained spot purchases of coal from the Powder River and Uinta Basins. Eastern rail delays forced market participants to use river barges when possible. Barge traffic, however, was impeded by lock maintenance, flooding and sunken barges. In Kentucky, stricter enforcement of weight limits on trucks hauling coal reduced the size of hauls by 40% to 50% and led to delays in delivery of central Appalachian coal.[13] Union Pacific struggled to keep up with increased demand with deliveries thwarted by a lack of equipment and insufficient personnel, in part reflecting the loss of more senior employees than anticipated.[14]

Transportation and Handling Costs



Source: Derived from Platts CoalDat data.

Coal Industry Concentrations

	Company	Production (Millions of Short Tons)	Percentage of U.S. Production
1	Peabody Coal Co.	192	17%
2	Kennecott Energy & Coal Co.	124	11%
3	Arch Coal, Inc.	115	10%
4	CONSOL Energy, Inc.	65	6%
5	Foundation Coal Corp.	60	5%
6	A.T. Massey Coal Co., Inc.	39	4%
7	Vulcan Partners, LP	36	3%
8	North American Coal Corp.	31	3%
9	Westmoreland Coal Co.	29	3%
10	TXU Corp.	24	2%
	All Others	392	35%
	Total	1,109	100%

Source: Derived from Platts CoalDat data.
Note: Sum of components may not equal total due to independent rounding.

Transportation and Handling Costs

Power Plant NERC Region	Average 2004 T&H Cost from Western Market
ECAR	$4.3
ERCOT	$2.3
FRCC	$12.6
MAAC	$15.5
MAIN	$10.3
MRO	$8.5
NPCC	$18.1
SERC	$7.5
SPP	$6.2
WECC	$4.0

Source: Derived from Platts CoalDat data.

Concentration Measures

Coal industry consolidation continued in 2004. Arch Coal Inc. (the third-ranked producer) acquired Vulcan Partners (the seventh-ranked producer). By the end of the year, the top 10 coal producers accounted for 65% of total coal production. By comparison, in 1994 the top 10 coal producers constituted 41% of total U.S. production.[15]

Coal Stocks

Total coal stockpiles declined by 18 million short tons in 2004. Coal-fired power generators drew down their stockpiles for the second year in a row with end-of-year stockpiles down 12%. U.S. coal stocks reached a record low of 37.5 days of supply in July.[16] PA Consulting estimated that less than a 30-day supply of coal existed in the Mid-Atlantic, South Atlantic, and East South Central census regions in July—all of which are central Appalachian coal-dependent.[17]

Endnotes

[1] "Table 8.2: World Estimated Recoverable Coal," International Energy Annual 2002, Energy Information Administration (EIA).

[2] In the past, coal prices have been relatively stable, especially compared with other fossil fuels. Changes currently underway in the industry, however, may augur a period of increased price volatility.

[3] "Coal Price Volatility Is Here to Stay," PA Consulting, Jerry Eyster, April 26, 2005.

[4] Exports minus imports of coal.

[5] "Coal Price Volatility Is Here to Stay."

[6] "U.S. Coal Supply and Demand: 2004 Review," Fred Freme, EIA, April 2005.

[7] Based on information derived from CoalDat, Spot transactions represented about 15% of total coal purchases in 2004; mid- and long-term contracts accounted for the remainder.

[8] Average annual percentage price differences derived from Bloomberg, L.P. coal price information.

[9] According to EIA, delivered coal prices in international coal markets soared because of the withdrawal of Chinese coal and coke from markets and extreme demand for bulk carriers by a booming Chinese steel industry.

[10] Includes all forms of intermodal transportation: rail, barge, and truck, plus any other transloading charges from one form of transportation to another.

[11] Sometimes referred to as minemouth plants.

[12] EIA.

[13] Coal Market Report, EIA, week ending July 25.

[14] EIA.

[15] "Coal Price Volatility Is Here to Stay."

[16] "What Does the Coal Market Do for an Encore?" *Coal Age*, PA Consulting, Jerry Eyster, January 2005.

[17] According to PA Consulting, the following states had unusually low coal inventories: Pennsylvania (15 days), South Carolina (23 days), Tennessee (24 days), Delaware/Maryland (28 days), North Carolina (29 days), and New Jersey (30 days).

Source notes

1. "U.S. Coal Supply and Demand: 2004 Review," EIA, Fred Freme, April 2005.

2. Excludes waste recovery coal.

3. "U.S. Coal Supply and Demand: 2004 Review," Fred Freme, EIA. April 2005.

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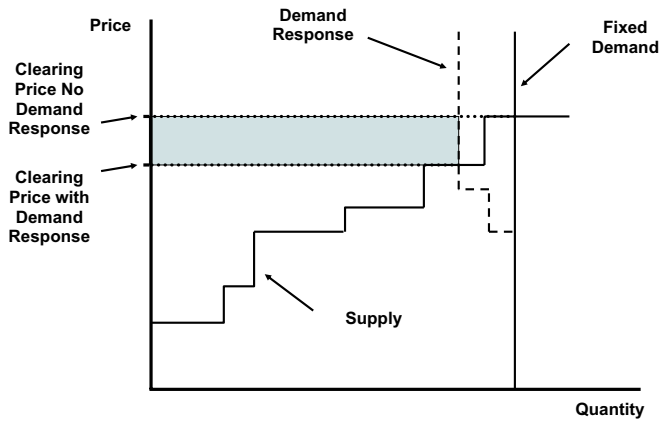
Demand Response

When generation outages occur, transmission is constrained or demand is high, the marginal costs of production and/or electricity prices can rise substantially, if only for short periods of time. As a consequence, market prices rise as well. During periods of such high prices, even a little load reduction could reduce total purchase costs substantially. Nevertheless, few customers have incentives to respond to these higher prices in time to help. Better integration of the demand side into electricity markets can improve market efficiency, help avoid the inappropriate exercise of market power, reduce price volatility, and reduce costly transmission and generation infrastructure investment needed solely to serve load during the limited periods of peak demand or other system stress. In addition, demand response supports system reliability and resource adequacy.

Effects of Demand Response on Markets



The term *demand response* is often confused with other demand-side market activities. For the sake of this section, demand response refers to the application of price and load adjustment mechanisms to balance energy supply and demand with particular attention to cases where market clearing prices are high because of either high marginal costs or scarcity pricing. The U.S. Demand Response Coordinating Committee (DRCC) further defines demand response as "providing electricity customers in both retail and wholesale electricity markets with a choice whereby they can respond to dynamic or time-based prices or other types of incentives by reducing and/or shifting usage, particularly during peak periods, such that these demand modifications can address issues such as pricing, reliability, emergency response, and infrastructure planning, operation, and deferral." Energy efficiency and distributed generation, which complement demand response near the point of use, are not included here.

Focal Points for 2004

- **Mild summer weather** limited incentives for participation and the need to operate demand response programs. Nationally, summer 2004 was the ninth coolest on record.[1] Most of this cooler than average weather affected eastern states where most wholesale demand response programs exist. Actual peak demand in the Northeast was 5% lower than projected for normal weather.[2] Reliability-based demand response programs in the eastern regional transmission organizations (RTOs) likewise were not triggered. Western states, on the other hand, experienced warmer than normal weather, requiring demand reductions in Arizona and conservation requests in California.

- **National and regional coordination** on demand response increased somewhat. Efforts led to information sharing among industry participants already in pursuit of successful demand response in markets and heightened awareness of demand response industry-wide. Coordination efforts included those of the DRCC, the Mid-Atlantic Distributed Resources Initiative (MADRI), and the PIER Demand Response Research Center.[3]

- **Innovative demand response technologies** and pricing programs continue to make some progress. Technologies that allowed an automated reduction in demand from signals like high prices comprised the following: advanced meters, energy information systems, advanced building controls, and internet communication systems between the system operator and customer to allow for real-time adjustments to energy usage. Dynamic pricing programs (electricity rates that vary by time of use) were offered in some states, including voluntary critical peak pricing in California and default real-time pricing for large Niagara Mohawk customers in New York. Northeast RTOs continued to explore ways to integrate demand into wholesale markets. PJM proposed, for example, to allow demand to bid in spinning reserve and capacity markets, as well as a financial options market for demand-side resources.

Demand response activity in 2004

According to the North American Electric Reliability Council (NERC), 3% of 2004 peak load was available for demand response.[4] Because NERC's estimates were compiled to support reliability planning, only demand response capability with a high certainty of operation during periods of peak demand was included. Additional demand response capability could have also been made available through price-based demand response programs or voluntary pleas for customers to cut load. The amount of demand response actually used during 2004 was not available on an aggregate regional or national level.

The NERC numbers may include wholesale demand response programs that vary by region and include both reliability and price-based demand response programs. Price-based demand response programs in northeast RTOs saved 61,373 MWh during the 2004 reporting period. Because California utilities and regulatory entities were advancing their own demand response programs in the state, California independent system operator (CAISO) participation in demand response was limited to its program. CAISO's program allows load to participate in the market as supplemental energy and ancillary services. During summer 2004, CAISO had an average of 77 MW of load participation available during peak times under its program.[5]

Northeast RTOs published estimates for the value and costs of demand response and associated programs in their region based on 2004 data, as summarized below.

- ISO-NE estimates showed that the greatest market price reduction (1%) was a result of its real-time price response program during the winter. Total price response savings were $4,876,349, with $1,040,206 paid by ISO-NE to market participants.[6]

- NYISO data showed that each 1% of load reduced in summer 2004 in turn reduced locational-based marginal prices by 1.2% to 2.3% in the day-ahead market and 0.6% to 1.8% in the real-time market, depending on zone. Total NYISO market savings during the summer equaled $45,936, with payments of $40,651 to market participants.[7]

- PJM estimates showed the price effect of its economic program to be $1 per MWh, on average, based on actual demand reductions and real-time supply curves. PJM surmised that a 1,000 MW load reduction would have led to a $5 per MW reduction in locational marginal prices. Total payments to market participants under the PJM demand response program amounted to $1,671,606.[8]

2004 NERC-Reported Demand Response

	Estimated Peak Demand Response (MW)	Actual Peak Demand (MW)	Estimated Demand Response as Share of Peak Demand	Peak Demand Reponse Growth from 2003 (MW)
ECAR	2,643	95,300	3%	-313
ERCOT	892	58,531	2%	173
FRCC	2,822	42,243	7%	27
MAAC	1,082	52,049	2%	-191
MAIN	3,191	53,348	6%	-18
MRO	544	34,852	2%	-1,052
NPCC	2,115	98,454	2%	2,115
SERC	5,781	157,678	4%	221
SPP	990	39,893	2%	-430
WECC	2,561	141,100	2%	740
TOTAL NERC	**22,621**	**773,448**	**3%**	**1,272**

Source: Derived from NERC Summer Assessments for 2003, 2004, and 2005. Note: "Estimated peak demand response" includes interruptible demand and direct-control, demand-side management.

Northeast RTO Demand Response Programs

	Program Type		2004 Program Usage			
	Price-Based	Reliability-Based	Achieved Reduction	Program Enrollment	Enrollment as % of 2004 Peak Load	Regional Variations
ISO-NE						
Real-Time Price Response Program (RTPR)	Price-Taker		9,216 MWh	108 MW	0.4%	Enrollment varies by zone. CT zone accounts for 89% of RTDR and 29% of RTPR. NEMA makes up majority (37%) of RTDR and ME is majority (91%) of Profile program.
Real-Time Demand Response Program (RTDR)		Emergency &	0	165 MW	0.7%	
Real-Time Profiled Response Program (Profile)		Contractual	0	83 MW	0.3%	
NYISO						
Day-Ahead Demand Response Program (DADRP)	Bid-Based		3,535 MWh	377 MW	1.3%	Enrollment varies by zone. NYC and Long Island (Zones J&K) account for 53% of EDRP load, 28% ICAP-SCR, & 4% DADRP. Western superzone (Zones A-E) is 29% of EDRP, 64% of ICAP-SCR, & 73% of DADRP.
ICAP Special Case Resources (SCR)		Contractual	0	981 MW	3.5%	
Emergency Demand Response Program (EDRP)		Emergency	0	581 MW	2.0%	
PJM						
Economic Load Response Programs (ELRP)			48,622 MWh	724 MW	0.7%	Economic program enrollment varies significantly by PJM Control zones. 82% of MWh reductions occurred in single zone (AP). Two zones had no DR activity (PEPCO and RECO).
• Day-Ahead Option (ELRP-DA)	Bid-Based		179 MWh			
• Real-Time Option (ELRP-RT)	Price-Taker		46,561 MWh			
• Nonhourly, Metered Program (Pilot)	Varies		1,881 MWh			
Emergency Load Response Program (Emergency)		Emergency	0	1,385 MW	1.3%	
Active Load Management (ALM)		Emergency	0	1,806 MW	1.7%	

Source: Derived from ISO-NE, NYISO, and PJM reports. See source note 1.

Price-based demand response in retail markets is designed using a form of dynamic pricing like time-of-use rates, critical peak pricing, or real-time pricing. Dynamic pricing helps markets operate more efficiently by creating more elastic demand. Time-of-use rates charge a premium during periods of higher system usage with rate savings during all other hours. Critical peak pricing includes a third, much higher, rate during only a few hours of high load days. Retail rates under real-time pricing change more frequently, often by the hour. A June 2004 PJM survey identified 7,030 MW of load in New Jersey and Maryland exposed to real-time prices either directly or through intermediary competitive suppliers.[9]

In addition to dynamic pricing, retail markets also incorporate demand response through programs that allow a utility to directly control the customer's load, interruptible rate schedules, and demand bidding programs. The PJM survey found 934 MW in the PJM territory enrolled in independent demand response programs, 203 MW in price-based programs, 453 MW under interruptible load programs, and 278 MW in emergency programs.[10]

Endnotes

[1] National Oceanic and Atmospheric Administration (NOAA), "Climate of 2004-Annual Review, U.S. Summary," National Climatic Data Center, January 13, 2005. Data for 110 years. NOAA defines summer as the period from June through August.

[2] Based on "projected net internal demand" and "last summer's peak demand" for the Northeast Power Coordinating Council and the Mid-Atlantic Area Council in 2004, as published in the North American Electric Reliability Council 2004 Summer Assessment and 2005 Summer Assessment.

[3] DRCC is a national group of utilities, regional transmission organizations, and governmental entities serving as the U.S. participant in the International Energy Agency's Demand Response Resources Task XIII Project. MADRI has a regional regulatory focus and includes utility commissioners from the mid-Atlantic states, along with representatives from PJM, DOE, EPA and industry stakeholders, similar to the New England Demand Response Initiative that concluded in 2003.

[4] 2005 Summer Assessment: Reliability of Bulk Electricity Supply in North America, North American Electric Reliability Council, May 2005.

[5] 2005 Summer Operations Assessment, California Independent System Operator, March 23, 2005, 11.

[6] ISO-NE estimates from the Independent Assessment of Demand Response Programs of ISO New England, Inc., FERC Docket No. ER02-2330-033, filed on December 30, 2004. Savings included $222,745 from the change in price for load cleared in real time and $4,653,603 saved from the corresponding reduction in monthly average real-time prices to bilaterally contracted load.

