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Energy Trader

Thursday, October 13, 2005

Duke Energy gets approval to sell trading book portion to Progress Energy; terms not discussed

Duke Energy has won approval from the Federal Energy Regulatory Commission to sell to Progress Energy a portion of its trading book related to the portfolio of eight southeast region generating plants sold in May 2004.

No price on the deal was mentioned, nor the number of deals nor the total capacity involved. Neither Duke nor Progress would comment on the commercial aspects of the deal.

FERC approved the Aug. 18 application late last week.

In its application, Duke told FERC it would "transfer" to Progress Energy's unregulated power trading operations, Progress Ventures, "a wholesale power and capacity sales transaction" originally done by Duke Energy Trading and Marketing and "a power purchaser for power and gas sales that occur at a delivery point on the Georgia Integrated Transmission System."

The application said that the transaction would be "effectuated through a contract sale agreement" between Duke Energy and Progress Ventures and "an assignment, assumption and consent agreement" between Duke Energy,

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FERC, aware that tight natural gas supplies may encourage market gaming, vows vigilance

Federal Energy Regulatory Commission Chairman Joseph Kelliher on Wednesday said tight natural gas supplies in the United States going into the winter heating season "could create temptations for improper behavior by some market participants," and promised that his agency "will act to prevent prices from going even higher because of manipulation."

In an opening statement at the commission's Conference on the State of Natural Gas Infrastructure, Kelliher said hurricanes Katrina and Rita have had a "severe effect" on U.S. energy infrastructure in the Gulf of Mexico, resulting in the loss of a "significant share of our natural gas supply." He said imports "cannot offset" the loss and the result "will be higher natural gas prices this winter."

The two hurricanes that tore through the country's main energy production corridor resulted in damage "greater and more enduring" than

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National Commentary

Winter gas supply, electric demand news abounds as markets await fresh indicators

The November NYMEX gas futures contract ended half a cent higher at $13.524/MMBtu Wednesday as the market took to consolidation following Tuesday's 54.4-cent leap. Power dailies were mixed to slightly higher across the regions.

Information the market was digesting on Wednesday included: Industrial demand destruction will balance the U.S. gas supply market this winter, but even with normal weather Henry Hub prices will average about $13/MMBtu during the winter, said an Arlington, Va.-based trade group representing U.S. natural gas producers and markets. Market players and analysts expect the Energy Information Administration today will estimate a build to gas storage between 40 Bcf and 65 Bcf, with most estimates coming in between 50 Bcf and 55 Bcf, for the week ended Oct 7. The damage done by back-to-back major hurricanes to the nation's natural gas production and processing infrastructure in the Gulf of Mexico has resulted in "a particularly difficult outlook" for the upcoming winter heating season, EIA Director Guy Caruso said Wednesday.

"I think [Tuesday's AGA natural gas outlook for winter 2005-2006] didn't make the market feel too good," said a Chicago-based broker. "It rallied on that news." On Wednesday, "there's a little bit of profit-taking and it's going back down." He added that with winter getting closer every day, he wouldn't be surprised to see the market spike upward again.

Key daily power and gas indexes

Hub/Delivery point	Index	Change
Power ($/MWh)		
PJM West	96.34	1.90
Cinergy Hub	70.51	-1.18
Palo Verde	106.37	13.60
Gas ($/MMBtu)		
Transco zone 6 N.Y.	14.600	0.085
Chicago city-gates	12.365	0.000
SoCal Gas	11.790	0.525

Key indicators

National Daily Power Index	$99.56	Up $3.66
National Forward Power Assessment	$94.98	Up 27 cents
NYMEX Nov Gas Contract	$13.524	Up 0.5 cent
National Daily Gas Index	$12.56	Up 16 cents

Platts national daily power index is the average of daily indexes for regionally significant power markets. The national forward power index is the average of the daily prompt-month assessments at the same hubs. For a full description of price methodology, click here. The indices are based on wholesale prices collected by Platts in eleven key regional markets that are among the most liquid in the U.S.—the Northeast (New England, New York); the Mid-Atlantic (PJM West); the Midwest (Cinergy Hub, Into ComEd); the South and South Central (Into TVA, Into Entergy, and ERCOT); and the West (Mid-Columbia, California, and Palo Verde). The national daily gas index is a weighted volume average for all United States price points. For more information on price methodology, see page 8.

EAST POWER MARKETS

Spot gas pushes Eastern dailies higher

Dailies in the East traded mostly higher for Thursday flow when spot gas prices climbed. Forwards were mixed as NYMEX natural gas futures traded flat to slightly higher.

New England dailies packed on another $1.50 to trade at $130/MWh for Thursday flow. Off-peak regained some strength to $91/MWh. Temperatures in the region were expected to climb a few degrees to the upper 50s and low 60s in Boston and Hartford, Conn., respectively. Other areas were expected to see colder temperatures, with highs falling to the mid-50s, several degrees below seasonal norms. Demand Thursday was expected to fall to 17,140 MW.

New York dailies for Thursday flow were flat to higher amid shifting fundamentals. Zone A dailies were assessed at $104/Mwh, up $4.25; Zone J dailies, at $165/MWh, up $15; and Zone G dailies, at $121.50/MWh, down 50 cents. Forecasts showed highs at 65 in New York City, near normal, and in the upper 50s in higher elevations, 3 degrees below normal. Transco Zone 6 New York spot gas averaged near $14.70/MMBtu, up 20 cents. Thursday load was projected at 19,989 MW, down 891 MW from Wednesday. Loads were expected to drop to 19,439 MW by Friday then increase to 20,151 MW by Monday.

Wednesday real-time going into noon was bolstered by strong demand and unseasonably chilly and stormy weather, priced above $187/MWh in Zone J, $108/MWh in Zone G, and $94/MWh in Zone A. The Long Island Power Authority issued a warning that strong gusty winds and soaking rains could bring down trees and power lines. Load was at 19,796 MW and projected to top 20,880 MW, up 332 MW from Tuesday. Supply totaled 25,481 MW, down 1,023 MW, with outages at 12,019 MW. Forecasts showed blustery weather with rain likely and a high at 60 in New York City, 5 degrees below normal.

New York ISO day-ahead prices for Thursday were mixed, with Zone J peak averaging near $174.35/MWh; Zone G, near $121.55/MWh; and Zone A, near $104.05/MWh.

PJM West dailies edged up to trade in the mid- to upper $90s/MWh for Thursday flow behind increasing spot gas prices, a new outage in the region and higher temperatures. Transco Zone 6-New York was trading at $14.705/MMBtu early Wednesday, up 19 cents or so. Weather forecasts called for high temperatures to

(continued on page 8)

Day-ahead markets for delivery Oct 13 ($/MWh)

East	Index	Change	Range	Deals	Volume	Avg $/Mo
On-Peak						
Mass Hub	130.00	1.50	130.00-130.00	N.A.	N.A.	131.42
N.Y. Zone-G	121.50	-0.50	121.50-121.50	N.A.	N.A.	128.50
N.Y. Zone-J	165.00	15.00	165.00-165.00	N.A.	N.A.	157.00
N.Y. Zone-A	104.00	4.25	104.00-104.00	N.A.	N.A.	107.33
Ontario*	100.00	-7.00	100.00-100.00	N.A.	N.A.	115.67
PJM West	96.34	1.90	96.00-97.25	12	700	102.76
Dominion Hub	97.45	0.95	97.45-97.45	N.A.	N.A.	104.44
VACAR	99.60	-4.20	99.60-99.60	N.A.	N.A.	107.31
Southern, into	95.65	-4.55	95.65-95.65	N.A.	N.A.	107.33
Florida	125.00	-2.00	125.00-125.00	N.A.	N.A.	137.22
TVA, into	75.10	-2.05	75.10-75.10	N.A.	N.A.	90.54
Off-Peak						
Mass Hub	91.00	1.00	91.00-91.00	N.A.	N.A.	94.92
PJM West	44.50	1.00	44.50-44.50	N.A.	N.A.	46.83
Dominion Hub	46.70	-1.30	46.70-46.70	N.A.	N.A.	48.52
VACAR	38.00	-1.00	38.00-38.00	N.A.	N.A.	43.13
Southern, into	37.40	-0.16	37.40-37.40	N.A.	N.A.	42.18
Florida	50.00	-0.45	50.00-50.00	N.A.	N.A.	51.28
TVA, into	32.20	-0.50	32.20-32.20	N.A.	N.A.	35.05

**Ontario prices are in Canadian dollars*

Near-term forward markets ($/MWh)

Contract	Date	Deal
PJM West		
Bal-week	10/12	93.00-94.75
Bal-week	10/11	93.00-93.00

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Potomac River/1-4/Mirant	394	c	Va.	MO	Unk	08/25/05
Pickering-6/Ontario Power	540	n	Ontario	PMO	Unk	08/31/05
McGuire-1/Duke	1,180	n	N.C	RF	Unk	09/18/05
Vogtle-2/Hatch	1,169	n	Ga	RF	Unk	09/18/05
Robinson-2/Progress	768	n	S.C.	RF	Unk	09/18/05
Peach Bottom-3/Exelon	1,119	n	Pa.	RF	Unk	09/20/05
Darlington-4/Ontario Power	935	n	Ontario	PMO	Unk	09/29/05
Millstone-3/Dominion	1,130	n	Conn.	MO/RF	Unk	09/29/05
North Anna-2/Dominion	917	n	Va.	RF	Unk	10/02/05
Bruce-5/Bruce Power	840	n	Ontario	PMO	Mid-Dec.	10/08/05
Salem-1/PSEG	1,150	n	N.J.	RF	Unk	10/11/05

For more on methodology, see page 6.

Long-term Forward markets, Oct 12 ($/MWh)

	Nov	Dec	Jan/Feb06	Mar/Apr06	May06	Jun06	Jul/Aug06	Sep06	Q406	CY06	CY07	CY08
Mass Hub	127.75	139.00	195.50	120.50	99.00	103.25	116.75	98.35	103.00	122.00	96.75	87.75
PJM West	90.15	94.75	114.75	94.00	78.85	88.50	106.75	81.00	76.00	92.75	77.00	70.00
N.Y. Zone-G	120.75	127.80	151.90	—	—	—	127.00	—	—	111.00	102.00	—
N.Y. Zone-J	142.25	149.65	201.00	—	—	—	153.25	—	—	131.75	121.75	—
N.Y. Zone-A	100.00	106.00	128.50	—	—	—	103.50	—	—	93.75	81.75	—
Ontario*	114.00	119.00	146.00	—	—	—	126.00	—	—	111.00	108.00	—
TVA, into	67.25	73.75	87.50	—	—	—	84.50	—	—	72.75	65.75	—

**Ontario prices are in Canadian dollar figures*

† All forward prices are for on-peak delivery

EAST GAS MARKETS

Cash prices rise on NYMEX hangover

Benefiting from the November NYMEX gas futures contract's 54.5-cent rally Tuesday and some storage buying, sellers saw Northeast spot prices typically run up by between a dime and 20 cents or so Wednesday after the market ignored the lack of regional demand for the second day in a row.

