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Inside FERC's Gas Market Report

July 8, 2011

Marcellus growth shifts dynamics on Tennessee's once-illiquid 300 leg

The booming growth of the Marcellus Shale has upended the Appalachian gas market, potentially turning a once-illiquid pipeline segment — Tennessee Gas Pipeline's 300 leg in northern Pennsylvania — into one of the more important hubs for the play and its participants, sources said.

When Marcellus production started to grow in 2008, "there was only a trickle on the line," said Rodney Waller, vice-president of Range Resources, one of the major producers in the Marcellus. "Now much of the appreciable growth is going onto Tennessee's 300 line. It's been a dramatic change."

Tennessee's 300 leg splits off from the 200 leg in western Pennsylvania, stretching across the northern part of the state into New York and Connecticut, before meeting the 200 leg again in Agawam, Massachusetts.

Tennessee operator El Paso has reported receiving some 1.3 Bcf/d of Marcellus gas into the 300 leg, a majority of the

(continued on page 12)

Summer-to-winter NYMEX spread tightens, curbing storage incentives

Record gas production has tightened the spread between summer and winter NYMEX gas futures values over the past few years, giving operators less financial incentive to inject into storage. However, some analysts claim storage will continue to have value for some market players and these spreads will widen out once again by 2012.

By the end of June, the spread between the NYMEX July contract and the December-through-February average was approximately 45 cents, a far cry from the 80-cent spread in 2010 and the $2 spread in the same period of 2009.

"The summer-winter spread is tighter this year because the market is more bearish about the supply balance than it was last year," Greg Ballheim, director of consulting at Pace Global Energy Services, said. "In 2010, the market was concerned that a halving of the rig count in late 2009 would result in lower production in 2010. It didn't. In fact, the rig count remains low,

(continued on page 18)

Energy options trading takes off, often outpacing interest in futures

Unrest in the Middle East, uncertainty surrounding new US market regulations and the growth of electronic trading have created a recent boom in energy options trading, even outpacing futures trading, analysts said.

"Typically, in times of greater volatility, options allow you to tailor your exposure to risk in a more precise fashion than a futures contract can," said Charles Reyl, CEO of Parity Energy. "An option can allow you to protect yourself against, say, a rise in the price of crude oil or ... to a drop in the price of crude oil if you're a producer."

Still, while energy options trading has dramatically increased at some exchanges, other products have leveled off or plummeted from a year ago, often with no correlation to their corresponding futures contracts, data shows.

Total options volume increased by roughly 23.6% at 75 worldwide exchanges over the first three months of this year, to 3.2 billion contracts from nearly 2.6 billion contracts, according to the Futures Industry Association. During the same time period, futures trading volumes climbed 14% worldwide, to 2.8 billion contracts from 2.5 billion con-

INSIDE THIS ISSUE

tracts, FIA data released last week shows.

However, this upward trend is not as consistent in energy futures and options trading. For instance, options trading has taken off at IntercontinentalExchange, but, depending on the product, has trended flat or lower at CME Group, parent company of NYMEX.

Open interest for the NYMEX gas futures contract jumped to 982,002 contracts last month, a 27.1% increase from June 2010, according to CME. NYMEX gas options open interest climbed just 5.7% during that same time period, to 5.9 million contracts from more than 5.6 million contracts.

And while open interest for the NYMEX crude oil futures contract climbed 19.1% from June 2010 to June 2011, jumping to 1.54 million contracts from 1.29 million contracts, options open interest for NYMEX crude fell 10.5% to 4.41 million contracts from 4.93 million contracts over the same period, CME data shows.

Open interest in ICE Brent crude futures climbed roughly 7% to 17.7 million contracts in June from nearly 16.5 million contracts the year before. But open interest in ICE Brent crude option skyrocketed to more than 6.5 million contracts last month from 324,817 contracts in June 2010, according to the exchange.

Open interest for ICE energy options also was on the rise even when trading of the corresponding futures contract declined.

For example, open interest for ICE West Texas Intermediate crude futures dropped 9.3% to 10.2 million contracts last month from nearly 11.2 million contracts in June 2010. However, open interest for ICE WTI crude options jumped to more than 3.6 million contracts from 250,800 contracts in June 2010, according to ICE.

Even in cases where options trading declined, the level of open interest sometimes came in at more than five times the level for futures, analysts noted. "The options are just enormous," said Tim Evans, an analyst with Citi Futures Perspective. "They're just outpacing all the activity in the futures."

Evans said the growth in energy options trading may be due to the "greater degree of flexibility" they offer over futures as volatility in the markets grows. Additionally, the rise could also be due to the ease with which different aspects of an option can be handled.

"For a certain range of consumers and a certain range of investor, they're concerned about their energy price exposure, but they're not necessarily in a position to watch a screen all day and point and click, so they go after what I call a 'set it and forget it' strategy," Evans said.

Options trading has grown considerably since the 2008 financial crisis since investors are looking at an easy way to hedge risk, said Jim Binder, a spokesman for the Options Industry Council, which focuses on equity options.

Options "can allow you to do a number of different things depending on what's happening in the market," Binder said. "You can speculate and make money, you can hedge your risks and in a flat market you can earn income."

— Brian Scheid

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TRADING

Barclays survey: hedging of production for 2012 is up by 16% from 2010 level

Increasing market complexity, price volatility and the demands of lenders and private equity sponsors are spurring exploration-and-production companies to boost their hedging of gas and oil production for 2011 and 2012, according to a recent survey by Barclays Capital.

According to its survey of a 37-company E&P peer group, approximately 59% of the group's gas production is hedged between $5.68/MMBtu and $5.72/MMBtu for the second through fourth quarters of 2011. For 2012, 33 companies have hedges in place, covering approximately 44% of production.

For the last three quarters of 2011, of the 37-member peer group, the average production mix is 39% oil and 61% gas. For those with gas hedges in place, 27 used swaps, with an average price of $5.72/MMBtu, while 20 used a combination of collars and puts, with an average floor of $5.68/MMBtu, according to the Barclays' report, released in early June.

Thirty-three of the 37 companies have some form of hedges in place for 2012, covering on average 44% of total production, about 16% higher than at year-end 2010, according to Barclays. Twenty-nine companies have hedged their oil production, while 30 companies have gas hedges in place.

For those with gas hedges in place for 2012, 27 companies used swaps with an average price of $5.65/MMBtu, while 18 used a combination of floors and collars at an average floor of $5.78/MMBtu.

The survey's top hedgers included Chesapeake Energy, Petrohawk Energy, Newfield Exploration, Range Resources, Pioneer Natural Resources, Denbury Resources, Bill Barrett, Quicksilver Resources and Southwestern Energy.

Smaller- to mid-sized E&P companies that did not hedge at all in the past have become "more aggressive" with their hedging strategies and have significantly increased their hedging volumes, Mike Corley, president of Mercatus Energy Advisors, said.

With the increase in production spurred by the shale boom in places such as Eagle Ford, the independents have increased the size of their operations, having "more market then they are used to," Corley said. This has led to higher volumes of physical trading and hedging.

Also, hedging is usually required by producers' banks, which demand that E&Ps hedge a certain share of their production, Corley said.

Analysts say hedging has become necessary of late because of price volatility and marketplace complexity. "Five, 10, 15 years ago, one had a decent idea what prices would do," Corley said. Now, market players have to weigh factors such as the Euro and US dollar rates, equities prices and geopolitics, he added.

Furthermore, producers saw that "there is money to be made in trading," according to Jay Levine, broker at Enerjay. During the last year and a half, large financial houses in Wall Street generated large portions of their income doing energy hedging, and many producers looked to follow suit.

"Earlier on it was a bit frightening to them" as many producer companies may have originally considered most trading to be speculative, in Levine's opinion, before they realized that there are many other ways of managing risk through hedging.

— Anastasia Gnezditskaia

Exchanges, brokers and more jockey to create SEFs for energy swaps trade

The world's top two energy exchanges, a media giant, an upstart electronic trading facility and at least seven brokerage firms are preparing to register as swap execution facilities that will offer energy swap transactions as soon as federal regulators finalize their financial reform rules.

However, with the new rules still in flux, most of these SEF hopefuls are wary of discussing their plans publicly, and even those following the issue closely said it is anyone's guess what these over-the-counter swaps trading facilities will look like when they are launched.

SEFs, which are mandated by the Dodd-Frank Wall Street Reform and Consumer Protection Act, are defined as a trading system or platform through which multiple participants will have the ability to execute or trade OTC swaps by accepting bids and offers by multiple participants through any means of interstate commerce.

That definition, and the subsequent rules unveiled by regulators, has given little insight into what SEFs will ultimately be and what impact they will have on OTC energy swaps trading.

Numerous sources said it is unclear how many energy-related SEFs will be launched, but all pointed to the same likely candidates: NYMEX parent CME Group, IntercontinentalExchange, Bloomberg and Parity Energy, which operates an online global electronic trading facility for US-traded commodity derivative products, with a focus on energy options.

Additionally, Nodal Exchange, which launched in 2009 and offers cash-settled contracts for power and gas in North America, may register as either a SEF or a designated contract market, according to Paul Cusenza, the exchange's CEO.

Lee Underwood, an ICE spokesman, declined to comment in detail, but said he could "confirm generally that [ICE does] anticipate registering as a swap, subject to the final rules."

CME spokesman Chris Grams also declined to comment, but numerous sources said that exchange would likely register as a SEF as well. However, these sources said CME's SEF may be a "SEF motel" or aggregator of other SEFs' prices.

Parity, which launched in 2006, "will apply for SEF status as soon as the CFTC finalizes the requirements," its President Charles Reyl said.

Additionally, brokers including GFI Group, ICAP, Spectron

Group Limited, Tradition Financial Services, BGC Partners, Tullett Prebon and OTC Global Holdings are expected to register as SEFs and provide a platform for energy swaps, sources said.

Sources noted that, apart from Parity and possibly ICE, few of these entities are likely planning to offer services exclusively for energy swaps.

During a June 29 Senate Banking subcommittee hearing, Kevin McPartland, a principal and the director of fixed income research at TABB Group, said a survey of market participants found that three to four SEFs per asset class, such as commodities, is the ideal amount. This would result in a total of 15 to 20 SEFs to cover interest rates, credit, currencies, commodities and equities, McPartland said.

Additionally, while many believe that as many as 100 SEFs will try to register with the Commodity Futures Trading Commission and Securities and Exchange Commission, the final number will be much lower due to the costs and hours required to meet the rules these SEFs must meet.

"If the US equities market has 68 venues and the US futures market has three main players, the swaps market will fall somewhere in the middle," McPartland said.

During his testimony, McPartland said that SEFs should be given "broad latitude in defining and implementing their business models," and "should not be driven to a particular trading model," such as the Request for Quote model the CFTC has proposed.

The CFTC's RFQ model would require swap dealers to offer swaps prices to as few as five market participants.

"The trading style and needs of a mutual fund are very different from those of a major dealer or a hedge fund," McPartland said. "We therefore should encourage [SEFs] to develop business models that help all market participants, and allow SEFs to compete with each other for whichever client base they choose to serve. This means allowing SEFs to not only define the method of trading, but requirements for entry."

In an interview this week, Michael Cosgrove, managing director with GFI Group, said what SEFs will ultimately look like will depend on the composition of the CFTC's final rules.

At a minimum, Cosgrove said, each SEF will likely have to operate a central limit order book, would likely need to provide customers with the ability to post indicative bids and offers and would probably have to provide an RFQ function.

"Clearly there's a significant technology element that's required of a SEF," Cosgrove said.

But once these technology requirements are met, Cosgrove said it would be "virtually free" for a SEF to offer additional products so an exchange or broker that has long concentrated in energy products could expand to offer a platform for interest rate swaps or credit default swaps, for example.

Moving cleared swaps to SEFs represents a sea change for swaps trading, the vast majority of which currently takes place over the phone between two parties.

In his testimony for the hearing, Stephen Merkel, chairman of the Wholesale Market Brokers' Association, said the CFTC's proposed limits on voice trading, or trading swaps over the telephone, are "inconsistent" with Dodd-Frank and far more stringent than the SEC's proposed rules.

Merkel said that regulators should set up a common regulatory organization for SEF rules to "ensure that a single, consistent standard is applied across multiple SEFs and prevent a 'race to the bottom' for rule compliance and enforcement programs."

— Brian Scheid

FUNDAMENTALS

Brighter US economy likely to prop gas prices through 2012, analysts say

Many analysts believe improving US economic performance and rising industrial production will prop up gas prices in 2011 or 2012.

According to analysts with Deutsche Bank, gas consumption is expected to remain flat throughout 2011, but stronger US economic growth in 2012 could be significantly supportive of gas demand. After a 2.9% rise in 2010, US GDP is forecast to grow by 3.5% in 2011 and 3.9% in 2012, the firm wrote in a recent research note.

A forecast from Bank of America/Merrill Lynch is just slightly lower: 2.9% growth in 2011 and 3.4% in 2012.

"Total US natural gas demand growth is currently running at a rate of 1.5 Bcf/d, clearly benefitting from low natural gas prices relative to other thermal fuels as well as the ongoing, albeit slow and grinding, US economic recovery," a research note from Bank of America said.

Demand for gas will grow in parallel with economic growth, according to Deutsche Bank analysts, adding roughly 25 cents/MMBtu per quarter, with physical fundamentals for gas beginning to strengthen in the fourth quarter of 2011.

"We expect natural gas prices to average $4.30/MMBtu in 2011, roughly in line with 2009-2010," the note said. "However, by the end of this year, we believe that prices will begin to recover toward $5/MMBtu and that 2012 prices will average higher than $5/MMBtu."

Deutsche Bank analysts pointed to a number of events that are having a positive impact on the US economic outlook in the near term. Specifically, an "unanticipated and expansive" fiscal stimulus package the US Congress passed late last year should be very supportive of US economic growth in 2011 and 2012, they said.

"As explained by the US economics team, the Bush-era reductions in tax rates for marginal income, capital gains and dividends were extended for an additional two years," the firm wrote. "Moreover, a one-year payroll tax holiday was implemented along with two years of accelerated capital depreciation allowances. The former should lift consumer spending or at minimum limit the implicit damage to household disposable income from higher energy costs; the latter will provide an added fillip to capital expenditures which have been a bright spot for the US economy."

According to analysts from Barclays Capital, economic growth will have a greater impact on gas prices in 2011 than in 2012. "The economic activity will reflect mostly on industrial gas consumption," Barclays analyst Biliana Pehlivanova wrote in a research note. "It has been growing robustly so far this year, at about +0.5 Bcf/d [year-over-year] in Q1, and we expect this to continue through 2011."