[7] Estimates from New York Independent System Operator, Inc Seventh Bi-Annual Compliance Report on Demand Response Programs and the Addition of New Generation in Docket. No. ER01-3001-00, e-filed December 1, 2004. Load-serving entities saved $8,996 in purchases from the NYISO and bilateral contract supply costs were reduced by $36,940 as a result of lower day-ahead prices.

[8] Estimates from 2004 State of the Market by the PJM Market Monitoring Unit, published March 8, 2005. The 1,000 MW load reduction estimate assumes real-time supply curves for a representative day during summer 2004.

[9] PJM survey results, as reported in PJM's 2004 State of the Market by the PJM Market Monitoring Unit, published March 8, 2005.

[10] Ibid.

Source notes

1. Derived from Independent Assessment of Demand Response Programs in ISO New England Inc., FERC Docket No. ER02-2330-033 filed December 30, 2004; New York Independent System Operator, Inc. Seventh Bi-Annual Compliance Report on Demand Response Programs and the Addition of New Generation in Docket No. ER01-3001-00, e-filed December 1, 2004; and 2004 State of the Market by the PJM Market Monitoring Unit dated March 8, 2005. ISO-NE and NYISO reductions and enrollment are for the period September 2003 to August 2004. In NYISO, 11 MW of unsold ICAP is included in the EDRP total. PJM reductions and enrollment are for the period January to September 2004 Emergency. In PJM, 317 MW of ALM resources are also included in the Emergency Load-Response Program.

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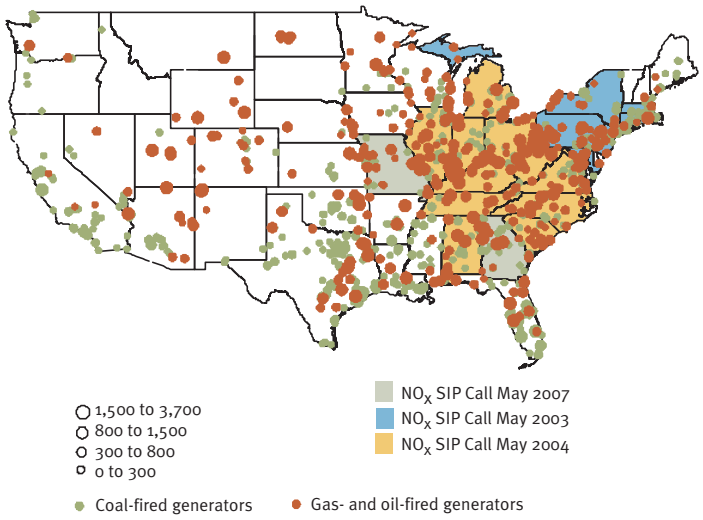
Emission Allowances

Market-based emission allowance trading helps generators choose their most cost-effective form of compliance with environmental regulations. Such trading also provides incentives for technology development and affects electricity and fuel markets in several ways. They have a bearing on infrastructure investments, fuel supply decisions, generator bidding behavior, and financial energy trading. The following pages address federal programs, although emission allowance markets also exist at the state level. Apart from environmental regulations surrounding emission allowance trading, power generators must meet other market and nonmarket-based environmental regulations exist at both the federal and state level.

Since 1994 and 1998, respectively, sulfur dioxide (SO_2) and nitrogen oxides (NO_x) have been traded as emission allowances under the two federal "cap-and-trade" programs, the Title IV Acid Rain Program and the NO_x Budget Program. Under these federal policies, power generators received initial emission allowances based on total heat input as a measure of their efficiency.[1] All current and future-year allowances were granted at the start of the program, creating emission allowance accounts and an opportunity for trading all future-year vintage allowances. Generators use allowances of current or earlier vintage years to meet annual limits.

Fossil Fuel Power Generators in the NOx and SO2 Allowance Market



Source: Derived from Platts data. See source note 1.
Note: Not all counties in highlighted states are included in the NOx SIP Call.

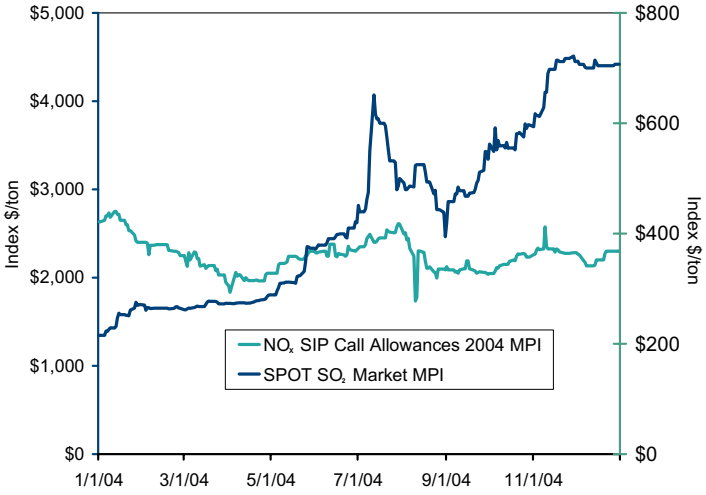
Federal cap-and-trade programs are not limited to power generators, although generators contribute 67% of SO_2 emissions and 22% of NO_x emissions.[2] In 2003, more than 90% of these two power plant emissions came from coal-fired power units,[3] only 22% (83 GW) of which had installed scrubber equipment to reduce emissions.[4] The map shows the location of fossil-fuel-fired plants in the United States, along with the region boundary for the NO_x State Implementation Plan (SIP) Call markets. The NO_x SIP Call requires states that contribute significantly to pollution problems in other states to reduce their NO_x emissions during the ozone (summer) season.

Focal Points for 2004

- **Increased SO_2 prices.** During 2004, daily SO_2 spot market index prices peaked at $722 per ton on November 29, 2004.[5] Prices began to rise in July, then declined throughout August, only to rise again in the fall. Average SO_2 prices in the second half of 2004 were approximately double the average price during the first half of the year. SO_2 prices increased due to several factors in the SO_2 and related markets, including (1) declining volume in the SO_2 bank as the market matured, (2) increasing spread between high- and low-sulfur eastern coal prices, (3) high oil and gas prices favoring increased coal use by power generators, and (4) uncertainty regarding pending regulations.[6]
- **NO_x SIP Call Expansion.** Starting May 31, 2004, areas in 11 additional states came under the NO_x Budget Program. Power generators in these areas were granted NO_x allowances, increasing the footprint of the NO_x market. The expanded region contributed to increased market liquidity as additional market participants became eligible to trade. During 2004, NO_x allowance transfer volumes were 26 percent higher than during the previous peak and nearly double the transfer volumes of the previous year. The 2004 vintage allowance prices remained lower than prices for 2003 vintages, in part because of expected surpluses in supply during the shortened compliance period.[7]
- **Diverse trading entities.** During 2004, emission allowances were transferred among pure emission traders—parties that do not themselves emit pollutants. As discussed in the market concentration section, brokers and financial players were active in the emission market during 2004. These parties may be holding allowances in their accounts only for limited periods of time, perhaps for clearing purposes, or under swap arrangements where allowances are transferred back to emitting entities prior to annual reconciliation.

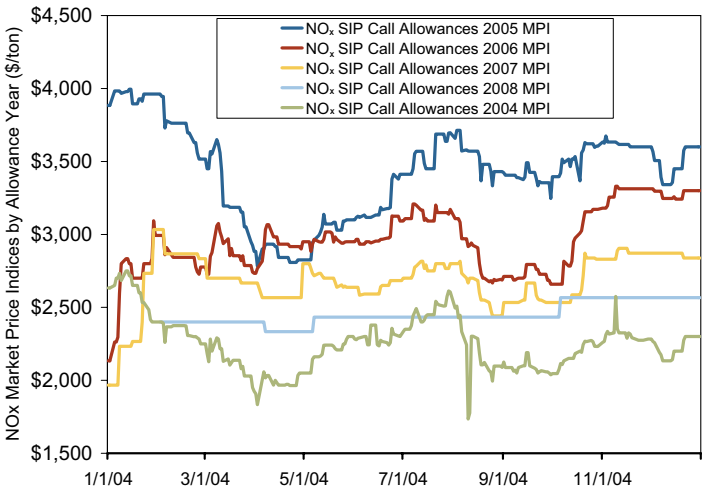
SPOT AND FUTURES PRICES

Spot Market Prices



Source: Derived from Cantor Fitzgerald market price indices.

Future Year Vintage NO_x Allowance Prices



Source: Derived from Cantor Fitzgerald market price indices.

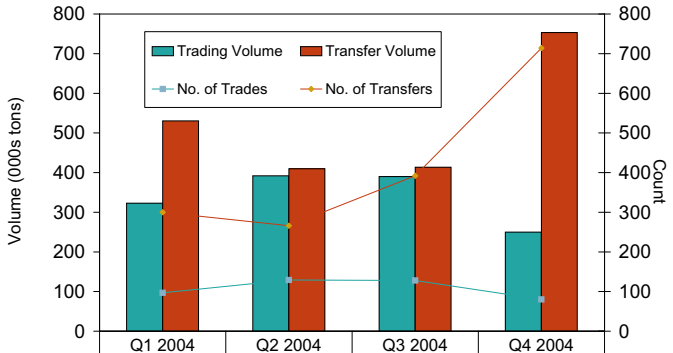
For SO_2, EPA holds an annual auction of allowances at the end of March. The 2004 auction cleared at $260 per ton—$10 per ton below the cash prices for the two weeks prior to the auction and $88.20 per ton above the previous year's auction prices.[8] Since the March auction, SO_2 spot market prices have more than doubled, whereas NO_x spot prices remained more level.

Although 2004 vintage allowances accounted for most 2004 trades, allowances for other vintage years were also traded. The traded value of future vintage NO_x allowances during 2004 was highest for the next-year vintage allowances and then dropped for all future years. Similar declining value of future vintage allowances occurred in the SO_2 market, partly in anticipation of new emission-reducing scrubber installations.

On December 10, 2004, the Chicago Climate Futures Exchange launched trading of SO_2 allowance futures contracts, called the Sulfur Financial Instrument (SFI). The contract is designed to facilitate price hedging for SO_2 allowances eligible for delivery on EPA's Allowance Tracking System (ATS). Nine contracts were available: quarterly contracts for the next six quarters and annual contracts for the next three years. On December 10, 2004, the March 2005 and June 2005 SFI contracts settled at $712 and $715, respectively.[9]

ALLOWANCE TRANSFERS AND TRADING VOLUMES

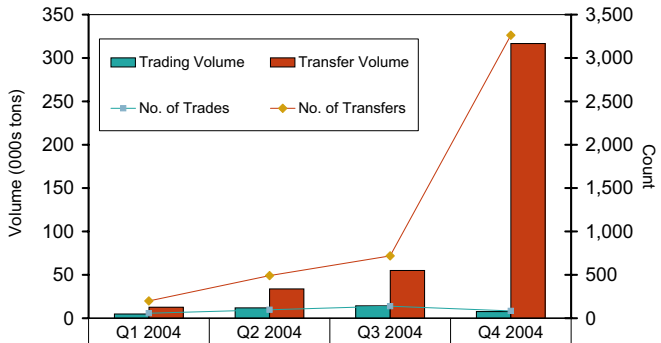
SO_2 2004 Vintage Transfers and Trading



	Q1 2004	Q2 2004	Q3 2004	Q4 2004
Trading Volume	323	392	390	250
Transfer Volume	531	410	414	753
No. of Trades	97	129	128	80
No. of Transfers	300	266	392	714

Source: Derived from EPA and Cantor Fitzgerald data. See source note 2.

NO_x 2004 Vintage Transfers and Trading



	Q1 2004	Q2 2004	Q3 2004	Q4 2004
Trading Volume	5	12	14	8
Transfer Volume	13	34	55	317
No. of Trades	57	98	139	84
No. of Transfers	199	491	718	3,263

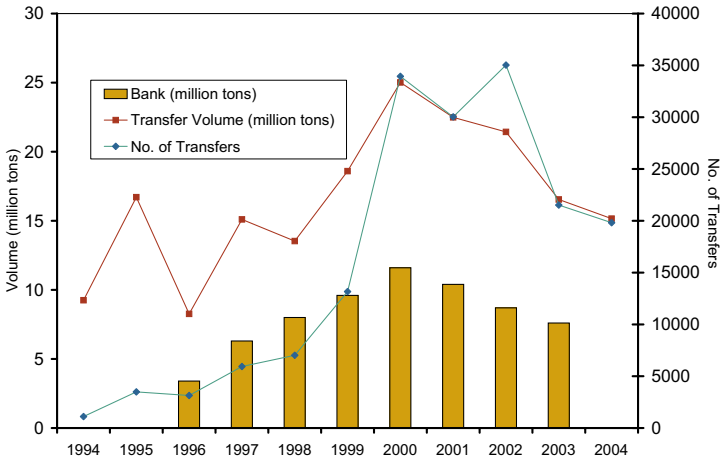
Source: Derived from EPA and Cantor Fitzgerald data. See source note 2.

Emission allowances can be acquired in several ways. They can be purchased directly from a company or an individual that holds them, through EPA's annual auction at the end of March (SO_2 only), or through a broker. Entities trade allowances according to individually agreed-upon terms. Some of these trades are surveyed by brokers and trade publications. Others are conducted under bilateral deals not transparent to the market. Before an allowance can be used to meet annual environmental compliance requirements, its transfer must be reported to EPA's Allowance Tracking System databases (i.e., ATS for SO_2 and NATS for NO_x).

The graphs show the volume and number of allowance transfers, as reported to EPA, along with trades surveyed by Cantor Fitzgerald, a leading broker, for 2004 vintage NO_x and SO_2 allowances. During 2004, the reported SO_2 transfer volume totaled 2.1 million tons, averaging 1,260 tons per transfer. Transfers of NO_x allowances reported to EPA equaled 418,108 tons, averaging 90 tons per transfer. Broker-surveyed trading totaled 1.4 million tons SO_2 and 39,000 tons NO_x.

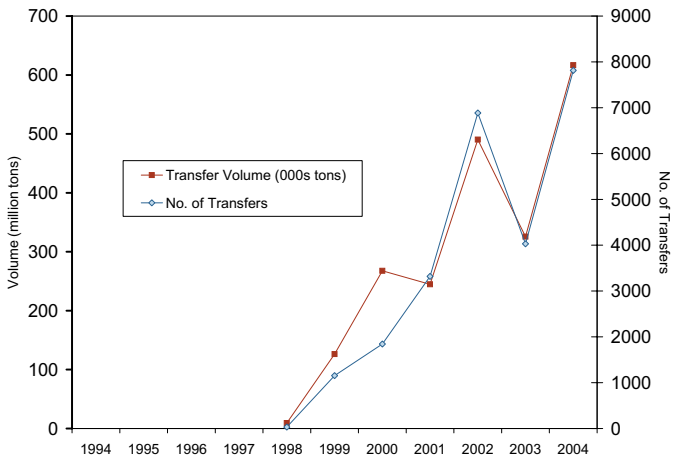
In addition to 2004 vintage allowances, generators used pre-2004 vintage allowances to meet 2004 compliance standards. Pre-2004 vintage allowances accounted for 74% of the total SO_2 transfer volume in the EPA database, whereas 2004 vintage allowances accounted for only 14%, probably because of the ability to bank allowances in the SO_2 market. Since the start of Phase II in the year 2000, the SO_2 bank has been declining, supporting the high transfer activity of pre-2004 vintage allowances. NO_x allowance markets are less favorable for banking.[10] Only 4% of NO_x allowances transferred in 2004 were for pre-2004 vintages allowances, whereas 68% were for current-year (2004) vintage allowances.