"It's nothing to get fired up about," a Canadian trader reported. "Prices caught a ride from the NYMEX and climbed higher, but with temperatures running a little below normal, there's little real demand," he said. Regional forecasts call for little change in the weather over the next day or two, with temperatures expected to range from the 50s to the 60s.

Despite light utility loads, the Transcontinental Gas Pipe Line zone 6-New York city-gates averaged up about 20 cents Wednesday to settle in the low $14.70s/MMBtu. Texas Eastern Transmission's zone M-3 trailed about a dime in back of Transco zone 6-New York to average in the low $14.60s/MMBtu.

The November NYMEX gas futures contract's rally Tuesday had a carryover effect on the Gulf Coast cash market Wednesday, sending prices in the region up in a range of more than a dime to nearly 40 cents. However, demand didn't seem particularly affected by loads, some traders noted.

As the volume of gas traded on Henry Hub began to approach pre-Hurricane Rita levels Wednesday, the average there moved up nearly 15 cents to between the high $13.70s/MMBtu and the low $13.80s/MMBtu. Transcontinental Gas Pipe Line's zone 3 climbed step for step with Henry Hub to settle in the mid- to high $13.90s/MMBtu.

The November NYMEX gas futures contract ended half a cent higher at $13.524/MMBtu Wednesday as the market took to consolidation following the prior day's 54.4-cent leap, sources said.

Traders noted a lack of fresh fundamental news to drive prices significantly in any one direction. "I think the only new news is that we're continuing to bring back production, but it's not as fast as some of the buyers would like for it to be," said a broker.

For the Energy Information Administration's weekly gas storage report Thursday, market players expect an injection in the 50s Bcf for the week ended Oct. 7. "After that, there might be some excitement," the analyst added.

After starting off the session at $13.45/MMBtu, the November gas futures contract traded between a $13.365/MMBtu low and a $13.615/MMBtu high.

Daily spot gas prices, Oct 12 ($/MMBtu)

	Midpoint	Absolute	Common	Volume	Deals
Northeast					
Algonquin, receipts	14.185	14.10-14.30	14.13-14.24	129	23
Algonquin, city-gates	14.240	14.10-14.45	14.15-14.33	104	21
Columbia Gas, Appalachia	14.270	13.95-14.50	14.13-14.41	358	73
Dominion, North Point	—	—	—	—	0
Dominion, South Point	13.975	13.88-14.20	13.89-14.06	362	59
Dracut, Mass.	14.030	14.00-14.05	14.02-14.04	78	10
Iroquois, receipts	13.470	13.40-13.53	13.44-13.50	245	31
Iroquois, zone 2	14.095	14.00-14.38	14.00-14.19	199	26
Leidy Hub	14.270	14.27-14.27	14.27-14.27	4	1
Niagara	13.405	13.37-13.46	13.38-13.43	144	13
Tennessee, zone 6 delivered	14.375	14.00-14.65	14.21-14.54	151	21
Texas Eastern, M-3	14.610	14.30-14.78	14.49-14.73	312	62
Transco, zone 6 non-N.Y.	14.655	14.40-14.71	14.58-14.71	172	30
Transco, zone 6 N.Y.	14.600	14.45-14.85	14.50-14.70	164	24
Gulf Coast					
Columbia Gulf, La.	13.735	13.62-13.86	13.67-13.80	203	39
Columbia Gulf, mainline	13.875	13.83-13.91	13.85-13.90	70	14
Florida Gas, zone 1	14.090	14.00-14.15	14.05-14.13	17	2
Florida Gas, zone 2	14.345	14.30-14.38	14.32-14.37	14	2
Florida Gas, zone 3	14.355	14.20-14.50	14.28-14.43	64	9
Florida Gas, Mobile Bay	14.400	14.40-14.40	14.40-14.40	7	1
Florida city-gates	15.295	15.10-15.49	15.20-15.39	20	2
Southern Natural, La.	14.510	14.20-14.66	14.39-14.63	162	10
Tennessee, zone 0	11.805	11.70-11.95	11.74-11.87	307	40
Tennessee, La., 500 leg	13.805	13.80-13.85	13.80-13.82	35	4
Tennessee, La., 800 leg	13.775	13.65-13.82	13.73-13.82	73	15
Texas Eastern, ETX	11.420	11.00-11.90	11.19-11.65	8	3
Texas Eastern, STX	11.755	11.70-11.85	11.72-11.79	144	26
Texas Eastern, WLA	13.490	13.30-13.57	13.42-13.56	204	36
Texas Eastern, ELA	13.630	13.50-13.90	13.53-13.73	107	21
Texas Eastern, M-1(Kosi)	13.750	13.68-13.88	13.70-13.80	66	14
Transco, zone 1	11.910	11.80-11.95	11.87-11.95	9	3
Transco, zone 2	12.150	12.15-12.15	12.15-12.15	8	1
Transco, zone 3	13.990	13.80-14.07	13.92-14.06	416	66
Transco, zone 4	13.980	13.70-14.90	13.70-14.28	50	4
Transco, zone 5 delivered	14.380	14.25-14.46	14.33-14.43	89	13

Platts oil prices, Oct 12

	($/b)	($/MMBtu)
Gulf Coast spot		
1% Resid	55.20-55.70	8.82
3% Resid	43.75-44.15	6.99
Crude spot		
WTI (Oct)	64.06-64.07	10.19
New York spot		
No.2	82.66-82.87	14.21
0.3% Resid HP	60.50-60.75	9.64
0.3% Resid LP	65.00-65.25	10.36
0.7% Resid	53.75-54.00	8.57
1% Resid HP	49.25-49.50	7.85

Platts Energy Trader spark spreads, Oct 12 ($/MWh)

	New England				PJM				Southern, into			
	Median	Change	Peak	Change	Median	Change	Peak	Change	Median	Change	Peak	Change
Gas	-20.50	1.07	-34.19	1.04	-77.56	1.32	-110.90	1.21	-123.04	-8.01	-203.87	-9.29
Oil	47.61	-0.79	26.16	-1.39	-16.09	-1.23	-35.18	-1.76	-31.28	-8.09	-58.43	-8.84
Coal	97.14	1.50			65.42	1.90	62.73	1.90	68.16	-4.55		
Nuclear	125.27	1.50			91.32	1.90			90.49	-4.55		

Platts Energy Trader spark spreads are the differences between on-peak spot electricity prices and spot fuel prices in a region calculated at two heat rates. A positive number shows the cost advantage (in $/MWh) of using that fuel to generate electricity; a negative number shows it is more economical to purchase power. The median heat rate is a composite of generating units using that fuel in each region. The peak heat rate is based on the least efficient 25% of generating plants.

CENTRAL POWER MARKETS

Warm weather leaves dailies mixed

Dailies were mixed across the Central region on forecasts for unseasonably warm weather and nearly unchanged natural gas spot prices. Forwards were also mixed as NYMEX natural gas futures settled flat to slightly higher in near months.

Dailies in the Midwest weakened marginally as spot gas prices traded nearly flat, and weather conditions in the region were expected to warm up a bit. Deals at the Chicago City-gates traded near $12.35/MMBtu Wednesday, just slightly lower. At the Cinergy Hub, power dailies traded near $70.50/MWh, losing a little more than a dollar from the previous day's index. Off-peak also weakened by a dollar or so, trading near $27.30/MWh.

Michigan Hub dailies maintained a premium to Cinergy Hub prices at $73.15/MWh, down $1.85. Illinois Hub dailies fell further to $65/MWh, losing $6. Minnesota Hub dailies were down a buck at $68/MWh despite rising temperatures. At the Northern Illinois Hub, dailies strengthened for Thursday flow, trading at $79/MWh, up roughly $10 from for-Wednesday's price. AEP Dayton deals came in slightly higher at $79.57/MWh. Off-peak packages at both hubs were in the lower $30s/MWh.

ERCOT peak trades for Thursday flow were mixed amid mild temperatures and declining loads. Seller's Choice traded mostly in the low to mid-$90s/MWh, while North Zone trades moved in a similar range. South Zone trades were done from $112/MWh to $117/MWh, nearly $2 weaker. Houston deals climbed nominally to a high of $150/MWh. Off-peak throughout most of the zones changed little, with deals in the mid- to upper $70s/MWh. The balance-of-the-month was bid at $88/MWh, with offers at $102/MWh.

Loads for Thursday are forecast to be about 1,000 MW lower than Wednesday's loads, near 40,400 MW.

TXU's 545-MW Sandow-4 was expected to restart Wednesday afternoon, according to company reports to the Texas Commission on Environmental Quality. The unit shut Oct. 5 for a planned maintenance outage.

Entergy dailies for Thursday delivery were mostly unchanged, with pricing from $94/MWh to $97/MWh on more active trading. Off-peak gained more than $2 on average to above $38/MWh.

Forwards in the Midwest were mixed as NYMEX natural gas contracts settled flat to slightly higher. In Cinergy, the prompt month fell 25 cents to $71/MWh. At the Northern Illinois Hub, November climbed 10 cents to $70.10/MWh. In ERCOT, the prompt month gained a nickel to $95.35/MWh. Winter gained 20 cents to $102.60/MWh. Entergy's prompt month was unchanged at $96/MWh. Winter moved up 20 cents to $101.90/MWh.

