DERAILMENT IN WYOMING (2005)

http://www.bigcountry.coop/coal.html

[Johnson, 2005] Steven Johnson, "Derailments, congestion on tracks in Wyoming present problems for G&Ts", Electric Co-op Today, July 2005.

"A bottleneck in shipments from the nation's most important vein of low-sulfur coal has cut into coal supplies for electric co-ops and other utilities, and could lead to an increase in the price they pay for power.
Track damage caused by two major derailments earlier this year has produced congestion along a 100-mile stretch of railroad that the Union Pacific and BNSF Railways use to transport coal from Wyoming's Powder River Basin.
The rail carriers attributed the accidents to heavy rain and snow, saying built-up coal dust in roadbeds prevented water from draining properly.
They started July 6 to replace defective ties and tracks, a process that Union Pacific spokesman Mark Davis said will take about five months.
Until then, though, shipments are down, prices are up, and some G&Ts are looking for other ways to handle summer air-conditioning needs.
"We usually rely on coal-based power plants to meet the demand in the summertime," said Rob Roedel, manager of corporate communications for Arkansas Electric Co-op Corp., Little Rock.
"Now, we're relying more on natural gas-fired plants, and purchasing market power to make up the difference is substantially more expensive," he said.
Arkansas Electric has sufficient power for the summer, although it has imposed coal burn limits at its White Bluff plant, located outside of Redfield, and its Independence plant, near Newport.
The higher fuel costs will have to be passed to its 16 distribution co-ops, and ultimately to more than 460,000 consumer-members in Arkansas, Roedel said.
At Sunflower Electric Power Corp., Hays, Kan., officials are monitoring shipments and anticipate that coal reserves could be lower than projected at the end of the year. "We're in pretty good shape, but it's something that we¹re keeping an eye on," said Steve Miller, senior manager for external affairs.
Dairyland Power Cooperative, La Crosse, Wis., which gets about 50 percent of its coal via rail, also is feeling the effects of the delays, spokeswoman Deb Mirasola said. "We're being impacted, but we do have sufficient generation," she said.
Rail failures and delays meant shipments from the Powder River Basin were down by 5.2 million short tons through June, and could fall 17.1 million short tons of initial projections for 2005, the Energy Information Administration said.
With tight supplies and high demand, spot market prices for Powder River Basin coal jumped 4.4 percent in just one week last month, EIA reported.
Utilities value coal from the Powder River Basin because it burns more cleanly than coal with higher sulfur content that is mined in other parts of the country.
Demand is so strong that Union Pacific declared an embargo July 18 on contracts for transportation from the southern Powder River Basin rail line, because shippers tried to lure extra deliveries of coal by offering the railroad more money than required by their contracts.
One federal official suggested the problem could cause brownouts on the power grid if it is not solved soon.
"There is the possibility, of course, that individual utilities that were low on stockpiles for whatever reason may find themselves short now," said Roger Nober, chairman of the Surface Transportation Board. "We want to avoid—if at all possible—utilities running out of coal and having to brownout."

http://www.usatoday.com/money/industries/manufacturing/2005-08-24-coal-usat_x.htm

E. B. Smith, "A mountain of coal waits for a ride**", USA TODAY**
A heavy snowstorm blanketed Wyoming's coal-rich Powder River Basin on May 11 just as the white-capped Big Horn Mountains to the west had begun to thaw. Icy water and coal dust merged into a thick, dirty slurry and oozed across large swaths of a 100-mile section of railroad freight track that is shared by the Union Pacific and Burlington Northern & Santa Fe railroads.

It is the world's most-heavily traveled track. Ten giant coal mines in Wyoming produce nearly 40% of the U.S. supply. And coal powers more than half of U.S. electricity generation. But the streaming sludge undercut bridges and switches, pushed steel rails out of gauge and destroyed concrete ties. Fifteen coal cars of a Burlington Northern train derailed May 14. A few hours later, 28 cars of a Union Pacific train derailed.
Today, the economic pileup stretches from federally leased mines in remote northeastern Wyoming to population centers throughout the East, Midwest and South, revealing how dependent the USA has become on its newly emerging Western coal belt.
Spot-market prices for the basin's coal are up nearly 70% year to date. That has contributed to the feverish run-up in energy prices, which threaten to sap the U.S. economy. During a summer heat wave that has sent electricity demand soaring to records over the past month, the interruption in coal supplies recently turned critical. If hot weather persists into September, brownouts are possible, energy analysts say.

Paul Lang, 44, president of Arch Western Resources, a subsidiary of Arch Coal, and, until recently, the chief of its Wyoming operations, says the rail disruption created a classic economic "panic" as hysteria-driven demand overwhelmed the already burdened supply chain.
Major electric utilities hoarded their dwindling caches of coal, which are nearing historic lows. The big mine operators squabbled with the rail companies over how to resolve the transportation bottleneck. And the rail companies, while starting major repairs, bickered over who might be taking advantage of the situation.
Pat Hemlepp, a spokesman for American Electric Power, which serves 5 million customers in 11 states and is the USA's biggest coal consumer — burning 75 million tons a year — says the utility expects to receive only 80% to 85% of its contracted deliveries from the basin this year. AEP intends to pass about 70% of the higher costs to its customers while the other 30% "will hit our bottom line," Hemlepp says. So far, consumer electricity prices have risen 6% nationally after climbing just 1.5% last year, according to the Bureau of Labor Statistics.
The USA's largest coal company, Peabody Energy (BTU), recently reported a triple-digit increase in second-quarter profit — citing the dramatically higher coal prices — but both it and the No. 2 producer, Arch Coal (ACI), acknowledged being unable to ship 7.3 million tons of basin coal between them in the quarter. They are grappling with a rail backup that could persist until next spring.
100-year supply
On the high plains, amid herds of wild antelope, mule deer and elk, the Powder River Basin is estimated to possess a 100-year supply of coal at the nation's consumption rate of 1 billion tons a year. It is the USA's greatest fossil energy resource. Its reserves stand in powerful contrast to the dwindling supplies extracted from 1,500 mostly small, rapidly depleting mines in the rest of the country from Appalachia to Washington state.
Discovered in 1842 by Army surveyor John Fremont, Wyoming's coal began to be commercially extracted in 1869 after the arrival of the Union Pacific railroad. For a century, most of that coal fed the railroads. Annual production topped out at 10 million tons in the 1950s, according to the Wyoming Mining Association. As railroads switched to diesel fuel, demand for the state's coal dipped under 2 million tons a year in the late 1960s. Then, the Arab oil embargo prompted Congress to open the untapped Powder River Basin to exploration in 1973. The state's production rose again, as more coal-fired electricity plants were built. Today, some of the basin's low-sulfur coal burns so cleanly that utilities use it to claim environmental credits under the federal Clean Air Act, a financially lucrative practice that led to the creation of a secondary trading market.
Arch Coal's Lang arrived in the early 1990s from a mine-engineering job in West Virginia. He describes the coal reserves he found as "staggering." In West Virginia, he says, "We were mining, literally, coal seams of 6 to 12 inches. And here I was standing in a 75-foot seam."
Today, Gillette, Wyo., with a population of about 23,000, has emerged as the citadel of the state's energy boom. Walls of unmined black rock rise up to 100 feet just outside town, where the coal has been exposed on the arid plain. Several big coal companies, along with natural gas and methane gas drillers, have crowded into town, setting off a boomlet in home construction and ringing the cash registers at chain restaurants.

About 5,000 coal mine workers in surrounding Campbell County earn $65,000 a year, on average. Its coal mines produce nearly $1.2 billion in state and federal taxes, generating one of the few state treasury surpluses in the country. The state is investing $700 million more in one-time coal-rights payments to upgrade its schools, according to Marion Loomis, executive director of the Wyoming Mining Association.

Arch's Black Thunder mine, the world's largest coal mine, initially was expected to produce 10 million tons a year. That estimate dramatically understated demand as nuclear- and natural gas-powered electricity fell from favor: nuclear power due to environmental concerns and natural gas because of price. "Now it's getting close to 100 million tons, which is about 10% of U.S. coal production," Lang says.

All told, the basin produces nearly 400 million tons of coal a year, according to Loomis.

At Black Thunder, big earth-scraping equipment nicknamed "Ursa Major" — the Big Dipper — is used to extract three tons of coal a second. Normally, the mine loads 25 miles of coal cars each day of the year, delivering the daily energy equivalent of 750,000 barrels of oil.

But, Lang says, "What hasn't changed at the mine site is the coal-storage capacity. We can only (hold) about 12 to 14 hours of (production). ... When the rail disruption occurred, it started to disrupt the mine."

Problems have been ongoing

The basin's coal-storage and transportation network has not kept pace with the staggering growth in demand. "Even before the train derailments, there were transportation issues affecting getting the coal out of the Power River Basin because they don't have adequate rail infrastructure in place," says Britt Burt, vice president of production research at Industrial Information Resources, a market intelligence firm.

In a statement, Arch spokesman Deck Slone said, "It's imperative that the railroads make the necessary investment in their infrastructure so we can take advantage of our coal resource base."

Burlington Northern spokesman Richard Russack responds that the company has invested $2.5 billion over the last 10 years under "an aggressive program" to support the basin's transportation network. A Union Pacific spokesman referred a reporter to the company's public statements. Meanwhile, the railroads are sniping over each other's access to the crimped network.

According to Union Pacific's public updates on rail repairs in the basin, the companies have begun to remove coal dust on 100 miles of roadbed and are replacing 37,000 ties on 14 miles of track. The maintenance work lasts up to 16 hours a day, reducing some double-tracked areas — sections where two trains can travel at a time — to single tracks, Union Pacific says. Some areas are triple tracked.

"The ultimate solution," says Arch's Lang, "is they have to put more triple track in."

Jim Thompson, managing editor of the Coal and Energy Price Report, promotes an alternate solution. "If the United States had an adequate (transmission) infrastructure," he says, "it would be possible to wheel that coal by wire." That is, generate the electricity in the Powder River Basin and transmit it nationwide on high-voltage electrical lines.

By the end of next week, the rail companies say, they hope to restore Basin shipments to pre-blizzard levels, despite weather-related track damage that won't be fully repaired until late this year or early next. But the companies have been unable to make up the lost shipments or add capacity equal to demand. The federal Energy Information Administration projects a 2.4% increase in U.S. demand for coal-fired electricity this year and a 2.1% increase next year. That's atop a 25% increase in global demand for coal over the past three years.