Pehlivanova added that in 2012,"the growth is likely to slow marginally, in our view. The majority of the strength so far has been from the chemicals sector, although some growth has come also from the steel and other industries as well. For chemicals, many facilities are already running at capacity, and increases in gas consumption levels from here would be limited without building new facilities."

Similarly, Bank of America noted that industrial gas demand is rising at a rate of about 700,000 Mcf/d this year, and the growth "could well keep up with this pace as the industrial recovery continues to unfold."

But some analysts' forecasts show a different picture. According to Jefferies & Co. analyst Subash Chandra, economic growth of less than 4% to 5% annually will keep gas in the low $4/MMBtu range.

As a result, it is "unlikely the economy will pull us out," Chandra said, adding that this might happen over a long time, but not in a near- to medium-term perspective.

— Anastasia Gnezditskaia

Analysts differ on how heat, supply will affect gas prices in 2011-2012

Several industry analysts differ on the potential market impacts of weather, storage and production for the rest of this year and next, with one trimming its gas price forecasts while two others raised their projections.

Stephen Smith Energy Associates said last week that with storage inventories likely to push the 4-Tcf mark again this fall and the latest data showing no slowdown in shale-driven production, gas prices are likely to stay relatively soft through next year.

Principal Stephen Smith trimmed his Henry Hub price forecast for the third quarter by 8.6% to $4.25/MMBtu, his fourth-quarter estimate by 7.4% to $4/MMBtu and his full-year 2011 prediction by 3.5% to $4.17/MMBtu. For 2012, Smith lowered his estimate by 5.4% to $4.35/MMBtu.

Storage is entering July with a roughly 172-Bcf surplus, well below the 424-Bcf surplus a year earlier, Smith noted. But the third quarter of 2010 saw record heat that kept storage injections low, while this year's third quarter is expected to be more moderate, he said.

In addition, the Energy Information Administration's gross gas production rate of April 2011 "came in at least as strong if not stronger than expected last week," he said. "Aside from the aberrational effect of winter freeze-offs, this is simply one more data point to confirm the durability of the shale-driven gas production ramp-up of the last 16 months."

Closing Prices for NYMEX Henry Hub Gas Futures Contract

Trading Date	6/22	6/23	6/24	6/27	6/28	6/29	6/30	7/1	7/5
Contract volume	**261,491**	**261,491**	**184,630**	**203,621**	**215,151**	**190,877**	**302,024**	**168,942**	**305,465**
Open interest	**968,024**	**971,309**	**977,665**	**967,977**	**960,530**	**964,537**	**972,829**	**980,004**	**974,776**
Jul 2011	$4.317	$4.193	$4.229	$4.256	$4.357*	$–	$–	$–	$–
Aug 2011	4.350	4.217	4.250	4.264	4.354	4.315	4.374	4.311	4.363
Sep 2011	4.375	4.243	4.275	4.286	4.373	4.334	4.393	4.330	4.371
Oct 2011	4.418	4.287	4.319	4.329	4.412	4.373	4.432	4.372	4.409
Nov 2011	4.551	4.424	4.454	4.461	4.535	4.493	4.553	4.501	4.541
Dec 2011	4.738	4.615	4.645	4.646	4.719	4.676	4.739	4.694	4.737
Jan 2012	4.840	4.720	4.750	4.748	4.818	4.777	4.844	4.798	4.838
Feb 2012	4.831	4.714	4.744	4.740	4.813	4.772	4.839	4.795	4.837
Mar 2012	4.774	4.657	4.689	4.684	4.760	4.719	4.790	4.750	4.794
Apr 2012	4.641	4.528	4.558	4.552	4.633	4.594	4.677	4.647	4.684
May 2012	4.663	4.552	4.582	4.575	4.655	4.616	4.700	4.670	4.706
Jun 2012	4.694	4.586	4.616	4.608	4.688	4.649	4.732	4.702	4.736
Jul 2012	4.739	4.634	4.664	4.656	4.733	4.694	4.776	4.746	4.778
Aug 2012	4.768	4.663	4.692	4.684	4.761	4.722	4.804	4.774	4.809
Sep 2012	4.779	4.674	4.704	4.696	4.771	4.732	4.814	4.784	4.818
Oct 2012	4.823	4.716	4.745	4.736	4.811	4.772	4.854	4.824	4.856
Nov 2012	4.958	4.855	4.883	4.878	4.947	4.908	4.990	4.961	4.991
Dec 2012	5.173	5.075	5.103	5.095	5.164	5.127	5.205	5.179	5.209
12-month ave.	**4.599**	**4.478**	**4.509**	**4.512**	**4.593**	**4.584**	**4.654**	**4.610**	**4.650**

Source: New York Mercantile Exchange
*Final closing price

Prices of Spot Gas Delivered to Pipelines, July 1 (per MMBtu)

	Range	Index	Volume	Deals
ANR Pipeline Co.				
Louisiana	$4.21 to $4.36	$4.31	427	31
Oklahoma	$4.15 to $4.26	$4.22	66	13
CenterPoint Energy Gas Transmission Co.				
East	$4.10 to $4.18	$4.14	39	11
Colorado Interstate Gas Co.				
Rocky Mountains	$3.87 to $4.08	$3.96	139	30
Columbia Gas Transmission Corp.				
Appalachia	$4.35 to $4.49	$4.48	524	65
Columbia Gulf Transmission Co.				
Louisiana	$4.22 to $4.34	$4.33	797	51
Mainline	$4.17 to $4.33	$4.30	962	88
Dominion Transmission Inc.				
Appalachia	$4.39 to $4.51	$4.49	1,063	109
El Paso Natural Gas Co.				
Permian Basin	$4.10 to $4.31	$4.21	683	100
San Juan Basin	$4.05 to $4.21	$4.09	278	42
Florida Gas Transmission Co.				
Zone 1	$4.34 to $4.38	$4.36	6	5
Zone 2	$4.37 to $4.42	$4.38	54	13
Zone 3	$4.42 to $4.50	$4.49	178	20
Kern River Gas Transmission Co.				
Wyoming	$3.88 to $4.10	$3.97	432	54
Natural Gas Pipeline Co. of America				
Midcontinent zone	$4.09 to $4.26	$4.16	228	53
Louisiana zone	NA to NA	NA	0	0
Texok zone	$4.12 to $4.31	$4.24	744	123
South Texas zone	$4.24 to $4.33	$4.29	236	23
Northern Border Pipeline Co.				
Ventura Transfer Point	$4.23 to $4.42	$4.26	20	3
Northern Natural Gas Co.				
Demarcation	$4.22 to $4.36	$4.29	94	21
Ventura, Iowa	$4.22 to $4.37	$4.29	88	20
Northwest Pipeline Corp.				
Rocky Mountains	$3.87 to $4.10	$3.95	584	77
Canadian border	$3.91 to $4.09	$4.00	176	39
Oneok Gas Transportation LLC				
Oklahoma	$4.13 to $4.28	$4.20	10	2
Panhandle Eastern Pipe Line Co.				
Texas, Oklahoma (mainline)	$4.05 to $4.24	$4.14	165	44
Questar Pipeline Co.				
Rocky Mountains	$3.88 to $3.88	$3.88	1	1
Southern Natural Gas Co.				
Louisiana	$4.25 to $4.38	$4.37	826	59
Southern Star Central Gas Pipeline Inc.				
Texas, Oklahoma, Kansas	$4.05 to $4.28	$4.10	43	15
Tennessee Gas Pipeline Co.				
Louisiana, 500 leg	$4.35 to $4.40	$4.36	188	28
Louisiana, 800 leg	$4.26 to $4.37	$4.35	78	15
Texas, zone 0	$4.13 to $4.33	$4.25	320	32
Zone 4-Ohio	$4.49 to $4.50	$4.49	129	21
Texas Eastern Transmission Corp.				
M-1 30-inch (Kosi)	$4.28 to $4.39	$4.37	441	73
East Louisiana zone	$4.22 to $4.36	$4.32	164	18
West Louisiana zone	$4.29 to $4.34	$4.32	93	10
East Texas zone	$4.05 to $4.28	$4.23	31	17
South Texas zone	$4.15 to $4.28	$4.22	215	23
Texas Gas Transmission Corp.				
Zone 1	$4.15 to $4.32	$4.27	329	39
Zone SL	$4.31 to $4.32	$4.31	15	3
Transcontinental Gas Pipe Line Corp.				
Zone 1	$4.32 to $4.37	$4.35	15	5
Zone 2	$4.34 to $4.37	$4.35	89	15
Zone 3	$4.35 to $4.42	$4.37	560	52
Zone 4	$4.26 to $4.41	$4.39	910	103
Transwestern Pipeline Co.				
Permian Basin	$4.07 to $4.17	$4.11	13	5
San Juan Basin	$4.06 to $4.25	$4.13	331	68
Trunkline Gas Co.				
Louisiana	$4.33 to $4.34	$4.33	42	8
Zone 1A	$4.24 to $4.33	$4.30	146	18

Smith's research model concludes that "gas rig-count levels would lead to production gains which could not be absorbed by 2010-2012 gas demand growth."

Excluding hurricane impacts, even above-average cooling degree days this summer are unlikely to prevent a 3.9 Bcf-plus storage level this fall, Smith added.

On the other hand, analysts at Bentek Energy looked at the recent winter chill and early onset of summer heat as it boosted its Henry Hub 2011 spot-price forecast by 8.9% to $4.04/MMBtu. Bentek, a unit of Platts, raised its 2012 price forecast 3.3% to $4.09/MMBtu.

Henry Hub spot prices are averaging at $4.27/MMBtu year-to-date, Platts data shows. The NYMEX futures 2012 calendar strip settled July 1 at $4.80/MMBtu and Platts M2M models as of last week showed Henry Hub cash averaging $4.84/MMBtu in 2012.

Although storage inventories now stand at around 2.4 Tcf, 10% behind last year's levels and 2.6% behind the five-year average, Bentek expects stockpiles to end March 2012 at 1.7 Tcf, similar to March 2009 and 2010 levels. Inventories are expected to peak at a little under 3.8 Tcf around the end of October, the report said.

Dry gas production, meanwhile, is forecast to come in at 61 Bcf/d, 600,000 Mcf/d lower than Bentek's previous estimates, as drillers continue to move away from pure gas plays toward oil and liquids production.

"Bentek observes that the rigs are being deployed in greatest numbers in combination plays, where rich gas and oil are produced," the report stated. "Bentek expects this trend to continue

Platts to add three North American gas points Aug. 1, discontinue three others Jan. 1

Following feedback from market participants, Platts will begin publishing natural gas spot prices August 1 for two new monthly locations – Emerson, Viking GL and Leidy Hub – and one new daily location – White River Hub.

Platts also will discontinue publishing assessments effective January 1, 2012 at three other North American locations where spot trading is no longer active, and it will not act at this time on a proposed assessment for Tennessee Gas Pipeline's 300-leg in zone 4 while it monitors how the market adjusts to changes to the pipeline's pooling structure and to capacity expansions in the region.

Additions:

White River Hub:

Platts will add a daily assessment to reflect trading at the White River Hub in Rio Blanco County, Colorado. White River Hub is a joint-venture header system owned by Questar Pipeline Co. and Enterprise Products Partners LP designed to provide access to downstream markets for gas produced in northwest Colorado's Piceance Basin. The hub has interconnects with Questar Pipeline Co., Wyoming Interstate Co., Colorado Interstate Gas Co., Rockies Express Pipeline, Northwest Pipeline GP, TransColorado Gas Transmission Co. and Enterprise Products' Meeker processing plant.

The point's description will be: "Deliveries to or from pools or interconnects that make up the White River Hub in Rio Blanco County, Colorado."

The daily "White River Hub" assessment will appear in the "Rockies" section of Gas Daily's "Daily price survey" table and the "Rockies/Northwest" section of Energy Trader's "Daily spot gas prices" table. Platts is not adding a monthly bidweek assessment for White River Hub at this time because of insufficient trading activity in the monthly market, but will continue to collect bidweek trade data and monitor activity there.

Leidy Hub:

Platts will add a Leidy Hub assessment in its monthly bidweek survey. The bidweek location will be identical to the location Platts publishes for the daily market. Platts' description for the Leidy Hub is "Deliveries into and from Dominion Transmission, National Fuel Gas Supply, Columbia Gas Transmission, Texas Eastern Transmission and Transcontinental Gas Pipe Line in the vicinity of the Leidy storage facility in Clinton County, Pa."

The monthly bidweek assessment will appear in the "Northeast" section of the "Market Center Spot Gas Prices" tables in Inside FERC's Gas Market Report, Energy Trader and Gas Daily Price Guide and the "Market Center Bidweek Physical Basis Prices" table in Inside FERC's Gas Market Report and Gas Daily Price Guide.

Emerson, Viking GL:

Platts will add an Emerson, Viking GL assessment in its monthly bidweek survey. The bidweek location will be identical to the location Platts publishes for the daily market. Platts' existing description for Emerson is "Deliveries into Great Lakes Gas Transmission from TransCanada PipeLines at the Emerson 2 compressor station at the US/Canadian border at Emerson, Manitoba, and deliveries into Viking Gas Transmission from TransCanada at the Emerson 1 station." Effective August 1, the description will change "Emerson 2 compressor station" to "Emerson 2 meter station."

The monthly bidweek assessment will appear in the "Upper Midwest" section of the "Market Center Spot Gas Prices" tables in Inside FERC's Gas Market Report, Energy Trader and Gas Daily Price Guide and the "Market Center Bidweek Physical Basis Prices" table in Inside FERC's Gas Market Report and Gas Daily Price Guide.

Discontinuations:

Effective January 1, 2012, Platts will discontinue assessments for three locations that no longer trade actively.

Stingray Pool:

In the daily survey, Platts will discontinue its assessment for the Stingray Pool, which appears in the "Louisiana-Onshore South" section of Gas Daily's "Daily price survey" table and the "Gulf Coast" section of Energy Trader's "Daily spot gas prices" table. Platts has never published a monthly Stingray assessment.

Stanfield, Ore.:

In the monthly bidweek survey, Platts will discontinue its assessment for Stanfield, Ore., which appears in the "Rockies/Northwest" section of the "Market Center Spot Gas Prices" tables in Inside FERC's Gas Market Report, Energy Trader and Gas Daily Price Guide. The Stanfield assessment will continue to be published in the daily survey.