Day-ahead markets for delivery Oct 13 ($/MWh)

Central	Index	Change	Range	Deals	Volume	Avg $/Mo
On-Peak						
Michigan Hub	73.15	-1.85	73.15-73.15	N.A.	N.A.	86.19
AD Hub	79.57	7.28	79.00-80.00	5	450	77.93
Cinergy Hub	70.51	-1.18	69.25-72.00	31	1,850	82.85
Illinois Hub	65.00	-6.85	65.00-65.00	N.A.	N.A.	81.03
NI Hub	79.00	9.75	79.00-79.00	N.A.	N.A.	78.09
Minnesota Hub	68.00	-1.00	68.00-68.00	N.A.	N.A.	74.78
MAPP, South	74.00	4.25	74.00-74.00	N.A.	N.A.	73.86
SPP, North	79.80	4.45	79.80-79.80	N.A.	N.A.	81.69
Entergy, into	94.91	-0.29	94.00-97.00	11	550	101.45
ERCOT	93.10	-0.06	93.10-93.10	N.A.	N.A.	96.68
ERCOT, North	93.60	-0.05	91.00-96.00	37	2,275	99.82
ERCOT, Houston	149.21	6.77	145.00-150.10	25	1,225	135.83
ERCOT, West	110.60	-3.30	110.60-110.60	N.A.	N.A.	111.68
ERCOT, South	115.55	-1.84	112.00-117.00	7	450	113.68
Off-Peak						
Michigan Hub	33.35	0.85	33.35-33.35	N.A.	N.A.	35.03
AD Hub	31.35	-0.65	31.35-31.35	N.A.	N.A.	30.48
Cinergy Hub	27.29	-1.01	27.00-28.00	13	700	30.63
Illinois Hub	26.55	-1.20	26.55-26.55	N.A.	N.A.	30.22
NI Hub	31.55	0.55	31.55-31.55	N.A.	N.A.	30.59
Minnesota Hub	20.00	-1.00	20.00-20.00	N.A.	N.A.	26.89
MAPP, South	22.25	2.00	22.25-22.25	N.A.	N.A.	24.16
SPP, North	35.00	0.65	35.00-35.00	N.A.	N.A.	36.28
Entergy, into	38.40	2.75	38.40-38.40	N.A.	N.A.	42.98
ERCOT	72.55	-2.80	72.55-72.55	N.A.	N.A.	71.12
ERCOT, North	73.08	-2.95	72.00-76.00	9	800	71.36
ERCOT, Houston	80.00	0.05	80.00-80.00	6	450	77.17
ERCOT, West	73.25	-2.85	73.25-73.25	N.A.	N.A.	73.18
ERCOT, South	78.15	1.35	76.95-79.05	7	650	75.85

Near-term forward markets ($/MWh)

Contract	Date	Deal
Mass Hub		
Bal-week	3/31	00.00-00.00
Next-week	3/31	00.00-00.00
PJM West		
Bal-month	3/31	00.00-00.00

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Watson 1-5/Mississippi Power	1,051	2c 3g	Miss.	MO	Unk	08/29/05
Michoud/Entergy	918	g	La.	MO	Unk	08/29/05
Paterson/Entergy	159	g	La.	MO	Unk	08/29/05
Grand Gulf/Entergy	1,207	n	Miss.	RF	Unk	09/18/05
Callaway/AmerenUE	1,171	n	Mo.	RF	Unk	08/17/05
Point Beach-1/WEPCO	497	n	Wis.	RF,PMO	Unk	08/24/05
Byron-1/Exelon	1,162	n	Ill.	RF	Unk	09/25/05
Oklaunion/AEP	690	c	Texas	MO	Unk	10/01/05
S Texas-2/STP	1,250	n	Texas	RF,PMO	Unk	10/01/05
Sandow-4/TXU	545	c	Texas	MO	Unk	10/05/05
Arkansas-1/Entergy	836	n	Ark.	RF	Unk	10/04/05
Comanche Peak-1/TXU	1,124	n	Texas	RF	Unk	10/09/05

For more on methodology, see page 6.

Long-term Forward markets, Oct 12 ($/MWh)

	Nov	Dec	Jan/Feb06	Mar/Apr06	May06	Jun06	Jul/Aug06	Sep06	Q406	CY06	CY07	CY08
Cinergy Hub	71.00	79.50	94.50	79.25	62.00	72.00	91.25	65.25	64.25	78.00	67.25	63.25
NI Hub	70.10	78.00	91.25	76.50	62.00	67.25	86.25	62.25	66.00	78.50	63.50	62.75
Entergy, into	96.00	98.75	101.90	93.60	82.80	84.85	95.10	84.65	80.15	90.65	76.85	67.20
ERCOT	95.35	98.05	102.60	94.85	86.95	97.25	110.70	95.00	82.30	95.80	81.50	71.35

† All forward prices are for on-peak delivery

CENTRAL GAS MARKETS

Gulf Coast stabilizes, boosts Midwest cash

Midcontinent spot prices were on the rise once again Wednesday, prompted in large part by the November NYMEX gas futures contract's run-up Tuesday. While the contract was quieter Wednesday, it still packed on an additional 15 cents from its open of $13.45/MMBtu.

Spot prices at many regional points more than doubled those gains, tacking on between 35 cents and more than 50 cents. Prices were also helped along by the ongoing normalization of Gulf Coast production. "Some Gulf Coast points are still at a premium, but not as much so," one trader explained. "It looks like things are flowing easier."

Panhandle Eastern Pipe Line continued to gain Wednesday, climbing more than 50 cents to average in the low $11.30s/MMBtu. Natural Gas Pipeline Co. of America's Midcontinent zone gained nearly as much from Tuesday to average at a slight premium to Panhandle, in the mid-$11.30s/MMBtu.

ANR Pipeline in Oklahoma, meanwhile, tacked on more than 35 cents to average in the mid-$11.20s/MMBtu. CenterPoint's East zone averaged about flat to ANR Oklahoma, gaining nearly 20 cents on Tuesday, and Natural's Texok zone averaged in the high $11.70s/MMBtu, up about a dime.

Spot gas prices throughout the upper Midwest were generally up, climbing between 20 cents and 50 cents on the strength of the November NYMEX. The Chicago city-gates dropped a couple of cents, however, due to a glut of gas and ensuing capacity constraints. "West-to-east capacity is still constrained," a Michigan trader explained. It's not related to area maintenance, but is a result of "more supply coming into Chicago than can be moved out." Consequently, Chicago hit the mid-$12.30s/MMBtu, down a few pennies from Tuesday's settlement.

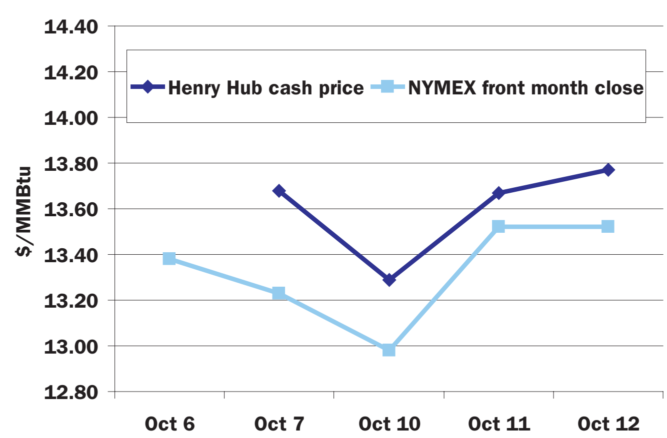
Elsewhere in the region, prices fell in line with the screen. "The NYMEX ruled the day again," the Wisconsin trader said. Michigan Consolidated Gas was trading in the high $13.30s/MMBtu, more than 20 cents higher than Tuesday's settlement, while Consumers Energy gained about the same to average flat to MichCon.

Dawn, Ontario, tacked on more than a quarter to its Tuesday midpoint to average in the high $13.30s/MMBtu. Meanwhile, Northern Natural Gas' Ventura averaged in the high $11.80s/MMBtu, nearly 40 cents higher than Tuesday, and Northern's demarcation point averaged similarly, gaining about 50 cents.

Daily spot gas prices, Oct 12 ($/MMBtu)

	Midpoint	Absolute	Common	Volume	Deals
Upper Midwest					
Alliance, into interstates	12.415	12.28-12.45	12.37-12.45	100	19
ANR, ML7	13.560	13.50-13.75	13.50-13.62	45	9
Chicago city-gates	12.365	12.15-12.60	12.25-12.48	788	123
Consumers Energy city-gate	13.355	13.27-13.44	13.31-13.40	187	22
Dawn, Ontario	13.355	13.29-13.42	13.32-13.39	635	64
Emerson, Viking GL	11.995	11.95-12.06	11.97-12.02	33	4
Mich Con city-gate	13.390	13.25-13.45	13.34-13.44	348	52
Gulf Coast					
Agua Dulce Hub	11.735	11.70-11.80	11.71-11.76	135	6
ANR, La.	13.800	13.70-13.89	13.75-13.85	47	16
Carthage Hub	11.215	11.20-11.25	11.20-11.23	30	10
Henry Hub	13.770	13.60-14.00	13.67-13.87	495	84
Houston Ship Channel	11.875	11.50-12.10	11.72-12.03	318	34
Katy	11.915	11.60-12.05	11.80-12.03	277	28
NGPL, STX	11.775	11.65-11.83	11.73-11.82	103	16
NGPL, Texok zone	11.800	11.65-11.90	11.74-11.86	357	53
NGPL, La.	13.300	13.30-13.30	13.30-13.30	5	1
Texas Gas, zone 1	13.565	13.35-13.75	13.46-13.67	64	10
Texas Gas, zone SL	13.805	13.58-13.95	13.71-13.90	102	26
Trunkline, WLA	—	—	—	—	0
Trunkline, ELA	13.705	13.55-13.82	13.64-13.77	17	4
Midcontinent					
ANR, Okla.	11.300	11.25-11.60	11.25-11.39	35	9
CenterPoint, East	11.250	11.10-11.30	11.20-11.30	101	19
NGPL, Amarillo receipt	11.515	11.46-11.60	11.48-11.55	72	11
NGPL, Midcontinent	11.330	11.26-11.42	11.29-11.37	166	39
Northern, demarc	11.880	11.85-11.95	11.85-11.91	98	21
Northern, Ventura	11.880	11.83-11.93	11.85-11.91	71	13
Oneok, Okla.	11.150	11.00-11.40	11.05-11.25	31	6
Panhandle, Tx.-Okla.	11.310	11.20-11.40	11.26-11.36	295	53
Southern Star, Tx.-Okla.-Kan.	11.115	11.00-11.35	11.03-11.20	19	4

NYMEX/Henry Hub spread



Platts Energy Trader spark spreads, Oct 12 ($/MWh)

	Cinergy				ComEd				Entergy				ERCOT East			
	Median	Change	Peak	Change	Median	Change	Peak	Change	Median	Change	Peak	Change	Median	Change	Peak	Change
Gas	-122.58	-3.32	-174.80	-3.88	-83.18	9.75	-118.37	9.75	-51.96	-1.84	-73.20	-2.07	-40.65	-3.33	-57.82	-3.75
Oil	-60.96	-2.34	-109.37	-2.76	-47.22	8.64	-81.18	8.34	-6.47	-1.20	-21.51	-1.34	-2.89	-0.92	-10.62	-0.99
Coal	44.48	-1.18	41.36	-1.18	48.87	9.75			64.35	-0.29			62.40	-0.06		
Nuclear	65.76	-1.18			74.52	9.75			89.83	-0.29			88.41	-0.06		

Platts Energy Trader spark spreads are the differences between on-peak spot electricity prices and spot fuel prices in a region calculated at two heat rates. A positive number shows the cost advantage (in $/MWh) of using that fuel to generate electricity; a negative number shows it is more economical to purchase power. The median heat rate is a composite of generating units using that fuel in each region. The peak heat rate is based on the least efficient 25% of generating plants.

WEST POWER MARKETS

Palo Verde outage boosts Southwest dailies

Western dailies climbed with the unexpected outage of a nuclear power plant in the Southwest, and continued restrictions on north-to-south transmission flows. Term markets held tight with a choppy day in the NYMEX natural gas futures contracts.