"There's not a lot out there that's going to allow prices to fall," says Platts energy analyst Andy Roberts.

Utilities take drastic steps

For now, some utilities have taken the drastic conservation step of cycling their coal-fired plants; turning them on and off. But cycling plants designed to run uninterrupted for a year or more adds heavily to their maintenance and shortens their life expectancy, says Industrial Information's Burt.

Some utilities are turning to natural gas, even though the Energy Information Administration says it costs $6.42 to produce 1 million British thermal units of electricity from natural gas, compared with $1.49 for coal.

"There is a lot of gas-fired capacity that sits around not getting used. That could end up being an important factor over the next decade," says Martin Edwards, vice president of legislative affairs at the Interstate Natural Gas Association of America, which represents transmission companies.

Without substantial investment in new rail and transmission lines, however, higher energy costs and even more transportation backups appear inevitable. The Energy Department reports that 124 new coal-fired electricity plants are under development for completion in the next decade, potentially increasing U.S. coal consumption by another 270 million tons, or 25%.

"Here's this 1,800-year-old industry — maybe not the oldest profession — but growing at 25%," says Peabody spokesman Vic Svec. "That's stunning even to people in the energy field."

http://archive.columbiatribune.com/2005/Aug/20050823Busi011.asp

Utilities face coal bottleneck
Some bide time, some raise rates.
Published Tuesday, August 23, 2005

KANSAS CITY (AP) - As utility companies across the Midwest have updated investors about their operations over the past month, there's been one constant - an eye toward slower shipments of coal used to fire up electric generators.

A pair of train derailments in May and subsequent repair work on the rail line coming out of the Powder River Basin of Wyoming, one of the nation's prime sources of coal, has reduced shipments between 10 and 15 percent as a hot summer has pressured utilities to crank out more watts.

The reaction has ranged from some companies saying they have enough stockpiled coal and are merely monitoring the situation to others which are already increasing customers' bills as they switch to more expensive natural gas or buy extra power on the open market.

"I'd say most utilities are in that first group," said Jason Cuevas, a spokesman for the Edison Electric Institute in Washington, D.C. "Their stockpiles are a little lower than they'd like but, realistically, it isn't a concern."

For example, Columbus, Ohio-based American Electric Power Co., the nation's largest purchaser of coal, said moving coal from eastern states flush with Appalachian coal and other methods have kept operations stable.

"Obviously it's not ideal and creates more challenging coal management issues on our side, but we have been able to manage it," said spokeswoman Melissa McHenry.

But Cuevas said companies that are extremely dependent on Powder Basin coal, either because of geography or because of its lower polluting qualities, could be seeking higher rates for customers by the end of the summer.

"Not to use a cliche, but we're looking at a 'perfect storm' scenario with the problems in rail use, a hot summer and demand for coal up across the board," he said.

Among the hardest hit are Alliant Energy Corp. and Xcel Energy Inc., both of which are looking to customers to help pay their higher operational costs.

Alliant, based in Madison, Wis., and serving 982,000 electric customers in three states, is asking state regulators in Wisconsin for permission to raise rates and recover between $14 million and $22 million in additional costs for its Wisconsin Power & Light subsidiary.

Xcel Energy, based in Minneapolis and serving 3 million customers in 10 states, said in its most recent quarterly filing that it was already buying power from third parties and increasing its use of natural gas to fuel its power plants, as well as reducing the amount of power it sells to other utilities.

The problems date back to May 14 and 15 when two coal trains derailed at different points on the rail line between Wright and Douglas, Wyo., which annually transports 370 million tons of coal, or almost a third of the nation's supply.

The rail line is owned and operated jointly by Burlington Northern Santa Fe Corp. and Union Pacific Corp. The railroads have begun a series of repairs along a 100-mile length of the line, which are expected to be completed by November.

Arch Coal Inc., a St. Louis-based company that owns the largest mine in the area, said it shipped four million fewer tons of coal in the second quarter than it expected because of bottlenecks on the railroad.

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http://www.casperstartribune.net/articles/2005/08/03/news/wyoming/02ac41bf71c385fa8725705100787259.txt

Wyo coal prices keep surging August 3 2005
By MATTHEW DALTON
Dow Jones Newswires

NEW YORK -- The price of coal mined in Wyoming's Powder River Basin continues to surge following train derailments that have limited shipments to power plants across the United States.

Basin coal prices for next-month delivery have risen 16 percent over the last seven days to about $11 a ton, as power plants across the Great Plains, the Midwest and the South struggle to keep their inventories above dangerously low levels.
"There are many people who are concerned about running out of coal," said Duane Richards, chief executive of the Western Fuels Association, a cooperative that buys coal for rural electric utilities. "We have some plants that have adequate inventories, but most are lower than where they'd like to be."
Average stockpiles of Wyoming coal had fallen by the end of June to 40 days worth of fuel, about 32 percent lower than normal levels at the beginning of previous summers, according to a power plant survey conducted by Energy Ventures Analysis, an energy consulting firm.
"The utilities definitely need to do some rebuilding of their PRB stocks," said Ralph Barbaro, a principal at Energy Ventures Analysis.
Two train derailments in early May on a stretch of track jointly operated by railroad giants Union Pacific Corp. and Burlington Northern Santa Fe have reduced coal shipments from the basin by at least 5 million tons, assuming shipping levels immediately before the derailments, Barbaro said. The lost shipments may actually be as high as 10 million tons, assuming the peak levels that prevailed in March.
The railroads have restored shipments to pre-derailment levels and have actually shipped more coal so far in 2005 than in the first six months of 2004, but that hasn't been enough to make up for lost shipments and increased demand from nontraditional users of Powder River Basin coal.
The derailments came at an inopportune time for electric utilities. Extreme heat swept across much of the country during July, prompting record demand for electricity, according to the Edison Electric Institute, the utility industry's main trade group. The hot weather could leave power plants with especially low stockpiles exiting the summer, Barbaro said.
And with more power plants in the Midwest and even the East looking to burn Wyoming coal because of its low cost and low sulfur content, utilities may not be able to rebuild their stockpiles until after next year, Barbano said.
"With the additional demand that's projected to come on line next year, it's going to be tough on the producers to meet all that demand in 2006," he said. "It make take until 2007 to rebuild those stockpiles."
Prices for all delivery periods of Wyoming coal have surged recently, but the prompt month delivery price has risen the most and for the first time in at least a year exceeded delivery prices for the next quarter and the next year. Market observers say this reflects the market's belief that near-term prices will cool somewhat when coal companies are able to ship more coal.
"Prices will never go back to $5 a ton, but we'll see a leveling off," Richards said.
A number of utilities have taken steps to conserve their coal to head off shortages. Xcel Energy Inc. has said it will rely more on natural gas-fired generation and power purchased from outside generators. Entergy Corp. has also said it will rely more on off-system power purchases to serve customers, while Alliant Energy is purchasing off-peak power to conserve its coal for fueling its own generation during peak hours.

http://www.utilipoint.com/issuealert/article.asp?id=2560

Coal Shipments Derailed - By Bob Bellemare
Daily IssueAlert
8/30/2005
Utilities are feeling the strain of a train derailment in the West that occurred after heavy weather in late winter and early spring. Coal inventories at many power plants were already at low levels because the high price of natural gas had coal-fired power plants running at full capacity. Now, with shipments from the Power River Basin (PRB) of Wyoming and Montana constrained, utilities curtailing coal generation and switching over to more costly generation to conserve supplies. Customers will feel the pinch in their wallets as the higher fuel costs are passed along through fuel cost adjustments in their electric rates.
The Rail System
The U.S. railroad freight industry is nearly a $40 billion annual business with coal making up about 40 percent of ton-mileage total of shipments. The coal found in the PRB region of Wyoming and Montana is a desirous

fuel for many utilities because of its low sulfur content and makes up about 35 percent of all coal burned in U.S. power plants. The coal is shipped long distances, primarily to power plants in Illinois, Texas, Wisconsin, and Missouri, and as far away as New England and Florida.
The two primary carriers in the PRB region are BNSF Railway and Union Pacific Railroad. While the rail traffic is heavy, there are a limited number of rail lines originating from the region. BNSF and Union jointly own rail lines emanating from Gillette, Wyoming. The South Power River Basin Joint Line (SPRBL) represents the busiest and highest density freight railroad in the world.

According to company reports, on Saturday, May 14, 2005, a BNSF train derailed 15 cars approximately 6 miles north of Bill, Wyoming, on the SPRBL. The next morning a Union Pacific coal train derailed 28 cars approximately 19 miles north of Bill, Wyoming, on the Joint Line. The two derailments are suspected to have been caused by severe weather and coal dust that had settled under the tracks. The eastern half of Wyoming experienced heavy rainfall and snow this past spring, including a major spring snowstorm on April 21 that virtually shut down mining operations in the Basin. On May 11 two inches of rain fell on the area followed by 6 inches of snow. Another contributing factor was the long-term accumulation of coal dust on the track which reduces water drainage thereby deteriorating the track structure. Photos of the rail problems can be found at http://www.uprr.com/customers/energy/sprb/photos_orin_1.shtml#.
As a result of the derailments the railroads ability to fulfill their contractual shipment obligations is limited to about 80 to 90 percent of normal. BNSF and Union Pacific agreed that postponing major rehabilitation work was not an alternative and that the best solution was to immediately remove coal dust from the roadbed and to replace several miles of ties and track. Extensive maintenance and track repair are expected to run through November 2005 with some maintenance and repair work to be carried over into next year.
BNSF is using two undercutters and a tie and rail replacement machine to perform track repair and maintenance. The coal dust will be removed from approximately 100 miles of roadbed and the ties and rail will be replaced on approximately 14 miles of track. Union Pacific reported on August 25, 2005 that maintenance activity shifted to "undercutting," which cleans coal dust out of the rock ballast supporting the track structure. They claim the primary cause now for reduced coal shipments has shifted from railroad repairs to the inability of mines to load trains, although Union experienced another train derailment in August caused by high winds. Since the beginning of August, 70 percent of the missed trainloads are attributable to mines unable to load trains for a variety of reasons, ranging from landslides in the pits, to no coal inventory, to equipment upgrades. Union Pacific reported it was able to fulfill 89.3 percent of its contracted demand in the month of July and is currently tracking at 85.62 percent of demand through August 15. Union Pacific is allocating coal proportionately among its customers based upon trains loaded as a percent of total train demand.