SO_2 Private Transfer History



Source: Derived from EPA data. See source note 3.

NO_x Private Transfer History



Source: Derived from EPA data. See source note 3.

Emission Prices and Electricity Prices

Higher emission allowance prices do not directly translate into higher electricity prices. Not all power generators need to purchase SO_2 allowances on the spot market to meet environmental compliance standards. Some generators are able to use their own allowances. In most regions, coal-fired units run as baseload units and do not tend to set marginal power prices, especially on-peak. Still, if a coal-fired unit in the Midwest, for example, needed to use SO_2 allowances and credited them to their marginal cost of generation, the SO_2 spot prices during 2004 could have added $0.80 to $17.40 per MWh to the price of electricity, subject to the type of coal burned. NO_x prices could have added $1.60 to $4.00 per MWh during 2004.[11] Generators consider the combined cost of coal and emissions when making their fuel supply decisions, because the lower-priced coal supply has higher sulfur content.

MARKET CONCENTRATION

During 2004, transfers of all vintage SO_2 emission allowances totaled 15.2 million tons compared with 0.6 million tons of NO_x allowances. The top 10 companies accounted for 36% of total SO_2 transfer volume. Morgan Stanley Capital Group, a financial services company, accounted for the most SO_2 allowance transfers by a single company (8%).

Market shares of transfer volumes for NO_x allowances were distributed more evenly. The top 10 transfer companies accounted for only 21% of the total volume. No one company contributed more than 4% of total NO_x transfer volume. In both the SO_2 and NO_x markets, electric utilities and their unregulated affiliates made up nearly 80% of transfer volumes by the top 10 companies.

In 2004, the top brokers for emission allowance trading were Cantor Fitzgerald, Amerex, Evolution Markets, and NatSource. These brokers facilitated trading between two parties and also took title to both SO_2 and NO_x allowances as recorded on EPA's Allowance Tracking System.

Top 10 Companies - SO_2 Transfers

Total Rank	Rank as Transferor	Rank as Transferee	Name	Total Amount (tons)	Amount as Transferor (tons)	Amount as Transferee (tons)
1	1	1	Morgan Stanley Capital Group	2,287,995	1,255,006	1,032,989
2	2	2	Ohio Power Company	1,696,668	915,729	780,939
3	9	3	CG&E General Account	1,086,178	397,508	688,670
4	4	5	Millennium Environmental Group	989,696	494,848	494,848
5	5	6	Kansas City Power & Light Co.	920,283	452,373	467,910
6	3	9	PSEG Energy Resources & Trade LLC	874,029	535,924	338,105
7	7	7	Dominion Energy Marketing, Inc	828,760	414,380	414,380
8	15	4	PSI General Account	818,177	249,185	568,992
9	8	8	APS	809,046	408,637	400,409
10	6	12	Constellation Energy Commodities Grp Inc	685,473	425,591	259,882

Source: Derived from EPA data. See source note 2.

Top 10 Companies - NO_x Transfers

Total Rank	Rank as Transferor	Rank as Transferee	Name	Total Amount (tons)	Amount as Transferor (tons)	Amount as Transferee (tons)
1	3	1	Constellation Energy Commodities Group Inc	41,423	15,889	25,534
2	1	3	DTE Coal Services	33,381	16,543	16,838
3	4	4	PPL Generation LLC	30,831	15,571	15,260
4	2	7	Mirant Americas Energy Marketing LP	28,662	16,500	12,162
5	26	2	CG&E General NO_x Account	25,275	6,753	18,522
6	29	5	Columbus Southern Power Company	20,944	6,143	14,801
7	9	8	Cantor Fitzgerald Brokerage	20,020	9,264	10,756
8	10	10	Cumberland	19,771	9,263	10,508
9	22	9	Orion MidWest	17,563	6,955	10,608
10	6	19	PPL Rights	17,458	10,479	6,979

Source: Derived from EPA data. See source note 2.

Emission Allowance Transfers by Brokers

	SO_2 Amounts (tons)			NO_x Amounts (tons)		
Broker	As Transferor	As Transferee	Total	As Transferor	As Transferee	Total
Amerex USA	52	52	104	3,781	3,781	7,562
Cantor Fitzgerald Brokerage	154,759	125,071	279,830	9,264	10,756	20,020
Evolution Markets LLC	7,600	55,612	63,212	1,621	2,001	3,622
Natsource	106	125	231	0	0	0

Source: Derived from EPA data. See source note 2.

Endnotes

[1] The number of allowances granted to a generator varies by state, although most states base allocations on heat input.

[2] U.S. Environmental Protection Agency, EPA Acid Rain Program 2003 Progress Report, Clean Air Markets Division, Office of Air and Radiation: EPA 430-R-04-009, September 2004.

[3] From Platts CoalDat emission data for 2003 and EPA's preliminary 2003 national emission totals.

[4] From Platts CoalDat plant data in the February 2005 data set.

[5] As reported by Cantor Fitzgerald.

[6] In 2005, Clear Skies and/or the Clean Air Interstate Rule may significantly reduce the amount of allowable SO_2 emissions in the future.

[7] The 2004 compliance period began on May 31, not May 1, as in 2003.

[8] Auction results are from EPA's Clear Air Markets website. For cash prices, see the Chicago Climate Futures Exchange Sulfur Dioxide Market Report, Vol. 2, No. 3, February 16–March 15, 2005.

[9] For price information, see the Chicago Climate Futures Exchange Sulfur Dioxide Market Report, Vol. 2, No. 1, December 10, 2004–January 14, 2005.

[10] The use of banked NO_x allowances above a certain threshold will require the generator to surrender two allowances for each ton of NO_x emissions.

[11] The cost estimate assumes a coal-fired power plant heat rate of 10,500 Btu/kWh, coal spot prices from Bloomberg, coal transportation cost derived from CoalDat, and SO_2 spot and 2004 NO^x market price indices from Cantor Fitzgerald. Heat content and rates of emission vary, depending on the source of coal, whether from Central Appalachia, northern Illinois, or the Powder River Basin. NO_x prices apply during the summer compliance period, May 31 to September 30, 2004, only.

Source notes

1. Capacity based on RDI Modeled Capacity data from January 2004 to November 2004. NO_x SIP Call states based on EPA's 2003 Progress and Compliance Report of the NO_x Budget Trading Program.

2. All private transfers confirmed and trades surveyed from 1/1/2004 to 12/31/2004.

3. EPA's ATS and NATS private transfers through December 31, 2004 and banked allowances as reported in EPA Acid Rain Program Progress Reports 2000-2003. Number of transfers counts the transfer of different allowance years within the same transaction separately. Banked SO_2 allowance volumes are as of reconciliation on March 1 of each year.

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Energy Debt and Equity

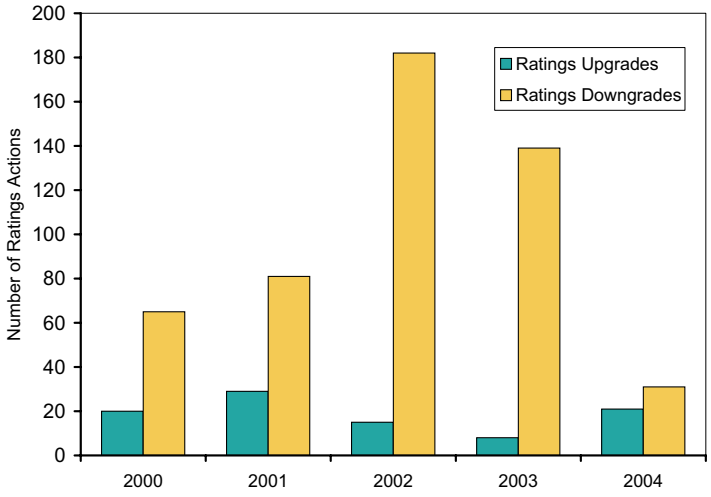
In 2004, debt and equity market performance in the energy sector reflected stabilizing operating performances and a growing perception of general—not necessarily pervasive—improvement in prospects. Two key debt and equity trends in 2004 were the stabilization of credit ratings, as companies took steps either to reduce debt or risk, and rising stock prices, price to earnings ratios, and dividends.

Credit Trends

The energy sector's credit situation stabilized in 2004. For the broad electric and natural gas sectors, the number of company credit rating actions declined, bucking the trend established in 2001. Also, the ratio of downgrades to upgrades was significantly lower.

The overall sector held an average BBB rating in 2003 and 2004, reflecting deterioration from the average A rating held in 2001.

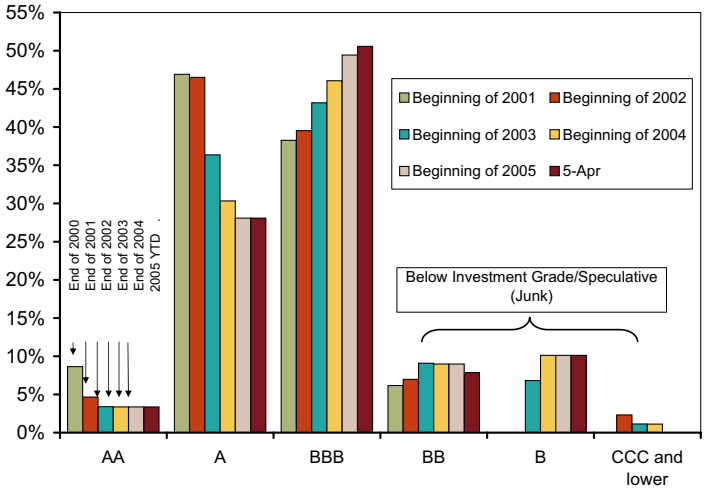
Standard & Poor's Gas and Electric Ratings Actions



Source: Derived from S&P Ratings Direct data and applied to the Energy Market Particpant Index (EMPI). Data through 12/31/04.

Strategies to improve credit ratings in 2004 were different for regulated and unregulated entities. Regulated utilities without large affiliated merchant activities were able to improve their financial profiles through a combination of paying down debt, scaling back investments in unregulated activities, and exiting non-core lines of business. By comparison, merchant generators and utilities with significant unregulated activities had to defer or restructure debt, sell performing assets and contracts, and raise additional equity and convertible securities. In general, the more regulated the business mix of the energy company, the greater the success in

S&P's Gas and Electric Ratings Distributions



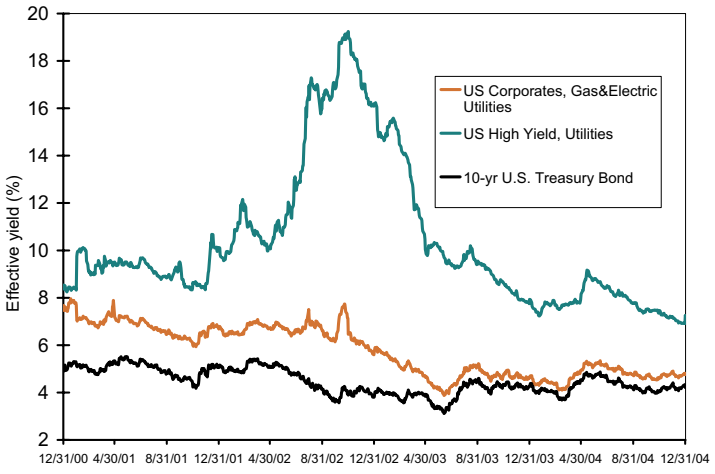
Source: Derived from S&P Ratings Direct data and applied to the EMPI. Data through 12/31/04.

stabilizing cash flows and improving the view of the debt markets and the credit rating agencies.

The sector was aided in its recovery by relatively benign conditions in the credit markets, affording companies that were taking action to improve credit fundamentals and lower leverage increased access to credit at lower costs. The cost of debt capital, particularly for noninvestment-grade energy companies, declined, allowing companies to borrow in the bond markets at absolute and relative rates that were close to historic lows.

Energy companies with noninvestment-grade ratings and significant exposure to unregulated activities were generally pre-

Utilities and Merchants



Source: Derived from Merrill Lynch data.

sented with the greatest reduction in cost of capital and improvement in access to capital. Standard & Poor's recently estimated that $30 billion of debt incurred by ten troubled energy companies has been successfully deferred since December 2003.[1] Though merchants continued to successfully defer repayment of principal by restructuring debt and extending maturities, they have not significantly reduced absolute levels of leverage.

Equity Trends

Most significant equity market valuation metrics of energy market participants, including stock prices, price to earnings ratios, and dividends, all improved in 2004. The market rewarded energy companies both for perception of future returns in the sector and the attractiveness of current earnings.[2]

Stock Prices

Most energy sector stocks outperformed the stock market on average, as measured by the Standard & Poor's 500 Index in 2004. The energy sector's equity market capitalization increased by $221 billion in 2004 to $1,114 billion. Even without considering the increase in equity values for producers (which dwarf increases for other energy subsectors), equity market capitalization increased $89 billion in 2004 to $476 billion, slightly surpassing the $84 billion increase in 2003, and recouping more than the $97 billion of equity losses experienced in 2002.

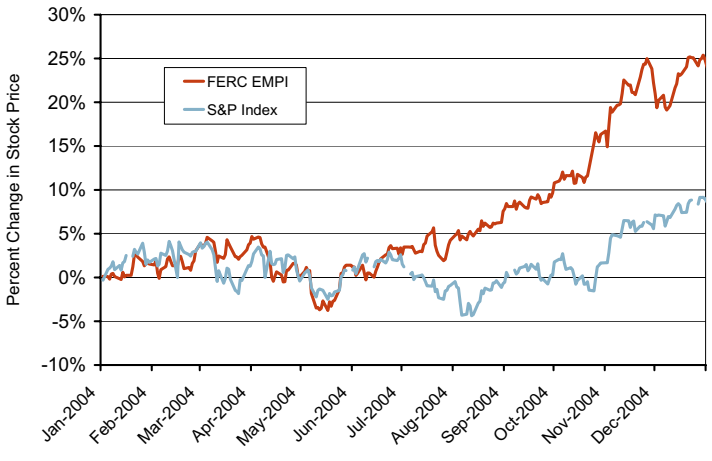
There was wide divergence in the equity performance of subsectors of the energy market. Electric generators, including AES, Calpine, and Reliant Resources, had the largest percentage increase in equity values in 2004. Much of this market optimism and outperformance was based on the ability of the generators to access debt markets, refinance existing debt at more attractive rates, and defer debt maturities.