NGPL, La.:

In both the daily and monthly bidweek surveys, Platts will discontinue its Natural Gas Pipeline Co. of America, Louisiana, assessments. The daily "NGPL, La." assessment appears in the "Louisiana-Onshore South" section of Gas Daily's "Daily price survey" table and the "Gulf Coast" section of Energy Trader's "Daily spot gas prices" table.

The monthly bidweek assessment appears in the "Prices of Spot Gas Delivered to Pipelines" tables in Inside FERC's Gas Market Report and Energy Trader and the "Bidweek Physical Basis Prices Delivered to Pipelines" table in Inside FERC's Gas Market Report.

because these plays generally offer superior returns."

But production next year is expected to average 63.4 Bcf/d, more than 1 Bcf/d higher than Bentek previously estimated.

In contrast, the overall demand forecast was revised up 300,000 Mcf/d for the remainder of this year and an average of 1.1 Bcf/d for the next five years. Bentek pegged residential and commercial demand for this year at 42.2 Bcf/d, up 100,000 Mcf/d from its last forecast.

"Some of this growth is a result of end-users' (like households and commercial customers) converting to natural gas from more expensive fuel sources, including propane," the report said. "Some of the recent growth observed behind the [local distribution company] delivery points is also likely a result of industrial fuel conversions and supplemental gas-fired power generation."

Power burn for the year, however, is expected to be 19.9 Bcf/d, or 2.2 Bcf/d lower than previously forecast. "An increase in natural gas prices caused switching to decline substantially," Bentek said. "Additionally, a well above-normal hydro season suppressed power burn in the West by an estimated 1.2 Bcf/d."

Meanwhile, analysts at investment bank Raymond James on Tuesday raised their 2011 gas price forecast 13% to $4.25/Mcf, with predictions of $4.30/Mcf prices at the Henry Hub through December.

But analyst Marshall Adkins is not getting bullish on next year, predicting 2012 prices will average $4.25/Mcf at Henry Hub, about 12% below where the NYMEX strip is trading.

This year's gas price got a huge boost from an abnormally cold winter, Adkins said, which burned up 2.5 Bcf/d more gas than Raymond James had predicted when it made its bearish

$3.75/Mcf estimate at the beginning of this year, citing gas supply gains of 4 Bcf/d.

"Thanks to the weather, summer-ending gas storage may now end slightly below last year rather than over-supplied as expected," Adkins said in a note to clients.

However, "looking ahead to 2012, the natural gas outlook remains ugly," Adkins added, for many of the same reasons he has been bearish all along: surging production growth, normal weather and a sluggish US economic rebound.

"Currently, US natural gas producers are growing year-over-year supply by about 4.5 Bcf/d," he said. And while dry gas rigs have dropped 8% as producers hunt for wetter, oilier prospects, those liquids plays will still produce enough gas to offset the decline in production from dry gas rigs.

Without more industrial and power demand than is being seen in the current economic environment, the US still ends up with 2 Bcf/d more than it consumes and there is not enough room in storage for all the extra gas, Adkins said.

"The point here is that our $4.25/Mcf forecast for 2012 will in all likelihood prove to be too high," Adkins said, but hedged his bets after this past winter's chilly surprise. "After the past couple of years, we don't want to call for a natural gas meltdown only to have the market bailed out by six sigma weather events."

Raymond James' first gas price forecast for 2012 calls for $4.25/Mcf average prices in the first quarter of 2012, $4/Mcf in the second and third quarters and $4.75/Mcf in the last quarter.

— Samantha Santa Maria, Stephanie Seay, Bill Holland

Market Center Spot Gas Prices, July 1 (per MMBtu)

	Range	Index	Volume	Deals
Northeast				
Texas Eastern, zone M-3	$4.66 to $4.70	$4.69	283	43
Transco, zone 6 N.Y.	$4.80 to $4.84	$4.80	264	46
Transco, zone 6 non-N.Y.	$4.72 to $4.75	$4.74	141	24
Iroquois, receipts	$4.74 to $4.93	$4.86	47	9
Iroquois, zone 2	$4.94 to $4.96	$4.94	36	4
Algonquin city-gates	$4.79 to $4.85	$4.82	196	33
Tennessee, zone 6 delivered	$4.51 to $4.81	$4.78	102	22
Niagara	$4.65 to $4.67	$4.66	52	7
Lebanon Hub	$4.47 to $4.49	$4.48	97	17
Rockies Express, Clarington Ohio	$4.46 to $4.49	$4.47	39	5
Upper Midwest				
Chicago city-gates	$4.26 to $4.51	$4.38	618	92
Consumers Energy city-gate	$4.44 to $4.59	$4.55	150	43
Mich Con city-gate	$4.39 to $4.56	$4.50	378	73
ANR Pipeline, ML 7	$4.47 to $4.69	$4.56	8	10
Dawn, Ontario	$4.52 to $4.67	$4.65	637	117
South Louisiana				
Henry Hub	$4.36 to $4.36	$4.36	203	18
East Texas				
Houston Ship Channel	$4.19 to $4.41	$4.37	439	43
Katy	$4.22 to $4.39	$4.30	253	21
West Texas				
Waha	$4.16 to $4.30	$4.23	100	15
Rockies/Northwest				
Cheyenne Hub	$4.00 to $4.15	$4.10	75	17
TCPL Alberta, AECO-C#	$3.48 to $3.70	$3.60	1,968	345
Stanfield, Ore.	NA to NA	NA	0	0
California				
PG&E Malin, Ore.	$4.17 to $4.33	$4.24	149	35
PG&E city-gate	$4.50 to $4.69	$4.59	353	54
PG&E South	$4.42 to $4.50	$4.44	30	8
Southern California Gas Co.	$4.34 to $4.57	$4.48	815	124
SoCal Gas city-gate	$4.40 to $4.60	$4.53	130	24
National Average	**$4.25**			

All prices U.S.$/MMBtu except TCPL Alberta, AECO-C, which is Canadian$/GJ (gigajoule). All volumes in (000) MMBtu/day.

FINANCIAL BASIS MARKETS

Holiday drains basis market liquidity; most points remain relatively stable

Liquidity was thin before and after the US Independence Day holiday weekend, with most financial basis markets barely budging this week despite a net 9.4-cent loss by the NYMEX August gas futures contract between July 1 and Wednesday.

In the West, Northwest Pipeline at Sumas, Washington, recorded the sharpest decline as August basis fell 3.25 cents to finish Wednesday at minus 31 cents/MMBtu. Balance-of-summer packages also weakened, although losses were again fairly moderate, falling 1 cent to minus 28 cents/MMBtu.

Northwest in the Rocky Mountains August dropped 1.75 cents to minus 24 cents/MMBtu, while the balance of summer lost 2 cents to minus 25.5 cents/MMBtu. Southern California Gas August basis was down 1.5 cents to end Wednesday at plus 13 cents/MMBtu, as was its balance of summer, which hit plus 5.75 cents/MMBtu. El Paso Natural Gas in the San Juan basin followed that cue as August basis fell 1.5 cents to minus 17.5 cents/MMBtu, but the balance of summer was slightly weaker, falling 1.75 cents to minus 21.75 cents/MMBtu.

Other points saw more modest movement, with Pacific Gas and Electric city-gate August shedding a mere quarter-cent to end Wednesday at plus 25.75 cents/MMBtu. The balance-of-summer package was down three-quarters of a cent between July 1 and Wednesday to plus 20 cents/MMBtu. Meanwhile, AECO-NIT in Alberta August bumped up a quarter-cent to minus 46 cents/MMBtu, while its balance of summer slipped a quarter-cent to minus 47.25 cents/MMBtu.

Midcontinent basis also recorded very small losses during the period. The biggest mover was El Paso in the Permian Basin, which weakened in line with Southern California and fell 2.5

Bidweek Physical Basis Prices Delivered to Pipelines, July 1 ($/MMBtu)

	Low	High	Avg.	Cash Equiv.	Vol.	Deals
ANR Pipeline Co.						
Louisiana	(0.050)	0.000	(0.047)	4.31	421	30
Oklahoma	(0.095)	(0.095)	(0.095)	4.26	5	1
CenterPoint Energy Gas Transmission Co.						
East	NA	NA	NA	NA	0	0
Columbia Gas Transmission Corp.						
Appalachia	0.113	0.135	0.125	4.48	521	64
Columbia Gulf Transmission Co.						
Louisiana	(0.025)	(0.015)	(0.018)	4.34	727	48
Mainline	(0.058)	(0.030)	(0.050)	4.31	885	79
Dominion Transmission Inc.						
Appalachia	0.128	0.150	0.137	4.49	1,046	107
Florida Gas Transmission Co.						
Zone 1	(0.020)	0.020	0.000	4.36	6	5
Zone 2	0.010	0.060	0.019	4.38	54	13
Zone 3	0.060	0.145	0.132	4.49	178	20
Natural Gas Pipeline Co. of America						
Midcontinent zone	(0.100)	(0.100)	(0.100)	4.26	0.15	1
Louisiana zone	NA	NA	NA	NA	0	0
Texok zone	(0.075)	(0.058)	(0.064)	4.29	189	25
South Texas zone	(0.070)	(0.030)	(0.060)	4.30	206	22
Northern Border Pipeline Co.						
Ventura Transfer Point	0.065	0.065	0.065	4.42	0.07	1
Northern Natural Gas Co.						
Demarcation	NA	NA	NA	NA	0	0
Ventura, Iowa	NA	NA	NA	NA	0	0
Oneok Gas Transportation LLC						
Oklahoma	NA	NA	NA	NA	0	0
Panhandle Eastern Pipe Line Co.						
Texas, Oklahoma (mainline)	(0.140)	(0.125)	(0.140)	4.22	35	4
Southern Natural Gas Co.						
Louisiana	0.005	0.020	0.018	4.38	806	56
Southern Star Central Gas Pipeline Inc.						
Texas, Oklahoma, Kansas	(0.075)	(0.075)	(0.075)	4.28	1	1
Tennessee Gas Pipeline Co.						
Louisiana, 500 leg	(0.010)	0.020	0.003	4.36	188	27
Louisiana, 800 leg	(0.010)	0.010	(0.005)	4.35	77	14
Texas, zone 0	(0.075)	(0.040)	(0.068)	4.29	180	19
Zone 4-Ohio	0.130	0.143	0.137	4.49	129	21
Texas Eastern Transmission Corp.						
Zone M-1 (Kosi)	0.008	0.030	0.012	4.37	436	72
East Louisiana zone	(0.020)	0.000	(0.017)	4.34	114	17
West Louisiana zone	(0.035)	(0.020)	(0.030)	4.33	70	7
East Texas zone	(0.165)	(0.080)	(0.130)	4.23	31	16
South Texas zone	(0.110)	(0.073)	(0.104)	4.25	110	12
Texas Gas Transmission Corp.						
Zone 1	(0.060)	(0.040)	(0.049)	4.31	198	26
Zone SL	(0.050)	(0.038)	(0.049)	4.31	15	3
Transcontinental Gas Pipe Line Corp.						
Zone 1	(0.033)	0.015	(0.012)	4.35	15	5
Zone 2	(0.018)	0.015	(0.002)	4.36	89	15
Zone 3	(0.010)	0.030	0.014	4.37	546	47
Zone 4	0.028	0.050	0.035	4.39	878	100
Trunkline Gas Co.						
Louisiana	(0.030)	(0.020)	(0.027)	4.33	42	8
Zone 1A	(0.055)	(0.025)	(0.048)	4.31	111	12

Market Center Bidweek Physical Basis Prices, July 1 ($/MMBtu)

	Low	High	Avg.	Cash Equiv.	Vol.	Deals
Northeast						
Texas Eastern, zone M-3	0.300	0.345	0.331	4.69	283	43
Transco, zone 6 N.Y.	0.440	0.480	0.446	4.80	264	46
Transco, zone 6 non-N.Y.	0.365	0.393	0.382	4.74	141	24
Iroquois, receipts	0.560	0.570	0.563	4.92	27	6
Iroquois, zone 2	0.580	0.600	0.587	4.94	36	4
Algonquin city-gates	0.435	0.490	0.463	4.82	196	33
Tennessee, zone 6 delivered	0.150	0.450	0.420	4.78	102	22
Niagara	0.290	0.310	0.302	4.66	52	7
Lebanon Hub	0.110	0.135	0.124	4.48	97	17
Rockies Express, Clarington Ohio	0.100	0.135	0.115	4.47	39	5
Upper Midwest						
Chicago city-gates	0.090	0.150	0.118	4.48	5	5
Consumers Energy city-gate	0.195	0.230	0.206	4.56	129	33
Mich Con city-gate	0.170	0.200	0.182	4.54	103	23
ANR Pipeline, ML 7	0.110	0.330	0.201	4.56	7	8
Dawn, Ontario	0.280	0.315	0.292	4.65	576	105
South Louisiana						
Henry Hub	0.000	0.008	0.006	4.36	203	18
East Texas						
Houston Ship Channel	0.020	0.025	0.021	4.38	120	4
Katy	NA	NA	NA	NA	0	0
Rockies/Northwest						
TCPL Alberta, AECO-C	(0.440)	(0.410)	(0.427)	3.93	820	121

Table comprises physical basis deals used in bidweek survey (see methodologies at www.platts.com)

cents to minus 12.25 cents/MMBtu, while its balance of summer dropped 2 cents to minus 17.5 cents/MMBtu.

Panhandle Eastern Pipe Line August was down 1 cent between July 1 and Wednesday to minus 16.25 cents/MMBtu, as was its balance of summer, which ended at minus 18.5 cents/MMBtu. Waha August also dropped 1 cent to minus 8 cents/MMBtu, and its balance of summer lost 1.5 cents to minus 13.5 cents/MMBtu. Meanwhile, Northern Natural Gas Pipeline's demarcation point was flat for August at minus 1.75 cents/MMBtu, but the balance-of-summer package dropped three-quarters of a cent to minus 1.5 cents/MMBtu.

Houston Ship Channel showed comparative strength as extremely hot weather and drought conditions across many nearby counties lent support to basis, sources said. Ship Channel August basis gained 1 cent to end Wednesday at plus 4 cents/MMBtu, while the balance of summer was flat at minus a quarter-cent/MMBtu.

Basis movements were mild in the East as well, although liquidity returned to the markets there by Wednesday. The late liquidity return was most sharply felt in the Southeast and Gulf Coast, where Columbia Gulf Transmission's mainline August basis picked up 1.75 cents to minus 5.5 cents/MMBtu.

