

Inside FERC

September 12, 2005

Oversight agencies seek to dampen claims of price gouging in wake of Katrina

The Bush administration last week sought to quash claims of widespread price gouging as petroleum and natural gas prices remained high after Hurricane Katrina, while a top FERC market investigator asserted that in perhaps the first major test since the Enron abuses, tightened measures against market manipulation appear to be working.

Members of Congress returned to Washington amid a storm of criticism

over the government's response after the hurricane pounded Louisiana, Mississippi and Alabama. But as prospects increased that hundreds if not thousands of people died during and after the storm, a subtext to the disaster played out in the House and Senate energy committees as disruptions to Gulf oil and gas production and delivery cast a bright light on just how tight the U.S. energy market remains.

Analysts warned that the U.S. is skat-

ing dangerously close to an energy crisis with serious implications for the broader economy, while Republican energy hawks and industrial end-users renewed their campaign to ease bans on offshore drilling in areas of the Outer Continental Shelf and to streamline the permitting process for new oil refineries. Lawmakers on both sides of the aisle held up for the cameras signs showing nearly \$4 gasoline and

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MISO begins to address stakeholder questions about resource adequacy plan

The new draft of Midwest Independent Transmission System Operator's resource adequacy white paper, which is to be discussed at a meeting today (Monday), tackles several "big-ticket items" raised in response to the original draft, a MISO official said last week. Including the latest draft, "we'll probably have three or four more iterations of the white paper over the next four to six weeks," according to Ron McNamara, vice president of market management.

"Probably in a month we will start working on some business practices rules that would ultimately lead to a business practices manual that will reflect the language being adopted or accepted in the white papers," he told *Inside FERC* on Wednesday. As with the white paper, the drafting of the manual likely will go through several iterations before work begins on tariff language.

"So there are three levels of detail that we expect to roll out" in the next three to

six months, McNamara said. "Hopefully at the end of that period we will have a high-level policy paper that has been signed-off on by our participants; a set of more detailed rules, business practices manuals; and then a filing" to FERC.

The goal is to reach consensus at the policy level so that there are "no surprises of any magnitude at all as we work down that chain," he added. "The tariff filing, it is our hope, would be completely antici-

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Citing Katrina, EIA dramatically revamps gas estimates

Making dramatic upward revisions to its natural gas price projections and sharply cutting its estimates of demand and storage, the Energy Information Administration last week painted a turbulent picture of the near-term market as it struggles to contend with severe disruptions in the aftermath of Hurricane Katrina's assault on the Gulf Coast.

Among other things, EIA in its September short-term energy outlook added nearly \$3.00/Mcf to its fourth-quarter Henry

Hub price estimate and \$1.19/Mcf to its 2005 target, while cutting its demand projection for this year by 560 Bcf to 22.28 Tcf. What's more, the agency now sees gas storage totaling just 2.81 Tcf at the close of the third quarter, a pullback of 280 Bcf from its month-ago estimate.

"Because considerable uncertainty remains regarding the specific extent of Katrina's damage, it is difficult to provide a single forecast for the upcoming winter and subsequent months as we typically

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do" in the monthly outlooks, said EIA. "More detailed damage assessments should be forthcoming over the next several weeks, which should clarify our forecast," it emphasized.

With that in mind, it established three basic scenarios to represent a range of plausible outcomes for oil and natural gas supply over the next several months and through 2006: fast recovery, "which assumes a very favorable set of circumstances for getting supplies back to normal"; slow recovery, "which assumes that significant outages in oil and natural gas production and delivery from the Gulf area continue at least into November"; and medium recovery, which assumes "a path in between slow and fast recovery." In all cases, return to normal operations would be achieved or nearly achieved by December.

In the medium recovery case, the 3Q Henry Hub spot price is expected to average \$10.03/Mcf, up \$1.83 from the August report, and \$11.49/Mcf for the October-through-December period, up \$2.98. EIA's new 2005 price target is \$8.82/Mcf, dropping to \$8.42/Mcf in 2006.

In August, the Henry Hub price averaged over \$9.00/Mcf, as hot weather in the East and Southwest increased gas-fired electricity generation for cooling demand and crude oil prices increased, EIA noted, adding that the market "is likely to stay tight over the next couple of months, particularly in light of the supply impacts from Katrina." And while spot prices are expected to ease going into 2006 as the effects of Katrina fade, prices at Henry Hub are likely to remain above \$10.00/Mcf until peak winter demand is over, said the report.