Changes in Stock Prices

Subsector	Increase from Jan-Dec 2004
Electric Generators	44%
Producers	30%
Midstream Gas	27%
Utility Parent - Sig Wholesale	26%
Gas Distributors	23%
Integrated Electric	10%
Electric Distributors	7%
Utility Parent – Min Wholesale	7%
S&P Index	9%

Source: Derived from Bloomberg L.P. data applied to sector components of the FERC Energy Market Participant Index (EMPI). Prices averaged per group of companies.

Stock Prices Compared with S&P Index



Source: Derived from Bloomberg L.P. data applied to subsector components of the FERC Energy Market Participant Index (EMPI), excluding Producers.

Producers, including super-majors like Exxon-Mobil and Chevron-Texaco as well as smaller producers such as Apache, saw the second greatest increase in stock prices. Midstream gas companies, including companies like El Paso Corp, Enbridge, Kinder Morgan, National Fuel Gas Co, Questar Corp, TransCanada Corp, and Williams Companies Inc, saw a 27% increase in stock prices. El Paso and Williams, like generators, increased from low initial share prices and benefited from more attractive debt market conditions as they unwound exposure to electric market positions (namely, tolling arrangements and generation ownership). Other midstream gas companies, such as Enbridge and Kinder Morgan, benefited from consistent year-on-year returns, as well as attractive dividend yields in the low-interest rate environment.

Utility parents with significant wholesale operations saw stock prices rise 26%, also outperforming the S&P index. Reasons for stock price gains differed among the 20 holding companies tracked in the Energy Market Participant Index (EMPI) (including companies like Allegheny Energy, Aquila, Constellation, Duke Energy, Exelon, First Energy, PG&E Corp, Pinnacle West, and Public Service Enterprise Group). These companies varied in region, scope, and scale of regulated operations as well as range of unregulated activities. Interestingly, equity markets were not consistent in rewarding revenue and earnings growth from wholesale operations based on perceptions of different abilities to repeat results and risk levels adopted to earn returns in trading

operations. In some cases, a company's ability to exhibit effective management of wholesale exposure aided in market outlook and improved share performance. In other cases, companies wound down wholesale exposure to avoid discounted earnings and blunted rewards for this growth. Finally, some decided to maintain wholesale trading operations in the face of lower equity valuations.[3]

Gas distributors, 24 of which are tracked in the EMPI, delivered stock price increases of 23%, generally because of a combination of constant dividends, solid revenue growth, and insulation from commodity price exposure.

Integrated electrics (20 companies), utility parents with minimal wholesale operations (10 companies), and electric distributors (9 companies) either matched the S&P 500's performance or narrowly underperformed it. These subsectors had performed well in 2003, and their performance can be considered in the context of their relative initial valuations.

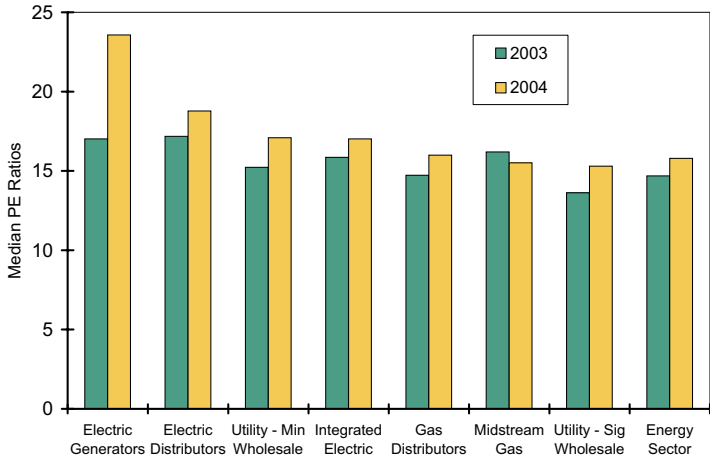
Price to Earnings Ratios

Last year, the median price to earnings (PE) ratio increased for the energy sector from 14.8x in 2003 to 15.7x.[4] During 2004, PE ratios for all subsectors were above historic average levels of 12x to 13x.

For midstream gas companies, increases in earnings outpaced increased stock prices resulting in a slight decline in PE ratios.

However, all other subsectors experienced increases. Electric generators enjoyed the highest PE ratios of any energy subsector, at 23.6x, and also expanded their PE ratios most on an absolute basis. As discussed earlier, the ability to access the debt markets and extend debt maturities played a large roll in allaying concerns among equity investors in the viability of the merchant generation companies.

2004 Year-End Price to Earnings Ratios



Source: Derived from S&P Research Insight data.

Dividends

Much of the increase in PE ratios, and therefore a significant component of the stock price appreciation in 2004 garnered by the sector, was explained by industry analysts as a function of increasing dividends paid by the sector. After-tax dividend yields increased because of the federal tax cut on dividends, and utility dividends compared favorably to bond yields and alternative investments, thereby attracting increased investment in the sector.

Average Dividend Yields

Subsector	2003	2004
Electric Generators	0.0%	0.0%
Midstream Gas	2.2%	2.8%
Utility Parent - Sig Wholesale	3.2%	3.3%
Gas Distributors	4.1%	3.3%
Utility Parent - Min Wholesale	4.3%	3.9%
Electric Distributors	4.3%	4.1%
Energy Sector	3.7%	3.2%

Source: Derived from S&P Research Insight data.

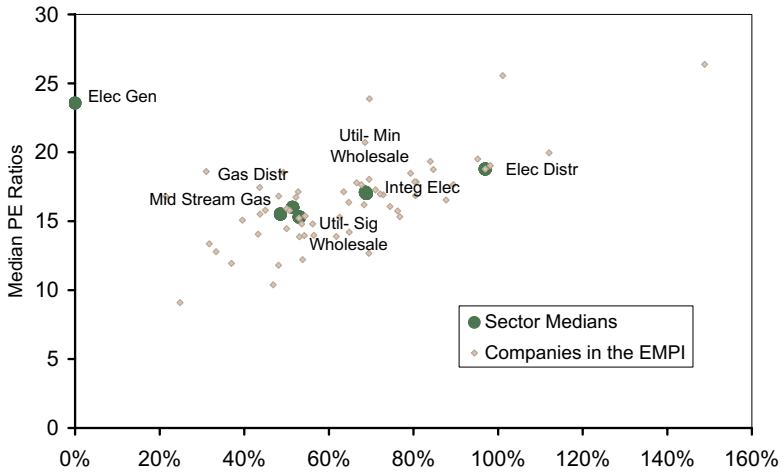
This was the case despite the fact that for the sector as a whole dividend growth did not keep pace with the increase in stock prices. Dividend yields declined slightly for the sector as a whole in 2004, from 3.7% to 3.2%. Of the subsectors, integrated electrics and electric distributors had the highest dividend yields, whereas midstream gas companies had the lowest yields of the dividend payers. Electric generators continued to pay no dividends.

Examining the relationship between trailing PE ratio to dividend payout shows that most energy companies follow a trend, with higher payouts associated with higher valuations. Put another way, PE ratios are higher for utility companies that pay out a higher portion of their earnings in the form of dividends to their shareholders and reinvest a smaller portion in their businesses.

Electric distributors that typically pay out nearly 100% of their

earnings in the form of dividends to their equity holders had the highest PE ratios of any dividend payers. Generally, those with the lowest dividend payouts, midstream gas, gas distributors, and utilities with significant wholesale operations, had the lowest PE ratios. Merchant generators were the exception to this trend as they are not dividend payers. Like "growth" stock companies past and present, they have a higher PE ratio than peers in other sub-sectors.

PE Ratios vs. Dividends



Source: Derived from S&P Research Insight data.

Endnotes

[1] Standard & Poor's "High Yield Energy Merchants: A Year in the Worst Case Scenario" presented at Shared National Credit Symposium, April 12, 2005.

[2] PE ratios show what investors are willing to pay for future earnings; dividend yields show requirements for return of capital.

[3] For example, Sempra and Constellation had relatively low valuations, more consistent with those of investment banks, as compared with higher valuations of Exelon and Pinnacle West, both of which have significant wholesale operations that were not perceived to be as focused on trading.

[4] The PE ratio, a widely used equity valuation measure, is calculated by dividing the stock price by annual earnings - PE ratio = Price/Earnings. In 2004, the median energy sector stock price was 15.7 times the median 2004 annual earnings (i.e. PE ratio = 15.7x).

Disclaimer: This report contains analyses, presentations, and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

Oil

The United States is the world's largest consumer of petroleum products, accounting for 21 million barrels per day (MMbd) or a quarter of world oil consumption. The United States depends heavily on oil imports, importing about 57% of its needs in 2004. The United States competes in a global marketplace for oil products, and demand from developing countries is growing rapidly. Domestic crude oil production in 2004 declined 5%.

Oil-fired generation consumed just 3% of U.S. petroleum requirements. In the power sector, petroleum products (jet kerosene, distillate, and residual fuel oil) compete directly with natural gas, especially in New England and some Gulf Coast states. Except during price spikes, distillate oil has tended to set the ceiling and residual fuel oil the floor prices of similarly located natural gas. Oil-fired plants provide regional fuel diversity. They foster electric power reliability when severe weather strains the natural gas system, and they can lower overall fuel costs.

Oil Spot Prices ($/MMBtu)

	2004	2003	5-year average
WTI	7.16	5.36	5.35
NY No. 2 Fuel Oil	8.05	6.11	6.10
NY Residual Fuel Oil	5.28	5.13	4.51
Gulf Coast Residual Fuel Oil	4.24	4.42	3.93

Source: Derived from Bloomberg, L.P. data.

World Oil Balance (MMbd)

Production	2003	2004	Consumption	2003	2004
OECD			OECD		
United States	9	9	United States	20	21
Other OECD	14	14	Other OECD	29	29
Total OECD	23	23	Total OECD	49	50
Non-OECD			Non-OECD		
OPEC	31	33	China	6	7
Former USSR	10	11	Former USSR	4	4
Other Non-OECD	15	16	Other Non-OECD	21	22
Total Non-OECD	56	60	Total Non-OECD	31	33
Total World Supply	**79**	**83**	**Total World Demand**	**80**	**83**

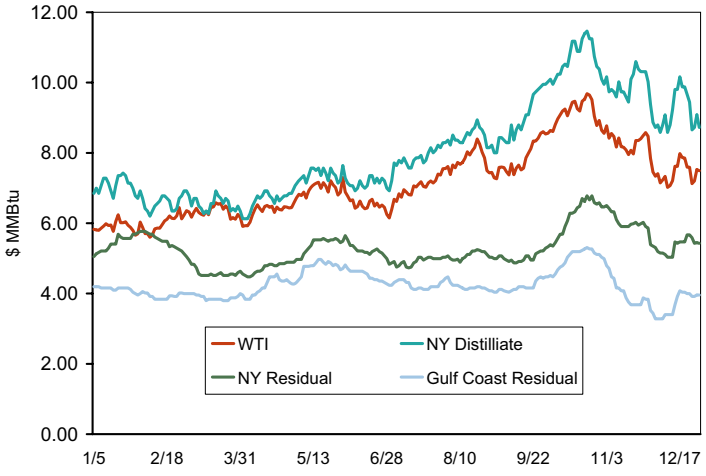
Source: Derived from EIA data. Includes production of crude oil (with leese condensated, natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery processing gain, alchohol and liquids processed from coal and other source.

Focal Points for 2004

- **Increased spot prices.** Tightness in the balance of global production and consumption spurred a 33% increase in the West Texas Intermediate (WTI) crude oil price. The average rose from $31.06/bbl to $41.51/bbl in 2004.
- **Hurricane-related production shut-ins.** Hurricane Ivan immobilized production of 38 million barrels of oil from the Gulf of Mexico or an estimated 6% of average annual production.[1] On September 16, the day after Hurricane Ivan made landfall, the shut-in amounted to 1.4 MMbd, or 83% of Gulf of Mexico oil production.[2]
- **Growth in global oil consumption.** With a 16% increase in oil use by the Chinese, world consumption grew 2.71 MMbd, the fastest rate since 1976 (3.29 MMbd). Chinese oil use accounted for 32% of the increase in global consumption.[3]
- **Less supply flexibility.** The Organization of Petroleum Exporting Countries' (OPEC's)[4] spare production capacity[5] dipped to 0.35 MMbd in 2004. U.S. refining capacity averaged 93% on an annual basis. U.S. crude oil stocks hovered near the bottom of the 5-year range.

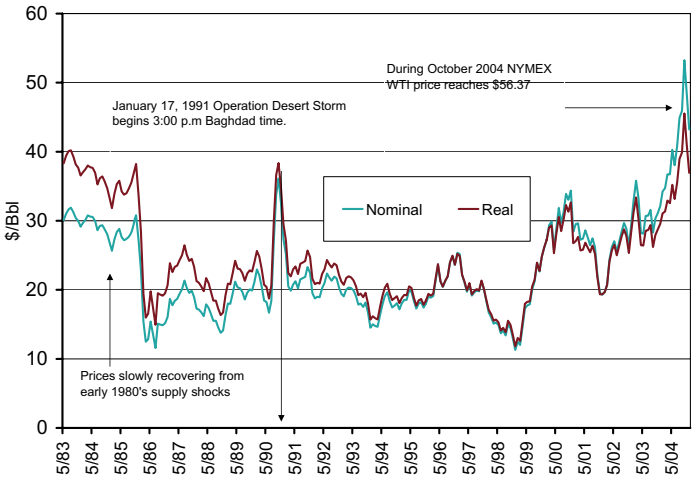
SPOT PRICES

Spot Petroleum Product Prices



Source: Derived from Bloomberg, L.P. data.

Real vs. Nominal WTI Prices



Source: Derived from Bloomberg, L.P. and Bureau of Labor Statistics data.

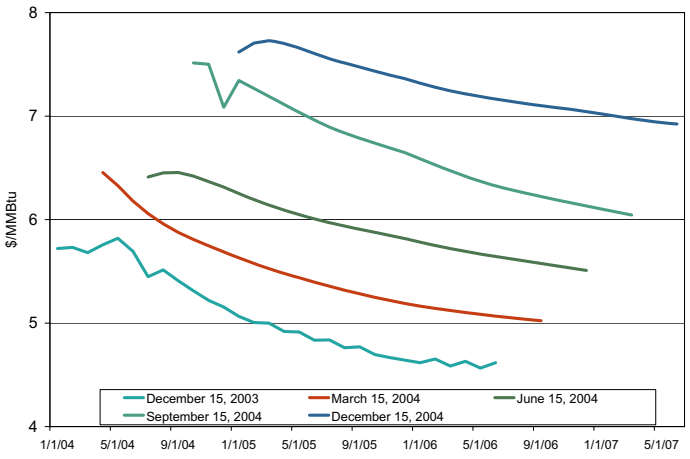
Petroleum price trends varied by product in 2004. Average annual WTI prices increased 33% due to tightness in the global supply-demand balance. Distillate prices increased 34%. Residual oil prices rose 4% in New York but declined 3% in the Gulf Coast. Oil prices increased most significantly beginning in August as a result of hurricane activity and declining inventories.