Arizona Public Service Co.'s Palo Verde Unit's 2 and 3 were taken off line Tuesday because of problems with emergency core cooling systems, the Nuclear Regulatory Commission reported. The outage of the 1,249-MW, Unit 2 and the 1,247 MW, Unit 3 combined with the already off line 1,249 MW Unit 1 shuts down the plant, located in Wintersburg, Ariz. Unit 1 went down for a scheduled refueling and maintenance outage Oct. 9, and is expected to return late December. The NRC has to approve the restart of Units 2 and 3.

Palo Verde on-peak dailies jumped to triple digits Wednesday, with trades reaching $108/MWh for Thursday packages, $12 higher than deals made the previous day. The Western Electricity Coordinating Council listed peak loads at the Rocky Mountain Desert Southwest region near 23,240 MW Wednesday, with outages around 7,470 MW.

NP15 on-peak dailies traded over $116/MWh, while SP15 on-peak dailies traded up to $117.25/MWh. Sacramento temperatures were expected in the mid-80s today and Friday.

The California Independent System Operator forecast its peak load at 32,365 MW Wednesday and 33,570 MW Thursday. The California-Mexico region had about 9,158 MW of outages Wednesday, the WECC said.

Mid-Columbia on-peak day-ahead trades were in the mid-$80s/MWh. Seattle temperatures were expected in the low to mid-60s Thursday and Friday. The WECC expected the Pacific Northwest to have a peak load of about 46,405 MW Wednesday, with about 9,745 MW of outages.

The Pacific DC Intertie will continue to be limited to 957-MW flowing north-to-south and 906 MW south-to-north until 5 a.m. Oct. 17 while crews perform annual maintenance on two Celilo converters, according to the Bonneville Power Administration.

Western term markets hardly moved Wednesday during a quiet day of trading. Traders said the market seemed to be waiting for a definitive direction, which could come after the scheduled release today of the Energy Information Administration's natural gas storage number. Packages across the curve generally held their ground Wednesday. Palo Verde November remained in triple digits. Mid-C November held in the mid-$90s/MWh. NP15 and SP15 November held around $110/MWh

Day-ahead markets for delivery Oct 13 ($/MWh)

West	Index	Change	Range	Deals	Volume	Avg $/Mo
On-Peak						
COB	93.06	2.45	92.25-93.75	52	1,450	92.97
Mid-C	85.49	2.02	84.00-86.75	119	3,225	87.07
Palo Verde	106.37	13.60	104.25-108.00	73	2,400	97.24
Mead	106.89	10.54	105.00-108.75	24	750	97.77
Mona	104.00	12.00	104.00-104.00	N.A.	N.A.	95.85
Four Corners	106.00	13.24	106.00-106.00	N.A.	N.A.	96.20
NP15	114.40	8.31	113.50-116.10	89	2,450	104.53
SP15	115.42	8.75	114.00-117.25	278	7,625	105.69
Off-Peak						
COB	83.60	2.84	82.25-85.00	28	775	81.85
Mid-C	81.38	2.51	80.00-82.75	81	2,175	80.30
Palo Verde	80.75	11.57	79.50-83.00	16	400	71.76
Mead	83.25	11.50	83.25-83.25	N.A.	N.A.	75.24
Mona	77.50	10.50	77.50-77.50	N.A.	N.A.	71.83
Four Corners	78.00	12.60	78.00-78.00	N.A.	N.A.	70.56
NP15	86.55	7.15	83.25-88.25	50	1,625	82.40
SP15	86.43	7.78	82.00-88.50	112	3,250	81.30

Near-term forward markets ($/MWh)

Contract	Date	Deal	Contract	Date	Deal
Mid-C			**NP15**		
Bal-month	10/12	84.50-84.50	Bal-month	10/12	108.00-108.25
Bal-month (opk)	10/12	80.50-80.50	Bal-month	10/11	[103.00/105.50]
Palo Verde			**SP15**		
Bal-month	10/12	[97.50/98.25]	Bal-month	10/12	107.50-109.00
Bal-month	10/11	93.75-94.00	Bal-month	10/11	109.00-109.00

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Alamitos-4/AES	335	g	Calif.	MO	Unk	10/11/05
Encina-1/Cabrillo	106	g	Calif.	PMO	Unk	10/08/05
Four Corners-5/APS	745	c	N.M.	MO	10/14/05	10/09/05
Gilroy/Calpine	135	g	Calif.	PMO	Unk	10/11/05
Helms-1/PG&E	407	h	Calif.	PMO	Unk	09/16/05
Helms-2/PG&E	407	h	Calif.	PMO	Unk	19/18/05
Helms-3/PG&E	404	h	Calif.	PMO	Unk	09/18/05
HuntingtonBeach-3/AES	225	g	Calif.	MO	Unk	10/07/05
Mohave-2/SCE	790	c	Nev.	MO	Unk	10/08/05
Palo Verde-1/APS	1,249	n	Ariz.	RF	12/31/05	10/09/05
Palo Verde-2/APS	1,249	n	Ariz.	MO	Unk	10/11/05
Palo Verde-3/APS	1,247	n	Ariz.	RS	Unk	10/11/05
Pittsburg-5/Mirant	312	g	Calif.	PMO	Unk	10/03/05
SunrisePP/Edison	590	g	Calif.	PMO	Unk	10/03/05

For more on methodology, see below

Daily generation outage references

MO	unplanned maintenance outage
PMO	planned maintenance outage
RF	refueling outage
Unk	unknown
OA	offline/available
Fuels:	Nuclear=n; Coal=c; Natural gas=g; Hydro=h

Sources: Generation owners, public information and other market sources.

Long-term Forward markets, Oct 12 ($/MWh)

	Nov	Dec	Q106	Q206	Q306	Q406	Q107	Q207	Q307	Q407	CY06	CY07	CY08	CY09
Mid-C	95.00	105.75	105.50	62.00	91.00	86.00	89.75	54.50	79.25	74.50	86.15	74.50	67.00	62.75
Palo Verde	101.00	110.00	110.75	84.25	107.00	88.00	90.50	75.75	93.00	78.00	97.50	84.30	79.50	74.75
NP15	110.00	118.00	116.75	86.75	110.75	95.75	98.75	78.00	98.25	86.75	102.50	90.45	84.25	80.75
SP15	110.25	118.00	117.25	88.50	113.75	95.50	99.00	80.00	103.00	86.25	103.75	92.05	86.00	82.25

† *All forward prices are for on-peak delivery*

WEST GAS MARKETS

South of Green River drops on maintenance

As other points in the Rockies gained Wednesday, Northwest Pipeline's south of Green River shed nearly $1.20 from Tuesday, as scheduled maintenance on a nine-mile section of Northwest's mainline just north of the Calf Canyon receipt point cut nominations to zero for southbound flows from Northwest's south of Green River station.

"You can't move north and you can't move south—south of Green was a train wreck that dropped more than a dollar and only traded 8,500 Mcf." South of Green River averaged in the low to mid-$9.20s/MMBtu.

Cash prices climbed between 20 cents and 30 cents in the Pacific Northwest and western Canada Wednesday, as buyers south of the U.S.-Canada border purchased gas for storage, sources said.

In the Rockies, spot markets generally surpassed gains on the November NYMEX gas futures contract on continued utility buying, sources said. The Cheyenne Hub gained nearly 50 cents from Tuesday to average in the mid- to upper $11.20s/MMBtu, and Colorado Interstate Gas climbed nearly 35 cents to close in the mid- to upper $11s/MMBtu.

Likewise, Kern River Gas Transmission's Opal, Wyo., plant found more than 35 cents from Tuesday's midpoint to settle in the mid- to upper $11.30s/MMBtu. Pacific Northwest and western Canada spot prices also climbed significantly as indicated by gains of more than 30 cents from Tuesday at Sumas, Wash., which averaged in the mid- to upper $11.20s/MMBtu. Westcoast's station 2 gained nearly as much to close in the low C$12.20s/Gj, and AECO found nearly 20 cents to close in the low C$12.50s/Gj.

Natural gas spot prices in the producing basins climbed more than 65 cents at some points, as Arizona Public Service's Palo Verde nuclear reactor faced outages at all three of its units. Heightened utility demand following the total outage at the APS Palo Verde nuclear reactor boosted Waha more than 65 cents from Tuesday to average in the low to mid-$11.50s/MMBtu, and Permian climbed nearly as much to close in the mid- to upper $11.40s/MMBtu. El Paso's San Juan Basin climbed nearly 60 cents to close in the low to mid-$11.20s/MMBtu.

Elsewhere, Southern California Gas gained more than 50 cents from Tuesday to average in the mid- to upper $11.70s/MMBtu. The Pacific Gas and Electric city-gate found more than 40 cents from Tuesday to average in the upper $12s/MMBtu, and Malin, Ore., climbed nearly as much to settle in the upper $11.60s/MMBtu.

Daily spot gas prices, Oct 12 ($/MMBtu)

	Midpoint	Absolute	Common	Volume	Deals
California					
PG&E, Malin	11.685	11.40-11.80	11.58-11.79	595	78
PG&E, South	11.685	11.62-11.82	11.63-11.74	145	25
PG&E, city-gates	12.095	12.05-12.17	12.06-12.13	713	89
SoCal Gas	11.790	11.60-11.92	11.71-11.87	1,039	121
Rockies/Northwest					
Cheyenne Hub	11.315	11.20-11.40	11.26-11.37	54	12
CIG, Rocky Mountains	11.140	11.04-11.19	11.10-11.18	20	8
El Paso, Bondad	11.305	11.25-11.35	11.28-11.33	56	10
El Paso, San Juan	11.245	11.10-11.32	11.19-11.30	323	48
GTN, Kingsgate	11.470	11.42-11.54	11.44-11.50	94	10
Kern River/Opal plant	11.395	11.28-11.47	11.35-11.44	343	45
Northwest, Wyo. pool	11.175	11.16-11.23	11.16-11.19	87	22
Northwest, south of Green River	8.685	8.24-9.50	8.37-9.00	88	20
Northwest, Can. border (Sumas)	11.280	11.21-11.37	11.24-11.32	190	41
Questar, Rocky Mountains	11.085	11.00-11.20	11.03-11.14	24	5
Stanfield, Ore.	11.520	11.45-11.62	11.48-11.56	190	28
TCPL Alberta, AECO-C*	12.505	12.43-12.61	12.46-12.55	1,260	104
Westcoast, station 2*	12.220	12.17-12.33	12.18-12.26	35	9
West Texas					
El Paso, Permian Basin	11.500	11.18-11.65	11.38-11.62	1,069	149
Transwestern, Permian Basin	11.160	11.00-11.25	11.10-11.22	10	5
Waha	11.530	11.30-11.70	11.43-11.63	514	95

** TCPL Alberta, AECO-C and Westcoast station 2 prices are in Canadian dollars per gigajoule.*

NYMEX Henry Hub futures contract closings, Oct 12

Month	High	Low	Close	Change
Nov 2005	13.615	13.365	13.524	0.005
Dec 2005	14.100	13.850	14.009	0.025
Jan 2006	14.450	14.300	14.430	0.026
Feb 2006	14.300	14.150	14.270	0.026
Mar 2006	13.850	13.700	13.830	0.031
Apr 2006	10.800	10.650	10.800	0.081
May 2006	10.350	10.240	10.350	0.076
Jun 2006	10.345	10.270	10.345	0.076
Jul 2006	10.375	10.255	10.375	0.076
Aug 2006	10.410	10.340	10.410	0.076
Sep 2006	10.385	10.320	10.385	0.076
Oct 2006	10.415	10.360	10.415	0.076
Nov 2006	10.830	10.800	10.830	0.076
Dec 2006	11.240	11.160	11.240	0.076
Jan 2007	11.550	11.400	11.550	0.076
Feb 2007	11.455	11.400	11.455	0.076
Mar 2007	11.145	11.100	11.145	0.071
Apr 2007	8.965	8.950	8.965	0.071

Open int., Oct 11: 73518; Total volume, Oct 11: 562093.