Volatility was relatively low in premium Northeast winter packages. Algonquin Gas Transmission city-gate prompt-winter rose half a cent to plus $2.26/MMBtu, and winter 2012-2013 was up three-quarters of a cent to plus $2.1775/MMBtu. Transcontinental Gas Pipe Line zone 6-New York prompt-winter

Daily Prices of Spot Gas Delivered to Pipelines ($/MMBtu)

	Midpoint 6/22	Midpoint 6/23	Midpoint 6/24	Midpoint 6/27	Midpoint 6/28	Midpoint 6/29	Midpoint 6/30	Midpoint 7/1	Midpoint 7/4**	Midpoint 7/5
ANR Pipeline Co.										
Louisiana	4.400	4.295	4.170	4.225	4.325	4.325	4.205	4.250	N.A.	4.370
Oklahoma	4.320	4.175	4.075	4.150	4.245	4.265	4.160	4.165	N.A.	4.280
CenterPoint Energy Gas Transmission Co.										
East	4.300	4.185	4.085	4.175	4.250	4.250	4.155	4.170	N.A.	4.295
Colorado Interstate Gas Co.										
Rocky Mountains	4.180	4.045	3.915	3.965	4.075	4.140	4.015	3.995	N.A.	4.090
Columbia Gas Transmission Corp.										
Appalachia	4.540	4.430	4.285	4.330	4.435	4.460	4.355	4.350	N.A.	4.485
Columbia Gulf Transmission Co.										
Louisiana	4.400	4.275	4.185	4.245	4.335	4.355	4.240	4.285	N.A.	4.365
Mainline	4.385	4.270	4.165	4.215	4.320	4.315	4.200	4.260	N.A.	4.365
Dominion Transmission Inc.										
South Point	4.540	4.435	4.280	4.335	4.420	4.505	4.395	4.375	N.A.	4.500
North Point	4.530	4.410	4.250	4.320	4.430	4.470	4.380	4.300	N.A.	N.A.
El Paso Natural Gas Co.										
Permian Basin	4.390	4.235	4.100	4.210	4.305	4.335	4.185	4.175	N.A.	4.255
San Juan Basin	4.320	4.205	4.035	4.150	4.190	4.240	4.145	4.140	N.A.	4.240
Bondad	4.310	4.175	4.025	4.110	4.170	4.220	4.125	4.090	N.A.	4.210
South Mainline	4.690	4.475	4.295	4.455	4.475	4.515	4.410	4.435	N.A.	4.640
Florida Gas Transmission Co.										
Zone 1	4.415	4.305	4.200	4.265	4.335	4.355	4.195	4.235	N.A.	4.395
Zone 2	4.455	4.335	4.210	4.270	4.345	4.350	4.310	4.280	N.A.	4.420
Zone 3	4.565	4.440	4.350	4.335	4.375	4.410	4.315	4.330	N.A.	4.505
Kern River Gas Transmission Co.										
Opal plant	4.220	4.070	3.900	3.950	4.080	4.160	4.050	4.030	N.A.	4.140
Natural Gas Pipeline Co. of America										
Midcontinent zone	4.330	4.195	4.080	4.155	4.240	4.295	4.185	4.190	N.A.	4.285
Louisiana zone	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Texok zone	4.370	4.255	4.145	4.210	4.295	4.310	4.215	4.255	N.A.	4.340
South Texas zone	4.370	4.260	4.220	4.220	4.320	4.315	4.210	4.270	N.A.	4.350
Amarillo reciept	4.355	4.240	N.A.	N.A.	4.305	4.345	4.210	4.205	N.A.	4.360
Northern Border Pipeline Co.										
Ventura Transfer Point	4.390	4.275	4.155	4.225	4.155	4.365	4.265	4.265	N.A.	4.370
Northern Natural Gas Co.										
Demarcation	4.410	4.295	4.170	4.170	4.350	4.355	4.265	4.275	N.A.	4.380
Ventura, Iowa	4.400	4.275	4.145	4.225	4.145	4.355	4.260	4.265	N.A.	4.380
Northwest Pipeline Corp.										
Wyoming	4.195	4.045	3.895	3.920	4.060	4.120	4.020	3.985	N.A.	4.105
Canadian border (Sumas)	4.170	4.020	3.865	4.045	4.125	4.110	3.955	3.955	N.A.	4.085
South of Green River	4.190	4.050	3.895	3.900	4.060	4.115	4.025	4.005	N.A.	4.125
Oneok Gas Transportation LLC										
Oklahoma	4.290	4.215	4.125	4.175	4.265	4.280	4.185	4.200	N.A.	4.305
Panhandle Eastern Pipe Line Co.										
Texas, Oklahoma (mainline)	4.260	4.155	4.050	4.140	4.220	4.255	4.140	4.170	N.A.	4.245
Questar Pipeline Co.										
Rocky Mountains	4.155	4.005	3.855	3.910	4.005	4.080	3.985	4.000	N.A.	4.065
Southern Natural Gas Co.										
Louisiana	4.435	4.310	4.190	4.255	4.350	4.390	4.245	4.275	N.A.	4.375
Southern Star Central Gas Pipeline, Inc.										
Texas, Oklahoma, Kansas	4.320	4.190	4.085	4.170	4.230	4.275	4.155	4.180	N.A.	4.250
Tennessee Gas Pipeline Co.										
Louisiana, 500 leg	4.410	4.300	4.205	4.260	4.355	4.380	4.230	4.240	N.A.	4.380
Louisiana, 800 leg	4.405	4.295	4.210	4.260	4.345	4.365	4.225	4.250	N.A.	4.395
Texas, zone 0	4.380	4.280	4.205	4.245	4.315	4.315	4.210	4.205	N.A.	4.340
Texas Eastern Transmission Corp.										
East Louisiana zone	4.395	4.285	4.180	4.245	4.330	4.345	4.190	4.255	N.A.	4.385
West Louisiana zone	4.370	4.290	4.195	4.255	4.350	4.335	4.235	4.265	N.A.	4.400
East Texas zone	4.260	4.170	4.000	4.100	4.150	4.170	4.080	4.140	N.A.	4.120
South Texas zone	4.330	4.240	4.110	4.185	4.240	4.265	4.175	4.135	N.A.	4.315
M-1 30-inch (Kosi)	4.450	4.325	4.160	4.270	4.375	4.385	4.260	4.245	N.A.	4.420
M-1 24-inch	4.445	4.340	N.A.	4.285	4.365	4.445	N.A.	N.A.	N.A.	4.440

** US holiday, no spot trades

Daily Prices of Spot Gas Delivered to Pipelines ($/MMBtu)

	Midpoint 6/22	Midpoint 6/23	Midpoint 6/24	Midpoint 6/27	Midpoint 6/28	Midpoint 6/29	Midpoint 6/30	Midpoint 7/1	Midpoint 7/4**	Midpoint 7/5
Texas Gas Transmission Corp.										
Zone 1	4.370	4.260	4.150	4.210	4.310	4.310	4.225	4.240	N.A.	4.355
Zone SL	4.370	4.280	4.145	4.210	4.345	4.340	4.190	4.220	N.A.	4.350
Transcontinental Gas Pipe Line Corp.										
Zone 1	4.400	4.285	4.185	4.215	4.370	4.335	4.200	4.240	N.A.	4.350
Zone 2	4.410	4.290	4.195	4.220	4.350	4.345	4.220	4.270	N.A.	4.385
Zone 3	4.420	4.320	4.205	4.265	4.360	4.395	4.290	4.300	N.A.	4.410
Zone 4	4.450	4.345	4.230	4.285	4.395	4.410	4.285	4.310	N.A.	4.430
Transwestern Pipeline Co.										
Permian Basin	4.300	4.185	4.045	4.180	4.310	4.310	4.120	4.110	N.A.	4.280
San Juan Basin	4.330	4.210	4.040	4.155	4.195	4.250	4.155	4.130	N.A.	4.230
Trunkline Gas Co.										
West Louisiana	4.390	4.260	4.190	4.250	4.355	4.350	4.225	4.290	N.A.	4.370
East Louisiana	4.365	4.280	4.170	4.205	4.320	4.310	4.190	4.195	N.A.	4.355

Market Center Spot Gas Prices, ($/MMBtu)

	Midpoint 6/22	Midpoint 6/23	Midpoint 6/24	Midpoint 6/27	Midpoint 6/28	Midpoint 6/29	Midpoint 6/30	Midpoint 7/1	Midpoint 7/4**	Midpoint 7/5
Northeast										
Texas Eastern, zone M-3	4.725	4.585	4.400	4.535	4.635	4.665	4.530	4.500	N.A.	4.695
Transco, zone 6 N.Y.	4.845	4.640	4.445	4.625	4.740	4.775	4.745	4.655	N.A.	4.865
Transco, zone 6 non-N.Y.	4.730	4.625	4.420	4.580	4.675	4.740	4.525	4.540	N.A.	4.705
Algonquin city-gates	4.805	4.635	4.540	4.640	4.840	4.925	4.805	4.875	N.A.	5.145
Tennessee, zone 6 delivered	4.815	4.600	4.450	4.555	4.815	4.840	4.785	4.840	N.A.	5.120
Niagara	4.705	4.585	4.495	4.530	4.615	4.640	4.505	4.570	N.A.	4.690
Leidy Hub	4.725	4.580	4.400	4.500	4.630	4.665	4.450	4.585	N.A.	4.680
Iroquois, receipts	4.915	4.805	4.620	4.675	4.845	4.840	4.755	4.855	N.A.	5.040
Algonquin, receipts	4.780	4.645	4.500	4.590	4.765	4.895	4.675	4.755	N.A.	4.735
Iroquois, zone 2	4.955	4.810	4.640	4.710	4.870	4.855	4.770	4.900	N.A.	5.135
Transco, zone 5 delivered	4.670	4.555	4.385	4.430	4.590	4.600	4.485	4.565	N.A.	4.625
Rockies Express, Clarington Ohio	4.540	4.425	4.275	4.345	4.450	4.490	4.380	4.360	N.A.	4.510
Tennessee, zone 4-Ohio	4.565	4.450	4.300	4.380	4.495	4.550	4.370	4.405	N.A.	4.555
Southeast										
Florida city-gates	5.160	4.960	4.820	N.A.	4.880	N.A.	N.A.	N.A.	N.A.	4.825
Upper Midwest										
Chicago city-gates	4.515	4.405	4.270	4.345	4.430	4.470	4.340	4.350	N.A.	4.455
Consumers Energy city-gate	4.620	4.570	4.450	4.445	4.525	4.515	4.410	4.490	N.A.	4.550
Mich Con city-gate	4.600	4.485	4.390	4.420	4.510	4.500	4.405	4.485	N.A.	4.550
ANR Pipeline, ML 7	4.475	4.485	4.255	4.330	4.485	4.475	4.345	4.410	N.A.	4.530
Dawn, Ontario	4.670	4.575	4.575	4.495	4.600	4.580	4.480	4.555	N.A.	4.645
Emerson, Viking GL	4.285	4.205	4.205	4.105	4.200	4.190	4.075	4.120	N.A.	4.230
Alliance, into interstates	4.525	4.430	4.430	4.355	4.450	4.490	4.335	4.355	N.A.	4.480
Dracut, Mass.	4.850	4.620	4.425	4.500	4.715	4.830	4.800	4.700	N.A.	5.130
South Louisiana										
Henry Hub	4.415	4.310	4.195	4.245	4.345	4.390	4.280	4.325	N.A.	4.405
Stingray Pool	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
East/South Texas										
Houston Ship Channel	4.425	4.335	4.270	4.335	4.435	4.465	4.365	4.365	N.A.	4.455
Katy	4.410	4.325	4.255	4.315	4.415	4.415	4.330	4.360	N.A.	4.455
Carthage Hub	4.265	4.175	4.100	4.175	4.295	4.340	4.215	4.225	N.A.	4.305
Agua Dulce	4.450	4.345	4.250	4.300	4.430	4.470	4.280	4.300	N.A.	4.410
West Texas										
Waha	4.370	4.215	4.130	4.220	4.320	4.360	4.230	4.230	N.A.	4.305
Rockies/Northwest										
Cheyenne Hub	4.245	4.110	3.990	4.050	4.175	4.240	4.080	4.110	N.A.	4.195
TCPL Alberta, AECO-C*	3.690	3.620	3.515	3.630	3.705	3.690	3.530	3.530	N.A.	3.660
Stanfield, Ore.	4.310	4.145	4.025	4.150	4.205	4.240	4.125	4.100	N.A.	4.320
Kern River, delivered	4.590	4.390	4.240	4.390	4.410	4.480	4.355	4.430	N.A.	4.575
GTN, Kingsgate	4.275	4.105	3.990	4.125	4.165	4.215	4.100	4.105	N.A.	4.295
Westcoast, station 2	3.575	3.465	3.380	3.610	3.425	3.555	3.110	3.110	N.A.	3.235
California										
PG&E Malin, Ore.	4.440	4.260	4.140	4.245	4.300	4.355	4.250	4.255	N.A.	4.405
PG&E city-gate	4.700	4.585	4.490	4.545	4.605	4.640	4.555	4.595	N.A.	4.690
PG&E South	4.555	4.420	4.240	4.400	4.420	4.485	4.350	4.385	N.A.	4.530
Southern California Gas Co.	4.585	4.430	4.260	4.420	4.440	4.505	4.380	4.395	N.A.	4.555

* NOTE: Price in C$ per gj.
** US holiday, no spot trades

was flat at plus $2.36/MMBtu, and winter 2012-2013 also was flat from July 1 to Wednesday at plus $2.09/MMBtu.

The trading slowdown also eased the continued fall at the back of Appalachian curves. Columbia Gas Transmission in Appalachia summer 2013 rose three-quarters of a cent over the period to plus 1.25 cents/MMBtu, and Dominion Transmission's south point summer 2013 picked up a quarter of a cent to plus a quarter-cent/MMBtu.

The flight of traders from the markets slowed down Upper Midwest basis markets considerably, leaving the front of the curve nearly flat between July 1 and Wednesday.

Chicago city-gates August basis dropped half a cent to plus 6 cents/MMBtu, and Michigan Consolidated Gas city-gate was flat at plus 14.75 cents/MMBtu. At the same time, Dawn, Ontario, basis continued to weaken, falling 1 cent to plus 24.75 cents/MMBtu and tightening spreads to Michigan.

— Leticia Vasquez

Marcellus uncertainty deflates basis in Appalachia; forward curve negative

After falling into negative territory for the first time ever in May, Appalachian forward basis shows continued weakness over the next four years, due to market uncertainty about the ability of future pipeline expansions to keep up with growing production in the Marcellus Shale.