In real dollars, WTI price increases resulted in the highest oil prices since the Gulf War and the oil price shocks of the mid-1980s and the late 1970s. Prices for the WTI near-month futures contract for November 2004 delivery reached a record $56.37/bbl on October 26.

Worsening market fundamentals during the year, coupled with anxiety about the adequacy of supplies, contributed to escalating price expectations in crude oil futures markets. Anticipated WTI prices for 2005 increased nearly $2/MMBtu during 2004.

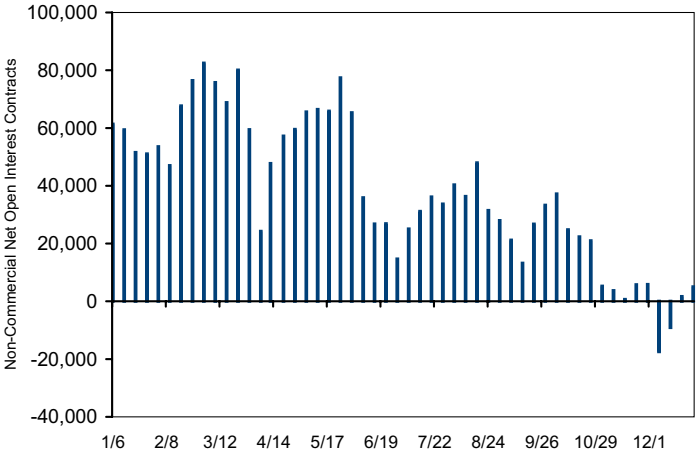
Market participants bought oil futures contracts at a record pace. The number of light, sweet crude oil futures contracts traded increased 16% from 45 to 53 million in 2004. More than 212,000 contracts were traded on a daily average basis. Net open interest by noncommercial market participants averaged 38 million contracts.

WTI Futures Curves



Source: Derived from Bloomberg, L.P. data.

Non-commercial Net Open Interest



Source: Derived from CFTC's Commitment of Traders Report.

Consumption

Developing economies in Asia, economic recovery in the United States, and fears of OPEC supply cuts contributed to rising oil prices. World oil consumption rose by 2.7 MMbd to 82.5 MMbd, a 3.4% increase from 2003. Much of that increase, 1.2 MMbd, occurred in Asia. Chinese consumption grew by 0.86 MMbd (16%), the lion's share of the increase in Asian demand, while consumption in India grew by 0.12 MMbd, or 5%.[6] Korean and Japanese oil consumption declined modestly. IEA reported that retail oil price subsidies by some developing countries in Asia suppressed prices and artificially stimulated consumption.

Higher fuel oil prices in the United States materially affected the use of petroleum products used for power generation. Net generation across all sectors using petroleum liquids declined 3.6% in 2004.[7] Electric utilities accounted for 62% and independent power producers for 34% of total net generation fueled by petroleum products. Independent power producers led the reduction, dropping 6% or 3.8 million barrels. Regional results differed, with New York's independent power producers increasing consumption by 22% or 3.5 million barrels because residual fuel oil was on the margin much of the year. Similarly, Mississippi electric utilities increased petroleum consumption by 74% or nearly 2 million barrels.[8]

Stocks

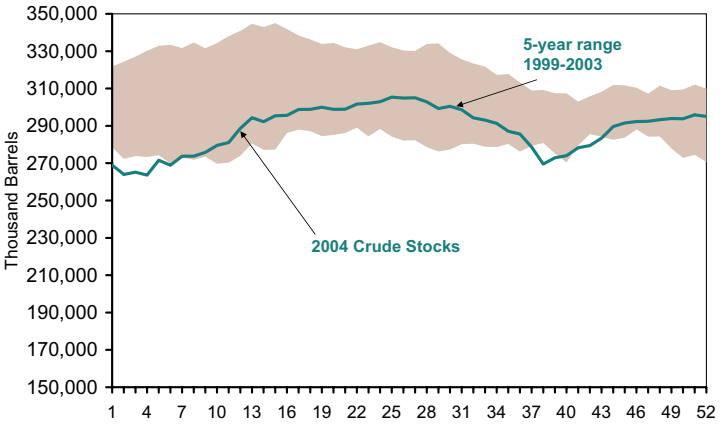
U.S. crude oil stocks trended near the bottom of the 5-year average inventory range during much of 2004. Concerns about the disposition of U.S. inventories contributed to higher WTI prices in 2004. Distillate stocks averaged within the 5-year average band for most of 2004. During November, distillate stock levels dipped below the 5-year range temporarily.

Production and Refining Capacity

Net worldwide oil production increased 3.5 MMbd in 2004. The Middle East accounted for 68% of the increase in production. Production was affected by, among other things, political instability and strikes in Venezuela; the destruction of energy infrastructure in Iraq; Nigerian labor strikes; and disputes between the Russian government and national oil giant Yukos. In the United States, oil production declined 5% from 5.7 MMbd to 5.4 MMbd. Falling production was attributed to field declines in Alaska and the Gulf of Mexico coupled with a series of Gulf of Mexico hurricane-related shut-ins (0.1 MMbd or 38 million barrels).

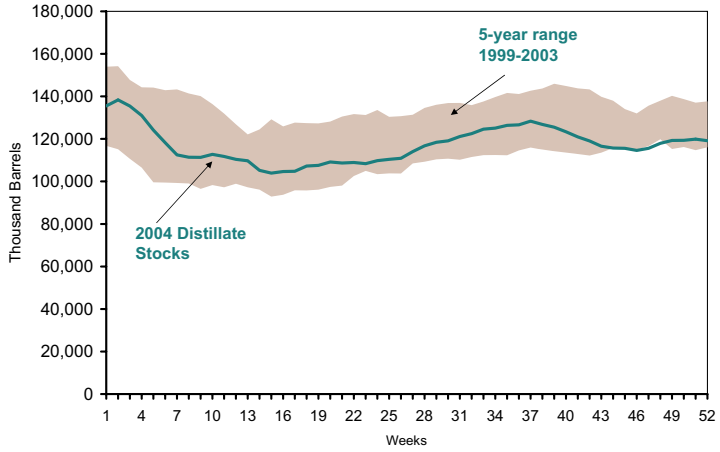
Refinery capacity use averaged 93% in 2004, essentially the same

Weekly U.S. Crude Oil Stocks



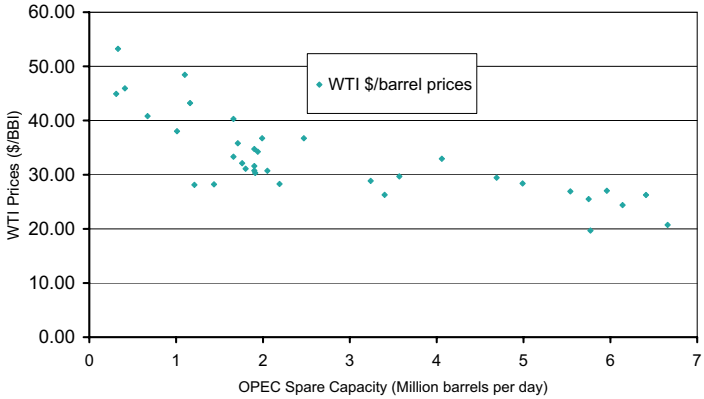
Source: Derived from EIA data.

Weekly Distillate Stocks



Source: Derived from EIA data.

Oil Spare Capacity and Prices



Source: Derived from International Energy Agency, http://omrpublic.iea.org, Oil Market Reports, February 2002 through February 2005 and derived from Bloomberg, L.P. data.

as in 2003. In August, U.S. refinery use reached 97%, its highest point since August 1998. Operable refining capacity has been growing for the past decade and grew 1% in 2004. Expansion is likely to continue as product margins remain favorable and the balance of consumption and production remains tight. Domestic and worldwide demand for refinery products is growing faster than refinery capacity, however, and the situation will worsen if the rate of demand growth continues.[9]

The availability of OPEC spare capacity influenced WTI prices. Average WTI prices increased from about $38/bbl to $55/bbl as average OPEC spare capacity declined from 2 MMbd in 2003 to 1.25 MMbd in 2004. Spare production capacity averaged as little as 0.35 MMbd between August and October.

Endnotes

1 Minerals Management Service Hurricane Ivan evacuation and production shut-in statistics as of January 3, 2005.

2 Ibid., September 16, 2004.

3 "Oil Market Outlook: 'New Paradigm' or Top of the Cycle?," Lehman Brothers, October 2004.

4 Members consist of Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

5 Spare capacity is defined as the difference between OPEC member country actual production and sustainable production, or the amount of production that can be achieved in 30 days and then sustained for 90 days.

6 "Oil Market Report, Monthly Oil Market and Stocks Assessment," International Energy Agency, April 12, 2005.

7 OMOI analysis of EIA data.

8 EIA *Electric Power Monthly*, March 2005.

9 "2004: A Sign of the Future for Refiners?," a presentation at the NPRA Annual Meeting, March 2005, EIA.

Disclaimer: This report contains analyses, presentations and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

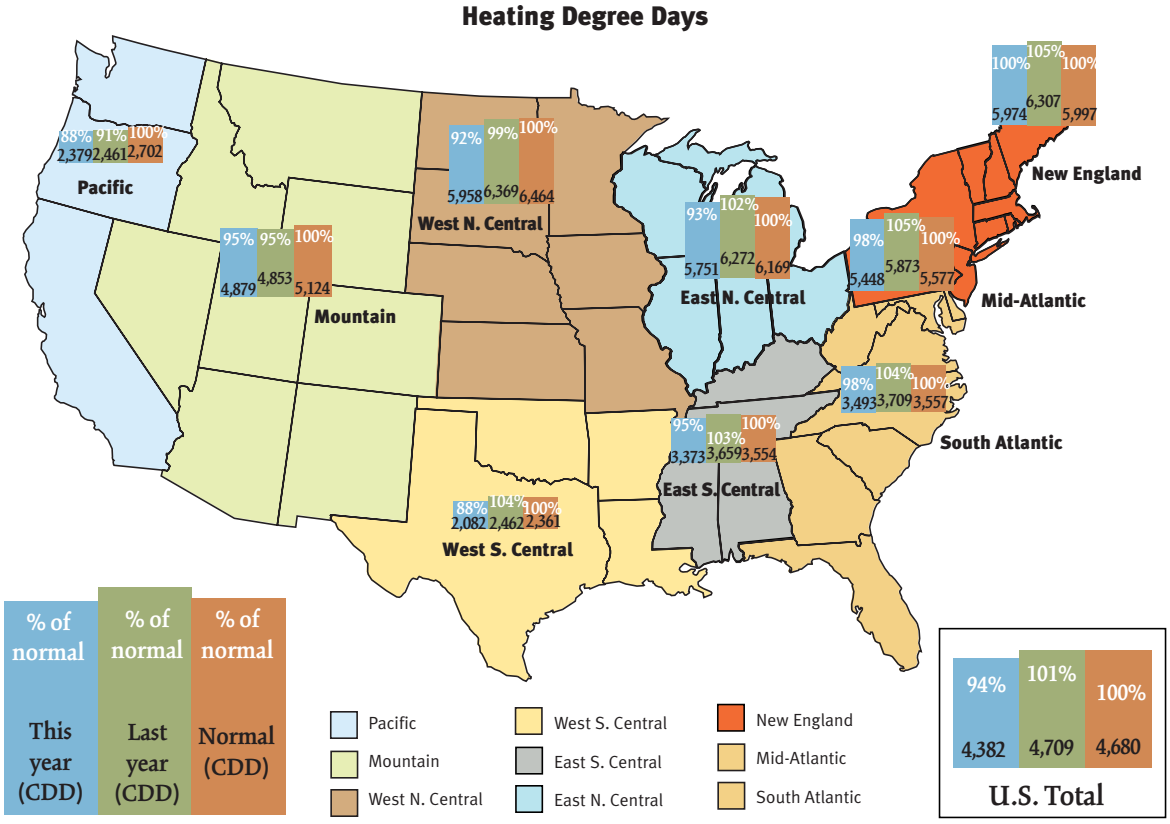
2004 was the nation's 24th warmest year on record.[1] Three states, Washington, Oregon, and Idaho, had average annual temperatures close to record highs, while most states saw above normal temperatures for the year. Only Maine was below normal. Figures show that the last five pentads, or 5-year periods (2000–2004, 1999–2003, 1998–2002, 1997–2001, 1996–2000), were the warmest in the last 110 years of record-keeping and include 1998, the warmest year on record. By comparison, the sixth warmest pentad was during 1930–34, when the western United States had an extended period of drought and warmth. Last year was also the sixth wettest on record for the nation as a whole, following a record wet year in 2003. Thirty-four states recorded above average precipitation for the year. Four states—Washington, Montana, Wyoming, and Maine—were drier than average.

A Brief Seasonal Look

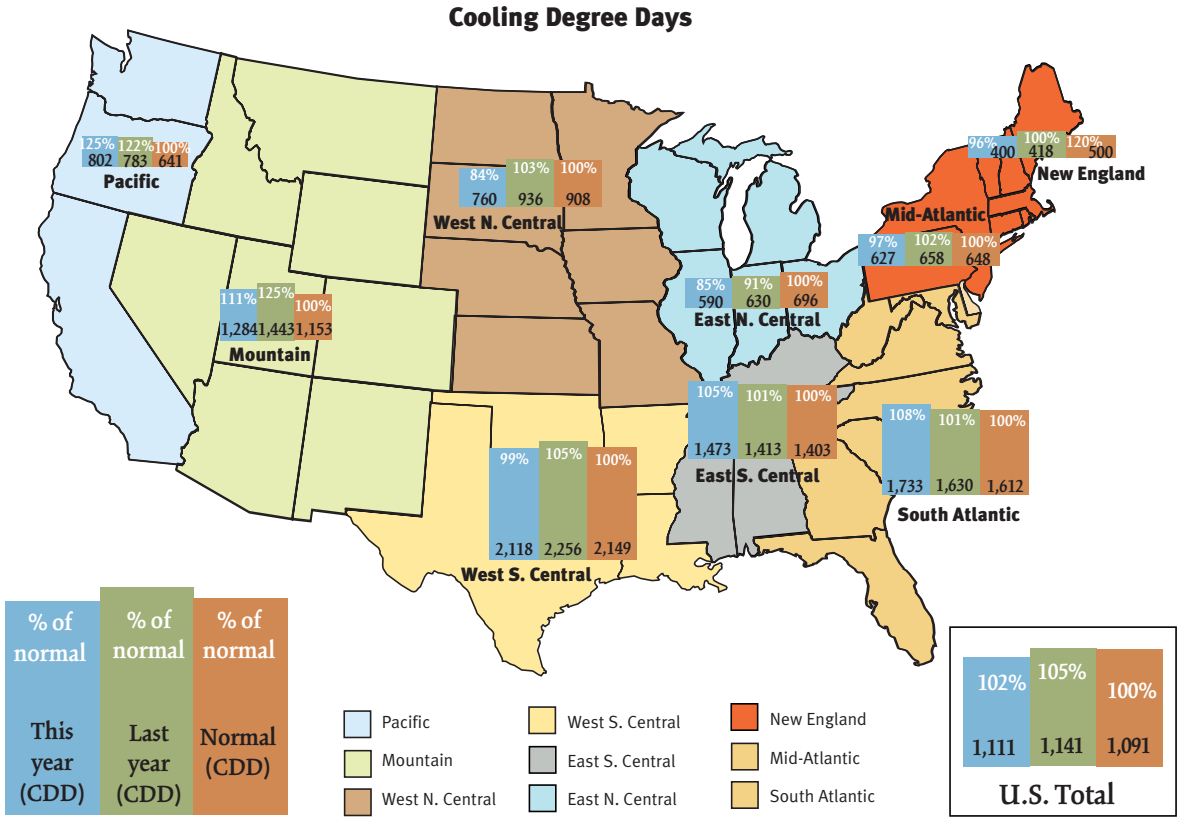
The winter of 2003–04 had near-average temperatures for the nation as a whole, with the eastern seaboard near normal and the central United States warmer. The major event of the winter was the cold snap in New England (see New England essay). Although this episode was serious for the region at the time, it had little overall effect on the warm national winter.