"Depending on the region of the country, increases for 2005 natural gas spot prices are expected to range between 37% and 50% above the 2004 averages" under the medium recovery case, EIS said, adding that city-gate prices and end-use prices "are expected to exhibit double-digit percent increases for the second year in a row in most regions." For the upcoming winter, "pressure on delivered natural gas prices may be sharpest in regions

where heating demands are likely to increase the most, such as in the central portion of the United States."

Working gas in storage was estimated at 2,633 Bcf as of Aug. 26, 1.9% lower than last year, but still 5.2% above the five-year average. The effects of the hurricane should reduce "the peak storage achievable over the remainder of the injection season from what was expected previously," said EIA, suggesting that stocks at the end of October should fall roughly 270 Bcf below the year-ago level and about 50 Bcf under the five-year average.

Gas demand for this year now is projected to fall slightly by about 1% from 2004 before recovering by 2.4% percent in 2006 "due to an assumed return to normal weather and continued strength in consumption for electric power production."

Domestic gas production in 2005 is expected to drop by 1.5% "due mainly to the major disruptions to infrastructure" in the Gulf of Mexico from Hurricane Ivan and Katrina, said EIA.

Meanwhile, imports of liquefied natural gas into the U.S. appear to have exhibited minimal year-over-year increases through the first half of 2005, the report noted. Total LNG imports for 2005 are expected to total roughly 710 Bcf, compared with 650 Bcf last year.

While the outlook focused on the supply impacts associated with the hurricane, EIA noted that "there are, of course, demand impacts such as reduced electricity and fuel demand related to destruction of or damage to residential and commercial buildings or industrial establishments in Louisiana, Mississippi and Alabama." And the loss of electricity supply due to damaged or impeded electric generating facilities "has reduced demand in fuel markets, particularly for natural gas," the report said.

"Thus, Katrina-related natural gas demand reduction is, at most, estimated to be between 15 and 25% of the peak level of lost production, and, as service restoration proceeds, should become an increasingly minor factor," said EIA.

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9th Circuit flatly rejects FERC's call on public power to fork over California refunds

Just because municipal utilities and government entities participated in the California spot market during the 2000-01 crisis does not mean they are on the hook for any refunds, the 9th U.S. Circuit Court of Appeals ruled last week. The Federal Power Act's refund authority simply does not cover public power, the court said in remanding the matter.

FERC contradicted itself when a majority held in July 2001 that nonjurisdictional entities would in effect be jurisdictional by dint of participating in a jurisdictional market under a commission-approved tariff (*IF*, 30 July '01, 1), the court found. "It should be obvious that FERC cannot invoke a 'one-time' rule for this circumstance," the court said.

The commission has long interpreted FPA sections 205 and 206 to mean that governmental entities and other nonpublic utilities are beyond the reach of FERC's ratemaking and refund authority, added the Sept. 6 opinion penned by Judge Margaret McKeown for a three-judge panel with Judges Sidney Thomas and Richard Clifton (*Bonneville Power Administration v. FERC*, 02-70270).

FERC last week had not yet decided if it would appeal, but it expects the court's ruling will pare back the amount of refunds in the pending California spot market crisis proceeding (EL00-95, *et al.*). "While the commission is still reviewing today's court decision, clearly the court's decision will limit the scope of refunds in the California refund case," a spokesman said.

But the finding won't apply to future cases because of an expansion of section 206 refund authority in the Energy Policy Act of 2005. It extends refund authority to nonpublic utilities participating in short-term energy transactions in an organized market, including co-operatives, if the sale violates the tariff, and to Bonneville Power Administration "only if" the sale is at an unjust and unreasonable rate.

"The import of this decision is retrospective only. Going forward, Congress recognized the problem and has rectified this disparity in the commission's Federal Power Act authority," the FERC spokesman said.

The refunds have been undergoing a recalculation and may be offset by upcoming cost recovery filings. An administrative law judge's preliminary assessment, which took place before a major change in the methodology with estimated gas price inputs, found that many munis, including BPA and Los Angeles Dept. of Water and Power, owed and were themselves owed refunds (*IF*, 16 Dec '02, 1).