Utility Customers Pay the Price

The rail companies have ridden through the derailments without much impact on the bottom-line. BNSF, for example, recorded coal revenues of $1.2 billion for the first six months of 2005, an increase of $116 million, or 11 percent, versus the same period a year ago. Average revenue per car increased 9 percent, primarily driven by contractual rate escalations, fuel surcharges and increased length of haul. Year-to-date net income was $361 million versus $323 million for the same period in 2004.
For utilities, however, the high U.S. demand for low-sulfur PRB coal has left little room for unplanned repairs to the rail lines, particularly in the summer when power demand is highest. And it's not a simple matter of just switching to some other coal. Coal comes with wide variation in physical and chemical characteristics and power plants are "tuned" to burn a specific blend of coal.
Fortunately the decreased western coal shipments are not expected to impact electric reliability. In late July the North American Electric Reliability Council (NERC) sent a letter to the 10 NERC regions requesting they assess the potential reliability impacts of the reduced coal shipments. The regions reported back that the anticipated impacts would not be reliability but financial as the delivery shortfalls would be made up by increasing the use of non-PRB coal, reducing the use of coal in off-peak hours, and switching to natural gas generation.
With western coal shipments down, upward pressure is being felt on the consumption and price of natural gas as well as the price for deliverable coal from other regions. This "substitute" coal from eastern regions will typically have higher sulfur content which also puts upward pressure on sulfur dioxide emission allowance prices.
For some coal merchant power plant owners like Midwest Generation, a subsidiary of Edison International, the impact has actually been a positive. The high natural gas prices and increased off-peak power purchases are

boosting wholesale electric prices. According to Dow Jones & Company, Midwest Generation reported $2.2 million in net income for the second quarter, compared with a loss of $63 million in the second quarter of 2004. While Midwest produced less electricity in the quarter, it realized an average price of $41.83 a megawatt- hour (MWh), compared with $24.89 in the same period last year. Exelon Corp. is another company that is claiming a financial benefit. It cited higher off-peak power prices in the Midwest as part of its explanation for a $300 million jump in net revenue from wholesale power sales in the second quarter from the year before.

But not all generation owners are so lucky. Wisconsin utilities Alliant, WPS Resources, and Wisconsin Energy have reported using coal generators less at night to conserves supplies. Wisconsin Energy burns about 12 million tons of coal a year, 9 million from the Powder River Basin. Xcel Energy with utilities spanning from Colorado to Minnesota is switching over some of its generation to natural gas fired plants to conserve coal. Entergy was reported in NGI's "Power Market Today" as adjusting its power plant dispatch in off-peak periods to reduce coal use. Rick Smith, group president for utility operations at Entergy was reported as saying in a call with analyst that "The transportation companies we're dealing with have reduced the trains moving this way to about 80 to 85 percent, but based on our wholesale market, we've been able to adjust our dispatch to really offset that and have stabilized our inventory levels at a very acceptable level …We have fuel clause mechanisms in all the jurisdictions, so we just pass that through to the customers … It's not a big change for us because the off-peak period, which is really where we're adjusting the dispatch, really there's still pretty favorable generation costs out there in off-peak."

Passing along any increase in fuel cost to customers is what many utilities are planning on. Utilities commonly have a "fuel clause" that can be adjusted to reflect actual fuel costs. Investor Owned Utilities (IOUs) justify any changes in fuel related charges to state regulators, so there is some risk to the utility that state regulators may find a portion of the increased cost as imprudent. That's not likely in this case since the coal shortage was created by an action not reasonably within control of the utility.

Take Xcel Energy, which notified commercial and industrial customers in a letter to expect a jump in fuel costs, although the exact amount of the increase is unknown. The initial projected wholesale fuel cost adjustment factor in Texas for July was 4.1 cents per kWh (kilowatt hour) but because of the coal constraints it was later projected that the fuel cost adjustment might increase by as much as 20 percent, but now they hope the impact will be less than that amount.

Wisconsin Power & Light, an Alliant Energy Corporation subsidiary, reported that it expects to ask regulators to recoup $14 million to $22 million in higher power costs from customers.

With the peak electricity season coming to an end it looks like utilities have been able to adjust their generation plans sufficiently to avert severe financial impacts from the coal shipment problems. Much work remains, however, to achieve a full recovery. Once full capacity is restored many utilities will need to replenish stockpiles, continuing a strong demand for coal well into 2006.

CALIFORNIA NATURAL GAS CRISIS (2000)

http://cacx.org//reports/2000-11-22_200-00-006.PDF

California Natural Gas Market Analysis And Issues
Bill Wood, Leon Brathwaite, Jairam Gopal, Todd Petersen,
Fuel Resources Office
Energy Information and Analysis Division
California Energy Commission
NOVEMBER 2000

Over the past six months, natural gas prices at the wellhead have far exceeded the price levels suggested by long-term market fundamentals. Prices at the California border have also been at record levels, considerably higher than any other part of the country. For instance, the natural gas price at the Topock border crossing (Arizona to California), where gas from the southwest producing regions enter the state, was $4.40 per MMBtu in June 2000 compared to prices of about $2.40 per MMBtu a year ago. Further, following the explosion of the El Paso natural gas pipeline segment in New Mexico on August 19, 2000, prices rose an additional $2.00 per MMBtu reaching about $6.40 per MMBtu. The cost of natural gas to the state is nearly $15 million more per day than in June 2000 and nearly $30 million per day higher than a year ago. In 1999, total natural gas expenditures averaged about $18 million dollars per day. While summer prices far exceeded long-term price trends, supply and demand expectations for the coming winter have already pushed California border prices above $10.00 per MMBtu.

In December 1998, Northern California experienced a series of very cold days and natural gas supplies were beginning to run short due, in part, to increased gas demand in the Pacific Northwest, which reduced the amount of gas delivered to California at its northern border by 200 MMcfd. To meet its commitments to firm supply customers, PG&E issued a call on its option to purchase gas from one of its large customers based on contractual agreements. Even with this additional supply, PG&E was forced to reduce natural gas service to 80 of its customers over a three-day period. While no natural gas service to central electric generation facilities was curtailed, several cogeneration facilities were forced to leave the gas utility system for a period of time.

During the same cold spell, one of the nuclear electric generation units was down at the Diablo Canyon power plant. The combination of natural gas curtailment and electricity generation capacity shortage forced the ISO to issue a Stage Two Emergency. This required PG&E to initiate voluntary interruption of its electric service to several of its electricity customers. With all new electricity generation facilities dependent on natural gas, the PG&E December 1998 situation may become more commonplace in the future if corrective measures are not taken. Integrated electric and gas supply and demand analysis is needed. The growing reliance on natural gas for power generation may imply that coincident demand for electricity and gas should be determined, electric generation and transmission line capacity evaluated, and gas supplies and pipeline needs assessed. The natural gas industry should be informed of these results so that they can make the necessary system adjustments.

In competitive markets, price increases are not uncommon. Weather conditions, unexpected disruptions, and natural events may all contribute to upward pressure on prices. As a result, price fluctuations are anticipated and market participants usually take appropriate actions to mitigate such price or supply excursions. However, these temporary price spikes may generate high levels of concern throughout the market. Such is the current situation in North America, and particularly in California, as we prepare for the winter season. Natural gas spot prices far exceed the Energy Commission s long-term cost-based price trends. California, as well as the rest of the nation, is experiencing abnormally high natural gas prices this year. During the year 1999 the average wellhead or commodity cost for natural gas was about $2.00 per MMBtu. Since the first of the year, natural gas commodity prices at the California border have increased, rising to about $4.30 per MMBtu in June/July 2000. Following the El Paso Pipeline rupture in mid-August, natural gas prices delivered to the California border peaked for a short time at over $7.00 per MMBtu, before retreating to $6.40 per MMBtu. Supply and demand expectations for the coming winter have already pushed California border prices above $10.00 per MMBtu.

Finally, with the loss of one of El Paso s pipelines in the August 2000 rupture, California deliveries dropped by 400 to 700 MMcfd. This reduction forced SoCal Gas to withdraw more gas than normal from storage to meet

customer needs. The reduction in delivery coupled with the knowledge that the supply drawn from storage would need to be replaced before winter season apparently pushed gas prices to $7.00 per MMBtu at the California border. California has been paying a premium well above the basis for its natural gas supplies. The term basis is the difference in price for natural gas when it enters a pipeline from a producing area and its price when it arrives at its destination.8 Normally the basis is the cost added for pipeline transportation. For most of the U.S., this is the case. However, for California prior to the El Paso rupture, the basis was about a $1.00 per MMBtu over the cost to transport. After the El Paso pipeline rupture on August 19, 2000, the basis to California jumped to $2.00 or more over transport costs. This $2.00 jump in prices is costing California ratepayers approximately $15 million per day. Additionally, the increase in natural gas prices at the California border following the El Paso rupture added another $15 million to California s daily cost. So, the current high natural gas prices seen at the state s border has cost consumers about $30 million per day more than last year. The typical bill for natural gas on an average day in 1999 was about $18 million per day.

http://www.sen.ca.gov/sor/reports/REPORTS_BY_SUBJ/ENVIRONMENT_NATURAL_RESOURCES/FYINATGAS.HTML

FYI: Natural Gas Issues in California
Kip Wiley
Reasons for Recent High Prices
There are three main reasons for the rising natural gas prices in California.
The first is connected to the tight supply-and-demand balance of natural gas nationally. Low wellhead prices and buyers' over-reliance on spot-market purchases over the last several years did not stimulate sufficient drilling to match the growth in demand. Over the last 10 years, an average of 454 rigs were drilling for gas each year. That number dropped to 371 in April 1999 and, with higher natural gas prices, has recently risen to over 800.
The second cause is the lack of extra pipeline capacity for delivering added natural gas to California. Until a rupture on the El Paso pipeline on August 19, 2000, pushed prices up in California, they had been in line with the rest of the nation. Then they rose again with perceived supply shortages in SoCal Gas's service area at a time when pipelines were running at full capacity, spurring withdrawals from storage.
When SDG&E was forced by these circumstances to curtail supplies to its non-core customers on November 13, 2000, natural gas prices rocketed up to over $60 per million BTUs. These prices impacted the entire West Coast from California to British Columbia.
The California Independent System Operator then placed a $250 per megawatt hour soft cap on electric prices. This limited the cost of electricity Cal ISO would pay to $250 per megawatt hour but would allow higher prices if their cost could be verified. Within a week, natural gas prices fell from the $60 range to between $10 and $20 per million BTUs.
The third cause is related to the purchase strategy for natural gas employed by one or more of the state's natural gas utilities. Past natural gas purchase-cost disallowances by the PUC, gas cost-incentive rate mechanisms, and the low spot-market prices lulled buyers away from a portfolio approach to supply and pipeline-capacity management.

http://www.ucan.org/law_policy/energydocs/gasoutlook.htm

THE NATURAL GAS EXPLOSION
Beginning in the summer of 2000, natural gas became expensive in the summer months because of the high cost of electric generation. So the utilities did not fill up all of their core storage allotments; they tried to skate a little bit and hope for better times ahead. The non-utility power generation sector (a polite term for the most sophisticated electric and gas conglomerates in the United States) and industrial customers decided that storage wasn't necessary at all and bought almost none of it for the winter of 2000.