The 2003–04 snow season saw generally below-average snowfall across much of the West. Above-normal snow was recorded early in the season, but rapid snowmelt during a warm spell in late winter led to some loss of snowpack before the end of the western snow season. This resulted in below-average end-of-season snowpack totals. Snow totals were also below normal for much of New England, the lower Great Lakes area (especially around Chicago), and the southwestern Great Plains states. Above-average snow totals occurred along the Appalachian Range and parts of the northern Great Plains.

During spring 2004, every state but Florida recorded warmer-than average temperatures. Overall, spring 2004 was the fourth warmest on record for the nation. Summer 2004, on the other hand, had temperatures well below average, ranking as the ninth coolest summer in 110 years of record-keeping.[2] The cool weather affected the much of the eastern two-thirds of the country; while the west coast states were warmer than average. Eight states in the central United States experienced a summer that was much cooler than average. Another 22 states, from Montana to Texas and eastward to the Mid-Atlantic, plus some states in the



Source: Derived from NOAA data.



Source: Derived from NOAA data.

Northeast, had seasonal temperatures significantly cooler than average. The fall, on the other hand, was the 12th warmest on record with many states in the central United States, from the Great Lakes and northern Plains to the Gulf Coast, recording near- record average temperatures.

Besides the cold snap in the Northeast during January 2004, the major energy-related weather event of the year was Hurricane Ivan. The storm became a tropical depression off the coast of West Africa on August 31 and was a rare, category 5 hurricane when it reached Jamaica on September 9. Hurricane Ivan moved through the central Gulf of Mexico with sustained winds of up to 140 miles per hour, directly affecting many oil and gas platforms off the shores of Louisiana, Mississippi, and Alabama (see discussion in natural gas section).[3] Wave heights reportedly reached nearly 90 feet before Hurricane Ivan made its United States landfall near Gulf Shores, Ala. on September 16.

In general, the Atlantic hurricane season was more active than average with 15 tropical storms and 9 hurricanes, including 6 major hurricanes. The season was also the most costly hurricane season on record with damage estimated at $42 billion for the United States.[4]

Endnotes

[1] National Oceanic and Atmospheric Administration (NOAA), "Climate of 2004-Annual Review, U.S. Summary," National Climatic Data Center, January 13, 2005. Data for 110 years.

[2] NOAA defines summer as the period from June through August.

[3] See a further discussion of Hurricane Ivan's effect on oil and gas production in the Gulf of Mexico in the Southeast regional section of this report.

[4] NOAA,"Climate of 2004 - Annual review, U.S. Summary," 7.

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Wind Review

In 2004, wind became the fastest growing fuel type for electricity generation in the United States, with an average annual growth rate exceeding 27%, starting with a small initial base of 2578 MW in 2000. The Federal Production Tax Credit (PTC) has played an influential role in wind production. In the past, lapses in the tax credit have created a boom-bust cycle in wind project installation.[1]

Federal Policies

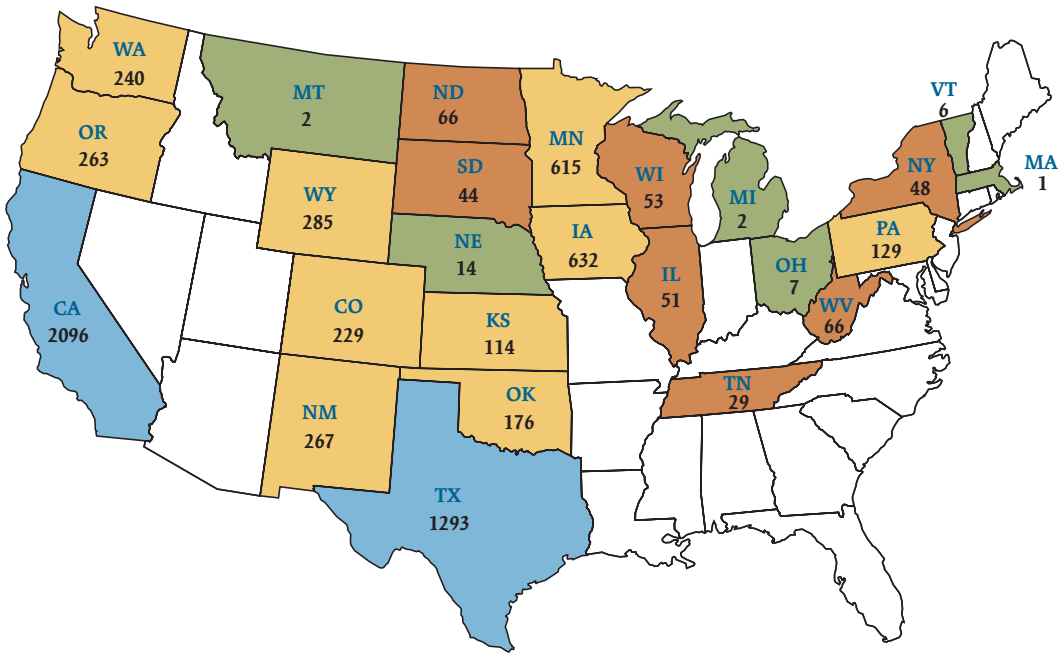
Wind project installation was weak in 2004. Investment strengthened after Congress renewed the PTC in October. Its renewal set off a flurry of new wind generation project announcements. Within a month, five utilities and their affiliates announced fully permitted facilities totaling 829 MW. The American Wind Energy Association (AWEA) expected somewhere between 2,000 MW and 2,500 MW to be

United States Wind Supply-Demand Statistics

	Actual 2003	Actual 2004	Expected Growth rate 2005	Expected Growth rate 2000-2004
Capacity, MW (AWEA)				
U.S., total installed	6,374	6,740	8,740 - 9,240	27.2%
Annual additions	1,696	389	2,000 - 2,500	
MW top 5* states:	4,656	4,921		
Top 5 as % of installed wind	73%	73%		
Generation, MWh (EIA)				
Wind generation (utility & non-)	11,187	14,153		26.1%
Wind generation as % of total	0.29%	0.36%		24.5%
Net Summer Capacity MW (EIA)				
Total MW	948,446	967,895		
Wind MW	5,995	6,384		
Wind as % of total	0.6%	0.7%		
* (CA, TX, MN, IA, WY)				

Source: Derived from data from the American Wind Energy Association (AWEA), Energy Information Administration (EIA) *Monthly Energy Review* and preliminary unpublished data, NREL, and Platts PowerDat. 2004 capacity is net summer capacity.

United States 2004 Year End Wind Power Capacity (MW)



Source: AWEA.

installed in 2005.[2] At 1.9¢/ kWh[3], the PTC applied to projects on line by the end of 2005, and each credit was valid for 10 years from the date of initial operation.

States, meanwhile, increased their promotion of renewable energy through renewable portfolio standards (RPS) and incentives that included loan funds, grant programs, tax exemptions, net metering, and green-power purchasing programs.

Accordingly, the Commission has sought to promote cooperation between federal and state authorities and regional transmission organizations through its policies on transmission and wholesale markets. FERC held two technical conferences in 2004[4]—one to re-examine its rules on wind interconnection and a second on wind transmission in wholesale markets—to ensure that its rules did not inadvertently erect barriers to new technologies or intermittent resources.

State Policies

As of 2004, 18 states and the District of Columbia had enacted an RPS; nine of these standards were passed or amended that year.[5] An RPS requires electricity suppliers to add renewable resources to their generation supply from eligible resources, usually at a rate that increases yearly until a goal is met. The goal may be relative to a supplier's peak demand, or an absolute amount of capacity. A few RPS have specified a percent of the total that must be met using a particular fuel, such as wind or solar power. States have enacted these standards to encourage fuel diversity, lessen dependence on fuel imports, acknowledge public environmental concerns, and meet more stringent Environmental Protection Agency (EPA) emission requirements. Wide variation exists regarding the duration of these standards, the share of renewables as a portion of the goals, and the fuels that are included. Some states offer "extra credit" for the use of certain renewables.

Many states with RPS have authorized related renewable energy credits (REC) and a trading mechanism. Creating a secondary market for credits separate from the energy commodity makes the RPS more fungible. RECs give retail suppliers flexibility on how to comply with an RPS, depending on their skill or business plan. Suppliers can demonstrate through ownership of a REC that they have generated, contracted for, or traded to achieve the required percent of renewables. Rules also vary as to credit duration and whether the renewable source must originate in the state itself or in the general region. As more states enact RECs, many are working together to create regional electronic tracking and verification systems.

Challenges to Wind Generation Development

Costs and Financing. Recent technological advances allowed wind turbines to generate electricity for 4 to 6¢/kWh, apart from any government subsidy or incentive. With subsidies in place, new, large-scale wind projects could sell power to utilities for somewhere between 2.5 and 3.5 ¢/kWh.[6] Given 2004 natural gas prices and wind subsidies, the levelized cost of building a new wind generation plant on a $/MWh basis compared favorably with the cost of a new gas-fired plant.[7]

In common with all generation technologies, wind developers had to secure long-term power purchase agreements, usually for 10–20 years, to obtain financial backing. When the Public Utility Regulatory Policy Act encouraged early wind development, long-term contracts were guaranteed as an incentive.[8] Today, most wind farms are built either as merchant facilities or in response to a utility's request for proposal for wind power. Though some states have required or encouraged long-term contracts, their absence elsewhere has continued to be a barrier to financing and development.

Location and Transmission Capacity. Wind generators produce and are paid only when the wind blows, so the nature of transmission rules and services are important to generators. The intermittent nature of wind compared with other technologies can present challenges to systems operations. FERC and many independent system operators are addressing these concerns through proposed reliability rules for wind. One way to minimize the impact of intermittency is through better forecasting.

Wind generation is generally sited in high-wind resource areas, which can be far from load. Often, transmission must be built from generation to load areas. The need for transmission investment raises questions of cost allocation and siting. Transmission capacity and capacity credit for wind are issues that states, public power authorities, regional coalitions, and independent system operators are beginning to address.

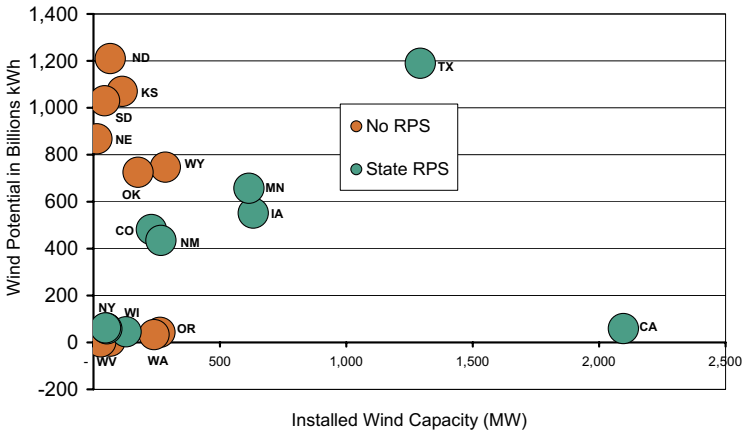
Potential for Wind

Optimal wind resources are not evenly distributed across the United States. Areas in the West and the Midwest have the best wind potential, usually classified as wind class 3 sites and above (See map page 234).

Through 2004, installations were negligible in some states with the highest potential for wind capacity. To illustrate the gap, the top 20 states with the most wind potential are plotted against their installed capacity. States in green had an RPS; the others did not, underscoring the ongoing importance of government policy in fostering wind development.

States with an RPS have more installed wind relative to their wind potential (See chart at right).

Top 20 States by Installed Capacity (MW)



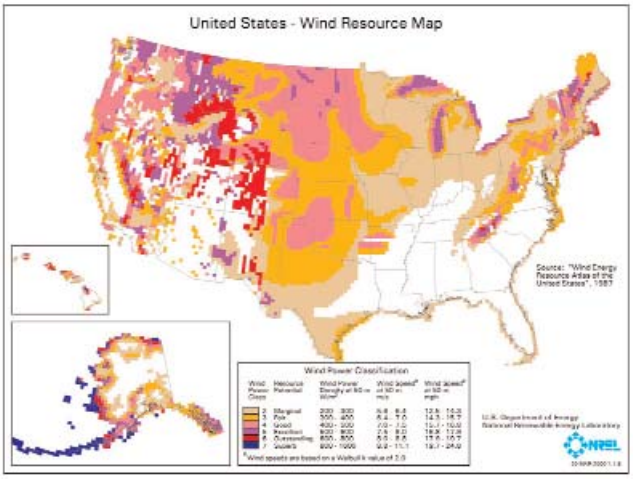
Source: Derived from data from Lawerence Berkley National Laboratory (LBNL) wind resources, AWEA database of installed wind resources, and various state websites.

Capacity and Concentration of Leading Wind Companies in the U.S.

Leading Wind Power owners, cumulative	2003 (MW)	2003 (%)	2004 (MW)	2004 (%)
FPL Energy	2,700	42%	2,758	41%
Shell Wind Energy	393	6%	315	5%
AEP	310	5%	311	5%
enXco	238	4%	298	4%
PPM Energy	201	3%	225	3%
Top 5 Owners	**3,604**	**57%**	**3,907**	**58%**
Total U.S. MW Installed	**6,372**		**6,740**	
Leading Wind Turbine Manufacturers: US Sales	**2003 (MW)**	**2003 (%)**	**2004 (MW)**	**2004 (%)**
GE Energy	903	54%	171	44%
Mitsubishi	201	12%	120	31%
Vestas	359	21%	97	0%
NEG Micon (now Vestas)	129	8%	N/A	N/A
Gamesa	56	3%	0	0%
Bonus (now Siemens)	0	0%	0	0%
Top 5 Manufacturers	**1,463**	**87%**	**388**	**99.9%**
Total U.S. Turbine Sales	**1,687**		**389**	**100%**
Utilities / power companies buying the most windpower: (output from installed MW)	**2003 (MW output)**	**2003 (% U.S.)**	**2004 (MW output)**	**2004 (% U.S.)**
Southern California Edison	1,080	17%	1,025	16%
Xcel Energy	829	13%	884	14%
Pacific Gas & Electric	680	11%	680	11%
PPM Energy	606	10%	606	10%
TXU	580	9%	580	9%
Top 5 wind-power purchasers	**3,775**	**59%**	**3,775**	**59%**
Total U.S.: MW installed	**6,372**		**6,740**	

Source: Derived from AWEA project database, as of December 31, 2004.