Munis cheered the ruling, while a disappointed California attorney general considered his options.

The ruling removes some \$1 billion of refunds from the table and allows market participants who "ripped off California during the energy crisis to escape unscathed for their misconduct," said Tom Dresslar, spokesman for Attorney General Bill Lockyer. "It's important to stress that the court in this ruling did not say these entities didn't gouge California businesses, taxpayers and ratepayers during the energy

crisis. What they said is, under federal law the entities can get away with it," he added.

"It's another example of how the legal construct that governed the wholesale market during the energy crisis has worked to impede justice for California," he added. Lockyer's office is weighing whether to ask for the 9th Circuit to hear the case *en banc* or to appeal to the state supreme court. It also is awaiting the outcome of a "bigger" case before the 9th Circuit brought against FERC by the California Public Utilities Commission in pursuit of refunds for the summer 2000 period and for California Dept. of Water Resources purchases made outside the spot market, the spokesman said.

Municipal utilities breathed a sigh of relief. "The decision was a good one. It was clear and unambiguous. The Federal Power Act is very clear on this," said Kevin Smith, senior attorney for the Sacramento Municipal Utility District. Refunds allegedly owed by SMUD before the court's decision totaled about \$13 million, said Smith.

"We're pleased," added Allen Mosher, the American Public Power Assn.'s director of policy analysis. But there are some "wrinkles to work through," he said.

There could be an issue with the fact that EPACT extends FERC jurisdiction to some of APPA's largest members that buy and sell through organized markets, he said. "Government utilities with annual sales of 8 million Mw or more are potentially subject to refund authority under the Federal Power Act for sales through organized markets," Mosher said.

In holding that FERC lacks FPA refund authority, the court said that the "text is clear and unambiguous." The court was "not unmindful" of the impact its decision may have on the total amount of refunds that can be collected, "but it is not our task to second-guess Congress' judgment as to the breadth" of FERC's refund authority.

"Our role is a limited one—interpreting the statute as Congress wrote it," the court added. In March 2001, when FERC laid the groundwork for a price cap, the commission stated it had no authority over nonpublic utilities to order refunds, but it changed its mind in the July 25 order covering all sellers, including nonjurisdictional entities, the court recalled.

The commission explained that it re-examined its authority in light of the particular circumstances at hand, including the centralized single clearing price auction under FERC jurisdiction. The court noted that then Commissioners Linda Breathitt and William Massey jointly dissented, calling the majority's conclusion "breathtaking."

The order was approved by then Chairman Curt Hebert Jr. and Commissioners Pat Wood and Nora Mead Brownell, the only commissioner from the time remaining at FERC. The court rebuffed the argument they put forward that the commission's broad powers over wholesale sales of energy should cover non-jurisdictional entities in this instance.

"This argument ignores a basic principle of statutory construction, namely that the specific prevails over the general," the court said. If FERC could invoke plenary jurisdiction

tion over the sale of electric energy, "then Congress could have saved time and ink by not bothering to narrow that jurisdiction," and section 201(b)(2), "which makes clear that FERC does not have broad jurisdiction over electric utilities, would have been superfluous."

The transactions may have been in markets run by public utilities under FERC-approved tariffs but that fact doesn't alter the nature of some of the participants, the court maintained. The commission "attempts to deflect our attention away from the fact that it is ordering refunds from the public entities by arguing that FERC is simply using its sections 205 and 206 authority to reset the prices of the single-price auction to a just and reasonable level," the court said.

But it was still a refund order that was applied to nonjurisdictional entities, the court added. It also was not persuaded by the argument that entities that are not FPA public utilities waived their exemption by participating in the jurisdictional market. "At bottom, FERC's waiver argument is an effort to have this court restructure the scope of FERC's statutory authority. In declining to do so, we take no position on remedies available outside the FPA."

Thursday meeting expected to spark OATT reform, initiate PUHCA repeal implementation

FERC is poised to take major new policy steps at the Sept. 15 regular agenda meeting with items on open-access transmission tariff reform and repeal of the Public Utility Holding Company Act. Other items of potential note relate to interlocking directorates and gas gathering jurisdiction.

Item E-1, "Preventing Undue Discrimination and Preference in Transmission Service," is expected to initiate a broad review of order 888. The proceeding (RM05-25) is likely to start in the form of a notice of inquiry.