Then two things happened which presaged the coming winter disaster. It centered around El Paso Natural Gas pipeline. The first was El Paso's controversial decision to sell off all surplus pipeline capacity to an unregulated affiliate for a fixed price. El Paso Natural Gas last spring sold a huge chunk of capacity to its marketing affiliate, El Paso Merchant Energy. [The El Paso affiliate sale got rid of a pesky requirement that El Paso give 35% of revenues from this pipeline capacity back to its firm capacity shippers [and eventually to small core customers in Nevada, Arizona, and New Mexico, and to large non-core customers in California due to different regulatory regimes.] The California Public Utilities Commission has filed a complaint challenging that deal as a violation of FERC's affiliate rules but the FERC has not responded.

Also, around Labor Day there was a huge explosion on the El Paso system that killed several people and knocked a big section of the system out of service for awhile. Prices in California went up immediately, and have never come down. Unfortunately, it is easy to assume that El Paso does not have much incentive to get the work done quickly for while it loses money on the lost throughput, its affiliate is clearly making a killing under the present circumstances. Prices go up for consumers, energy marketers reap windfall profits and the pipelines look innocent.

So now, we have a pipeline system that couldn't fulfill California's needs even at full capacity has now lost at least 5% of its statewide capacity. We have a hungry unregulated merchant marketer prowling around ready to profit instead of a stodgy old utility that had to share its profits with ratepayers.

MISSISSIPPI RIVER FLOOD (1993)

http://lists.uakron.edu/geology/natscigeo/lectures/streams/miss_flood.htm

Mississippi River Flood: 1993
D McConnell - Natural Science Geology, 2000 - enterprise.cc.uakron.edu
http://lists.uakron.edu/geology/natscigeo/lectures/streams/miss_flood.htm
This lecture describes the characteristics of the most devastating flooding disaster in U.S. history, the 1993 Mississippi River flood. After reviewing the material you should know:
A **flood** is defined as the temporary overflow of a river onto adjacent lands not normally covered by water. The most devastating flood in U.S. history occurred in the summer of 1993
The Mississippi River itself is a crucial part of the Midwest's economic infrastructure. Barge traffic normally moves goods through a system of 29 locks between Minneapolis and St. Louis. Barges carry 20% of the nation's coal, a third of its petroleum, and half it exported grain. Barge traffic was halted for two months; carriers lost an estimated $1 million per day. Some power plants along the river saw their coal stocks dwindle from a two-month supply to enough to last just 20 days.

http://www.bts.gov/publications/transportation_statistics_annual_report/1994/pdf/report.pdf

TRANSPORTATION STATISTICS: Annual Report 1 9 9 4
Bureau of Transportation Statistics
U.S. DEPARTMENT OF TRANSPORTATION
January 1994

System Vulnerability:
Impact of the 1993 Midwest Flood
An important indication of the transportation system's reliability is its performance during instances of natural disasters and other large-scale catastrophes. Natural disasters such as floods, hurricanes, and earthquakes have the potential to damage infrastructure severely and disrupt the movement of people and essential commodities. The ability of the system to overcome such disruptions is essential, both to the continuation of national productivity and to the recovery of the impacted area.
This section discusses the impact of the 1993 Midwest flood on the national transportation system. The impacts on the air, highway, waterway, and rail networks are discussed in terms of the number and extent of closures resulting from the flood, the number of MSAs in which closures occurred, the impacts on related industries, and damages to the network infrastructure. (See figure 4-28.)
This information was compiled using Situation Reports generated during the flood by the U.S. Department of Transportation Research and Special Programs Administration along with network databases implemented on a geographical information system. Because the Situation Reports were developed to describe the state of the transportation system during the crisis, rather than for statistical purposes, the accuracy of the data is unknown. Furthermore, these reports only describe the impact on the transportation system during the period from May 24 to September 15, 1993.
Waterway
Effects on Routing and Service.
During the flood, 1,612.2 miles of the waterway network were closed, as follows:
• 789.6 miles of the Mississippi River from Minneapolis-St. Paul, Minnesota, to a point south of St. Louis, Missouri, were closed and/or experienced lock closings.
• The entire Missouri River (669.8 miles) was closed from Sioux City, Iowa, to St. Louis, Missouri.
• The Illinois River was closed from Peoria, Illinois, to the confluence with the Mississippi River (152.8 miles).

In addition to river and lock closings, the Coast Guard imposed speed restrictions in many areas to protect levees from wake damage. Furthermore, draft, lengthof-tow, time-of-day, and type-of-cargo restrictions were also implemented. The waterway network was significantly affected due to lock closings on the upper Mississippi. A total of 26 locks closed from Minneapolis-St. Paul, Minnesota, to Cairo, Illinois, cutting off waterway access to 10 MSAs. From around June 29 to August 19 (approximately 52 days), lock closings occurring at various times made it impossible to traverse the Mississippi completely. (See figure 4-29.) Although the entire Missouri River and sections of the Illinois River were closed, these rivers carry relatively fewer barges than either the Mississippi or the Ohio Rivers and had less of an effect on the waterway system. It is estimated that more than 5,000 barges were affected by extant flooding and river closures. An estimated 1,075 barges were stranded in the Upper Mississippi River; 15 were stranded in the Missouri; and 30 were stranded in the Illinois. Other barges remained in docking bays, and many waited to travel up river.

Impacts on Related Industries.

Barge industry sources indicate that the economic impact on the industry is estimated at $500,000 to $1 million per day. However, it is extremely hard to derive any definitive loss figure, as impact can be calculated either in lost shipping days (loaded barges tied up) or lost opportunity (empty barges sitting idle because of no product to move). Also, the precise number of barges affected is hard to determine because the barge industry has not reported total numbers.

The only estimates available have come from a Corps of Engineers' (COE) database that counted only barges that were tied up to a lock structure. COE did not include those barges that may have been holding in an operator's fleeting area.

The number of barges affected, that is, unable to deliver currently loaded cargo or get to port to load cargo for further movement may be as high as two thousand. Some ocean-going vessels were also affected because cargoes were not readily available for loading.

In addition to waterway disruptions within the region, other parts of the waterway network were affected as well. During the flood, most of the principal U.S flagged liner operators experienced delays of one to six days in cargo arriving at some West Coast ports from the east.

Containers bound for Hawaii missed vessel departures from ports in Southern California. Deliveries to Chicago and further east were delayed by three to five days. Export cargo operations in the New Orleans area also slowed down, as the flow of coal and grains was drastically reduced. Also, stocks on hand at grain elevators dwindled, threatening to close several elevators.

The severe disruption of the barge industry greatly affected the movement of grain in the U.S. Between 150,000 and 300,000 tons of grain shipments that customarily move through the Gulf were diverted to the Pacific Northwest. Also, Archer Daniels Midland, the nation's largest grain processor and third largest barge operator, indicated that flood delays cost the company about $1.5 million per day. Most of their 2,000-barge fleet was tied up on the Mississippi and Illinois Rivers. As a result, shipments had to be diverted to rail at twice the cost, and, in some cases, the company used trucks, which were even more costly than rail.

Railroads

Effects on Routing and Service.

Track washouts, damaged bridges, flooded rail yards, and high water over tracks effectively shut down approximately 3,764 miles of mainline rail service in 18 MSAs. (See figure 4-30.) Still, many rail lines were open, and arrangements between rail companies allowed shipments to be diverted to operational lines. It is estimated that more than 1,000 trains were rerouted over other railroads. However, due to traffic congestion, many cars experienced delays of up to five days. The opening and closing of both freight and passenger service changed daily as water levels rose and fell and as detour routes were negotiated.

The closure of the Atchison, Topeka and Sante Fe mainline bridge over the Mississippi at Fort Madison, Iowa, was one of the most significant mainline closings during the flood. This route is a major corridor for intermodal traffic from the Ports of Los Angeles/Long Beach east and from eastern manufacturing plants to California.

Effects on the Infrastructure. The Association of American Railroads (AAR) issued a preliminary estimate of $109.5-$200 million in rail damages to midwesternClass I railroads:

Washed out track
(50-100 miles) $50–100 million
Track under water
(300-500 miles) $30–50 million
Bridges $15–25 million
Signals $10–20 million

Switches $3–5 million
Rolling stock $1.5–2 million
Still, AAR believes that all major lines will be able to absorb the loss and that none of the costs will be passed on to the shippers through increased freight fares. However, the railroads will suggest a tax relief package. Gateway Western Railroad, which suffered significant washouts and the collapse of a bridge across the Missouri River, estimated damages of around $12 million, approximately 40 percent of its revenue. Gateway Western Railroad did receive some federal assistance from the Local Rail Freight Assistance Program and is temporarily operating trains on tracks owned by other rail companies.
The midwest flood was responsible for the construction of at least one additional link in the rail network. In order to facilitate rerouting, the Union Pacific Railroad, in cooperation with the Atchison, Topeka, and Santa Fe Railroad, constructed a 1,600 foot section of track in Topeka, Kansas, to physically connect the two railroads.
Effects on Other Industries. Ports on the West Coast were affected as trucks and trains were delayed in arriving with export cargoes. Transportation to haul imports east from the ports were consequently in short supply. Because of this equipment shortage and the en route delay of several days in rail movements to the east, some cargo was held in the ports of Los Angeles and Long Beach, creating a backlog of cargo. Also, Ford Motor Co., which uses a just-in-time system to keep its inventory costs low, used airplanes and trucks to replace deliveries that couldn't be made by rail.

http://www.eia.doe.gov/cneaf/coal/coal_ref_pdf/text.pdf

Coal Data: A Reference
February 1995
Energy Information Administration
Office of Coal, Nuclear, Electric and Alternate Fuels
U.S. Department of Energy