Platts Energy Trader spark spreads, Oct 12 ($/MWh)

	Mid-C				Northern California				Southern California			
	Median	Change	Peak	Change	Median	Change	Peak	Change	Median	Change	Peak	Change
Gas	-14.56	-0.77	-47.16	-1.68	-17.58	3.51	-62.49	1.87	-6.28	3.33	-63.14	0.80
Coal	80.83	2.02										
Nuclear	80.94	2.02			109.91	8.31			110.55	8.75		

Platts Energy Trader spark spreads are the differences between on-peak spot electricity prices and spot fuel prices in a region calculated at two heat rates. A positive number shows the cost advantage (in $/MWh) of using that fuel to generate electricity; a negative number shows it is more economical to purchase power. The median heat rate is a composite of generating units using that fuel in each region. The peak heat rate is based on the least efficient 25% of generating plants.

East Power ... from page 2

climb a few degrees to the mid- and upper 60s, near normal for this time of year. Public Service Enterprise Group's 1,150-MW Salem-1 unit in Hancocks Bridge, N.J., was shut Tuesday night for a scheduled refueling outage, a company spokesman said. Meanwhile, the company's Salem-2 unit continues to operate at full power.

Southeast dailies for Thursday delivery declined ahead of forecasts calling for unseasonably warm weather. Into Southern dailies moved in the mid-$90s/MWh, a decline of about $5 from the previous day's index.

Into TVA dailies for Thursday flow declined a couple of dollars on average to the mid-$70s/MWh in response to warmer weather forecast in Nashville in the upper 70s, well above seasonal norms.

The Dominion Hub struggled to gain about $1 from the previous day's index, moving near $97.45/MWh on rising spot gas prices and higher prices in nearby regions.

VACAR dailies weakened more than $4 on average, finally breaking free of the triple-digit zone on pleasant weather keeping loads light.

Northeast forwards were mixed behind slightly higher NYMEX gas futures. The NYMEX natural gas contract for November closed at $13.524/MMBtu, up a half-cent after trading between $13.365/MMBtu and $13.615/MMBtu. In New York, November was assessed at $100/MWh in Zone A, at $120.75/MWh in Zone G, and at $142.25/MWh in Zone J. In PJM West, the prompt month climbed 15 cents to $90.15/MWh. At the New England Mass Hub, November fell 25 cents to $127.75/MWh.

Ontario dailies traded at C$100/MWh (US$85.42/MWh) for Thursday flow, down C$7 with near-normal weather expected to continue. Forecasts showed a high of 59 in Toronto, 1 degree above normal. Balance-of-the-week was offered at C$105/MWh, with outlooks showing a high of 61 on Friday and through the weekend. Weekend peak was bid at C$60/MWh and offered at C$100/MWh. Three nuclear reactors totaling 2,315 MW remained down for maintenance. Next-week traded down to C$105/MWh, with the follow bid at C$103/MWh on offers at C$106/MWh. Highs were forecast from 56 to 61 degrees. Ontario term markets remained generally flat, with November assessed at C$114/MWh.

Market coverage

Platts provides a detailed Data Submission Guide specifying the information it collects in its North American gas and electricity price surveys. The guide is available at www.platts.com. From the home page, follow links to either Electricity or Natural Gas and then to Methodology & Specifications.

IN THE NEWS

Shut-ins stall as feds warn of slow recovery

The recovery of natural gas production in the Gulf of Mexico region ground nearly to a halt Wednesday as the federal government produced its first forecast indicating that significant amounts of gas will be off line through the winter heating season.

The Minerals Management Service said producers reported 59%, or 5.92 Bcf/day, of the Gulf's normal 10 Bcf/day production remained shut in Wednesday, a tiny 1% increase in production over the day before. Producers told the MMS that 256 of their platforms had yet to be remanned, amounting to 31% of the Gulf's 819 platforms. All but three drilling rigs have been remanned, the MMS said.

At least 2 Bcf/day of production will remain shut in through December, the Energy Information Administration predicted in its Short-Term Energy Outlook, released Wednesday, with the Gulf not reaching full production until March of next year.

The EIA noted that 20 gas-processing plants along the Gulf Coast remain out of action for either lack of electricity or being flooded by hurricanes Rita or Katrina.

"A number of non-operating plants with a total capacity of 4.76 Bcf/day are operational, but are not active owing to upstream or downstream infrastructure or supplies being unavailable," the EIA said. Several plants with 2.87 Bcf/day of processing capacity are expected to be restarted in the next four weeks.

The first signs that industry is already exploring work-around solutions to the gas processing bottleneck came Wednesday as Tulsa-based Williams announced an "expedited open season" for up to 250,000 Dt of firm transportation on its Discovery pipeline system (see separate story. Discovery runs from the deepwater Ewing Banks in the central Gulf through the South Timbalier blocks to come ashore in central Louisiana east of the Henry Hub.

Williams said it had received approval from the Federal Energy Regulatory Commission to construct a new receipt point at Texas Eastern Transmission's Larose compressor station in Lafourche Parish, La.

The new connection is designed to "provide an alternate outlet for natural gas that has been stranded following damage to third-party facilities during Hurricane Katrina," Williams said, indicating the transmission path will bypass damaged processing stations in St. Bernard's and Plaquemines Parishes. Three processing plants with a combined 4.2 Bcf/day of processing capacity were flooded in those parishes during Katrina.

Offshore and upstream, new details became available Wednesday from larger producers about the progress of their recovery efforts.

Shell said it had returned 44%, 200,000 barrels of oil-equivalent/day, of its 450,000 boe/day of pre-storm gas and oil production, with full production coming from its Brutus, Popeye, Fairway, North Padre Island, Bullwinkle, Boxer, Enchilada, Salsa, Conger and Cougar fields. Shell's production ratio is 60% oil and 40% gas.

Chevron's ill-fated Typhoon production platform "may be a total loss," Chevron's president for North American operations, Ray Wilcox, warned in a luncheon speech Wednesday in Houston.

Typhoon was found capsized in 2,000 feet of water in Green Canyon 236-237 after Hurricane Rita, about 70 miles from its original location. While Chevron's investigation is continuing, government leaders in Washington have speculated that an unmoored drilling rig collided with Typhoon, effectively decapitating the platform from its wells and moorings.

Wilcox displayed photos of the capsized facility and told the audience: "The cables broke loose; it flipped over and stopped when the helicopter deck hit the mud. We have our hands full."

Wilcox said Chevron plans to resume production at the field as soon as possible. He could provide no target timeline for assessment, and said Chevron would evaluate the remaining reserves at Typhoon before determining the best method for resuming production there.

Onshore, the Louisiana Dept. of Natural Resources said Wednesday that the operators of onshore and shallow-water wells in a 38-parish region of the state have restored 686,800 Mcf/day, 31% of the region's pre-storm output of 2.235 Bcf/day.

Wednesday's numbers are virtually unchanged from those of Tuesday, when DNR said operators had restored 683,600 Mcf/day of its gas production.

The DNR said that as of Wednesday, 1,253 wells—representing 21% of the region's 5,949 producing wells—have been restored to production. DNR said 2,756 wells, or 46% of the region's total, remain shut in. The status of 1,949 wells, or 33% of the region's wells, has not been reported. Only two of the state's intrastate pipelines are fully operational, DNR said, while 42 remain shut in, nine are partially open and two cannot be contacted.

EIA: U.S. demand for electricity to rise 3.5%

Citing the impact of higher natural gas prices in the wake of hurricanes Katrina and Rita, the Energy Information Administration on Wednesday raised its earlier forecast for 2005 residential electricity prices to 9.3 cents/kWh, adding wide regional differences are likely, depending on the generation fuel mix.

The agency in September projected that average residential electricity prices this year would be 9.1 cents/kWh. The 2006 estimate remained unchanged at 9.5 cents/kWh.

In its October Short-Term Energy Outlook, EIA said estimated 2005 prices for delivered energy across all end users will range from 6.4 cents/kWh in the West-North-Central region to nearly 12 cents/kWh in New England. Largely because of higher utility fuel prices, EIA said, average electricity prices for all customer classes are projected to increase by 8.9% in New England and 8.2% in the West-South-Central region, but less than 6% for all other regions between 2004 and 2005.

EIA, in its forecast for winter (October through March) heating prices, estimated that households heating primarily with natural gas can expect to spend about $350 more—a 48% hike—this winter to heat their homes than last year. Households relying on heating oil will pay an average of $378 more (32% more); those with propone can expect to pay $325 more (30%), on average; and those heating primarily with electricity will likely pay $38 more (5%).

About 29% of U.S. households heat with electricity, and EIA said that, "while winter electricity expenditures are not as high as expenditures for natural gas and heating oil, households in the South are projected to pay about 9% more this winter on electricity bills due to increased consumption and prices relative to last year."

The agency also predicted that U.S. demand for electricity will rise 3.5% in 2005—compared with its September forecast of a 2.5% growth rate—largely because of weather conditions and continuing economic growth. In 2006, EIA believes power demand will rise by 1%, down from its September forecast of 1.9%.

EIA estimated that coal demand by the electric power sector will increase 4.5% in 2005 and remain at 2005 levels in 2006. In its September outlook, the agency put 2005 growth in coal demand at 3.1%, and projected 0.4% growth in 2006. U.S. coal production, it said, is expected to grow by 2.6% in 2005 and by an additional 1.6% in 2006. In its September outlook, EIA had coal demand growing 1.9% in 2005 and by an additional 2% in 2006.

EIA: Hurricanes cause grim energy outlook

The damage done by back-to-back major hurricanes to the nation's natural gas production and processing infrastructure in the Gulf of Mexico has resulted in "a particularly difficult outlook" for the upcoming winter heating season, Energy Information Administration Director Guy Caruso said Wednesday.

Caruso released an EIA report that asserts the 2005 Henry Hub natural gas price will average $9/MMBtu, dipping slightly to $8.70/MMBtu in 2006. The agency in September issued a 2005 Henry Hub target price of $8.82/MMBtu and a 2006 price of $8.42/MMBtu.