According to traders and analysts, how well those expansions deal with the new supply opens the possibility of large amounts of stranded regional gas, making negative basis to the NYMEX Henry Hub futures contract the new normal in the region.

"People are seeing that even if the planned expansions get done, there is a good chance that parts of the Marcellus will run out of export capacity and gas will get stranded," a regional basis trader said. "No one wants to buy 2014 supply and then be 50 cents underwater in case that comes true."

Regional basis values began turning negative April 21 when Dominion Transmission's South Point calendar year 2014 package fell to minus half a cent/MMBtu, according to the Platts-ICE Forward Curve. Other 2013 packages soon followed at both Dominion Transmission and Columbia Gas Transmission storage hubs in what market sources described as a financial play by producers to de-risk their exposure to Marcellus production and the start of a longer-term trend in the region.

Although 2013 basis packages did briefly rebound through June, with Dominion 2013 basis reaching a regional high of plus 4.5 cents/MMBtu June 2, the back of the curve in Appalachia began a new march downward by mid-June with 2014 basis falling deeper into negative territory and 2013 packages nearing negative values again. On June 29, Dominion summer 2013 basis turned negative again, falling to minus a quarter-cent/MMBtu, and Columbia summer 2013 basis was sitting barely positive at plus a quarter-cent/MMBtu.

Platts' M2M models show both Columbia and Dominion, south basis remaining negative in a range of minus 4 cents/MMBtu to minus 7 cents/MMBtu through 2029.

Between November 2011 and November 2013, there is 1.7 Bcf/d of new pipeline capacity scheduled to be added out of the Marcellus via Texas Eastern Transmission's Time III, TEMAX and TEAM 2012 expansions; Tennessee Gas Pipeline's 300 leg; and Transcontinental Gas Pipe Line's Northeast Supply expansion.

Even when the new capacity hits, regional basis recovery will likely be limited, another trader said. "You've got an anomaly with the market area rather than the supply area," the trader said. "Structurally, the Northeast is changing with flows; Columbia [in Appalachia] will be weaker, but the market will adjust."

But some analysts disagree. "Our projection shows Marcellus production growing by 4 Bcf/d by 2014 on a smooth curve ... [but] growth will not be as smooth as that projection because it will likely face limitations as capacity fills and producers need to wait for additional expansions," Bentek Energy analyst Jennifer Robinson said.

Bentek's projection calls for Northeast production to reach 5.5 Bcf/d by January 2012 and 6.5 Bcf/d by January 2013, an increase over previous projections largely due to gains in production in northern Pennsylvania, one of the target areas for the new pipeline expansions. Bentek is a unit of Platts.

According to Black & Veatch managing partner Greg Hopper, slow demand growth for gas in Northeast market areas will also force moderation of supply growth by producers, which should keep regional basis supported. And despite continued forecasts for high production growth in the Marcellus, the cost of capital for producers versus a continued low-price environment will make a drilling slowdown inevitable.

Hopper also noted that the realities of transportation costs relative to Henry Hub would also likely support Appalachian basis long-term, because traders will be able to keep Marcellus gas within the margin of variable transportation costs from the Gulf Coast.

"Our view is that you can't have Henry Hub and Marcellus at parity because you've got variable costs to move from the Gulf to the Marcellus," Hopper said. "So long as you have optionality to reach down to the Gulf Coast and you don't have gas in the Gulf Coast not needing to move to the Northeast, you'll have some regional spread in price."

— Joshua Starnes

Marcellus shifts dynamics *... from page 1*

more than 2 Bcf/d of supply that has come online from the Pennsylvania part of the shale.

Production in the shale is expected to hit around 6 Bcf/d in the next five years, analysts have said.

"We're very fortunate that the system lies right in the heart of the Marcellus play in northwest Pennsylvania," El Paso pipeline group manager Jim Yardley said in a presentation to analysts in late May.

Yardley said Tennessee's 300 leg has added 33 tap-ins from local producers and has 14 more under construction.

But with this production boom, shippers on the 300 leg have seen increasing complications moving gas to market, including constraints that have blocked up the pipe and backhauls to get gas from the restrictions. "This is a supply center that grew around an existing pipeline, and one that wasn't that large to begin with," Waller said. "Somewhere along the way it was going to get constrained."

Those constraints have thrown the market out of balance, as more supply has hit the system than can effectively be offloaded to meet demand, sources said. A Northeast trader said as the pipe has been overloaded in the production area, the impacts are showing up in the zone 6 market area.

Since 2006, prices for both the 200 and 300 legs of Tennessee zone 6 were priced at most only a few cents apart, according to prices on IntercontinentalExchange.

That spread in zone 6 has, over the past two months, blown out significantly — hitting as much as 55 cents on July 1 — as the glut of supplies weighs on the price for deliveries upstream of the Agawam connector.

In the monthly markets, ICE reported a $4.807/MMBtu July average for Tennessee zone 6 on the 200 leg — 30 cents higher than the 300 leg's average of $4.507/MMBtu.

Platts reported a trading range of $4.51/MMBtu to $4.81/MMBtu for Tennessee zone 6 delivered for July, with a final index of $4.78/MMBtu. Platts' zone 6 listing includes deliveries from Tennessee on both the 200 and 300 legs.

Black & Veatch analyst Denny Yeung said that wide differential could well be the new normal for the market. "Until any incremental capacity comes online that relationship should continue because of the constraints on the 300 line," Yeung said. "But Tennessee is working to alleviate those constraints."

Part of El Paso's solution is a shifting of pooling points that allows for backhaul of interruptible shipments from the 300 leg to the 200 leg at Mercer, Pennsylvania, where Marcellus gas will meet supplies from the Rockies and the Gulf Coast. Those changes went into effect on July 1.

The new aggregation is aimed at helping producers and end-user buyers more easily move supplies from field to market. ICE also moved to add the two new pooling points for active trading shortly after the shift.

"It's reflective of the fact that Marcellus is here to stay," Black & Veatch managing director Greg Hopper said.

Midstream companies are also becoming increasingly aware of that fact. A half-dozen pipeline proposals are targeting more takeaway capacity from Pennsylvania Marcellus fields by November, including an expansion of Tennessee's 300 leg.

In the short-term, however, constraint issues may continue to plague shippers. "A lot of people [are] rushing to help put out the fire, but it's still burning," Waller said. "Companies are spending billions of dollars drilling in the Marcellus and it's totally underserved. It's going to be hand-to-hand combat getting gas to market."

Waller said producers with firm contracts on any pipeline that takes gas from Marcellus will likely be forced to pay more to transport, cutting heavily into wellhead profits.

"It's so cheap in Marcellus it's not much of an issue now," Waller said. "But the ultimate solution when storage gets full is that they'll have to shut-in wells."

Waller said in the longer term, despite the increase in takeaway capacity, this expansion of supply so near the market area could also spell trouble for long-haul pipelines like Tennessee and others that link the Gulf Coast with Appalachia and the Northeast.

"There will be less gas moving through the pipe, so it becomes less efficient and costs more to move gas," Waller said, adding that long-haul pipelines "would need to raise rates, which makes them become less competitive. It becomes a vicious cycle."

Yardley said in the recent presentation that future growth in power generating needs in Ohio, Kentucky, Tennessee and many parts of the Southeast could mitigate those issues and provide demand for space on the pipeline upstream of Marcellus.

Still, the Northeast remains the largest gas consumption area in the country and will be the market of first resort for producers in general. Hopper said end-users will likely seek the cheaper gas in nearby fields first, but ultimately gas from the Gulf Coast and Rockies will be required to fill the great needs for supply.

"Until the Northeast is totally self-sufficient on supply, the Gulf Coast and other basins will supply some percentage of supplies and will create basis spreads," Hopper said. "The Northeast is a 12 to 20 Bcf/d market, so there's a long way to go."

— Adam Bennett

REGULATION

Some CFTC officials fear agency is rushing to enact financial rules

The Commodity Futures Trading Commission on Thursday began what is expected to be a months-long process of finalizing dozens of financial reform law rules, but some commissioners said they are worried the agency may be rushing rules into law before they are properly considered.

"We are beginning without a plan," Commissioner Jill Sommers said at Thursday's CFTC meeting.

The CFTC plans to soon finalize an order keeping many new derivatives rules from taking effect next week, as mandated by the Dodd-Frank Wall Street Reform and Consumer Protection Act, but it has only laid out a loose timetable that would see the agency approve 46 rules over the next six months, Sommers said.

"While a few of these rules will be relatively straightforward and noncontroversial, the vast majority are based on extremely complex proposals for which staff has yet to even complete a comment summary," Sommers said. "If we stick to such a schedule, I foresee a process that haphazardly requires votes to be taken when the commission has not had time to sufficiently consider all of the implications of the final rules."

Commissioner Scott O'Malia, who again pushed the CFTC to release a formal rulemaking schedule which would be open for public comment, called the CFTC's rulemaking process a "rulemaking mystery."

O'Malia said that market participants need clarity on when they will have to comply with the new rules, such as swaps clearing and reporting requirements.

"I believe firms are sincerely interested in fully complying with the final regulations, if only the commission would inform them when they should be prepared to comply," O'Malia said. "Market participants are preparing to implement the final regulations, but have no idea if they should be ready in eight or 18 months. By providing the market with a plan, it will improve compliance with our regulations."

Commissioner Bart Chilton said the agency was committed to not rushing rules into law. "I think we're in agreement," he said. "It's more important to get it right than to do it fast."

Commissioner Michael Dunn called the CFTC's rulemaking process "extremely transparent," but cautioned that he would be far more critical of rules as they are considered for final implementation, than he was when they were proposed.

"I was purposely liberal with voting on proposed rules, because I felt it was more important to get public comment than to nitpick the rules at their formative stages," Dunn said.

Dunn said that while he wants all final rules to follow the agency's principles-based model, budget constraints at the CFTC could force him to approve rules that are "more prescriptive than [he] would generally favor."

Meanwhile, energy firms are urging the CFTC to maintain status quo in derivatives markets after the July 16 reform deadline passes. The Coalition of Physical Energy Companies is worried that regulatory changes could still take place, even with a new order in place to delay the rules deadline.

In a letter to the CFTC on July 1, the coalition wrote that while it was "generally supportive" of the proposed order, it "lacks such an affirmative statement that the status quo of swap markets in effect today will continue after July 16" — something that could affect existing swap agreements.

According to the letter, counterparties in those swaps "could seize on the remaining ambiguity to attempt to unravel or otherwise escape obligations under existing and future transactions entered into before the full implementation of the new Dodd-Frank regulatory regime." The coalition wants the order to state "unambiguously" that swaps entered into after July 16 "will be equally enforceable as those made prior to that date."

The coalition includes Apache, Shell, El Paso, Iberdrola Renewables, Kinder Morgan, MarkWest Energy Partners, Noble Energy, NRG Energy, SouthStar Energy Services and Targa Resources Partners.

The coalition's letter was one of 18 the CFTC received last week on the proposed order, including one from Nodal Exchange, which wants the CFTC to issue its final rules on designated contract markets and swap execution facilities at the same time. That would give the exchange time to determine which entity it plans to be, Nodal said.

CME Group, the parent of NYMEX, said the proposed order was not ideal. "In particular, the expiration of exemptive relief on December 31, 2011 — less than 6 months from the date of any final order — is likely to require similar [CFTC] action again just a few months from now in order to avoid plaguing the markets with the legal uncertainty the CFTC aimed to avoid," wrote CME CEO Craig Donohue.

Better Markets, a financial reform advocacy group, applauded the move to delay the effective date of the rules but stressed the need to set an implementation deadline. "The most important thing regulators can do is to provide a clear date for implementation," the group wrote. "If no deadline is established, the potential for needless delay resulting from extended but unnecessary debate is very real."

— Brian Scheid

CFTC approves new rules to overhaul how it polices fraud and manipulation

The US Commodity Futures Trading Commission on Thursday unanimously approved two final rules that will dramatically broaden the agency's power to police manipulation and fraud in futures and swaps markets.

Under the two rules, the commission will no longer have to prove that a potential defendant acted intentionally nor will it have to prove that the defendant caused an artificial price. The lower standard for the CFTC is expected to increase the number of fraud and manipulation cases that the agency can now pursue.

"That's a big change from where we were," said a CFTC official during a background call with reporters Wednesday. "Our current authority in manipulation cases requires us to prove that a defendant acted intentionally and that a defendant intended to cause an artificial price. Under the new rules we have to prove that a defendant acted recklessly," which is a lower threshold than having to prove a defendant acted intentionally.

The official said the new authority, part of which was modeled after authorities that the Securities and Exchange Commission, the Federal Energy Regulatory Commission and the Federal Trade Commission already have, will allow the CFTC to "capture a larger category of fraud cases. It's very, very broad language."

The rules will take effect 30 days after they are published in the *Federal Register*, which will likely be in mid-August.

CFTC Chairman Gary Gensler said the new rules would allow the agency to be a "more effective cop on the beat," and Commissioner Bart Chilton called the new rules "critical ammo in the commission's enforcement arsenal."

"With the adoption of this new rule, the commission will be able to prosecute a broader array of commodity law violations," Chilton said.

These violations include manipulation in crude oil markets, profiting from the misuse of privileged information and recklessness from false reporting, Chilton said. For example, a trader that starts a rumor that oil will be released from the strategic petroleum reserve would be a type of violation the CFTC could now go after, Chilton said.

Commissioner Scott O'Malia said that while he supports these new rules he is concerned that the anti-manipulation rule "has not provided adequate clarity and that such vagueness as to the course of action that will be taken by the commission in enforcing this rule will add confusion to the markets."

O'Malia said that by incorporating standards the SEC adopted, these new authorities "run the risk of disregarding the unique qualities of the futures and derivatives markets in its attempts to apply concepts developed in the securities markets such as insider trading based on misappropriation."

Energy groups, including the Coalition of Physical Energy Companies and the American Petroleum Institute, have criticized the new anti-manipulation and anti-fraud rules as being overly broad and having the potential to cause turf wars with other federal agencies.

— Brian Scheid

User fee proposal stagnates at OMB as officials debate end-user treatment

A contentious proposal by the Obama administration to place user fees on futures and swaps transactions has yet to be released as officials wrestle with the treatment of end-users, differences between securities and futures markets and the impact of the ongoing budget battle in Congress, sources said.

This bid to impose user fees on futures and swaps transactions, included in the administration's fiscal 2012 budget proposal, would partially fund the Commodity Futures Trading Commission. The budget, proposed in February, includes $308 million for the CFTC for fiscal year 2012 and offsets of $117 million that would be paid through fees the agency would charge market participants.