In recent years the supply of coal from U.S. mines has averaged about 19 million tons per week. This is more than enough to provide the fuel required to generate electricity for a metropolitan area the size of New York City for about a year. The weekly supply of coal from the mines varies considerably. Sharp rises occur in response to increased demand, including increased use of coal-fired electricity generation to offset declines in generation from other sources. These declines occur, for example, when nuclear power generation drops because of scheduled maintenance, when hydroelectric generation falls during periods of low water, or when coal stockpiles are built up in anticipation of a coal miners' strike. Downward swings in weekly coal production and supply usually are caused by miners' vacations and holidays. Strikes by coal miners and workers involved with coal shipments can sharply curtail the supply of coal from the mines. Delays in delivering railroad cars to the mines can result in a drop in coal shipments. Freezing temperatures can hamper the unloading of railroad cars. Although coal shipped by rail in winter is generally treated with freeze-control agents, this protective treatment can be washed away and the coal can freeze solid in the railroad cars. Coal frozen in railroad cars is thawed in heated sheds and/or mechanically broken into pieces of manageable size. Heavy rains and flooding can also impede mining operations and coal shipments. For instance, from June through August 1993, severe flooding along the upper Mississippi and Missouri river basins disrupted coal deliveries to power plants in about nine Midwest States and to power plants in States beyond that area, because trains were delayed or rerouted around the flooded region. As insurance against a disruption in deliveries, large coal consumers generally maintain a 45- to 60-day stockpile of coal. Large quantities of coal are generally stored in open stockpiles on the ground, piled in diverse forms, such as cones, blocks, and rows. Coal is also stored in covered ground storage—in bins, bunkers, and silos. Year-end coal stocks since 1990 have averaged nearly 190 million tons, equivalent to about one-fifth of the average annual coal consumption. More than 80 percent of the stockpiled coal was at electric power plants.

Since 1960, an average of 1 out of every 10 tons of coal mined has been exported. The amount has ranged widely, from 36 million tons in 1961 to a record 113 million tons in 1981 and totaled 75 million tons in 1993. The 1993 coal exports were the lowest since 1979, a decline generally attributed to a combination of adverse

factors: a slump in the world economy, a strike by the United Mine Workers of America, a slowdown of barge shipments due to flooding in the Midwest, and price competition from foreign coal producers. Although coal was exported in 1993 from 15 States, West Virginia, Virginia, and Kentucky predominated, together accounting for three-fourths of the total.

HURRICANES KATRINA AND RITA (2005)

http://www.msnbc.msn.com/id/9601237/

Natural gas output will take months to restore
WASHINGTON - Heavy damage by Hurricanes Katrina and Rita mean it probably will take months to return offshore natural gas production to normal levels.
Interior Secretary Gale Norton said Tuesday that while the production shortfall will mean high prices for natural gas this winter, there should be no widespread shortages of the fuel. The Gulf Coast produces about one-fifth of the natural gas used by industry and to heat homes, especially in the country's midsection.
Noting that a year ago Gulf oil and gas producers recovered fairly fast from Hurricane Ivan, Norton said at a news conference, "We are not seeing this kind of quick recovery this time around." It may take into next year for some of the heavily damaged oil and gas platforms to be repaired, she said.
The Interior Department said only 10 percent of the Gulf region's offshore oil production and 28 percent of the gas production has been brought back on line. While most drilling rigs and platforms survived the storm, Norton said repairs "clearly will be in the billions of dollars."
Johnnie Burton, director of the department's Minerals Management Service, said it appears the two hurricanes did less damage to underwater gas pipelines than Hurricane Ivan, but a clear assessment of pipeline damage has not yet been made.
"It's primarily a question of how fast (processing) facilities get back on line," Norton told reporters as she gave an update on hurricane damage to offshore energy facilities.
Hurricane Katrina, because of strong storm surges, heavily damaged a number of gas processing plants in the New Orleans area. Rita had less of a surge, but did damaged some onshore facilities in Texas.
On a positive note, Norton said that despite the twin hurricanes' widespread damage and heavy winds that gusted at times to 200 mph over the Gulf, there was no loss of life among some 25,000 offshore oil and gas industry workers and no significant oil spill from underwater pipelines or any of the 3,050 drilling platforms and rigs.
The platforms were shut off in advance and the shut-off valves, located on the sea floor, prevented any spills, said Norton.
But Norton said the storm exposed a possible design problem in the mooring of some drilling rigs. She said the anchors at 19 drilling rigs tore from their mooring when they should have held, causing them to be whipped across the water by the high winds. In one case, such a rig may have collided with a major, 28,000-barrel-a-day drilling platform, destroying it.
The platform, owned by Chevron, was the only large one in the Gulf built after 1988 that was destroyed. Four other major platforms were heavily damaged, Norton said. She said the department plans to meet with industry next month to discuss improvements in rig mooring.
Norton said the storm destroyed 108 older, small drilling rigs that were built before tougher construction standards were put into effect in 1988. Those rigs, which account for about 1.5 percent of the Gulf production, will likely not be rebuilt, she said.

http://www.eia.doe.gov/emeu/steo/pub/contents.html

Short-Term Energy Outlook
Energy Information Administration
September 7th, 2005 Release
The Gulf of Mexico coast region is a major oil and natural gas supply center for the United States with significant offshore oil and natural gas production, refining capacity, and petrochemical facilities, and serves as

a major import hub and nexus for pipeline infrastructure. In the Gulf coast region, Federal offshore crude oil production accounts for 1.5 million barrels per day (29 percent of total U.S. production); crude oil refining capacity accounts for about 8.0 million barrels per day (47 percent of total U.S. production); and offshore natural gas production accounts for about 10 billion cubic feet per day (19 percent of total U.S. production). A significant portion of the Gulf coast's petroleum products—gasoline, diesel, and jet fuel—is shipped to Eastern U.S. markets through the Colonial and Plantation pipelines or transported to Midwest markets by pipeline or the Mississippi River.

Hurricane Katrina caused significant direct damage to offshore rigs, refineries, pipelines, and ports in the Gulf of Mexico , with wide-scale electricity outages and flooding exacerbating the already devastated infrastructure, compounded by the evacuation of thousands of employees. Katrina initially reduced oil supplies by an estimated 1.4 million barrels per day and natural gas supplies by an estimated 8.8 billion cubic feet per day (bcfd) due to shut-ins as well as direct damage. In addition, a bout 1.9 million barrels per day of crude oil refining capacity was shut down as Katrina approached. Following the storm a number of other refineries were forced to reduce operating rates because of disruptions to oil supply and product distribution systems and electricity outages.

Recovery has started and we are seeing daily improvements (see the Minerals Management Service (MMS) and the Department of Energy) with shut-in oil and natural gas production down to 58 and 42 percent, respectively, of pre-Katrina production levels as reported by the MMS on September 6, compared to initial losses of 95 and 88 percent. Electricity has been restored to most refineries, and major pipelines are resuming operations. Actions taken by the U.S. Government, including the loan of crude oil from the Strategic Petroleum Reserve (SPR), the offer of SPR oil for sale, the waiver of the Jones Act to facilitate shipments between U.S. ports, and the nationwide waiver on the requirements for summer gasoline and for low-sulfur diesel, should help alleviate pressure on markets and increase the flexibility of the distribution system. In addition, the International Energy Agency (IEA) directed its member nations to make an extra 2 million barrels of oil per day available to the market for the next 30 days, with half of this contribution to come from United States' SPR. A large portion of the oil from outside of the United States will be released in the form of refined products.

Because considerable uncertainty remains regarding the specific extent of Katrina's damage, it is difficult to provide a single forecast for the upcoming winter and subsequent months as we typically do in the monthly Outlook. More detailed damage assessments should be forthcoming over the next several weeks, which should clarify our forecast. For this month's Outlook, EIA has established three basic scenarios to represent a range of plausible outcomes for oil and natural gas supply over the next several months and through 2006. The three scenarios are: Fast Recovery, which assumes a very favorable set of circumstances for getting supplies back to normal; Slow Recovery, which assumes that significant outages in oil and natural gas production and delivery from the Gulf area continue at least into November; and Medium Recovery, which assumes a path in between Slow and Fast Recovery. In all cases, return to normal operations, in terms of oil and natural gas production and distribution, is achieved or nearly achieved by December. By the end of September all but about 0.9 million barrels per day of crude oil refining capacity is expected to be back at full rates under the Medium Recovery case.

We assume the announce-ments regarding the waivers, and the loans and releases of crude oil and petroleum products have reduced concerns about the adequacy of oil supply in the near term. Consequently, in the Fast Recovery case, average monthly West Texas Intermediate (WTI) prices show no incremental impact due to Hurricane Katrina; the announcements counteract any upward price pressure. In the Medium and Slow Recovery cases, some incremental crude oil price pressure is assumed to remain for up to 3 months. Product prices for all three cases do reflect an impact from the hurricane. The table below provides a summary of the cases with selected outcomes for petroleum and natural gas prices. Unless otherwise noted, the price summary, table and figures in this edition of the Outlook reflect only the Medium Recovery case.

This Outlook focuses on the supply impacts associated with Hurricane Katrina. There are, of course, demand impacts such as reduced electricity and fuel demand related to destruction of or damage to residential and commercial buildings or industrial establishments in Louisiana , Mississippi , and Alabama . In addition, loss of electricity supply due to damaged or impeded electric generating facilities has reduced demand in fuel markets, particularly for natural gas. The hurricane also reduced demand by affected refineries, industrial plants, power generators, and residential/commercial customers. Estimates of the maximum reduction in natural gas demand are: 0.25 bcfd for the nine affected refineries, 0.7 bcfd by industrial plants, 0.3 to 0.4 bcfd by power generators, and perhaps 0.1 bcfd by residential/commercial consumers. Thus, Katrina-related natural gas demand reduction

is, at most, estimated to be between 15 and 25 percent of the peak level of lost production, and, as service restoration proceeds, should become an increasingly minor factor.

The Henry Hub natural gas spot price is expected to average $8.82 per thousand cubic feet (mcf) in 2005 and $8.42 per mcf in 2006 in the Medium Recovery case. Depending on the speed of recovery from the supply losses in the Gulf of Mexico due to Katrina, the average price across the recovery cases for the fourth quarter of 2005 ranges from $11 to $13 per mcf. On an annual basis, the range is around $8.75 per mcf to $9.14 per mcf in 2005. In August, the Henry Hub natural gas spot price averaged over $9 per mcf, as hot weather in the East and Southwest increased natural gas-fired electricity generation for cooling demand and crude oil prices increased. The natural gas market is likely to stay tight over the next couple of months, particularly in light of the supply impacts from Katrina. Spot prices are expected to ease going into 2006 as the effects of Katrina fade. However, prices at the Henry Hub are likely to remain above $10 per mcf until peak winter demand is over.