In its Short-Term Energy Outlook for October, EIA said its earlier warnings 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 effect of the storms on oil and gas production, oil refining, natural gas processing and pipeline systems, EIA said, "have further strained already-tight natural gas and petroleum product markets on the eve of the 2005-06 heating season."

The agency said its baseline projections in the outlook assume continued recovery of the energy infrastructure in the Gulf through the end of 2005 and project that shut-ins in the Gulf in December will average 20.6% for natural gas (4.2% of total U.S. production) and 33.1% for crude oil (10.4% of total U.S. production).

EIA said Henry Hub spot gas prices averaged $12.40/Mcf in September, largely because hot weather in the East and Southwest increased demand by gas-fired generators, followed by the effects of Katrina. "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," the agency said, adding that Henry Hub prices are likely to remain above $12/Mcf until winter peak demand is over.

Caruso said in a press conference the current spot gas price is about $13.50/Mcf.

On average, consumers across the country will likely spend about $350, or 48%, more for natural gas as a heating fuel this winter, EIA added.

The EIA said residential natural gas price increases from 2004 to 2005 are expected to range from 14% in the New England region to 27% in parts of the southeast. Gas consumption is expected to rise 4% in the West where the average price has increased 29% over the same period a year ago. In the south, consumption is expected to increase 5% and the average price has increased 48%. In the Midwest, consumption is expected to increase 4% and the average price has increased 44%.

Gas consumption in the Midwest is expected to expand because the region experienced a warmer than normal winter in 2004-2005 and the National Oceanic and Atmospheric Administration is predicting a winter with normal temperatures for the region this winter.

Industrial users, EIA added, can expect gas price increases ranging from 16% in the Rocky Mountain region to 40% in the Pacific and West-North-Central regions of the country. Given the United.States' limited ability to import natural gas, it warned that retail prices could be "significantly higher should winter weather be 10% colder than predicted."

In addition, EIA said working gas in storage as of Sept. 30 was estimated at 2.93 Tcf, 151 Bcf below what it was at the same time last year, though 1.4% above the five-year average and about 122 Bcf above last month's projection.

The agency said that although storage levels are above the five-year average, the hurricanes reduced peak storage achievable over the remainder of the injection season from what was expected previously. Working gas in storage by year-end is expected to total about 2.5 Tcf—200 Bcf below 2004 levels and about 50 Bcf above the five-year average, EIA said.

Natural gas demand in the United States is expected to drop by 1.1% to 1.2% this year vs. 2004 because more industrial plants are switching to residual oils as a fuel source and the petrochemical sector is using less gas in the wake of production cuts resulting from the hurricanes, Caruso said.

Demand, however, will recover by 3% in 2006, based on an assumed return to normal weather and a recovery in consumption by the industrial sector, the agency added. Caruso told reporters EIA does not see the demand destruction continuing. He insisted "we would see a rebound" by gas-consuming industries and industrial demand for gas should increase 3% in 2006 compared with this year. "The demand destruction is not permanent," he said.

He said the chemical and pulp and paper businesses have been switching to other fuels when possible. Otherwise, they have been importing more raw materials from other countries.

Caruso said at a press conference he expects a steady recovery of the oil and natural gas infrastructure in the Gulf of Mexico, but it will be “a months-long recovery” that will continue through 2006.

Caruso noted on several occasions that residences that rely on electricity probably will only experience a 5% increase in home heating costs this winter. He attributed the low increase to the industry’s dependence on coal and nuclear energy as its fuel source.

The EIA noted that imports of liquefied natural gas “appear to have exhibited little change through the first half of 2005.” 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. The agency said imports for 2005 are expected to be about 680 Bcf compared to 650 Bcf in 2004. It estimates LNG imports will be greater than 1 Tcf in 2006.

EEA: Demand destruction to balance winter gas

Industrial demand destruction will balance the U.S. gas supply market this winter, but even with normal weather Henry Hub prices will average about $13/MMBtu during the winter, an Arlington, Va.-based analyst said Wednesday.

Speaking at the 2005-2006 Winter Fuels Outlook conference in Washington, D.C., Kevin Petak, the director of modeling and forecasting for Energy and Environmental Analysis, warned that there is still much uncertainty over the upcoming winter and the Gulf coast production recovery.

Petak said the hotter-than-normal summer followed by production shut-ins from hurricanes that hit the Gulf of Mexico coast resulted in a tight market that could get tighter if a colder-than-normal winter hits or production returns more slowly than expected.

“A slower recovery scenario for Gulf Coast supplies than what is applied herein would lead to higher gas prices and greater demand destruction,” Petak said. “Under some scenarios where much of the gas supply that is currently off line remains out of service for most of the winter, load curtailment could be required even under normal weather conditions.”

Petak said a winter that is 6% or more colder also could require government intervention to allocate supplies.

Last summer averaged from 14% to 22% hotter than normal, he said, resulting in a 15% higher usage by gas-fired power plants. In addition, supply disruptions due to hurricanes Katrina and Rita have averaged about 2 Bcf/day during the injection season.

Petak said the combination makes it unlikely U.S. storage will fill to the 3.26 Tcf level expected before the hurricanes. Instead, Petak said, he expects storage to reach 3.09 Tcf by Nov. 1.

Even with a normal winter, residential and commercial demand is expected to be up over last winter since last winter was 4% warmer than normal, he said.

Offsetting that, however, is an expected increase in liquefied natural gas imports from Egypt and Trinidad. Canadian imports are also expected to be higher than last year since Canada had a colder-than-normal winter last year.

Additionally, high prices will cause fuel switching, closed facilities and conservation, which will bring the nation’s supply-demand into balance.

Long term, Petak said, demand will lead supply with gas consumption in the power sector growing substantially as more than 200 GWh of new gas-based generating capacity is used to satisfy an increasing electric load that has grown by 2% per year in the past 15 years. Coal generation is expected to increase as well, but will only satisfy 40% of growth in the electricity load, Petak said.

Industrial gas use will continue to decline at current price levels, but should level off as prices moderate in the longer term.

While Petak said the supply can support the growing market, he warned that it cannot be done unless new pipelines, storage and liquefied natural gas infrastructure is built.

The analyst said that with production from mature producing areas declining about 1% a year, new frontier supplies will account for 38% and 45% of total U.S. and Canada gas supply in 2015 and 2025, respectively, vs. 18% today.

Petak said that continued price pressure is expected to persist for the next few years, with Henry Hub prices averaging between $6/MMBtu and $9/MMBtu. “1990 levels will not return,” Petak said.

LG&E, KU ask FERC to let them to leave MISO

LG&E Energy has asked the Federal Energy Regulatory Commission for permission to pull its two Kentucky utilities from the Midwest Independent Transmission System and hire the Tennessee Valley Authority to serve as their reliability coordinator and the Southwest Power Pool as their tariff administrator, a company spokeswoman said Wednesday.

LG&E Energy filed the request on behalf of its Kentucky Utilities and Louisville Gas & Electric subsidiaries on Oct. 7, but the filing was not publicly available on FERC’s Website.

LG&E expects the alternative arrangements will cost less than MISO membership, with lower administrative and energy expenses, the spokeswoman said. MISO “was fine in the beginning,” but its Day 2 markets have proven “more costly,” she said.

A Kentucky Public Service Commission hearing on the costs of the Midwest regional transmission organization concluded recently and a ruling is pending.

Under the proposal filed with FERC, the LG&E utilities would continue to control transmission under normal circumstances, but during times of constraints, TVA would direct them, the spokeswoman said. As an independent tariff administrator, SPP would serve as an overseer and “help manage use on the grid,” she added.

Even with two entities replacing MISO’s Day 1 services, LG&E

still expects the proposal to be "the most cost-effective way" to comply with FERC regulations and North American Electric Reliability Council standards, the spokesman said.

National Fuel seeks nod for N.Y. gas pipeline

National Fuel Gas Wednesday said its Empire State Pipeline subsidiary has asked the Federal Energy Regulatory Commission to approve its plan to build and operate a $144 million, 78-mile connector that will tie its pipeline into the Millennium Pipeline near Corning, N.Y.

The Empire State Pipeline is a 24-inch-diameter natural gas transmission pipeline that originates at the U.S.-Canada border at the Chippewa Channel of the Niagara River, and extends 157 miles east from Buffalo to near Syracuse, N.Y. National Fuel acquired the line in 2003. Developing the Empire Connector involves constructing a pipeline southward from this existing line near Rochester, N.Y., to connect with the Millennium Pipeline near Corning.

Empire said it plans to build about 78 miles of 24-inch pipeline and one 20,620-horsepower compressor station. The Empire Connector will be designed to move about 250,000 Dt/day and provide customers with access to gas supplies at the Dawn hub through the Empire State Pipeline's connection with the TransCanada PipeLine system at Chippawa.

"The Empire Connector Project will provide a necessary and important alternative for providing natural gas supplies to customers in New York state," said Philip Ackerman, National Fuel's chairman, president and CEO. "Recent catastrophic weather events and record-setting natural gas commodity prices have emphasized the need for diversification of natural gas supply options in order to ensure that reliable supplies of natural gas will be available to meet our nation's energy needs."

Empire has asked FERC to approve its project in the spring of 2006 and expects to begin construction a year later. The line is expected to be in service in the fall of 2007.

KeySpan Gas East Corp, a subsidiary of KeySpan Energy Corp, which is the largest distributor of natural gas in the Northeast, has subscribed for at least 150,000 Mcf/day of transportation service through the Empire Pipeline and the Millennium Pipeline systems.

Reliant strikes $299M loan to cover gas costs

Reliant Energy has borrowed $299 million from the New York branch of Deutsche Bank AG to "support collateral posting obligations" and to "maintain prudent liquidity reserves in light of increased natural gas prices."

Reliant revealed the loan in a Securities and Exchange Commission form 8-K filing Oct. 11.

The five-year term loan, which matures April 2010, was priced at 2.375% over the London Inter-Bank Offered Rate (LIBOR).

Houston-based Reliant provides retail power to 1.9 million residential, small business, large commercial, industrial and institutional customers in Texas. It also serves industrial and commercial clients in the PJM Interconnection and owns 19,000 MW of merchant generating capacity mainly in the Northeast.

Along with the entire power industry, Reliant faces what it describes as a doubling of natural gas prices since December 2004. The borrowing from Deutsche Bank, which heads up a syndicate of banks that provide other credit facilities to Reliant, is seen as a move by Reliant to insure it has funds to make future purchases of natural gas.

The company has asked for some relief from state regulators. On Oct. 3, Reliant Energy asked the Public Utility Commission of Texas for permission to increase the fuel portion of electric bills for Houston-area residential and small business customers. Reliant told the Texas PUC that based on current prices for natural gas, Reliant's new price for power should be 16.04 cents/kWh, compared with the current price of 12.88 cents/kWh, a 25% increase.