Chairman Joseph Kelliher has long bemoaned what he describes as lingering opportunities for undue discrimination in electric transmission. His second meeting as the agenda-setting chairman provides the opportunity for him to elaborate on those concerns and what could resolve them.

The PUHCA repeal proceeding, listed as M-1 on the agenda, will follow mandates in the Energy Policy Act of 2005. The repeal provision, which takes effect in February, provides FERC access to the books and records of companies to help it keep an eye out for cross-subsidization of nonutility activities (*IF*, 8 Aug. 4).

The law directs the commission to issue regulations in December to implement the access requirements. Kelliher has met with Securities and Exchange Commission Chairman Christopher Cox, and staffs from the two agencies "are working hard to make the transition," a FERC source related.

In item G-10, FERC plans to address criteria for reassertion of jurisdiction over the gathering services of natural gas company affiliates. Kelliher recently recalled how courts have "consistently rebuffed" commission attempts to reassert jurisdiction of

facilities that had been spun down from gas transportation operations (*IF*, 15 Aug. 15).

Also on the agenda is a pending rulemaking (RM05-6) to strengthen rules on interlocking directorates that have either been misunderstood or ignored. Kelliher in the past grouched that the rules have been too loose (*IF*, 28 March, 1).

In addition, item E-2 is a merchant transmission line proposal. Sponsors of the Sea Breeze Pacific Juan de Fuca Cable (ER05-1228) proposed in July to sell transmission rights at negotiated rates. The 540 Mw direct current transmission line would run 20 miles underneath the Strait of Juan de Fuca between Washington and British Columbia. It would connect to substations owned by Bonneville Power Administration and British Columbia Hydro and Power Authority.

New England generators join other groups to combat anti-LICAP forces

Moving "to set the record straight," a new coalition comprising New England generators and other groups was launched last week to take up the cause of ISO New England's embattled locational installed capacity proposal pending at FERC.

"The facts about LICAP have been distorted for too long," said Cindy Eid, executive director of the New England Coalition for Reliable Electricity (NECORE). "LICAP is good for New England's economy, good for our environment and good for New England families," Eid said in a Sept. 8 statement announcing formation of the group.

FERC is scheduled next week to hold oral argument on an administrative law judge's June 15 initial decision (ER03-563) that endorsed the LICAP demand curve and price-setting mechanisms (*IF*, 20 June, 1). The commission previously had accepted the overall concept of LICAP, while setting a hearing on the parameters. Regulators, consumer advocates, lawmakers and others in New England have been sharply critical of the proposal, which they say would provide the region's generators with a revenue windfall but not ensure that any new capacity is built.

"We support more generation in New England and believe LICAP to be the best proposal currently out there," Eid said in the statement, which described NECORE as a diverse group of organizations and electricity experts. According to its Web site, NECORE's members are the Independent Energy Producers of Maine, Josiah Bartlett Center for Public Policy, New England Power Generators Assn., New England Renewable Power Producers Assn. and Independent Power Producers of New York.

The group's advisory committee includes former New Hampshire Public Utilities Commission Chairman Douglas Patch, now with the law firm Orr & Reno, who asserted in a statement issued Thursday that "the current climate is not providing incentives for generators to invest in new power plants or increased capacity at existing plants. LICAP would solve this problem."

PIPELINE RATES

Gas coalition plans to press FERC to revisit Form 2 financial reports on pipeline rates

Insisting that the current format does not give an accurate picture of how pipelines set their rates, a coalition of natural gas producers and local distribution companies wants FERC to revisit financial reporting rules.

Officials from the American Public Gas Assn. and Natural Gas Supply Assn., both based in Washington, told *Inside FERC* last week they intend to press the commission this fall to consider revisions to Form 2 annual reporting requirements. In doing so, they want to resurrect a proposal simmering since FERC issued its quarterly reporting rule in February 2004, then later denied rehearing from industry petitioners (*IF*, 31 May '04, 4).

While the commission refused to consider changes to Form 2 reports as part of the order 464 reporting proceeding, FERC said it would consider the adequacy of those reports in separate proceedings. Former Chairman Pat Wood III told reporters at the time he intended to begin a rulemaking process on the matter. The full commission also assured stakeholders in its rehearing order that the industry coalition would "be given the opportunity to provide input and comment on improvements to the quarterly and annual financial reporting requirements" after a full reporting cycle.