Depending on the region of the country, increases for 2005 natural gas spot prices are expected to range between 37 and 50 percent above the 2004 averages under the Medium Recovery case. Citygate prices (prices that natural gas utilities pay at the point where they take delivery) and end-use prices (prices charged by utilities for natural gas delivered to end-use customers, including distribution or other charges not included in the utilities' natural gas costs) are expected to exhibit double-digit percent increases for the second year in a row in most regions. For the upcoming winter, pressure on delivered natural gas prices may be sharpest in regions where heating demands are likely to increase the most, such as in the central portion of the United States.

Working gas in storage was estimated at 2,633 billion cubic feet (bcf) as of August 26, a level 1.9 percent lower than 1 year ago but still 5.2 percent above the 5-year average. Natural gas demand is projected to fall slightly by 0.7 percent in 2005, but recover by 2.4 percent in 2006 due to an assumed return to normal weather and continued strength in consumption for electric power production. Natural gas storage remains above the 5-year average, but Katrina is likely to reduce the peak storage achievable over the remainder of the injection season from what was expected previously. As it is, end-August storage was about 120 bcf below last month's projection. Expected storage at the end of October is expected to be about 270 bcf below the year-ago level and about 50 bcf below the 5-year average.

Domestic natural gas production in 2005 is expected to drop by 1.5 percent due mainly to the major disruptions to infrastructure in the Gulf of Mexico from both Ivan and Katrina. Preliminary EIA data through June yield an apparent decrease in output of 1.5 percent for the first half of 2005 compared to the same period in 2004, as recovery from the disruption caused by Hurricane Ivan in 2004 was not yet complete. Meanwhile, imports of liquefied natural gas (LNG) into the United States appear to have exhibited minimal year-over-year increases (on average) through the first half of 2005. Currently, total LNG imports for 2005 are expected to be approximately 710 bcf compared to 650 bcf in 2004.

Electricity and Coal Outlook (Figures 9 to 11)

Electricity demand is expected to increase by 2.5 percent in 2005 and 1.9 percent in 2006 due largely to weather conditions as well as continuing economic growth. Very hot weather conditions generated a large increase in demand in the third quarter of 2005. Thus, third and fourth quarter 2005 year-over-year electricity demand growth rates are expected to be particularly strong, as cooling and heating demands are likely to be higher than in the mild third and fourth quarters of 2004. Seven out of the ten regions are expected to show substantial increases in residential demand for electricity in 2005 compared with 2004. Hydroelectric power availability, which fell somewhat in 2004, is expected to increase by 3 percent in 2005 nationally, and by 10 percent in 2006.

The Department of Energy's Office of Energy Assurance reports that, as of September 6, less than 1 .4 million customers remain without electric power due to Hurricane Katrina in Alabama , Louisiana , and Mississippi . This is down from a peak of 2.7 million. Inaccessibility, as well as extensive damage from flooding and saltwater, continues to be a major issue impacting electricity restoration.

Coal demand in the electric power sector is expected to increase by 3.1 percent in 2005 and 0.4 percent in 2006. Power sector demand for coal continues to increase, as oil and natural gas prices continue to rise. U.S. coal production is expected to grow by 1.9 percent in 2005 and by an additional 2.0 percent in 2006.

Short Term Energy Outlook and Winter Fuels Outlook

October 12, 2005 Release
(Next Update: November 8, 2005)

Overview

Warnings from previous Outlooks about the potential adverse impacts of an active hurricane season on domestic energy supply and prices are unfortunately being reflected in the challenging realities brought about by Hurricanes Katrina and Rita. The impact of the hurricanes on oil and natural gas production, oil refining, natural gas processing, and pipeline systems have further strained already-tight natural gas and petroleum product markets on the eve of the 2005-2006 heating season (October through March). This combined Short-Term Energy and Winter Fuels Outlook provides a current view of domestic energy supply and prices and provides projections for average household heating expenditures this winter by fuel and by region; baseline forecasts for domestic fuel markets; and projections for international petroleum demand, supply, and price. Energy market projections are subject to considerable uncertainty. Price projections are particularly uncertain, because small shifts in either supply or demand, which are both relatively insensitive to price changes in the current market environment, can necessitate large price movements to restore balance between supply and demand. On the supply side, this Outlook reflects a "Medium Recovery" baseline scenario for recovery of energy operations in the Gulf of Mexico based on information available to EIA as of the end of the first week of October. On the demand side, the baseline projections incorporate the mean values for heating degree-days by Census Division as provided by the National Oceanic and Atmospheric Administration's (NOAA) Climate Prediction Center. EIA also examines 10-percent colder and 10-percent warmer winter cases to provide a range of heating fuel market outcomes.

Highlights from this Outlook include:

Average Winter Heating Expenditures. This winter, residential space-heating expenditures are projected to increase for all fuel types compared to year-ago levels. On average, households heating primarily with natural gas are expected to spend about $350 (48 percent) more this winter in fuel expenditures. Households heating primarily with heating oil can expect to pay, on average, $378 (32 percent) more this winter. Households heating primarily with propane can expect to pay, on average, $325 (30 percent) more this winter. Households heating primarily with electricity can expect, on average, to pay $38 (5 percent) more. Should colder weather prevail, expenditures will be significantly higher. These averages provide a broad guide to changes from last winter, but fuel expenditures for individual households are highly dependent on local weather conditions, the size and efficiency of individual homes and their heating equipment, and thermostat settings.

Energy Product Prices. Prices for petroleum products and natural gas will remain high due to tight international supplies of crude and hurricane-induced supply losses. Under the baseline weather case, Henry Hub natural gas prices are expected to average around $9.00 per thousand cubic feet (mcf) in 2005 and around $8.70 per mcf in 2006. Retail gasoline prices are expected to average close to $2.35 per gallon in 2005 and about $2.45 in 2006. Residential electricity prices are expected to average 9.3 cents per kilowatthour (kwh) in 2005 and about 9.5 cents per kwh in 2006, with significant regional differences depending on the fuel mix used to generate electricity in each region of the country. Under a colder weather scenario, prices for natural gas and all petroleum products are projected to be somewhat higher.

Weather Forecast. NOAA projects a 0.4-percent colder winter in the lower-48 States, in terms of heating degree-days, relative to normal winter weather, which would be 3.2 percent colder than last winter.

U.S. Energy Demand. Total U.S. energy demand is projected to decline from 25.2 quadrillion Btu in the third quarter of 2005 to 25.1 quadrillion Btu in the fourth quarter due to hurricane-related destruction and higher energy prices. Total energy demand is projected to increase 0.3 percent between 2004 and 2005, compared with 1.5 percent from 2003 to 2004.

Demand growth is projected to rebound in 2006.

Hurricanes Katrina and Rita

The loss of a considerable amount of crude oil and natural gas production from the Gulf of Mexico region and significant disruptions to the nearly half of the U.S. refining industry located in the region following Hurricanes Katrina and Rita have resulted in significantly higher natural gas and petroleum product prices in U.S. markets than were anticipated in mid-summer. These developments are expected to carry very high prices for heating fuels (and other products) into the coming heating period compared to the situation last winter Hurricane Rita made landfall on September 24, 2005, just as the Gulf was well into recovery from Hurricane Katrina. See EIA's September Short-Term Energy Outlook for discussion of the impacts of Hurricane Katrina. As Hurricane

Rita approached, 16 refineries along the Gulf Coast shut down as a precautionary measure and to allow employees to evacuate. Damage to some of these refineries, and the lack of electrical power supply to others, prevented their immediate return to service.

Hurricane Rita resulted in over a dozen natural gas processing plants going off-line owing either to flooding, lack of supplies, an inability to move stored liquids, or safety precautions. Natural gas pipelines sustained significant damage and the Sabine Pipeline, operator of the Henry Hub, implemented a force majeure.

Hurricane recovery is underway but it will take many months for a complete recovery. As of October 11, three refineries are still shut down from Hurricane Katrina, and 4 from Hurricane Rita, amounting for a total of about 1.9 million barrels per day of refining capacity that is currently off-line (11 percent of the Nation's refinery capacity) due to hurricane-related outages.

According to Minerals Management Service (MMS) data and EIA data, as of October 11, shut-in Federal Gulf of Mexico crude production has declined to about 1.1 million barrels of oil per day, about 67 percent of normal Gulf of Mexico crude oil production. Shut-in natural gas production has declined to 6.0 billion cubic feet (bcf) of natural gas, about 60 percent of normal Federal Gulf of Mexico natural gas production. There are also significant outages of natural gas and oil production remaining in areas under Louisiana's jurisdiction. The MMS reports a cumulative loss of crude oil and natural gas production in the Federal Gulf of Mexico from August 26 through October 11 of 55 million barrels, with a loss of 272 bcf of natural gas production over the same period. As of October 6, there are 20 natural gas processing plants in Texas, Louisiana, and Mississippi each with capacities equal to or greater than 100 million cubic feet per day, which are not active. A number of the inactive plants are expected to be operating within 4 weeks.

By October 11, the Department of Energy's Office of Electricity Delivery and Energy Reliability reports that about 181,290 customers in Louisiana and Texas remain without electric power, down from a peak of 2.7 million.

EIA's baseline projections in this Outlook reflect a scenario of continued recovery of energy infrastructure in the Gulf region through the end of the year. In this scenario, Gulf of Mexico shut-ins for December 2005 are projected to average 33.1 percent for crude oil (10.4 percent of total U.S. production) and 20.6 percent for natural (4.2 percent of total U.S. natural gas production). For refinery capacity, 1.7 percent is projected to be offline.

International Petroleum Markets

Prices. The WTI crude oil price averaged about $66 per barrel in September, with an average price of about $64 per barrel projected for October under the baseline weather scenario, accounting for hurricane damage. Quarterly averages for the WTI price are projected to remain above $63 per barrel for the rest of 2005 and 2006. Continued high crude oil prices had been expected prior to Hurricanes Katrina and Rita.