However, Reliant said it would base its fuel factor for the remainder of 2005 on natural gas prices that were in effect prior to Hurricane Katrina, which hit the Gulf Coast Aug. 29. Reliant said this would result in a 14% discount to the fuel factor, or a price of 14.7 cents/kWh.

In its statement to the Texas PUC, Reliant said that the increase in natural gas prices is a national trend "affecting all electricity suppliers and their customers."

"All of the other affiliated retail providers in Texas have filed for at least one price increase this year. The reason is that natural gas is the primary driver of the cost of electricity in Texas. Reliant Energy's current fuel factor, which was set in December, is based on a natural gas price of $7.50/MMBtu. The price of gas in the company's current fuel filing is $11.39/MMBtu," Reliant said.

Discovery has open season for bypass service

Williams' Discovery Gas Transmission LLC unit on Wednesday launched an expedited open season for up to 250,000 Dt of "emergency" firm transportation service after the pipeline received approval to build a new receipt point with Texas Eastern Transmission to bypass the damaged and currently shut-in Venice gas-processing plant in Louisiana.

The company proposed using Discovery Producer Service's gas-gathering line to transport unprocessed offshore gas to an alternative processing plant in Larose, La., from which the gas will be distributed through the Texas Eastern network.

The in-service date for the connection with Texas Eastern at the Larose station in Lafourche Parish is set for mid-November. The open season will end at 5 p.m. CST Oct. 21.

The primary term for the emergency service will be for one year or until certain processing facilities return to service, whichever comes first, Williams said. Service will be performed at Discovery's existing FT-2 rate schedule.

Shippers may contact Kevin Rehm at (713) 215-2694, or Asa Roberts at (713) 215-3078, for a copy of the transportation services agreement.

The Federal Energy Regulatory Commission late Tuesday granted Discovery emergency waivers that will allow it to reroute its pipeline system to transport natural gas shut in due to damage incurred at the Venice plant in the aftermath of Hurricane Katrina.

The exemption from some federal regulations addresses Discovery's request to build about $3 million in interconnections without triggering rules that restrict emergency transactions to 120 days.

"This emergency action will help speed the recovery of badly damaged energy supplies in the Gulf Coast," said Chairman Joseph Kelliher. "The more natural gas that reaches the market, the less the price impact will be for homeowners this winter heating season."

NOAA: Equal chances for cold in N.E., Midwest

The Midwest, Northeast and Southern California coast have equal chances for warmer, cooler or near-normal temperatures this winter, according to the 2005-06 Winter Outlook released Wednesday by the National Oceanic and Atmospheric Administration.

The forecast, covering December through February, calls for warmer-than-normal weather across the rest of the central and western United States, including Alaska and Hawaii.

NOAA said its precipitation outlook calls for wetter-than-normal conditions across most of Arkansas, Louisiana, Oklahoma and northeastern Texas. Drier-than-normal conditions are expected across the Southwest from Arizona to New Mexico. There are equal chances for above- or below-normal precipitation levels in the Pacific Northwest and California, where hydroelectric generation is prevalent.

"For the sixth year in a row, drought remains a concern for parts of the Northwest and northern Rockies," NOAA said. The agency added that it would take "a number of significant winter snowstorms to end the drought" in that area.

NOAA said it does not expect a La Nina or El Nino to play a role in the winter forecast. Without those factors, forecasters are looking to other short-term climate trends such as the North Atlantic Oscillation in determining overall patterns, NOAA added. "Under these conditions there tends to be more variability in winter weather patterns across the nation, especially in the Great Lakes region and the northeast United States," NOAA said.

The agency said it would update its winter forecast on Oct. 20 and Nov 17.

PNM Resources: May lose $3.6M in hedge fund

PNM Resources may not recover $3.6 million it has invested in a troubled hedge fund, Wood River Partners, the Albuquerque, N.M.-based electric and natural gas utility holding company told the Securities and Exchange Commission late Tuesday.

PNM said it determined Oct. 7 that its Wood River investment "had experienced a loss in market value," PNM said. "At this time, PNM does not have any basis by which to estimate the amount, if any, of recovery of the Wood River investment," the company said.

PNM said it invested in the San Francisco, Calif.-based hedge fund as part of its efforts to achieve higher returns than it could get with passive cash management plans, the company said. PNM has $12 million invested in its "enhanced" cash management program.

Wood River is not returning calls to investors and is under investigation by the SEC, according to media reports.

APS' 3,745-MW Palo Verde nuclear unit off line

Arizona Public Service Co.'s 3,745-MW Palo Verde nuclear power plant is off line, with no specific date for return.

Units 2 and 3—a total of 2,496 MW—were taken off line Oct. 11 because of problems with both units' emergency core cooling systems (ECCS), the Nuclear Regulatory Commission reported.

The outage of the 1,249-MW Unit 2 and the 1,247-MW Unit 3, combined with the already off line 1,249-MW Unit 1, make for a complete outage at the nuclear plant in Wintersburg, Ariz. Unit 1 has been down for a scheduled refueling and maintenance outage since Oct. 9, and is expected to return to service in late December.

An NRC inspection team identified the problem last week while verifying that APS had taken appropriate actions to address a "yellow" finding issued in April because of problems with the cooling system, said NRC spokesman Victor Dricks.

As designed, the ECCS at Palo Verde draws water from the refueling water tank (RWT) during a loss-of-coolant accident. When the water level in the RWT drops to 7.4%, a valve trips, prompting the ECCS to then draw water from the containment sump, Dricks said. The concern was whether there was sufficient pressure to make that transition to the containment sump, he said.

If the baffles at the bottom of the RWT are exposed, the safety injection pumps could be rendered inoperable, he said. "It's not that the system won't work" as designed, APS spokesman Jim McDonald said Oct. 12. "It's that right now, that they can't prove that it could." McDonald was unable to say how long the units would be down. NRC doesn't think the situation exists at other pressurized water reactors but has asked NRC resident inspectors to verify that, Dricks said.

NRC issued the yellow finding because an ECCS pipe that runs from the containment sump to the pumps had been incorrectly left empty of water in each of Palo Verde's three reactors since the plant began operations in the 1980s. The inspection team plans a second weeklong visit to the plant later this month. An inspection report is to be issued in December. A yellow finding indicates a substantial safety issue. Only a red finding, which indicates a high safety issue, is more serious.

Standard & Poor's said Wednesday's announcement that the Palo Verde-2 and -3 nuclear units have been taken off line because of safety concerns detracts from credit quality of part owner Arizona Public Service Co. and its parent Pinnacle West Capital Corp. The effect of the outages on ratings, however, cannot be determined at this time, S&P added.

S&P said critical to its assessment of the credit impact will be the length of time that the units will likely be off line, the cost of replacement power, and the ability of the company to absorb these costs without a significant impact on its near-term financial performance.

The ratings agency said concerns with the unit's emergency cooling systems were first identified in August 2004, when it was found that piping in the emergency cooling system that should have been filled with water was dry. This led to concerns that under certain accident scenarios, the equipment could malfunction, S&P said.

APS owns 29.1% of Palo Verde, and the units annually provide about 27% of the utility's retail energy requirements, S&P said.

Enron to pay $3.6M to resolve market claims

Enron put to rest its tangle with Salt River Project Agricultural Improvement and Power District and affiliate New West Energy by agreeing in an Oct. 11 joint settlement to pay them about $3.6 million.

The settlement addresses the 2000-2001 California crisis spot market refund proceeding, the Enron gaming case and other related proceedings.

During the crisis, SRP was a net buyer in the California spot market and New West was a retail provider in the state. SRP also purchased bilateral energy from Enron in Western spot and forward markets.

If the settlement is approved by the Federal Energy Regulatory Commission and the U.S. Bankruptcy Court for the Southern District of New York, which is presiding over the Enron bankruptcy, Enron will provide an unsecured claim of $2.7 million to the SRP parties.

In addition, in connection with SRP having opted into a global settlement Enron clinched with California agencies and investor-owned utilities, Enron will pay it $884,065 in cash.

DOE helps Entergy plan system reconstruction

The Dept. of Energy is developing recommendations to help Entergy Corp. incorporate the best available technology as it rebuilds its electricity infrastructure in the New Orleans area, a company official said Wednesday.

At Entergy's request, DOE held a meeting Monday with representatives of Entergy, other electric utilities and the department's national laboratories to discuss technologies that would enable the company to replace generation and distribution facilities ruined by Hurricane Katrina as quickly as possible, while putting together the most resilient system possible, Floyd Galvan, a senior project research and development manager with Entergy, said in an interview.

"We're not only rebuilding but also implementing new technologies," he said. "It's important to us to have the community understand what the deal is with us so they can help us as we go forward."

DOE's Office of Electricity Delivery and Energy Reliability will prepare recommendations based on the discussions Monday, Galvan said.

Among others participating in the meeting were representatives of American Electric Power, Exelon Corp. and the Tennessee Valley Authority as well as the Lawrence Berkeley, Oak Ridge, Pacific Northwest and Sandia national laboratories, he said.

The topics discussed included new technologies for managing loads, sensing disruptions and building modular substations. The group also talked about distributed-energy systems that Galvan said could help provide electricity to temporary mobile-home developments.

Galvan said DOE plans to convene another meeting that would also include representatives of state and local governments with a say in utility matters.

Earlier this week, Kevin Kolevar, the director of the DOE office, said the department would promote collaborations involving industry and governments at various levels to help rebuild energy infrastructure in the Gulf Coast region. Kolevar declined, however, to discuss the meeting with Entergy.

Attorneys cast ex-traders as crooks, victims

Former Duke Energy employees Tim Kramer and Todd Reid either were engaged in a plot to manipulate Duke's earnings and line their own pockets, or were two loyal employees who were unjustly cast as scapegoats and fired by a company suddenly fearful over investigations into its trading practices, according to opening statements at the conspiracy and fraud trial in Houston Tuesday.

The trial got under way in the U.S. District Court for the Southern District of Texas Tuesday morning following the seating of a jury Monday.

The two are charged with mail fraud, wire fraud, falsifying books and records, and conspiracy. Prosecutors claim Kramer, the former head of the financial portfolio management group and head trader for the Duke North America East Desk, and his boss, Reid, DENA head of trading, engaged in a scheme to improperly book the results of gas trades in 2001 and the first several months of 2002.

Assistant U.S. Attorney James Powers said the two engaged in a conspiracy to do round-trip trades at prices that were out of the market price to book about $50 million in false profits and to increase their own performance bonuses.

Duke discovered the fraud in mid-2002 and launched an internal investigation, during which the defendants made false statements, Powers said. On June 30, 2002, "Duke had to adjust the books to the tune of over $50 million," he said. "When the dust cleared, the defendants were terminated."

"Todd Reid and Tim Kramer became scapegoats for Duke," said Jack Zimmerman, attorney for Kramer. "They had no intent to violate the law at all."