Such a separate proceeding on Form 2 never happened under Wood, and it is unclear where current Chairman Joseph Kelliher stands on the issue. But industry officials indicated they hope to compel Kelliher to revisit the issue as he establishes his top priorities for the remainder of the year.

Kelliher sideswiped the issue of financial reporting in July, shortly after taking office, when at a press conference he suggested it was "strange" that so few complaints are filed to challenge gas pipeline return on equity (*IF*, 25 July, 3). The chairman characterized as "curious" the absence of ROE complaints under Natural Gas Act section 5.

Since section 5 complaints rely heavily on Form 2 data, the financial report must be a detailed, clear and accurate reflection of the ratemaking process, LDCs and gas producers argue, rather than a jumbled and confusing mound of data.

Among the explanations that individual LDCs and producers provide for their reluctance to file complaints is the cost of doing so, the drawn-out process and the complicated nature of producing evidence to effectively challenge pipeline rates. The Natural Gas Act does not grant FERC the same refund authority as provided under the Federal Power Act, they argue, including a refund effective date that could result in accrued damages. Transmission providers are motivated to cooperate in the complaint process because of the refund date. Consequently, far fewer complaints are filed by the gas industry than on the electric side.

Laura Schepis, APGA vice president for regulatory affairs, said distributors would like to see regulators and industry

take "incremental steps" to improve the usefulness of annual and quarterly reports and, more broadly, improve methods for enforcing the "just and reasonable rates" standard for interstate pipelines.

"Let's have the right tools," added Patricia Jagtiani, NGSA vice president for regulatory affairs, referring to clearer and more expansive financial reports. NGSA uses Form 2 reports to develop an annual pipeline cost recovery study, which assesses the five-year average rates of return of major pipelines.

The interstate pipeline industry, however, has argued that a turn toward a more "activist" regulatory approach to pipeline rates would send a negative signal to the markets (*IF*, 25 July, 3).

In dusting off last year's petition to the commission, APGA and NGSA hope to bring on board other groups that had been named on the original proposal, including the Canadian Assn. of Petroleum Producers, the Independent Petroleum Assn. of America and the Process Gas Consumers Group. The coalition garnered support from the Missouri Public Service Commission and the New York Public Service Commission.

The original coalition proposal (RM03-8) noted that Form 2 reports are the primary source for evaluating the adequacy of cost-based rates. "Given the fact that gas pipelines are no longer required to file section 4 rate cases on a regular basis, it is important that this threshold matter be addressed as soon as possible," the coalition asserted in its original petition.

The proposal suggested that "only minimal changes to Form 2 reporting are needed in order to substantially improve the industry's ability to accurately assess" cost of service used for ratemaking purposes. To help, the reports should at a minimum separate cost-of-service data from other cost components. "In many cases, the necessary information is already there, but assumptions have to be made as to whether it should be used for ratemaking purposes," said the coalition proposal.

A predetermined formula should be used to determine a pipeline's earned return on equity. Also, the Form 2 report should include more rate base data to determine which parts of a deferred asset and liability balance are included in a rate base, along with a page for miscellaneous assets to help identify payables. Without clear information, the report "prevents an accurate assessment of whether the pipeline's current rates are adequate, and whether a pipeline is over or under-recovering on a current cost basis," the proposal said.

In terms of cost and revenue information, the coalition said greater detail and separate components should be reported on gas purchase and sales accounts, including purchase and sale imbalances or fuel retained from shippers; state income tax rates; administrative costs; revenues associated with negotiated rate contracts; a listing of costs and revenues tied to at-risk facilities; and an indication of whether a company's capitalization is used by the pipeline for ratemaking.

"As it stands now, there is no way to accurately remove these costs and revenues in order to assess whether the pipeline's rates themselves continue to be just and reason-

able," the proposal asserted.

Gas association officials have acknowledged that part of the problem with the reporting requirement is systemic. FERC is inundated with information and, unless it is presented in a clearer and more useful format, reports won't help the commission "accurately evaluate the pipeline's operations as they related to that pipeline's currently effective cost of service rates," said the original proposal. —*Joel Kirkland*

KATRINA COVERAGE

FERC further eases standards of conduct compliance for utilities carrying out repairs

As mammoth power grid restoration efforts continued in the Gulf Coast last week, FERC provided an additional measure of regulatory relief by suspending the requirement that standards of conduct deviations be recorded. Utilities achieved significant inroads in repair work but many areas remained severely damaged and unlit.