Under the baseline weather scenario, the projected fourth-quarter average WTI price of $64.40 per barrel is approximately $16 per barrel above the year-ago level, but is about $3 per barrel lower than in the previous Outlook, which was made prior to the additional loss of crude oil production and refining capacity resulting from Hurricane Rita. While oil product prices rose in response to the resulting product shortages, the loss of operable refining capacity from Rita (which was more than twice as large as the shut-in crude production resulting from Katrina) reduced the demand for crude oil, moderating WTI prices. Should 10-percent colder weather prevail in the United States this winter, WTI prices are projected to be $ 4 per barrel higher than the baseline. Should the U.S. winter be 10 percent milder, WTI prices are expected to be $3 per barrel lower this winter. WTI prices will also be significantly impacted by demand in other parts of the world, which is sensitive to both weather and economic conditions, and by global supply developments.

Demand. Worldwide petroleum demand growth is projected to slow from 2004 levels, but still remain strong during 2005 and 2006, averaging 1.8 percent per year over the 2-year period, compared with 3.2 percent in 2004. This reflects a downward revision from the previous Outlook. The average annual worldwide oil demand growth is now projected to be about 1.2 million barrels per day in 2005, down from the 1.7-million-barrels-per-day growth projected for 2005 in the previous Outlook.

Production. Moreover, only weak production growth in countries outside of the Organization of Petroleum Exporting Countries (OPEC) is expected. With the loss of production in the Gulf of Mexico from the hurricanes, production declines in the North Sea, and the slowdown in growth in Russian oil production, non-OPEC supply is projected to increase by an annual average of only 0.1 million barrels per day during 2005 before increasing by 0.9 million barrels per day in 2006. In addition, worldwide spare production capacity is at its lowest level in 3 decades; and in reality, only Saudi Arabia has any spare crude oil production capacity

available. Lastly, the continued geo-political risks, such as the insurgency in Iraq and potential troubles in Nigeria and Venezuela, have boosted the level of uncertainty in world oil markets.

High levels of production from OPEC members contributed to inventory builds in the Organization for Economic Cooperation and Development (OECD) countries in the first half of 2005, with these stocks moving above the upper end of the 5-year historical range. However, OECD stocks have not grown as quickly in terms of days' supply (the number of days that inventories would satisfy demand) because demand has grown rapidly as well. In addition, stocks were drawn down in the aftermath of hurricanes Katrina and Rita, with OECD inventories moving back towards the middle of the 5-year historical range.

U.S. Natural Gas Markets

Demand. Total natural gas demand is projected to fall by 1.2 percent from 2004 to 2005 due mainly to higher prices, but recover by 3.0 percent in 2006 due to an assumed return to normal weather and a recovery in consumption by the industrial sector, which is projected to increase by about 6 percent over 2005 levels. Residential demand is projected to decline slightly from 2004 to 2005 mostly because of relatively weak heating-related demand during the first quarter, while industrial demand is estimated to decline by nearly 8 percent over the same period due to the much higher prices for natural gas as a fuel or feedstock. By 2006, both end-use sectors recover somewhat with residential demand estimated to increase 2.6 percent from 2005 levels and industrial demand increasing by 6 percent. The industrial rebound in 2006 is partly because of assumed reactivation of damaged industrial plants in the Gulf of Mexico region but also reflects renewed fuel demand growth as domestic industrial plants adjust to higher prices. Power sector demand growth continues through the forecast period along with electricity demand growth. The pace is slower that the 5.7 percent rate projected for 2005 because an unusually hot summer and high cooling demand boosted 2005 growth significantly.

Production. Domestic dry natural gas production in 2005 is expected to decline by 3.0 percent (due in large part to the major disruptions to infrastructure in the Gulf of Mexico from both Hurricanes Katrina and Rita), but increase by 4.2 percent in 2006. Net imports of natural gas (pipeline and liquefied natural gas (LNG)) are expected to increase only slightly in 2005 (0.1 percent over 2004) but increase by 10.4 percent between 2005 and 2006.

Imports of LNG appear to have exhibited little change through the first half of 2005 compared to year-ago levels. High natural gas prices in other world markets during the first three quarters of 2005 have served to attract available supplies of LNG that might otherwise have been directed to the United States, although fourth quarter imports are estimated to increase in response to high U.S. prices. Currently, total LNG imports for 2005 are expected to be approximately 680 bcf compared to 650 bcf in 2004; LNG imports are projected to be just over 1,000 bcf in 2006.

Prices. The Henry Hub natural gas price is expected to average about $9.00 per mcf in 2005 and $8.70 per mcf in 2006. In September, the Henry Hub natural gas spot price averaged $12.40 per mcf, as hot weather in the East and Southwest increased natural gas-fired electricity generation for cooling demand, crude oil prices increased, and Katrina hit. The natural gas market is likely to stay tight over the next couple of months, particularly in light of the supply impacts from Katrina and Rita. Henry Hub prices are likely to remain above $12 per mcf until peak winter demand is over. Depending on the region of the country, residential natural gas price increases from 2004 to 2005, on an annual average basis, are expected to range from 14 percent (New England region) to 27 percent (East South Central). Similarly, for industrial users, the natural gas price increases are expected to range from 16 percent (Mountain region) and 40 percent (Pacific and West North Central) between 2004 and 2005. Pressure on delivered natural gas prices may be exacerbated in regions where heating demands are likely to increase the most, particularly during the heating season.

Given that the opportunity to offset the market impact of a weather-related increase in demand through an increase in imports is far more limited for natural gas than for oil products (net natural gas imports are estimated to account for about 15 percent of total U.S. demand in 2005 and 16 percent in 2006), weather conditions in the United States have an even larger impact on U.S. natural gas markets than on petroleum product markets. Consequently, retail natural gas prices are expected to be significantly higher should winter weather be 10 percent colder than predicted.

Storage. Working gas in storage as of September 30 was estimated at 2.93 trillion cubic feet (tcf), a level 151 bcf below a year-ago but still 1.4 percent above the 5-year average, and about 122 bcf above last month's projection. Although natural gas storage remains above the 5-year average, the double blows of Hurricanes Katrina and Rita reduced the peak storage achievable over the remainder of the injection season from what was expected previously. Expected working gas in storage at the end of the fourth quarter is expected to be about 2.5 tcf, 200 bcf below year-ago levels and about 50 bcf above the 5-year average. End-of-year storage levels are

expected to decline 7.3 percent between 2004 and 2005 but increase about 5.2 percent in 2006 over 2005 levels. However, storage levels will be very sensitive to weather and the return of domestic natural gas production following the recent hurricanes. For example, each 3.3 bcf of daily supply reduction sustained over the course of a month translates into a supply loss of roughly 100 bcf. Recovery profiles that differ from the scenario used for this month's baseline forecast would significantly affect the storage forecast.

Electricity

Demand. Electricity demand is expected to increase by 3.5 percent in 2005 and about 1.0 percent in 2006 due largely to weather conditions as well as continuing economic growth. Very hot weather conditions generated a large increase in demand in the third quarter of 2005. Thus, year-over-year electricity demand growth rates are expected to be particularly strong, as cooling and heating demands are likely to be higher than in the mild third and fourth quarters of 2004. Regional demand exhibits increases for nine out of the ten regions (Alaska and Hawaii, treated as one region, are the exception) in 2005 compared with 2004. Commercial and industrial demand also increases across most regions, but the rate of growth tends to be smaller compared with residential demand.

Prices. Estimated 2005 prices for delivered electricity across all end uses range from 6.4 cents per kwh in the West North Central region to nearly 12 cents per kwh in New England. Due primarily to increased utility fuel prices, average electricity prices for all end uses are estimated to increase by 8.9 percent in New England and 8.2 percent in West South Central, but less than 6 percent for all other regions between 2004 and 2005. End-use electricity prices – residential, commercial, and industrial – also exhibit regional variability. For example, 2005 estimated residential prices range from 7.3 cents per kwh in East South Central to 13 cents per kwh in New England. Estimated 2005 industrial prices range from a low of 4.2 cents per kwh in East South Central to 8.1 cents per kwh in New England.

Coal

Demand. Coal demand in the electric power sector is expected to increase by 4.5 percent in 2005 and remain at about 2005 levels in 2006. Power sector demand for coal continues to increase as oil and natural gas prices continue to rise. U.S. coal production is expected to grow by 2.6 percent in 2005 and by an additional 1.6 percent in 2006.

Short-Term Energy Outlook
November 8th, 2005 Release
(Next Update: December 6th, 2005)
Overview

Hurricanes Katrina and Rita damaged, set adrift, or sunk 192 oil and natural gas drilling rigs and producing platforms, the most significant blow to the U.S. petroleum and natural gas industries in recent memory.

At the beginning of November almost 53 percent of normal daily Federal Gulf of Mexico oil production and 47 percent of Federal Gulf of Mexico natural gas production remains shut in. Moreover, in Louisiana 1.0 billion cubic feet (bcf) per day of onshore natural gas production remains offline and 0.8 million barrels per day (bbl/d) of crude oil refining capacity remains shut down. Some wells were temporarily shut in as a precaution to Hurricane Wilma. While no damage was reported from that storm, hurricane recovery remains a key factor in this Outlook. Indeed, recent information on damaged and destroyed platforms and shut-in production suggests that the recovery path will be slower than predicted in the October Outlook.

This short-term forecast projects that total energy demand is likely to respond to higher prices and hurricane-related destruction by showing relatively flat growth between 2004 and 2005, compared with 1.5-percent growth between 2003 and 2004. However, energy demand is expected to recover in 2006 at a rate of about 2 percent. Prices for crude oil, petroleum products, and natural gas are projected to remain high during the remainder of 2005 and through 2006 because of tight international supplies and hurricane-induced supply losses. The price of West Texas Intermediate (WTI) crude oil is expected to average $57 per barrel in 2005 and $64-$65 per barrel in 2006 (Figure 1. West Texas Intermediate Crude Oil Price). Retail regular gasoline prices are expected to average $2.29 per gallon in 2005 and $2.43 in 2006 (Figure 2. Gasoline and Crude Oil Prices). Henry Hub natural gas prices are expected to average $9.15 per thousand cubic feet (mcf) in 2005 and $9.00 per mcf in 2006 (Figure 3. U.S. Natural Gas Spot Prices).

Hurricane Recovery Path is Revised from October Outlook

Recovery of production facilities and other infrastructure in the Gulf region is expected to continue, but it now appears unlikely that anything close to complete recovery will occur before the end of the second quarter of 2006. This extends the recovery period by about 3 months beyond what was assumed in the previous Outlook. The changes to our production path are driven by more detailed information on damage to production wells, pipelines, and natural gas processing plants from the hurricanes. The Minerals Management Service (MMS) reports that more than 150 offshore platforms have been heavily damaged or destroyed and are not expected to be fully operational for several months.