United States Wind Resources by Wind Class



Source: Department of Energy, National Renewable Energy Laboratory
http://www.nrel.gov/wind/wind_map.html

Endnotes

[1] The PTC lapsed in 2000, 2002, and 2004, with corresponding drops in wind project installation in those years.

[2] AWEA press releases, January 27, 2005 and April 26, 2005.

[3] Initial Authority: 26 USC § 45; reauthorizing authority: H.R. 1308, the "Middle Class Tax Bill," October 4, 2004. In 1992, the Energy Policy Act created the production tax credit for wind projects and set the amount at 1.5¢/kWh, to be adjusted for inflation. Subsequently, the Internal Revenue Service adjusted the PTC for inflation to 1.9¢/kWh for all projects placed into operation in 2005. 70 Fed. Reg., 18,071, April 8, 2005.

[4] Technical Conference on Interconnection for Wind Energy and Other Alternative Technologies, Docket Nos. PL04-15-000, et al., September 24, 2004; and Technical Conference on Assessing the State of Wind Energy in Wholesale Electricity Markets (Docket No. AD04-13-000), December 1, 2004.

[5] States that passed or amended their RPS in 2004 included Colorado, Hawaii, Maryland, New Jersey, New Mexico, New York, Pennsylvania, Rhode Island, and the District of Columbia (which passed an RPS in 2004 and signed it in 2005).

[6] Ryan Wiser, LBNL, email correspondence, November 2004.

[7] Mark Bolinger, LBNL, "State Policy Impacts on Wind Project Financing," presented at the AWEA Wind Power Finance & Investment Workshop, September 28, 2004; updated by correspondence, April 2005. LBNL analysis based on data from EIA's Assumptions to the Annual Energy Outlook 2005 and Nymex closing prices, April 1, 2005.

[8] PURPA: 16 U.S.C. §824a-3, 796(17-22) (1982)

Disclaimer: This report contains analyses, presentations and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

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Glossary

12-month strip: Prices for the next 12 months of consecutive natural gas futures trading contracts, usually starting with the nearest, or prompt, month.

Ancillary services: Those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system. Ancillary services supplied with generation include load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services.

Arbitrage: The simultaneous purchase of a commodity/derivative in one market and the sale of the same, or similar, commodity/derivative in another market in order to exploit price differentials.

Assessment period: For the purposes of this report, the time period between January 1, 2004, and December 31, 2004.

Automated mitigation control: A procedure under which the bids of individual suppliers would be capped under certain predetermined conditions. As implemented in New York, this procedure is triggered when the locational marginal price exceeds $150/MWh. Individual bids are then subject to a conduct test and an impact test. The conduct test is failed if the bid exceeds a threshold based on a predetermined "reference bid." The impact test is failed if the change in the market-clearing price, using reference bids in place of actual bids, exceeds a certain threshold.

Automatic generation control: The automatic regulation of the power output of electric generators within a prescribed range in response to a change in system frequency, or tie-line loading, to maintain system frequency or scheduled interchange with other areas within predetermined limits.

Availability: The maximum load-carrying ability of a generator, exclusive of station use and planned, unplanned, or other outage; or derating.

Balancing: The requirement imposed by electricity grids or natural gas pipelines that supply and demand be equal over a certain time period.

Baseline: In electric markets, refers to an agreed-upon level of electricity consumption from which deviations are measured. Usually based on a customer's historical usage. Variations may be billed at a different rate.

Baseload: The minimum level of electric power demand of a utility, region, or utility customer delivered or required over a given period of time at a steady rate; generally expressed in units of kilowatts or megawatts. The minimum continuous load or demand in a power system over a given period of time.

Baseload Unit: An electric power plant, or generating unit within a power plant, that is normally operated continuously to meet the base load of a utility.

Basis: The difference in prices between identical products but in two different markets (in this report, different geographical natural gas markets).

Bid-ask differential: The difference in price between what a buyer offers to pay for a commodity and what a seller offers to accept for a commodity.

Bilateral physical electricity transaction: A direct contract between an electric power producer and either a user or a broker outside of a centralized power pool or power exchange.

Bus: A conductor or group of conductors that serves as a common connection for two or more electric circuits within a station.

Capacity factor: A value used to express the average percentage of full capacity used over a given period of time. For example, a generating facility that operates at an average of 60% of its normal full capacity over a measured period has a capacity factor of 0.6 for that period. Can apply to an individual generating unit or a collection of them. Capacity factor is the ratio of the gross electricity generated over a year to the energy that could have been generated at continuous full-power operation during the year.

Capacity margin: The amount of capacity above planned peak system demand available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen demand.

Capacity markets: Designed to allow companies with an obligation to deliver electricity to customers to competitively procure contracts with power plant owners to have their units up and running and able to produce additional energy.

Clearing: The registration and settlement of a trade that includes provisions for margin requirement and performance guarantee.

Coalbed methane: An unconventional gas produced from gaseous beds or layers of coal ranging from brown coal (lignite) to bituminous coal. Coalbed wells are drilled and usually completed open-hole as opposed to cased and perforated, as done in a conventional natural gas well.

Combined-cycle generators: Power-generating units that increase the efficiency of electric generation by capturing and reusing waste heat; the latest units achieve heat rates near 6,000 Btu/kWh with more than 50 percent fuel-to-electricity conversion efficiency.

Combined-cycle power plant: A power plant that uses two different thermal cycles for producing electricity. The first cycle burns a fuel inside a gas turbine, and the gas turbine drives an electric generator. The hot air coming out of the gas turbine is used to turn water into steam, and the steam turns a second electric generator. Combined-cycle power plants are the most efficient technology currently available for turning a fuel into electricity. They can use a wide variety of liquid and gaseous fuels, but almost all such plants in the United States burn natural gas.

Combustion turbine power plant: A combustion turbine burns a fuel to produce a large volume of hot air, which then goes through a series of precision fan blades, which convert the energy of the hot air to rotate a shaft. The shaft, in turn, is connected to an electric generator. The technology is closely related to that used in the jet engines of airplanes. Such plants can be built at a lower cost than other large power plants, but they are relatively inefficient in converting fuel into electricity.

Congestion: A characteristic of the transmission system produced by a constraint on the optimum economic operation of the power system, such that the marginal price of energy to serve the next increment of load, exclusive of losses, at different locations on the transmission system is unequal.

Congestion costs: Charges assessed and redistributed due to electricity network constraints.

Control area: An electric power system or combination of electric power systems to which a common automatic control scheme is applied in order to:

- Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load in the electric power system(s)
- Maintain, within the limits of Good Utility Practice, scheduled interchange with other Control Areas
- Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice
- Provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Cooling degree days: A measure of cooling energy demand determined by how far a location's temperature averaged above 65 degrees Fahrenheit.

Credit clearing: A mechanism for settling mutual claims, the result of which is that the risk that a company might fail to fulfill its contract is pooled among many companies.

Credit rating: A statistical technique wherein several financial characteristics are combined to form a single score to represent a customer's creditworthiness.

Credit risk: The risk that an issuer of debt securities or a borrower may default on his obligations, or that the payment may not be made on a negotiable instrument.

Critical notices: Pipeline issuances that provide information on conditions that affect natural gas scheduling or adversely affect scheduled gas flow.

Curtailable load: Electricity deliveries that are subject to interruption by the grid operator.

Day-ahead markets: Forward markets for electricity to be supplied the following day. This market closes with acceptance by the independent system operator, power exchange, or scheduling coordinator of the final day-ahead schedule.

Debt financing: Providing the necessary capital by selling bonds, bills, or notes to individuals or institutions.

Demand: Represents the requirements of a customer or area at a particular moment in time. Typically calculated as the average requirement over a period of several minutes to an hour, and thus usually expressed in kilowatts or megawatts rather than kilowatt-hours or megawatt-hours. Demand and load are used interchangeably when referring to energy requirements for a given customer or area.

Demand elasticity: The demand response, or lack thereof, of customers as a result of a change in price.

Demand responsiveness/demand response: A situation

that occurs when customers respond to an increase in price by lowering demand for a good or service and respond to a decrease in price by increasing demand for a good or service.

Dispatch declines: The 16 categories for which a generator may decline a dispatch instruction in CAISO's automated dispatch system (e.g., safety, unit derating, or environmental constraints.) If an automated dispatch instruction is not responded to within two minutes, it is considered declined.

Dual-fueled (or dual-fired) unit: A generating unit that can produce electricity using two or more fuels. In some of these units, only the primary fuel can be used continuously; the alternate fuel(s) can be used only as a start-up fuel or in emergencies.

Economic withholding: An exercise of market power intended to raise the market price above competitive levels by pricing offer blocks high enough to effectively "withhold" or reduce the quantity of supply that is offered at "competitive" prices. It was concluded that energy could be offered at higher prices than on a cost basis as long as:

- Suppliers assume the risk of being out of merit
- If offered in such a way that it does not preclude a market response.

Electronic trading platform: An electronic system that attempts to eliminate third-party orders entered by an exchange market maker or an OTC market maker and permits such orders to be executed in whole or in part. The platform allows major brokerages and individual traders to trade directly.

Equity financing: The provision of needed capital through the sale of common or preferred stock to investors.

Exchange: A marketplace in which shares, options, and futures on stocks, bonds, commodities, and indices are traded.

Financial liquidity: An entity's ability to obtain funds to meet its cash flow obligations, with consideration for the speed with which such funds can be obtained.

Financial transmission right: A contract that entitles the holder to receive compensation (or pay) for certain transmission charges that arise when the grid is congested and differences in locational prices result from the redispatch of generators to relieve that congestion.

Firm transportation: Contracted energy deliveries that are guaranteed not to be interrupted.

First Contingency Reliability Criteria: An electric system is planned and operated so that it can safely withstand the loss of the largest single system element (i.e., power plant or transmission line).

Forward price curve: The chronological set of prices determined by a market for a good that will be delivered in the future. Fuel-adjustment clause: A provision of a power sales agreement or rate schedule that allows for the electricity price to be changed based on changes in the price of the fuel used to generate the power.

Futures market: A market in which contracts for future delivery of a commodity or a security are bought or sold.

Gas turbine: See Combustion turbine power plant.

Generation: The act of producing energy, or the amount of energy produced. A facility's energy output is often referred to as its generation. In measurement, generation is the gross amount of electric energy produced minus the electric energy consumed at a generating station for station use.

Generator: An electrical device used to convert mechanical energy to electrical energy. The generator moves a conductor through a magnetic field and directs the current produced by the induced voltage to an external electric circuit.

Heat rate: A number that tells how efficient a fuel-burning power plant is. The heat rate equals the Btu content of the fuel input divided by the kilowatt-hours of power output. Heat rate is expressed as the number of BTUs of heat required to produce a kilowatt-hour of energy. Operators of generating facilities can make reasonably accurate estimates of the amount of heat energy of a given quantity of any type of fuel, which can be compared with the actual energy produced. The resulting figure tells how efficiently the generator converts fuel into electrical energy.

Heating degree days: A measure of heating energy demand determined by how far a location's temperature averaged below 65 degrees Fahrenheit.

Hedging: A risk management tool used to protect the value of an investment or contractual commitment from the risk of loss due to price fluctuations.

Hub: A geographical location where multiple participants trade services.

Independent market monitor: A party that identifies flaws in market rules or other issues affecting market efficiency and market power abuses. To ensure the independence of the monitoring function, the market monitor reports to the independent board of directors of the RTO and FERC.

Independent system operator (ISO): An organization that has been granted the authority to operate, in a nondiscriminatory manner, the transmission assets of the participating transmission owners in a fixed geographic area. ISOs often run organized markets for spot electricity.

Injection season: The April 1 through October 31 period, during which gas is injected into natural gas storage reservoirs in preparation for withdrawal and use during the winter heating season.

Installed capacity:

- The total potential output of a given set of existing generators, usually measured in megawatts
- A share of potential (not actual) output that load-serving entities are required to procure as an administrative measure to ensure adequate generation supply

See also locational installed capacity.

Interruptible or nonfirm transportation: Transmission service that is reserved and scheduled on an as-available basis and is subject to curtailment or interruption.

Intertie: The point of physical interconnection between adjacent transmission systems.

Load: Often synonymously used with demand, load is the total amount of power carried by an electric system at a point in time.

Load pocket: An area isolated by the limits of the transmission network to get power into the area; demand within the load pocket exceeds internal generation, so imports are needed or reliability will fail.

Load-serving entity (LSE): Any entity, including a load aggregator or power marketer, that serves end-users within a control area and has been granted the authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to end-users located within the control area.

Locational installed capacity (LICAP): Installed capacity in a restricted location (e.g., New York City), rather than in a broader area (e.g., anywhere in New York State).

Locational marginal price: The market-clearing price for electricity at the location the energy is delivered or received.

Long position: The market position of a futures contract buyer whose purchase obligates acceptance of delivery unless the contract is liquidated by an offsetting sale.

Loop flow: The fact that electricity flows on transmission lines in accord with the physical laws of electricity and not on the route contracted for by the seller. In some areas, system configuration is such that electricity flows in large cross-regional loops, as around the Great Lakes area of southern Canada.

Losses: Energy (kilowatt-hours) and power (kilowatts) lost in the operation of an electric system. Losses occur principally as waste heat in electrical conductors and apparatus such as transformers.

Margin requirement: The amount of money required to hold futures contracts and cover changes in the value of futures contracts.

Marginal electric generating unit: The last unit turned on in an area to serve load. In organized wholesale markets, the price of the marginal source of electricity usually sets the price for all generation within the market.

Mark-to-market: The process whereby the book value or collateral value of a security – including a security such as a multiyear contract – is adjusted to reflect current market value for the applicable period.

Market capitalization: A measure of company size that is computed as current market price per share of stock times the total number of shares outstanding.

Market liquidity: The ease, or lack thereof, with which a buyer can buy or a seller can sell at a prevailing price in a marketplace.

Market monitoring unit: An independent and objective overseer of organized power markets. The MMU evaluates and reports on the operation of the markets, including transmission congestion costs and the potential for a market participant to exercise undue market power.

Market participant: A market buyer or a market seller, or both, that meets reasonable creditworthiness standards established by the market operator.

Market power: A measure that can include, but is not limited to, the ability of a firm to raise its price or withhold its output with the effect of raising market prices above competitive levels for a sustained period of time.

Market share analysis (Hirschman-Herfindahl Index HHI): Often used to evaluate mergers, the HHI is a commonly accepted measure of market concentration. It is calculated by squaring the market share of each firm competing in a market, and then summing the resulting numbers.

Merchant generator: A generating plant built "on spec," with no energy sales contracts in place. Merchant plants will compete in the deregulated market on their ability to generate low-cost power and support the local grid system.