The Office of Management and Budget has been working on the proposal, with some technical assistance from the CFTC, for months, sources said. But a variety of "outstanding issues" has kept the OMB from releasing it, according to spokeswoman Meg Reilly.

"With the debt ceiling approaching, there are many [issues]," Reilly said, declining to elaborate.

A CFTC official, who did not want to speak on the record since the proposal is still developing, said that one issue in the legislative language circulating at OMB revolves around how end users, such as energy firms who use energy swaps to hedge commercial risk, will be treated.

Last week, Commissioner Bart Chilton, a Democrat, said that his support of the proposal may ultimately hinge on the treatment of end-users.

"As long as end-users are treated fairly, I think such a fee makes sense," Chilton said. "Without it, it doesn't appear we will have anywhere near the resources needed to effectively regulate these markets."

Another CFTC official, also not authorized to comment, said the administration has yet to determine if user fees can even work in the futures and swaps markets, given how differently they trade compared with securities products.

"Securities are here in the United States, they're not really fungible and they're not really traded across borders and listed on German stock exchanges, [for example], because they're unique," the official said. "But commodities are fungible and not unique. If I want to go and trade oil and I don't like the cost of trading it here, I can go somewhere else because oil's oil. Or I can trade over there to get access to oil here. It's not a unique product."

Of the five CFTC commissioners, only Republican Scott O'Malia has spoken out against the proposal. In an official dissent of Obama's proposed budget, O'Malia called the fees a "transaction tax" which would create a hole in the budget.

"This is a disingenuous effort that only puts us further behind the requested funding level and will continue to add to the federal deficit," O'Malia said.

Several exchange officials and Republicans have also spoken out against user fees.

They "represent one more [way] to attempt to grow government even more, and done in this way it would be outside the traditional congressional appropriations process - an off-budget accounting gimmick that will hide the true cost and scope of the federal government," said Representative Scott Garrett, a New Jersey Republican and chairman of the House Financial Services Subcommittee on Capital Markets and Government-Sponsored Enterprises.

— Brian Scheid

CANADA

Record Northwest Territories lease sale reignites push for Mackenzie project

A record sale of oil and gas exploration rights in northern Canada's Central Mackenzie Valley has put the spotlight on an emerging liquids-rich shale gas play and provided fresh ammunition for those pressing the Canadian government to negotiate a fiscal framework for the stalled Mackenzie Gas Project.

The response to the offering of 11 parcels by the Northern Oil & Gas Directorate of Aboriginal Affairs and Northern Development Canada has left observers reeling as they try to explain what the successful bidders are keeping under wraps.

Led by all of the MGP's partners and Husky Energy, the sale, whose results were announced Monday, attracted $534 million (*all dollar figures Canadian*) in successful bids for 3.1 million acres, including the three highest prices paid for single parcels in the onshore Northwest Territories.

Husky shelled out $188 million each for two blocks, which cover a combined 432,000 acres; ConocoPhillips pledged $67 million for a 217,000-acre parcel; Shell Canada committed $43.4 million for three parcels totaling 498,000 acres; and the Imperial Oil-ExxonMobil joint venture paid $43 million for three parcels totaling 443,000 acres.

MGM Energy, the sole explorer in northern Canada over recent years, and partner 6362 NWT Limited landed three parcels covering 629,000 acres for $5 million, and Arctic Energy & Minerals obtained 521,000 acres in the Beaufort Sea for $2 million.

Amid persistent gloom over the MGP and years of exploration inactivity in the region, Calgary-based consultant Kenneth Drummond said the land sale demonstrates a renewed interest by global heavyweights.

"Most of the best lands in the Mackenzie Valley were up for bid," he said, suggesting conventional oil likely underlies the ConocoPhillips bid.

Pat Boswell, CEO of International Frontier Resources, a partner in nine of the 14 wells drilled in the Central Mackenzie Valley over the past decade, said it appears there is a scramble to lock up the entire land area west of the Mackenzie River and south of Norman Wells.

International Frontier has openly suggested over the past year that the lack of infrastructure in the Central Mackenzie Valley provides an opportunity to secure land at lower prices than would have been possible if there was a pipeline system from the Mackenzie Delta to southern markets.

Currently, plans for the MGP include a possible 1.8 Bcf/d gas line owned and operated by TransCanada PipeLines along the Mackenzie River Valley and a parallel liquids line by Enbridge from the Delta to the company's existing — but underutilized — 45,000 b/d crude oil line from Norman Wells to northern Alberta.

Bob Reid, president of the Aboriginal Pipeline Group, which holds an option for a one-third equity stake in the gas pipeline, said signs of fresh interest in the Beaufort and Central Mackenzie Valley give a positive lift to the MGP.

Winning bidders have five years to cover their work commitments and obtain a four-year license extension. Any discoveries during that time that can support sustained hydrocarbon production can qualify for a Significant Discovery License, which carries indefinite tenure.

AANDC said it does not speculate on the reasons for industry interest, and the companies are keeping tight-lipped beyond describing the new properties as "prospective" and indicating their first objective will be to gather 3-D seismic data.

Husky spokeswoman Colleen McConnell said the company's parcels are located 10 to 40 miles southeast of Imperial's producing oilfield at Norman Wells and close to three SDLs in which Husky has interests. However, "we're not prepared to speculate now on what may or may not be there," she said.

A Husky-operated SDL for the 2004 Summit Creek B-44 gas and light oil find has tested at 20,000 Mcf/d and 6,300 b/d of oil.

Macquarie Capital Markets analyst Chris Feltin said the premium bidding by Husky are a hint the company is targeting an oil-rich play, adding, "maybe they think they've keyed into a new play in that region."

Pius Rolheiser, a spokesman for Imperial, the lead partner in the MGP, said the parcels offer a "range" of hydrocarbon prospects, noting that gas trends also exist in the Norman Wells oilfields. "You don't know for sure until you drill," he said.

Northwest Territories Industry Minister Bob McLeod said this year's National Energy Board approval for the MGP may have motivated companies to revive gas exploration plans and renewed their confidence in the future of Arctic gas.

He said northern government and aboriginal leaders believe the Canadian government is "not doing nearly enough to support development" of the resource and called on Ottawa to negotiate a satisfactory fiscal regime with the MGP proponents as soon as possible.

McLeod, who meets frequently with Canadian and US lawmakers to promote the value of gas as a clean-burning fuel, said he is counting on Prime Minister Stephen Harper to fulfill a recent election pledge to negotiate a fiscal and infrastructure package that would enable the MGP to proceed on a commercial basis.

Reid said a fiscal regime would restart MGP activities that were curtailed in January 2007 because of slow progress on the regulatory front, including detailed engineering, field work and more accurate cost estimates, leading to a corporate decision in 2013 and initial gas deliveries in 2018.

Rolheiser said the MGP proponents are re-engaging in financial discussions with Harper's new majority government and are making progress in seeking a benefits and land access agreement with the Dehcho First Nations, the last holdout among aboriginal communities along the Mackenzie pipeline right-of-way.

John Manzoni, CEO of Talisman Energy, told an audience of bankers and business executives last month that frustration over a lack of government leadership on infrastructure, including that for gas exports, is intensifying. "Let's be very clear on this, farthest from the market means first to be shut out," he said.

Encana spokesman Alan Boras joined the chorus, arguing that regulators need "to carry through a prompt, efficient and sound process that will ultimately enable Canadian energy companies to compete on a global scale."

Acknowledging industry concerns, Alberta Energy Minister Ron Liepert has put himself in the forefront of efforts by Canadian provincial governments to develop a National Energy Strategy to accelerate project approvals and secure future oil and gas markets.

Backed by Canadian corporate leaders, he will take his arguments to an Alberta conference from July 16 through 19, when Canada's federal, provincial and territorial energy and mines ministers attempt to resolve their long-standing differences over an NES.

Liepert said a "coherent, collaborative Canadian energy framework is needed if we are going to realize our full potential as a global resource powerhouse."

He said harmonizing regulations across Canada would also ensure all parties are treated fairly on environmental issues and will not have to deal with different sets of regulations in different provinces.

— Gary Park

STORAGE

Industry officials say FERC should abandon new storage capacity policy

Industry representatives believe the Federal Energy Regulatory Commission should reconsider its new policy that requires gas storage companies to seek capacity releases before expanding their facilities because it could allow customers to walk away from their contracts and discourage storage development.

The new policy, along with FERC's recent decision to reject the proposed Turtle Bayou gas storage project (*IFGMR*, 24 Jun, 15), appears to be part of a broader trend at the commission to require gas storage developers to provide more proof of demand before launching a project, some argued in recent filings with FERC. But they added that this is not necessarily a step in the right direction.

"We should be trying to remove the barriers for gas infrastructure development, not raising them," said Joseph Fagan, a Washington attorney who represents energy clients.

Some storage customers said the policy is important because it prevents overbuilding and minimizes impacts to the environment and landowners.

One decision under industry scrutiny is FERC's recent approval of Pine Prairie's request to expand its storage facilities (*IFGMR*, 27 May, 18). Last October, the company asked FERC to allow it to expand its gas storage facility in Evangeline Parish, Louisiana, to 80 Bcf from 48 Bcf. BP Energy protested, arguing Pine Prairie should comply with FERC's capacity open-season policy.

First delineated in a 1995 FERC statement, the policy requires pipelines to hold an open season to seek capacity release from existing customers before embarking on an expansion. The policy is intended to reduce costs and avoid the possibility that existing customers will end up paying for the expansion.

Capacity that is turned back to the pipeline can be used as a substitute for some or all of the planned expansion, minimizing the cost, environmental impact and use of eminent domain related to the expansion project, according to the policy.

BP said it had unwanted capacity that it would like to return, and this capacity could reduce the size of Pine Prairie's planned expansion.

"The fact that Pine Prairie is seeking certificate authorization to charge market-based rates for expansion capacity does not exempt Pine Prairie from the requirements of the public convenience and necessity, including the need for the pipeline to justify a market need for its proposed expansion," BP said. "Certainly, the fact that existing shippers wish to turn back capacity is a strong indication of the lack of market support for the level of expansion capacity proposed by Pine Prairie."

Pine Prairie pushed back, arguing the turnback policy was developed for cost-of-service pipelines, not market-based storage facilities. Applying the policy to storage facilities would allow customers to get out of their contracts, which are the sole mechanism for storage facilities to recoup their costs, the company said.

But FERC in its May 19 decision sided with BP and decided to expand the policy to all storage expansion projects.

FERC said the policy is intended to address discrimination and overbuilding and therefore should apply to all storage facilities regardless of how they recover their costs. And customers will not be able to walk away from their contracts because storage facilities can require customers to meet terms to keep the company financially whole, the commission said.

Pine Prairie is now asking FERC for a rehearing and clarification of the decision, arguing that the commission has failed to justify the new requirement. The company also filed a document outlining the terms it proposes to impose on customers that turn back capacity and making other tariff changes that the FERC order required.

The policy would not resolve the problems it is intended to address, Pine Prairie said. First, market-based rates cannot be distorted by unsubscribed capacity or costs of overbuilding, so current customers could not subsidize the expansion. Second, it would not necessarily lead the developer to change its project's size, and any overbuilding is likely to benefit the customer through lower rates. Third, the Pine Prairie expansion would have only a small environmental impact and would not add a new burden on any landowner.

Uncertainty about turnbacks could also lead to development delays. "This unsupported policy change, if not corrected, can be expected to drive storage service providers to defer storage capacity expansions until long after they are actually needed to meet market demand," Pine Prairie added.

Enstor echoed those concerns in its separate request for late intervention and rehearing. According to the company, FERC is applying the policy industry-wide without any record of harm caused by market-based rate storage providers. "The commission has apparently devised a solution in search of a problem, and in response to what even BP acknowledges is a 'limited protest,' has imposed a sweeping open-season obligation that is simply not justified by the evidence in the record," Enstor stated.

If the commission does not grant rehearing, it should initiate a rulemaking to take comment on the new policy, Enstor said.

Earlier this month, FERC rejected a plan by Turtle Bayou Gas Storage to build and operate a high-deliverability gas salt dome storage facility in Texas. The commission argued the company had not shown that there was enough demand to justify the negative impacts to the environment and landowners.

This decision fits a trend of caution at FERC, according to a client alert by the law firm Dewey & LeBoeuf. "FERC's order clearly signals to the industry that applicants will need to provide a more robust showing of market need for natural gas projects when there may be substantial adverse impacts as to any of the stakeholder groups identified in the Certificate Policy Statement," the alert stated.

— Kate Winston

NYMEX spreads tighten *... from page 1*

but we are exceeding production level highs last seen about 40 years ago."

Pax Saunders, vice president of energy markets at Gelber & Associates, echoed that sentiment. "This is not just the amount of gas, but an oversupply condition," he said. "Storing gas right now is not much of a favorable arbitrage."

A recent research note from Bank of America/Merrill Lynch added, "At this point, the market is barely covering for the costs of storage, embedding expectations of a below-normal injection season next summer."

The analysts said the market "is placing very little marginal value to storage at the moment," either due to incremental working gas storage capacity that has been added in recent years, expectations for a quickly improving market balance or both.

Kyle Cooper, director of research at IAF Advisors, estimated between 100 Bcf and 150 Bcf of new storage capacity was added over the last five years.

Furthermore, "operators are taking their time fracking and connecting wells to the system," Raymond James analyst Christopher Butschek said. "This 'uncompleted backlog' of wells is in effect *de facto* storage, as the gas could hit the market within a month or two."

Analysts show consensus that despite tightening spreads, storage will continue to fill, as end-users and utilities will continue to inject regardless of spreads.

"The goal of the utilities and end-users is to lock in the price, so they would store anyway," according to Saunders, adding that they are not typically concerned with price spreads. They do not speculate, but buy and sell gas based on their hedging programs as required by public utility commissions, he said.

"Gas storage remains a necessary component of the US market — on a daily basis, gas production is basically flat throughout the year while demand remains highly seasonal," Ballheim added. "Gas must be injected in the summer so long as producers want to monetize their production capacity."

Merchant traders, however, are "reticent" to store gas as there is "no reward with lack of market contango," Saunders added.

"It crushes the heart of the value for storage capacity in this year for anyone that does not have a specific need they are storing for; i.e. a real winter demand," International Gas Consulting President Ken Beckman said. "With traders unable to find attractive spreads, storage capacity finds little value in the short term. It is really hard to sign up for new storage capacity this year in that scenario. Consequently, it takes a company with a long view to sign up for capacity."