In this Outlook, shut-in Federal Gulf of Mexico production is projected to gradually decline through March 2006, when shut-in Gulf crude oil falls to 353 thousand bbl/d (22.6 percent of its pre-hurricane production level), and shut-in natural gas falls to 2.1 bcf per day (20.6 percent of its pre-hurricane level). Refinery capacity improves more rapidly; by the end of February, refinery capacity is fully restored to pre-Katrina levels. (Figure 4. Shut-In Federal Offshore Gulf Crude Oil Production, Figure 5. Shut-In Federal Offshore Gulf Natural Gas Production, Figure 6. Shut-In Gulf Crude Oil Refinery Capacity). Also, on-shore oil and natural gas production in Louisiana was less than 50 percent of capacity at the end of October, but are expected to be fully restored by the end of March. Although our recovery projections are based on more detailed information than previously available, damage assessments are still underway, and estimates of impacts to oil and natural gas production remain uncertain.

Winter Heating Expenditures

Our current projections for winter residential heating oil and natural gas expenditures reflect slight revisions downward from our last Outlook. In the case of the petroleum market, this change reflects the return to more normal wholesale and retail price margins as refineries have come back on line supported by an increase in imports. For the natural gas market, the adjustment reflects our reassessment of the markup between wellhead and end-use markets in our new regional natural gas model. However, residential space-heating expenditures are still projected to significantly increase for all fuel types compared to year-ago levels.

On average, households heating primarily with natural gas likely will spend $306 (41 percent) more for fuel this winter than last winter. Households heating primarily with heating oil can expect to pay, on average, $325 (27 percent) more this winter than last. Households heating primarily with propane can expect to pay, on average, $230 (21 percent) more this winter than last. Households heating primarily with electricity can expect to pay, on average, $33 (5 percent) more. Should colder weather prevail, expenditures could be significantly higher. These averages provide a broad guide to changes from last winter, but fuel expenditures for individual households are highly dependent on local weather conditions, the size and efficiency of individual homes and their heating equipment, and thermostat settings (Table WF01. Selected U.S. Average Consumer Prices and Expenditures for Heating Fuels for the Winter).

U.S. Natural Gas Markets Remain Tight Despite Slower Demand Growth

In response to higher prices, total natural gas demand is projected to fall by 0.8 percent in 2005 compared with 2004 levels, then recover by 2.8 percent in 2006, assuming a return to normal weather and a recovery in consumption by the industrial sector (Figure 11. Total U.S. Natural Gas Demand Growth). Residential demand is projected to decline by about 1 percent from 2004 to 2005 mostly in response to relatively weak heating-related demand during the latter part of last winter, while industrial demand is estimated to decline by over 8 percent during the same period due to the much higher prices for natural gas as a fuel or feedstock. By 2006, both end-use sectors are expected to recover somewhat, with residential demand estimated to increase 3.2 percent from 2005 levels and industrial demand to increase by 6.8 percent. The projected industrial demand rebound in 2006 rests in part on the assumed reactivation of damaged industrial plants in the Gulf of Mexico region. Power sector demand growth likely will track electricity demand growth through the forecast period.

Domestic dry natural gas production in 2005 is expected to decline by 4.2 percent, due in large part to the major disruptions to infrastructure in the Gulf of Mexico from the hurricanes, then increase by 4.7 percent in 2006. Total liquefied natural gas (LNG) net imports for 2005 are expected to remain at about 650 bcf as they were in 2004, but are projected to average slightly above 1,000 bcf in 2006.

On October 28, working gas in storage stood at an estimated 3,168 bcf, a level 119 bcf below 1 year ago but 2.6 percent above the 5-year average and about 28 bcf above last month's Outlook. End-of-year storage levels are expected to be 7.9 percent lower at end-2005 than they were at end-2004. Natural gas storage levels at the end of 2006 are expected to be about even with the 2005 level (Figure 12. U.S. Working Natural Gas in Storage).

Hurricane-related natural gas production losses have cut down on the amount of natural gas available for the market, which increases the projected requirement for withdrawals of gas from underground storage this winter. The Henry Hub natural gas spot price is expected to average $9.15 per mcf in 2005 and $9.00 per mcf in 2006. In October 2005, the Henry Hub natural gas spot price averaged $13.82 per mcf and the monthly average spot price is likely to remain above $10 per mcf until peak winter demand is over (Figure 3. U.S. Natural Gas Spot Prices).

Strong Electricity Demand Forecasted

Weather conditions and continuing economic growth are expected to move electricity demand 3.3 percent higher in 2005 and an additional 1.3 percent higher in 2006 (Figure 13. Total U.S. Electricity Demand Growth Patterns). Year-over-year electricity demand growth rates are expected to be particularly strong, as cooling and heating demands are likely to be higher than in the mild third and fourth quarters of 2004. When compared to 2004 figures, regional residential demand in 2005 rose in nine of the ten regions (Alaska and Hawaii, treated as one region, is the exception). Commercial demands increased across all ten regions, but industrial demands fell in the four regions along the East Coast and Midwest. Estimated 2005 prices for delivered electricity across all end uses range from 6.0 cents per kilowatt hour (kwh) in the East South Central region to nearly 12 cents per kwh in New England. In response to higher utility fuel prices, average electricity prices for all end uses are projected to rise by 9.5 percent in New England and 7.8 percent in West South Central, but by 6 percent or less in all other regions in 2005 compared with 2004.

Power Sector Demand for Coal Continues to Increase

Electric power sector demand for coal is expected to increase by 3.2 percent in 2005 and by 1.2 percent in 2006 (Figure 14. U.S. Coal Demand). Power sector demand for coal continues to rise in response to higher oil and particularly natural gas prices. U.S. coal production is expected to grow by 1.2 percent in 2005 and by an additional 3.3 percent in 2006 (Figure 15. U.S. Coal Production). Coal prices to the electric power sector increased significantly in the first half of this year, growing by 15.3 percent compared with the first half of 2004. The large coal price increase was the result of low coal inventories because of the increase in demand and also because of higher transportation costs. The price of coal to the power sector is expected to increase through the forecast period, although at a lower rate than in the first half of 2005. Coal prices are projected to increase by an average 14.2 percent in 2005 and by an additional 3.9 percent in 2006, rising from $1.35 per million Btu in 2004 to $1.60 per million Btu in 2006.

COAL MINERS STRIKES

http://www.eia.doe.gov/cneaf/coal/coal_ref_pdf/text.pdf

Coal Data: A Reference
February 1995
Energy Information Administration
Office of Coal, Nuclear, Electric and Alternate Fuels, U.S. Department of Energy

Coal Miners' Unions and Strikes
The United Mine Workers of America (UMWA) ranks first among about 40 labor unions that represent U.S. coal miners. Formed in 1890, the UMWA has been the leading coal miners union and has been in the forefront as a collective bargaining organization representing coal miners. It is the major union in the coalfields in the East. UMWA coal miners currently account for about 40 percent of the U.S. coal mining workforce and produce about one-fourth of the total coal output. Other unions represent 24 percent of the coal miners and account for a 9-percent share of production. By contrast, nonunion workers compose about 55 percent of the coal mining workforce and account for about two-thirds of U.S. coal production. Major coal miners' strikes—those creating a significant disruption on coal supplies—are generally precipitated when a contract expires and no agreement is reached between the UMWA and the Bituminous Coal Operators Association (BCOA) over the terms of a new contract. The principal bargaining issues focus on wage and fringe benefits, including health and retirement benefits. Contract agreements between the UMWA and the BCOA traditionally set the pattern for contracts between smaller unions representing coal miners and other mining companies or associations that do not belong to the BCOA, such as the Independent Bituminous Coal Bargaining Alliance. Overall production is usually not significantly affected by the small "wildcat" strikes that occur locally from time to time, usually over miners' grievances and local issues. During a major strike, nonunion mines may also be idled by pickets or by miners walking out in "sympathy" strikes. Generally, strikes by the UMWA are most significant at underground mines in Appalachia, the center of UMWA membership. Before 1984, major coal miners' strikes were generally nationwide. Since then, the UMWA's tactic has been to call selective strikes against one or more companies. The striking miners are supported through UMWA payroll assessments into a selective strike fund. The early history of the coal industry often featured long strikes, commonly over needed reforms. In 1922, anthracite miners in Pennsylvania went on strike for 160 days and bituminous coal miners for 140 days. The Nation's longest coal miners' strike—166 days in the anthracite region—was in the fall and winter of 1925-26, before the Taft-Hartley Act for ending strikes was enacted. In 1949-1950, a coal miners' strike lasted 116 days, although the miners went back to work several times during that period. Since 1960, major coal miners' strikes have occurred in 1966 (16 days), 1968 (13 days), 1971 (44 days), 1974 (28 days), 1977-78 (111 days), and 1981 (72 days). In October 1984, a nationwide strike was averted for the first time in 20 years with the signing of a new UMWA-BCOA contract extending through January 1988, and in early February 1988 another new agreement was ratified without striking. The new contract was for 5 years, whereas past contracts usually lasted about 3 years. From April 1989 through most of February 1990, a UMWA strike against the Pittston Coal Company, with which it was negotiating a separate contract, affected the company's mines in Virginia, West Virginia, and Kentucky before a 4 1/2-year agreement was reached. At issue were job security and health and retirement benefits. In 1993, unsuccessful contract negotiations between the UMWA and the BCOA led to a series of selective strikes that idled more than 16,000 miners in seven States in Appalachia. The first selective strikes were against the operations of Peabody Holding Company, the Nation's top producer, and Eastern Associated Coal Corporation. The strikes lasted from February 2 to March 3 and ended when the negotiators agreed to extend the contract for 60 days. Failing to reach an agreement at the end of the period, the union expanded its selective strikes to include large mines operated by other companies. This new series of strikes lasted from May 10 until December 14, 1993, when an agreement was reached that will remain in effect through August 1, 1998. In addition to increasing wages and pensions, the new agreement provides for 60 percent of new job openings to be filled by UMWA workers, increases health care benefits, and gives the company the right to establish 7-day work schedules. In a separate collective bargaining agreement signed June 20, 1994, the UMWA and the Pittston Coal Company concluded a new labor pact in June 1994 that extends through 1998.