Reid's attorney, Thomas Hagemann, echoed the same theme, saying the two defendants were victims of a company looking to distance itself from a wave of scandals involving wash trades that swept the energy trading industry in the spring of 2002.

"This is a tale of two Dukes," he said. One was "the Duke that loved success" and encouraged its traders to be flexible in their quest to make money. The other was "the Duke that got scared."

On Aug 1, 2002, Duke fired Kramer, which Hagemann called "the second-biggest tragedy," of the situation. "They also fired his boss. They decided to absolve everyone else," Hagemann said. "There was no conspiracy to defraud Duke Energy. There was never a moment when Mr. Reid lied to anyone at Duke Energy about what was going on."

Powers, in his statement, said Kramer was responsible for maintaining two types of books accounting for trades—the mark-to-market book, which was valued against the NYMEX settlement price at the end of trading each day, and the accrual book for long-term trades, in which the trades were not valued until the underlying transaction took place.

"The accrual book lost a lot of money," Powers said, while the mark-to-market book "made out like a bandit."

He said accounting rules permit the transfer of trades between the two sets of books, provided certain safeguards are in place. However, he said, Reid and Kramer went around those safeguards for their own purposes.

"Kramer was called upon by Reid to cover up for Reid's section," Powers said. He said Kramer produced a fraudulent profit in the mark-to-market book, by choosing profitable trades for inclusion while putting unprofitable trades in the accrual book.

"Sometime in the fall of '01, the mark-to-market book had made its target as far as bonuses," he said. At the end of 2001, Reid received a $5 million bonus, Kramer a $4 million bonus, substantially higher than those of other traders, Powers said.

In addition, Powers said the defendants generated false profits by doing more than 50 round-trip trades at off-market prices. Although Duke permitted round-trip trades—the simultaneous buying and selling of the exact same commodity at the same price—for limited purposes, Powers said the two used the trades to manipulate earnings by doing them at off-market prices.

Because the two sides of the round-trip trade canceled each other out, "the counterparty might not care if the price is off-market," Powers said. However, the practice was prohibited under Duke's trading guidelines, he said. "Traders signed agreements saying they wouldn't do trades at off-market prices."

Powers said the traders under Kramer's direction used a number of "tricks" to record round-trip trades at off-market prices, such as using the previous day's settlement prices. In a single two-day period, May 15-16, 2001, using this method, the traders were able to book $5 million to $6 million in bogus profits, he said.

"By the time June rolled around, other traders had gotten suspicious," Powers said. A Duke middle office employee began an investigation during which Kramer lied about the timing of the trades, Powers said. "Kramer said the trader did the trade the day before and didn't get it in the book that day," he said.

After the back-office investigation, Kramer allegedly changed the method of booking the off-market round-trip trades, Powers said. From June 23, 2001, to mid-2002, when the fraud was discovered, every off-market round-trip trade was split up into two or more separate trades, with different prices and volumes, to make detection more difficult, Powers said.

At around this time, Powers said Kramer recruited former Duke gas trader Brian Lavielle into the conspiracy. Lavielle, who was arrested with Kramer and Reid in April 2004, last February pleaded guilty to one count of falsifying DENA's books and agreed to cooperate with prosecutors. Powers said that Lavielle would testify that Kramer directed him in the methods of the fraud, such as how to record round-trip trades so as not to appear on the back office's "radar screen."

Zimmerman said Kramer, who graduated from the Naval Academy in Annapolis, Md., in 1986 and served for seven years as a naval engineering officer, "always sought guidance on the rules and always followed the rules" and "always let everyone know what he was doing."

He contended that the wash trades that were done were not illegal and that the transactions that were placed in the mark-to-market book were there for legitimate business reasons. "All these things were done in the open," Zimmerman said.

Zimmerman also said that Kramer earned his bonus legitimately for being Duke's top trader in 2001, the best year in history for Duke Energy, in which the company booked $4 billion in profits. He added that top managers who awarded the bonuses looked at accrual books as well as the mark-to-market book and other factors such as Kramer's teaching a course at Rice University and publishing a book in that time period.

He suggested that professional jealousy led less successful traders to suspect Kramer. "Kramer was the most productive trader, not the most popular," he said.

Hagemann said Reid, as head of trading, could not be connected to the individual trades that prosecutors claim were bogus. "Reid did not trade. Reid was responsible for being strategic, for looking at the big picture," he said. "Reid was not aware of any trades being done at off-market prices."

After his firing, Reid appeared before the Commodity Futures Trading Commission and the Securities and Exchange Commission, where he "answered every question," and did not seek the protection of the Fifth Amendment, Hagemann said. Reid also sued Duke Energy for unjust firing, his attorney said.

"Todd Reid is a good man," Hagemann said. "Todd Reid's basic strategy was to shine a bright light on everything."

The trial judge, U.S. District Judge Nancy Atlas, predicted the trial would last four weeks.

Duke Energy ... from page 1

Progress Ventures and the power purchaser.

Progress Ventures will pay to Duke Energy "cash in consideration for the assignment of the transferred power sales transaction." Progress was ranked 54th in the second quarter of

2005 among wholesale power sellers.

Duke Energy says that the transaction involves "legacy business," such as contracts with commercial entities, from the group of eight generating facilities with a combined 5,300 MW of capacity, that were sold for $450 million to KGen Energy, an affiliate of the MatlinPatterson private equity group, in May 2004.

Duke Energy, which has long been among the nation's 10 largest wholesale power sellers, has been winding down its trading for almost two years.

Duke Energy recently said it intends to sell most of subsidiary Duke Energy North America's remaining trading book, and some 6,100 MW of merchant power capacity, as it prepares for its merger with Cinergy.

In mid-2003, Duke also began winding down the trading operations of its 60/40 Duke Energy Trading and Marketing (DETM) joint venture with ExxonMobil, begun in August 1996.

According to a spokeswoman at Duke Energy North America in Houston, the unwinding of DETM is now roughly 90% complete. One early move to sell off DETM assets came in January 2004 when FERC approved a DETM transfer of 241 separate power market agreements to Morgan Stanley Capital Group.

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experienced last year in Hurricane Ivan, FERC staff reported. The storms exacerbated tight supply and demand conditions that by early September had already left natural gas markets in disarray and caused upward pressure on prices.

Highly volatile natural gas prices continue to reflect extreme, yet fundamental conditions in the market—supply shortages, interruptions at Henry Hub, high crude oil prices and fear that storage levels aren't sufficient to guarantee winter supplies in the East, FERC's Office of Market Oversight and Investigations (OMOI) reported.

Stephen Harvey, deputy director of OMOI, said there is no evidence that market manipulation has played a role in gas prices staying above $13/MMBtu in recent weeks. But he stressed that conditions are ripe for market manipulation to occur. Prices are twice that of a year ago, and uncertainty about winter supply and price volatility are unabated. FERC and the Commodity Futures Trading Commission are prepared to investigate if signs of manipulation emerge, he said.

"We are mindful that the tight natural gas supplies could create temptations for improper behavior by some market conditions," Kelliher said. "The commission will monitor, and if necessary investigate and penalize, any evidence of market manipulation."

FERC, Kelliher added, issued rules two years ago to prevent manipulation of gas markets and received additional authority under the Energy Policy Act of 2005 to prevent gaming and ensure price transparency.

Kelliher added that FERC and the CFTC earlier Wednesday signed a memorandum understanding to work together to monitor the spot and futures markets for regulated natural gas and electricity transactions.

In a joint statement, CFTC and FERC said the MOU is for the "sharing of information and the confidential treatment of proprietary energy trading data," as directed by the EPAct. Congress directed the MOU to ensure that data requests are "properly coordinated to minimize duplicative information requests."

Under the MOU, which was required by the Energy Policy Act, the two agencies will share trading information and abide by mutual confidentiality standards for proprietary data. Kelliher said the MOU, which was signed four months before Congress required it to be, allows both agencies to "more readily identify and sanction market manipulation."

"This means the agreement is in place well before the winter heating season, when already stressed energy prices will require vigilance," Kelliher said. "This agreement will contribute to better coordination of enforcement," he added.

Kelliher added that the government won't be able to protect consumers from high natural gas prices this winter, saying "the only questions are how much higher and whether such price increases reflect only the operation of supply and demand."

Further, he said FERC "stands ready to act quickly on emergency filings to authorize efficient use of existing gas infrastructure," noting that the agency Tuesday approved in less than a day Discovery Gas Transmission's proposal to reroute gas transportation to bypass Dynegy's heavily damaged gas-processing plant in Venice, La.

CFTC Chairman Reuben Jeffery III, co-signer of the MOU, said the agreement will result in a more "effective and efficient" working relationship with FERC. "It will enable both agencies to work actively to assure the price integrity of the markets for natural gas and other energy products," he said.

With the pounding that production platforms, pipelines and processing plants took in the hurricanes, regulators and industry representatives all stressed that prices will rise significantly this winter. Neither Canadian or liquefied natural gas imports will offset the loss of approximately 7 Bcf of natural gas flow from the market.

Kelliher and Commissioners Suedeen Kelly and Nora Mead Brownell reiterated that FERC was prepared to respond quickly on emergency filings "to authorize efficient use of gas infrastructure."

Reflecting broad concerns about winter prices, producers and shippers disagreed on the extent of the danger to supply, and producer and shipper groups sought to reassure the public on their ability to meet demand.

Skip Horvath, president of the Natural Gas Supply Assn., said adequate storage and industrial demand-response measures would assure supplies are available for home and office heating. "In this way, markets have always proven to be the most effective way to allocate resources during times of scarcity," he said.

"Even in most colder-than-normal weather scenarios, we believe a resulting spot market price spike would temporarily lead sufficient industrial demand off the system to assure essential heating for homes, offices and all public services," Horvath told FERC's conference attendees.

He added that while gas producers have "taken quite a beating this hurricane season, natural gas markets appear to be breathing a little easier now. There are still challenges ahead, but somewhat lower futures and cash-market prices recently appear to be a reflection of the recovery efforts and above-average storage levels."

KeySpan Energy, a major Northeast shipper, reported to FERC that its gas storage facilities would be filled by Nov. 1, supplying about 29% of winter requirements, but more than 40% of winter supply will come out of the Gulf Coast region.

"We are currently implementing contingency plans to replace Gulf supplies with supplies that might be available in other locations," said David Manning, senior vice president at KeySpan.

Participants in the conference agreed that pipeline, LNG and storage infrastructure needed to be built. Encouraging long-term contracts, or building a better regulatory framework for encouraging major investment, should occur at the state level, participants suggested.

But the bulk of that activity should be outside the Gulf Coast, to deliver gas from the Rocky Mountain region, spur development of the North Slope Alaska pipeline project and continue the push for LNG terminals along the East Coast.

In the short-term LNG will help fill a gap as U.S. demand continues setting the spot market price, Harvey said, but in viewing the long term, participants expressed concern that the United States will meet hefty competition from Europe and Asia.

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