But Bank of America analysts predict an eventual widening of spreads, as they believe the market will come more into balance in 2012 and as the summer prices will get much lower than winter.

"In our view, storage will ramp up very quickly under normal weather for the remainder of this summer," the report said. "[By] our estimates, inventories will likely build above the five-year average and will end the injection season at 3.75 Tcf. This will likely depress near-dated prices relative to forward winter prices.

"Moreover, we firmly believe that the market will see little improvement in fundamentals next year," the firm added. "Given the ongoing successes on the production side, storage injections next year are also likely to proceed at a quick pace in 2012. As such, we place a much higher value on storage than the market does and we believe summer-winter spreads will widen from here."

Ballheim also believes the storage situation will change as the spread widens. "A low seasonal spread only shows that the majority of market participants are betting that they will not need to pay a premium to get the supply they need during the winter months," he said.

If one looks at historical settlement prices, one would see very limited winter premiums at Henry Hub over the past few years, according to Ballheim.

"Of course, this mentality will work right up to the point at which it doesn't," he said. "Sooner or later, winter supply will get tight, those that are short will pay the piper, and winter spreads will return the following summer."

— Anastasia Gnezditskaia

EXPLORATION AND PRODUCTION

E&P officials criticize *Times* stories that question viability of shale gas

Two recent *New York Times* articles that questioned the viability of shale gas drilling drew the ire of exploration-and-production companies and other industry advocates, who believe the newspaper's assertions were unfounded, while at least one lawmaker took it as a cue to demand more information from the Energy Information Administration on how it determines shale gas reserves.

The *Times*' stories, published on June 26 and 27, quoted emails from several anonymous Energy Information Administration officials, who purportedly cast doubt on whether the exploitation of shale gas basins would live up to the hype that producers such as Chesapeake Energy and others have generated. The article quoted one EIA adviser as saying some producers "will go bankrupt" due to ill-advised investment in shale gas.

They also cited emails, with names redacted, from industry consultants who argued that shale plays are, for instance, "just giant Ponzi schemes," are "inherently unprofitable" and are causing firms to have "an Enron moment."

Aubrey McClendon, CEO of Oklahoma City-based Chesapeake, argued that the shale gas revolution is not, as some in the articles suggested, a bubble, and that it will prove to be long-lived. He criticized the newspaper for having "an anti-natural gas agenda" and said it "chose not to interview a single reliable source and instead selectively quoted emails from unnamed sources or well-known industry critics dating back to as early as 2007 to invent a series of inaccurate and misleading allegations."

McClendon countered arguments made in the stories that, following impressive initial production volumes, shale gas wells typically experience high decline rates that threaten the plays' long-term economic viability.

"By analyzing our own and industry peer well performance, we know that the initial productivity of a majority of the industry's shale gas wells have been steadily improving, both in initial production rates and the expected ultimate recoveries of natural gas," McClendon said. "We fully expect that the majority of these wells will be productive for 30-50 years, or even longer."

Analysts at Tudor Pickering Hold made similar arguments, saying the newspaper "trotted out the Barnett Shale as where they seek to poke holes in the shale story. As the first shale play with such considerable production onshore US, the Barnett provides a good amount of history. Production doesn't lie ... natural gas production from the Barnett is now higher (at ~5.6 Bcf/d) than it was in 2008 (previous peak was ~5.3 Bcf/d in 2008) despite the rig count being more than cut in half. If wells are declining faster than expected, the Barnett would not be at record production with reduced rig count."

Ed Ireland, executive director of the Barnett Shale Energy Education Council, concurred. In 2008 "there were 197 rigs running, and now there are about 70," Ireland said. Yet at the end of 2010, Barnett Shale production "was right at 5.1 Bcf/d" and has been on the increase this year.

"We are seeing more and more monster wells, wells that are just orders of magnitude larger than previous wells," Ireland said. While the average Barnett well typically sees initial production of 4,000 Mcf/d to 5,000 Mcf/d, in recent months several wells in the play have recorded initial production of 12,000 Mcf/d to 15,000 Mcf/d, he said.

One of the *Times* stories quotes Terry Engelder, a professor of geosciences at Pennsylvania State University. Engelder told Platts that the newspaper took his quotations from an email he wrote on shale economics and that email did not express the full range of his views on the subject.

"The reporters didn't talk to me in person," Engelder said, adding that his email had "a lot of nuance in it. The reporters could have learned something from the nuance."

Eric Wohlschlegel, a spokesman for the American Petroleum Institute, said the *Times* reporting was "based on old information, unverified sources, and ignores the rules of economics. It is an insult to journalism, and we can't take it seriously."

Regina Hopper, president and CEO of America's Natural Gas Alliance, similarly accused the newspaper of a lack of balance in its reporting. "This selective use of facts implies a clear bias and continues the reporter's demonstrated pattern of telling one-sided stories without providing readers with any sense of context, nuance or balance," she said.

Michael Levi of the Council on Foreign Relations complained about the newspaper's use of anonymous email sources. "There are very few emails from industry accountants or economists in the story. The *Times*' descriptions of the emails (not just in the article, but in the document database) also betray a serious lack of understanding of the industry," he said.

In its own response to the *Times* articles, EIA said that "recognizing that the characterization of shale gas resources is both uncertain and important, the [Annual Energy Outlook 2011] features a prominent Issues in Focus discussion of cases with both lower and higher availability of shale gas than in the reference case."

"While resource estimates will continue to be updated as new information become available, experience suggests that EIA has been more likely to understate rather than overstate the contribution of unconventional oil and natural gas resources in recent AEO reference cases," added Michael Schaal, director of EIA's Office of Petroleum, Natural Gas and Biofuels Analysis.

"The assumptions regarding shale gas resources currently being used as the basis of EIA's reference case projections are consistent with estimates of technically recoverable resources from a wide range of academic and industry experts," EIA said. The agency "uses contractors to supply critical expertise in resource assessment for regions and resource categories where development activities undertaken since the last available resource assessments by government agencies have added significant new knowledge about resources. This longstanding EIA practice has been applied for resources other than shale gas, including tight sands gas, shale oil, and enhanced oil recovery. EIA's procurement of contractors for this and other purposes conforms with all applicable federal rules and policies."

EIA Administrator Richard Newell added in an interview, "I think EIA has done an outstanding job of keeping track of something that is a rapidly emerging change in the [US energy] system.

"It is something that a government agency could easily not be on top of, and it is a part of the system that in a year things change so much that you can be out of touch," he said. "So to stay in touch you get access to the best information, and you incorporate that into your outlook. And I think that is exactly what we have done."

Newell defended the work of his agency and emphasized that domestic gas output is indeed increasing. "This isn't just perception. Natural gas is being produced, it is being measured, and it is being produced from shale gas reserves," he said.

Shale gas critic defends work

The development of hydraulic fracturing and horizontal drilling has led to big increases in the amount of gas produced in the US over the past several years, particularly from shale plays — and that trend has led some independent estimates of US gas reserves to more than double. The resulting gas supply boom has helped send prices from their 2008 peak above $12/MMBtu to between $4/MMBtu and $5/MMBtu this year.

But the shale phenomenon has its share of critics, with many environmental groups and government officials voicing concerns over the undisclosed chemicals pumped into the ground by gas companies extracting gas and oil from shale formations and their impact on drinking water supplies.

Several critics of the *Times*' reporting pointed out that much the research was based on the work of Art Berman, an independent geologist who has devoted part of his career to trying to disprove the economic viability of shale gas.

But Berman said in an interview that much of the criticism of him has been misplaced.

"I'm a proponent of shale gas, too," he said, adding that he believes shale plays are important for the nation's future energy supply. "I'm not critical; I want them to succeed."

Where Berman differs with the gas industry, though, is in his contention that shale gas drilling cannot be turned into a "manufacturing process" that is economic at relatively low gas prices. He said many producers are investing huge sums of money into shale plays that are not economic in the current market.

"Some of the companies involved are destroying capital right and left not approaching these plays with the discipline they should. It's like it was back in the early '80s when we wasted money like crazy," he said.

Berman said that wells drilled in shale plays, like those in all other oil and gas plays, show wide variances in profitability from one part of a field to another. "Something like 25% of them are going to make any money," he said. "There's never been a situation where you can drill and make money from any well in the play."

And the large volumes of gas produced in prolific plays such as the Barnett Shale do not necessarily translate to producers' bottom lines, he believes. "Volumes and profitability are not the same thing. I've looked at thousands of individual wells and most of them lose money."

Berman said he agrees with many industry experts that most shale plays are not economic to drill at prices below $6/Mcf. That assumption is especially true for dry gas plays such as the Barnett and Haynesville shales, Berman said.

Meanwhile, a Democratic congressman and frequent critic of the E&P industry on June 27 demanded that EIA provide the methodology and supporting materials behind the agency's estimates of shale gas reserves.

Representative Ed Markey of Massachusetts also asked EIA for a list of outside contractors used to determine estimated reserves, as well as any information that could cast doubt on "the economic viability of shale gas production."

"We need to know whether the natural gas located underneath the surface is a real source of fuel for the next generation, or a speculative bubble hyped by the oil and gas industry, and echoed by the federal government's energy experts," said Markey, the ranking member of the House Natural Resources Committee and a senior member of the Energy and Commerce Committee.

"Natural gas has been touted as a 'bridge fuel' that will take us from dirtier fossil fuels to cleaner renewable energy technologies," Markey said. "If these claims are accurate, natural gas could offer a viable pathway towards meeting our energy needs while reducing CO_2 pollution. If they are not, America's natural gas future could be a bridge to nowhere."

Jonathan Cogan, an EIA spokesman, said last week, "We will certainly be responsive to Representative Markey's request for additional information on EIA's shale gas projections."

— Jim Magill

TRANSPORTATION

FERC grants Weaver's Cove request to abandon LNG import terminal plans

The Federal Energy Regulatory Commission agreed Wednesday to revoke its authorization for Weaver's Cove Energy to build an LNG import terminal in Fall River, Massachusetts.

Weaver's Cove in June told FERC it had decided to terminate the project and asked the agency to vacate authorization for it to build the terminal and the affiliated Mill River Pipeline.

Gordon Shearer, president of project sponsor Hess LNG, said at the time that the company was abandoning the project because low US gas prices had made it difficult to import LNG at time when European and Asian buyers are paying higher prices for imported gas.

In a separate order Wednesday, FERC also accepted the company's request to withdraw its application to build a related offshore berth for receiving and unloading LNG for the terminal.

The commission's action closes the book on the company's decade-long quest to build the plant despite opposition from landowners, businesses, politicians and others who expressed concern about its impact on local waterways and the potential for tanker accidents.

DTE Energy's Bluestone Gathering has signed a long-term agreement with Southwestern Energy Services to build and operate a gas gathering system in Susquehanna County, Pennsylvania, and Broome County, New York, Bluestone said Tuesday.

Bluestone will deliver gas from the Marcellus Shale to Millennium Pipeline in Broome County and to Tennessee Gas Pipeline in Susquehanna County, the company said.

Bluestone said it plans to spend more than $250 million over the next five years on the lateral and in-field gathering system. The project is comprised of about 37 miles of 16-inch and 20-inch diameter pipeline and will include smaller-diameter line for the in-field gathering system.

Bluestone's initial capacity will be more than 250,000 Dt/d to both the Millennium and Tennessee pipelines and is projected to be in-service in the second quarter of 2012.

Millennium has approved its first two expansions slated to be in-service in late 2012 and late 2013, Bluestone said. These two expansions are expected to increase Millennium's capacity from 525,000 Dt/d to about 825,000 Dt/d. DTE Energy owns 26.25% of Millennium Pipeline.

Energy Transfer Equity on Tueday announced a binding agreement to transfer Southern Union's 50% interest in Citrus Corp., which owns 100% of the 5,500-mile Florida Gas Transmission system, to its publicly traded partnership Energy Transfer Partners for $1.9 billion in cash.

The transfer of the stake in Citrus is subject to the closing of ETE's proposed acquisition of Southern Union and is not subject to any financing condition on the part of ETP, or ETP unitholder approval, ETE added.

ETP would operate the pipeline, while El Paso would hold on to the remaining 50%.

ETE executives on Tuesday acknowledged Florida Gas was a standout asset in the Southern Union family. "You don't have a more premium pipeline than FGT," Chairman Kelcy Warren said on a conference call. "You've got no nuclear plants being built there, so the future of natural gas through FGT is very, very good."

The acquisition of Southern Union would effectively make ETE the largest gas pipeline company in the US with about 44,000 miles of pipe, transporting 30.7 Bcf/d, Warren said.

Western Gas Partners has agreed to buy the Bison natural gas treatment plant and related midstream assets in the Powder River Basin from Anadarko Petroleum for $130 million, Western Gas said Tuesday.

Western Gas said it will acquire Anadarko's full ownership interests in the Bison assets in northeast Wyoming. The facilities have a combined CO_2 treatment capacity of 450,000 Mcf/d.

Midstream master limited partnership Western Gas Partners was purchased by Anadarko in August 2006 as Western Gas Resources, and converted into an MLP to operate as Anadarko's owner and operator of gathering and processing assets in Texas, the Rocky Mountains, and the Midcontinent.

Western Gas expects to finance the deal with $25 million in cash and the issuance of about 2.9 million common units to Anadarko and 60,210 general partner units to Western Gas Holdings, the general partner of Western Gas, at an implied price of $34.88/unit.

That price represents about 8.8 times the assets' forecasted earnings before interest, taxes, depreciation and amortization for the next 12 months, Western Gas said.

Western Gas said it expects to close the deal in July, with an effective date of July 1.

Pacific Gas and Electric has informed California regulators that some of its gas transmission lines have been incorrectly classified, and fixing the problem will result in even more pressure reductions along its system — potentially impacting power generators and other large customers.

In a report last week, PG&E said about 550 miles of pipe surveyed by an outside consultant have changed classification since the utility's system was updated. Under federal law, the greater the population density, the higher the class location of a pipeline and the higher the safety margin required.

PG&E already has reduced pressure on about 7.5 miles of pipe and is reviewing records for another 100 or so miles in highly populated areas, and it may make additional pressure reductions as needed, the utility said in its report.

PG&E said it is in the process of implementing pressure reductions at more than 30 locations. Some of those reductions will affect electric generators and potentially other customers, the utility said. The work may include replacement of pipeline segments or equipment such as valves and fittings, and that work has been re-prioritized above all other non-emergency work on its system.