Mitigation: A process by which a market operator can deter market behavior that may interfere with the competitive and efficient operation of the markets when market participant conduct falls outside certain prescribed guidelines.

Mothballed Capacity: A power plant that is out-of-service, but is being maintained in such a condition that an operator can bring it back into service.

Native load: Wholesale and retail customers that the transmission provider is obligated to serve.

Nitrogen oxide (NOx): NOx is a key pollutant in the formation of acid rain and ground-level ozone (smog). NOx also contributes to the formation of fine particles that are associated with significant health effects and regional haze.

NOx Budget Trading Program (NBP): An ozone season cap-and-trade program intended to help states meet their NOx SIP call required reductions. Twenty-one states and the District of Columbia began participating in 2003-04 or will participate in the future.

NOx State Implementation Plan (SIP): Building upon analyses done by the Ozone Transport Assessment Group (OTAG), this rule was finalized by the Environmental Protection Agency (EPA) in 1998. It required states significantly contributing to ozone nonattainment problems in other states to reduce their NOx emissions during the ozone season beginning in 2003. This rule gave states the flexibility to reduce emissions through various means and gave them the option to participate in the NOx Budget Trading Program.

Open access:

- Evolving access to a transmission system by all generators and wholesale customers
- The use of a utility's transmission and distribution facilities on a common-carrier basis at cost-based rates.

Over the counter (OTC): Named for what was once an informally organized market, the OTC is today a well-organized marketplace, although with little or no regulatory oversight compared with an exchange or customized derivatives traded outside of an organized exchange.

Peak load, peak demand: These two terms are used interchangeably to denote the maximum power requirement of a system at a given time, or the amount of power required to supply customers at times when need is greatest. Refers either to the load at a given moment (e.g., a specific time of day) or to average load over a given period of time (e.g., a specific day or hour of the day). Usually expressed in megawatts.

Peaking capacity: Generating equipment normally operated only during the hours of highest daily, weekly, or seasonal loads; this equipment is usually designed to meet the portion of load that is above base load.

Peakshaving LNG facility: A liquefied natural gas plant that supplies a gas pipeline system during peak-use periods. During slack periods the liquefied gas is stored. With the need for additional gas, the liquid product is gasified and fed into local distribution and gas pipeline systems.

Plant factor: The capacity factor of an entire generating facility including all available generating units. See also capacity factor.

Pivotal supplier: A power supplier whose capacity must be used to meet peak demand and whose capacity exceeds the market's supply margin.

Power purchase agreement: Guarantees a market for power produced by an independent power producer and the price at which it is sold to a purchaser. Such an agreement imposes legal obligations on both the parties to perform previously accepted tasks in a predetermined manner.

Project financing: A form of asset-based financing in which a firm finances a discrete set of assets (the project) on a stand-alone basis.

Ramp rate: The rate at which a load on a power plant can be increased. The rate for a hydroelectric facility may depend on how rapidly water surface elevation changes on the river.

Real-time market: An electric market that settles—determines the price—for one-hour periods or less during the day of delivery.

Real-time pricing: A system that provides signals to customers on the value of consuming energy at the time of consumption.

Reference price: The settlement price of a derivatives contract, based on a particular location and commodity, or an estimated electricity price, based on a forecast of market conditions.

Regional transmission organization (RTO): An organization with a role similar to that of an independent system operator but covering a larger geographical scale and involving both the operation and planning of a transmission system. RTOs often run organized markets for spot electricity.

Reliability must run (RMR): A unit that must run for operational or reliability reasons, regardless of economic considerations.

Reserve margin: The percentage of installed capacity exceeding the expected peak demand during a specified period.

Retail unbundling: Disaggregating electric utility service into its basic components and offering each component separately for sale with separate rates for each component. For example, generation, transmission, and distribution could be unbundled and offered as discrete services.

Ring-fencing: Techniques used to isolate the credit risk of a subsidiary within a corporation from the risk of its affiliated companies.

Risk management: The process of analyzing exposure to risk and determining how to best handle such exposure.

Safe harbor: The ability of management to discuss in good faith a company's prospects and financial projections with analysts and investors without fearing litigation.

Seams: Barriers and inefficiencies resulting from equipment limitations and differences in market rules and designs, operating and scheduling protocols, and other control-area practices that inhibit or preclude the ability to transact capacity and energy between regions.

Short position: The market position of a futures contract seller whose sale obligates delivery of the commodity unless the contract is liquidated by an offsetting purchase.

Single settlement system: A market structure that provides only a real-time market.

Spark spread: The cost difference of converting natural gas into electricity. It can also be the difference between gas and electricity futures prices. Marketers use the spark spread as an arbitrage opportunity, using tolling or reverse tolling.

Spot market: The natural gas market for contractual commitments that are short term (usually a month or less) and that begin in the near future (often the next day, or within days). In electricity, spot markets are usually organized markets for day-ahead and real-time electricity run by an independent system operator or regional transmission organization.

Spread trading: Buying one instrument/commodity and selling another, with a view to profiting from the change in the gap between the two markets.

Steam plant: A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler where fossil fuels are burned.

Sulfur dioxide (SO2): SO2 is a key pollutant in the formation of acid rain and contributes to the formation of fine particles that are associated with significant negative health effects and regional haze.

Swaps: An exchange of streams of payments over time according to specified terms. A common type is a fixed-for-floating swap, in which one party agrees to pay a fixed price in return for receiving a changing price (e.g. spot) from another party.

Time-of-use pricing: A rate design imposing higher charges to customers during periods of the day when higher demand is experienced.

Tolling agreement: An agreement whereby a party moves fuel to a power generator and receives kilowatt hours (kWh) in return for pre-established fees.

Transaction costs: Costs incurred when buying or selling assets, such as commissions and the spread.

Transmission loading relief (TLR): Interrupts specific transmission flows or transactions and may curtail service to specific customers or future transmission schedules. A TLR is called to preserve the reliability of the electric transmission system when electricity flows exceed permitted levels.

Transparency: A measure of the extent to which a market's current trade and quote information is readily available to the public.

Turbine: A machine that converts the kinetic energy of a moving fluid to mechanical power by the impulse or reaction of the fluid with a series of blades arrayed about the circumference of a wheel or cylinder.

Two-settlement system: A system under which the price for electricity on any given day is established both on a day-ahead and a real-time basis. Day-ahead prices are based on forecasted energy demand and transmission and generation availability. Real-time prices reflect not only day-ahead anticipated events, but what actually occurs in real time—for example, generation or transmission trips, and changes in forecasted load.

Unconventional natural gas: A term applied to natural gas that is difficult and expensive to find and produce; if found, it often is bypassed in favor of more easily obtainable supply that is less costly to produce. Higher gas prices, however, increase the interest in these more-costly gas sources. Examples of unconventional gas can be found in tight sandstone reservoirs and shale, including the increasingly popular Barnett Shale in Texas.

Usage charge: Refers to charges levied on power suppliers or their customers for the use of transmission or distribution wires.

Virtual bidding: A practice that allows participants to hedge against the risk that real-time and day-ahead prices will differ, or to speculate on the difference.

Voice broker: A trading intermediary matching buyers and sellers using the traditional approach of telephone confirmation, etc.

Volatility: A measure of the price fluctuation of an underlying instrument that takes place over a certain period of time.

Volumetric risk: The effect on revenue of fluctuations in demand for a product or service.

Wash trade: A trade that is structured so that one company sells power to a second company and then, at the same split second, buys an equal amount of power from the second firm. Such trades could be used to inflate market prices or traded volumes. The trades potentially add directional momentum to the market and increase sales volume and revenues of the company carrying out the trades.

Wholesale electricity markets: The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Winter heating season: The November 1 through March 31 period, during which most natural gas use for space heating takes place.

Zonal price: A pricing mechanism for a specific zone within a control area.

Acronyms

AEP	American Electric Power Company
AMP	Automated mitigation procedures
ARR	Auction revenue rights
ATC	Available transfer capability
AWEA	American Wind Energy Association
AZ-NM-SNV	Arizona-New Mexico-Southern Nevada (NERC subregion)
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
Btu	British thermal unit
CAISO	California independent system operator
CA-MX	California-Mexico (NERC subregion)
CC	Combined cycle
CCRO	Committee of Chief Risk Officers
CERA	Cambridge Energy Research Associates
CERS	California Energy Resources Scheduling
CFTC	Commodity Futures Trading Commission
COB	California-Oregon Border
COOP	Cooperative
CT	Combustion turbine
DA	Day-ahead
DCA	Designated congestion area
DEC	Decremental (energy)
DOE	Department of Energy
DPL	Delmarva Peninsula
ECAR	East Central Area Reliability Coordination Agreement (NERC region)
EFP	Exchange of futures for physical
EFS	Exchange of futures for swaps
EIA	Energy Information Administration
EQR	Electric Quarterly Report
ERCOT	Electric Reliability Council of Texas (NERC region)
ESP	Electric service providers
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council (NERC region)
FTR	Financial transmission right
GISB	Gas Industry Standards Board
GW	Gigawatt (one billion watts)
GWh	Gigawatt-hour (one billion watt-hours)
HVDC	High voltage direct current
ICAP	Installed capacity
ICE	IntercontinentalExchange
INC	Incremental (energy)
INP	Indian Point (nuclear plant in NYISO)
IOU	Investor-owned utility
IPP	Independent power producer
IRP	Integrated resource plan
ISDA	International Swap Dealers Association
ISO	Independent system operator
ISO-NE	Independent system operator-New England
JOA	Joint operating agreement
kWh	Kilowatt-hour (one thousand watt-hours)
LBMP	Locational-based marginal price
LBNL	Lawrence Berkeley Laboratory
LDC	Local distribution company
LIPA	Long Island Power Authority
LMP	Locational marginal price/pricing
LNG	Liquefied natural gas
LSE	Load-serving entity
MAAC	Mid-Atlantic Area Council (NERC region,

	geographically within PJM)
MAIN	Mid-America Interconnected Network (NERC region)
MAPP	Mid-Continent Area Power Pool (NERC region)
MISO	Midwest Independent System Operator
MMBtu	Million British thermal units
MMG	Market Monitoring Group (in ISO-NE)
MMU	Market monitoring unit
MW	Megawatt (one million watts)
MWh	Megawatt-hour (one million watt-hours)
NAESB	North American Energy Standards Board
NEMA	Northeast Massachusetts
Nepool	New England Power Pool
NERC	North American Electric Reliability Council
NGX	Natural Gas Exchange (in Canada)
NP-15	North of Path 15 (in CAISO)
NPC	National Petroleum Council
NPCC	Northeast Power Coordinating Council (NERC region, geographically includes ISO-NE and NYISO)
NREL	National Renewable Energy Laboratory
NWPP	Northwest Power Pool (NERC subregion)
NY	New York
NYC	New York City
NYISO	New York independent system operator
Nymex	New York Mercantile Exchange
NYPP	New York power pool
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and maintenance
OMOI	Office of Market Oversight and Investigations (FERC)
OOM	Out of market
OOS	Out of sequence
OTC	Over the counter
PA	Public power authority
PG&E	Pacific Gas & Electric
PJM	PJM Interconnection
PPA	Power purchase agreement
PSC	Public service commission
PTC	Production tax credit
PUSH	Peaking Unit Safe Harbor
PX	Power Exchange (formerly in CAISO)
REC	Renewable energy credit
RMPA	Rocky Mountain Power Area (NERC subregion)
RMR	Reliability must run
RPS	Renewable portfolio standard
RSI	Residual supply index
RT	Real time
RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission organization
RTS	Real-time scheduling
SBC	System benefit charge
SCADA	Supervisory control and data analysis
SCE	Southern California Edison
SERC	Southeastern Electric Reliability Council (NERC region; includes Entergy, Southern, TVA, and VACAR)
SoCal	Southern California Gas Co.

SP-15	South of Path 15 (in CAISO)
SPP	Southwest Power Pool (NERC region)
SWCT	Southwest Connecticut
TLR	Transmission loading relief
Transco	Transcontinental Gas Pipe Line
TVA	Tennessee Valley Authority (NERC subregion)
VACAR	Virginia-Carolinas area (NERC subregion)
VAP	Dominion-Virginia Power
VIU	Vertically integrated utility
VRD	Virtual regional dispatch
WECC	Western Electricity Coordinating Council (NERC Region)
WUMS	Wisconsin-Upper Michigan subregion
ZP-26	Zone at Path 26 (in CAISO)

Analytic Note on Net Revenue Calculations

The State of the Markets Report includes analyses of net revenue for electric generators. In general, net revenue is the revenue that a hypothetical new plant could have earned from all sources during the year less the running cost of operating the plant. Comparing it to the annualized capital cost of building such a new plant is a rough measure of the attractiveness of investment.

We assumed the new facility would be a combined cycle or combustion turbine natural gas plant because those are normally the most economic to build relatively quickly.

Revenues. In most cases, the bulk of the revenues for a hypothetical plant would come from the energy market. A plant can earn money from the energy markets in all time periods when the spark spread between natural gas and electric power prices is above a break-even threshold, based mostly on the heat rate of the plant. To estimate revenues, we:

- Calculated spark spreads as the difference between the spot price of power and the spot price of gas in the region (as reported in Platts Megawatt Daily and Gas Daily), multiplied by the appropriate heat rate conversion in MMBtu/MWh.
- Assumed a heat rate of 7,000 MMBtu/MWh for combined cycle plants and 10,500 MMBtu/MWH for combustion turbines.
- Subtracted an estimate of operation and maintenance expenses of $1/MWH for combined cycle plants and $3/MWh for combustion turbines.
- Summed all the positive results. This provides an estimate of the amount of money the plant could have earned if it operated during all periods when it would have been profitable to do so.

For regions with capacity markets (the northeastern RTOs), we considered the revenue a plant could have made from the capacity market, based on prices published by the RTOs.

We did not include estimates of what a plant could have earned from ancillary service markets. Except for combustion turbines in New England, these revenues appear to be small compared to the cost of a new plant.

Cost of a New Plant. Estimates of the cost of building a new plant vary widely. We used Energy Information Administration (EIA) cost characteristics, combined with regional adjustors as published in EIA's Annual Energy Outlook 2005. These estimates tend to be lower than many estimates for new plant costs. Based on discussions with EIA, we created annual revenue targets for a new plant, assuming:

- A 45/55 debt/equity ratio
- 11.25 percent weighted average cost of capital
- 2 percent inflation
- 38 percent tax rate
- 20 year debt term
- 20 year depreciation term
- 16 percent return on equity.

Comparison. We divided the revenue estimate by the annual target for a new plant to produce a ratio. This ratio indicates whether a plant would have been profitable for 2004 – greater than 100% would appear to have been profitable.

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State of the Markets Report

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Industry Overviews and Essays

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Natural Gas Markets

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Evaluation Form

To improve future State of the Markets Reports we strongly encourage comments.

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Area of focus (e.g., gas, electricity, both)

Contact information

Did you find this report useful? (Circle 1-10, 1=not useful at all, 10=very useful)

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Please return form to the address below or e-mail comments to SOM.2004@FERC.gov.

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