Those pressure cuts range anywhere from 2% to nearly 50% on some segments, the report noted. PG&E said it is working closely with the California Independent System Operator to assess daily demand from power generators in particular, and may issue more frequent operational flow orders and emergency flow orders.

The impact will be felt throughout the utility's system, PG&E spokesman David Eisenhauer said Wednesday.

"We are keeping in close contact with large customers and power generators and are working to get this addressed. We're doing evaluations of specific segments, and in some cases we may find evidence that we are operating at the correct pressure and that we don't need to cut pressure," he said.

Currently, swing capacity has been reduced from 600,000 Mcf/d to 200,000 Mcf/d on PG&E's intrastate backbone system, Eisenhauer said.

In a Wednesday notice to customers along PG&E's California Gas Transmission system, the utility said that while some reductions are likely to be temporary, others may last throughout the summer.

Some of the work may involve simple records validation, while other segments may need to be dug up and the correct pipeline and equipment validated visually. "As a result, suppliers and customers will need to more closely match gas supply and usage," the notice warned.

Starting this week, PG&E will begin calling simultaneous high- and low-inventory OFOs "for the foreseeable future, throughout the period of pressure reductions," the notice said. During this time, suppliers and large customers must balance supply within a specified tolerance range, to be announced daily.

The utility said it will update the California Public Utilities Commission biweekly on its progress and perform a system-wide class location review yearly going forward.

The classification review was ordered after a fatal explosion along one of PG&E's transmission lines killed eight people and destroyed 38 homes in San Bruno, California, last September. The PUC has launched several proceedings related to the incident, and PG&E faces the potential for hefty fines related to inaccurate records for its pipelines.

PG&E has been hydro-testing various pipeline segments this summer to validate maximum operating pressures, which also may result in pressure reductions.

"We hope we're nearing the end of the revelations about PG&E's poor safety efforts," PUC Executive Director Paul Clanon said. "This is a serious failure with serious safety repercussions. PG&E faces another investigation and more potential fines. How PG&E reacts to this discovery now and in the weeks ahead is a chance to show us and the public that it's a new company and operating safely is its first priority."

FERC on July 1 gave the green light for **Transcontinental Gas Pipe Line** to install new facilities on its system in Virginia to provide an additional 142,000 Dt/d of firm gas transportation service to Mid-Atlantic customers.

The Mid-Atlantic Connector expansion, a combination of new compression and pipeline segments, is fully subscribed by Virginia Power Services Energy and Baltimore Gas and Electric. Precedent agreements hammered out after a September 2009 open season and October 2009 reverse open season require the parties to execute firm transportation service agreements with primary terms of 20 years, the order stated.

The project design calls for installation of a 1.46-mile segment of 42-inch diameter pipeline looping from compressor station 185 in Prince William County to an interconnection in Fairfax County; replacement of 1.32 miles of 30-inch diameter pipeline with 42-inch stock in Fairfax County; addition of 3,550 HP of new compression at the existing compressor station 165 in Pittsylvania County; and a net addition 15,400 HP of compression at compressor station 175 in Fluvanna County.

Transco put the estimated price tag at $74 million, to be financed initially through short-term loans and funds on hand.

The commission approved the project, agreeing with the applicant that there would be no adverse impacts on other pipelines in the market or their captive customers, and only minimal impacts on landowners and the environment.

Transco was cleared to establish its existing firm transportation rate as the recourse rate for the new service. FERC also granted the requested predetermination that the pipeline may roll the costs of the project into its system-wide cost of service in its next Natural Gas Act Section 4 rate case.

However, "if cost overruns occur which would increase the project's cost above project revenues, such an event may constitute a significant change in circumstances warranting a reconsideration of the roll-in predetermination," the order warned.

Cheniere Energy Partners' Sabine Pass Liquefaction has pulled its request for the novel transaction structure it planned to use for LNG exports and imports, the company said July 1.

"Subsequent to its filing of the petition, Sabine Pass Liquefaction has concluded that the transactional structure it will utilize in conjunction with the liquefaction project will be different than that described in the petition and will not necessitate a declaratory ruling or waivers from the commission," the company said in a filing with FERC.

Diane Haggard, a spokeswoman for Cheniere, said the company is negotiating with its customers and no longer needs the flexibility the declaration would have provided.

She added the company could not provide any more details at this time.

In May, Sabine Pass won approval from DOE to widely export domestic LNG from its import terminal in Louisiana. In conjunction with its application to FERC to build liquefaction facilities, the company also asked the commission to confirm its planned transactional structure would not violate the commission's rules on capacity release and buy/sell transactions.

Sabine Pass said in its May 25 petition it planned to provide both LNG processing and pipeline transportation to its customers. The company said the approach was necessary because its needs for transportation will fluctuate widely with the addition of liquefaction facilities.

There was some concern, however, the transactions could violate commission rules that prohibit shippers from transporting gas at the direction of another entity. Sabine Pass argued uncertainty about the issue could hold up export and financing deals.

Chevron raised concerns about the approach and argued the bundled transactions could lead to a loss of transparency. Kinder Morgan Louisiana Pipeline said Sabine Pass had not provided enough information to determine whether the transactions would be discriminatory or anti-competitive.

Spectra Energy Partners said July 1 it has completed its purchase of the Big Sandy Pipeline from EQT for $390 million.

Houston-based Spectra said May 11 it would buy the 70-mile gas pipeline, which runs through eastern Kentucky and can transport 171,000 Mcf/d.

Its interconnections with Tennessee's system link the Huron Shale, located in Kentucky and West Virginia, with conventional and unconventional supplies coming out of Appalachia.

EQT will be the main shipper on the line, and plans to use sale proceeds to develop its holdings in the Marcellus and

Huron shales, Spectra said when it announced the deal.

Northwest Pipeline can abandon 15 miles of corroded, 16-inch-diameter gas line in Oregon and replace it with over seven miles of 20-inch-diameter pipeline, FERC said last week.

In January, Northwest asked FERC to allow it to abandon and replace the segment on its 260-mile Grants Pass Lateral, which connects the company's mainline facilities in Clark County, Washington, to its Eugene Line and Grants Pass Line.

After testing and inspection, the company discovered numerous pipeline failures and evidence of stress corrosion cracking. In response, the company conducted over 200 digs and replaced about 10,000 feet of pipeline between 2001 and 2010.

The inspection, remediation and monitoring has led to disruptions for landowners and the environment and the shorter replacement pipeline will reduce these impacts, Northwest claimed. The project will cost about $17.2 million and will be financed with internally generated funds, it said.

FERC found that the project is in the public convenience and necessity. "Abandonment of the existing 16-inch-diameter pipeline segment is appropriate given its history of anomalies and stress corrosion cracking. The replacement project will reduce ongoing disruptions to landowners.

Further, replacement of the capacity lost by abandonment is necessary to maintain existing service to Northwest's customers," the June 30 order said.

— *Staff Reports*

BRIEFS

US gas storage stocks rose by 95 Bcf to 2.527 Tcf during the week that ended Friday, the **ENERGY INFORMATION ADMINISTRATION** said Thursday in its weekly report. The net injection was well above consensus expectations of a build between 78 Bcf and 82 Bcf, and higher than the 76-Bcf injection reported a year earlier. In the same week of 2010, EIA reported 2.751 Tcf in storage. As a result, the 243-Bcf deficit to the year-ago level shrank to 224 Bcf and the 63-Bcf deficit to the five-year average of 2.575 Tcf narrowed to 48 Bcf. EIA reported a 62-Bcf injection in the East, raising inventories to 1.189 Tcf, compared with 1.334 Tcf a year ago; a 16-Bcf injection in the West to 351 Bcf, compared with 457 Bcf a year ago; and a 17-Bcf injection in the producing region to 987 Bcf, compared with 959 Bcf a year ago. Inventories now are 117 Bcf below the five-year average of 1.306 Tcf in the East, 37 Bcf below the five-year average of 388 Bcf in the West, and 107 Bcf above the five-year average of 880 Bcf in the producing region.

Canada's marketable gas production is set to fall 8.5% this year, according to a forecast released by the **NATIONAL ENERGY BOARD** on Wednesday. Overall production by December is projected at 372.3 million cubic meters/d, down 8.5% from 406.7 million cu m/d reported in January, the agency said. The largest overall drop is expected in Alberta, which continues to provide the bulk of the country's gas supplies but where conventional production has been declining for years. The NEB forecast output there to fall 15% by December to 248.7 million cu m/d, from 294 million cu m/d in January. The advent of the Horn River and Montney shale plays resulted in an uptick in British Columbia, where supplies are expected to increase some 13% to 102 million cu m/d in December from 90.6 million cu m/d in January. But in New Brunswick, where shale production has hit more snags, volumes are expected to slide some 93,000 cu m/d, or 19%, to an anticipated 398,000 cu m/d in December from 491,000 cu m/d in January. In Nova Scotia, meanwhile, some gains are expected by year's end, likely from the offshore Deep Panuke field. NEB projects that production from the province will rise some 11%, to a projected 8.2 million cu m/d in December from 7.4 million cu m/d in January.

ENERGY TRANSFER EQUITY has upped the ante in its ongoing fight to acquire pipeline firm Southern Union with a renewed bid of $8.9 billion, effectively pipping rival company Williams' offer by $1 to $40/share, the companies said Tuesday. ETE's original offer was for $33/share, equating to some $7.9 billion (*IFGMR*, 24 Jun, 1), while the Tulsa-based Williams' June 23 offer came in at $39/share, or $8.6 billion with the assumption of $3.7 billion in debt. Dallas-based ETE said the boards of both companies unanimously approved the revised agreement. Under the new deal, Southern's Chairman and CEO George Lindemann and Vice Chairman, President and COO Eric Herschmann said they would terminate their controversial non-competition and consulting agreements with ETE. Lindemann and Herschmann would have received $10 million each for five years under this separate agreement, according to filings with the Securities and Exchange Commission after the deal was announced. This separate deal was a sticking point with Southern shareholders, analysts said, who viewed Williams' offer as the more lucrative bid. Williams spokeswoman Julie Gentz said the company was "evaluating our options."

New York may issue Marcellus Shale gas drilling permits by year's end if certain conditions are met, state **DEPARTMENT OF ENVIRONMENTAL CONSERVATION** Commissioner Joe Martens said July 1. "It depends on how many comments we get," Martens said at a press conference. "If real issues are raised, we have to figure out if additional mitigation is required. We are going to do this safely." Martens' comments came a day after the DEC released a summary of its long-awaited recommendations on hydraulic fracturing, saying the state should ban fracking in watersheds and on state lands while allowing it on private property with "rigorous and effective controls." Since the DEC began the study two years ago, New York has had an effective ban on gas drilling. The department will release the full Supplement Generic Environmental Impact Statement on July 8 and initiate a 60-day comment period in August. Martens stressed that the review of comments on the last SGEIS released in 2009 "took months and months." As a result, "we won't be looking at a final SGEIS until late in the fall or early winter," he said. While Martens said the state could begin issuing drilling permits once the SGEIS is finalized and before the regulations are developed, he stressed that the DEC may not have the manpower to do so. Martens defended the DEC's recommendation to exempt the Syracuse and New York City watersheds from any kind of drilling that involves fracking. He noted that both cities rely on unfiltered drinking water supplies.

Gas output in the Lower-48 states was up slightly in April, rising 1.1%, or 720,000 Mcf/d, from March to 69.05 Bcf/d, the **EIA** said June 29. Production gains were led by Louisiana, which was up 2%, or 160,000 Mcf/d, to 8.15 Bcf/d, and by what EIA categorizes as "other states," where output rose 2.1% to 18.49 Bcf/d. "Drilling activity in the Haynesville and Marcellus shale plays are largely responsible for the gains in Louisiana and other states," EIA said. Production in the federal offshore Gulf of Mexico fell 1.4% in April to 5.44 Bcf/d, while New Mexico dropped 1.3% to 3.66 Bcf/d. Total US production including Alaska was 78.58 Bcf/d in April, up 0.5% from a revised 78.16 Bcf/d in March.

Canadian gas exports to the US fell 7.3% in April to 239.4 million cubic meters/d from 258.2 million cu m/d in March, according to statistics released June 29 by the **NATIONAL ENERGY BOARD**. Shipments of US gas to Canada were unchanged at around 4.1 billion cu m for April, NEB data showed, while LNG imports to Canada plunged 49.7%. The drop in exports to the US reflects a decline in weather-related demand in major consumption markets of the Midwest and Northeast as winter made its slow exit, giving way to the lackluster utility demand that marked the start of shoulder season. Export volumes saw the biggest drop at Iroquois Gas Transmission in New York, where gas flows into the Northeast. Iroquois exports fell from 20.7 million cu m/d in March to 13.9 million cu m/d in April. Exports through the Kingsgate point, which allows gas to flow to the Pacific Northwest, were up nearly 3.4 million cu m/d month-on-month to 46.9 million cu m/d as that region saw the return of unseasonably cold weather. US shipments of gas to Canada via US Midwest border points into Ontario continued to dominate, making up nearly 93% of total Canadian imports, the NEB data showed. The NEB also released LNG imports into the country at its lone terminal, Canaport in New Brunswick, where no long-term volumes were recorded. Short-term volumes fell dramatically from 316.8 million cu m in March to 159.4 million cu m in April.

Gas producers do not have the right to build large drilling operations on a third party's land to take gas from underneath the surface of an adjoining property, a West Virginia landowner contended in a recently filed lawsuit. Plaintiff Richard Cain said **XTO ENERGY** and **WACO OIL & GAS** should not be allowed to use 36 acres of his 105-acre farm as a staging area for the extraction of gas from the Marcellus Shale under an adjoining parcel, as alleged in a June 21 suit. XTO, a Fort Worth, Texas, subsidiary of ExxonMobil, has been preparing the site and will conduct a vertical drilling operation from that site, he said in the suit. Waco Oil & Gas, of Glenville, West Virginia, owns the mineral rights in the area to be drilled. Cain's attorney, David McMahon, said Tuesday he does not know why XTO chose his client's property for a drilling operation. It may be one of several sites the company plans to use in that area, he said, adding that he believes XTO intends to drill up to 18 horizontal wells from three sites on Cain's property. Court records show XTO has plans to drill three well bores from the surface of Cain's property down 7,482 feet and turn the bores horizontally for more than 3,000 feet. The company intends to inject more than 6 million gallons of fluid into the seam, the records said. Jeff Neu, a public and government affairs adviser for XTO Energy, said the company does not discuss litigation matters. An attorney representing Waco likewise had no comment.