A week earlier, the commission announced that companies could ignore the requirement that deviations from standards of conduct be posted within 24 hours and told them instead to report after Sept. 30. Designed to ensure that companies with electric or gas transmission operations do not allow employees to share nonpublic information in anticompetitive ways, the standards were first implemented a year ago (*IF*, 27 Sept, 1).

Revisiting the issue, FERC decided that, "due to the extreme nature of the emergency," it would also temporarily waive the recording requirement. "The commission will consider extending the waiver if it continues to be needed after" Sept. 16, it said in the Sept. 7 notice (EY05-14, RM01-10).

Before FERC eased the standards and even before the storm hit, Entergy Services suspended standards of conduct compliance, it told the commission in an Aug. 30 filing (ER05-13). Entergy's communications and information systems "suffered significant damage" at a time when it was working to restore the grid. It was not clear when the company would be able to return to the standards, but it planned to update FERC.

As of Thursday morning, more than 730,000 customers remained without power in Louisiana and Mississippi, according to DOE's Office of Electricity Delivery and Energy Reliability. That's down from about 2.7 million at the peak of outages wrought by the disaster.

Both Mississippi Power, a Southern Co. utility, and Entergy Mississippi hoped to have all customers online by Sunday (Sept. 11), DOE added in a situation report. For Mississippi Power, all customers means those that can actually receive power, as many are located at residences and businesses in coastal areas that were completely destroyed.

Mississippi Power's efforts involve more than 9,000 line workers, 6,000 new poles and 1,000 miles of wire, it said in a

Sept. 8 update. Affiliate Alabama Power had restored nearly all customers, according to Southern's main Web site.

Several electric cooperatives in the impacted states were making progress with restoration as well but major outages remained. For example, the Electric Power Associations of Mississippi reported on Wednesday that 152,940, or 22%, of co-op customers were without power, down from 64% at the peak of the impact.

The Southern Louisiana Electric Cooperative Assn. in Houma and the Dixie Electric Membership Cooperative in Baton Rouge had fully restored power with a few exceptions, while repairs continued at Washington-St. Tammany Electric Cooperative, which had 45,000 members without power. Also in Louisiana, Cleco is aiming to have power restored to about 80% of its customers that can take power by Sept. 20 and the rest by early next month. Its service area includes St. Tammany and Washington parishes, where about 54,000 of more than 80,000 customers are without service.

In addition, about 370,000 Entergy customers were still out as of Wednesday, according to DOE. That included much of New Orleans, but the company had restored power in parts of the city to water pumping stations and the Central Business District. In addition, power was restored to several refineries and hospitals in the area, as well as Louis Armstrong International Airport and the Port of New Orleans headquarters building.

But "security concerns and access to flooded facilities continue to be an issue for crews" working on the Entergy system, DOE said. Entergy retained Guiliani Partners to consult on the recovery process, the company announced.

Guiliani, which already advises Entergy on the security plans of its five nuclear power plants in the Northeast, "can provide enormously valuable advice in helping us ensure that we address all key priorities as the states of Mississippi and Louisiana, along with the city of New Orleans, try to recover from the Hurricane Katrina disaster," said Wayne Leonard, Entergy's chief executive.

The damage sustained was the worst ever for the company. Entergy Gas Operations continued to supply gas to pumping stations while assessing damage to areas in its New Orleans system that are relatively dry and calling for rescue workers to report signs of leaks. While there had been some large fires in the city, there was "no indication" any were attributable to gas leaks, the company said. However, "we have seen a limited number of small gas fires in unoccupied areas surrounded by water," Entergy Gas Operations added in a Sept. 7 statement.

Meanwhile, Entergy Services notified FERC of a one-month delay, until Oct. 20, in the filing of a planned cost-based tariff that would serve in the absence of market-based rates for electricity sales. The company previously dropped pursuit of continued market-based rate authority in its home control area to avert further investigation of alleged market power (*IF*, 22 Aug, 8).

Computer files needed to assemble the tariff proposal are inaccessible and all personnel, "regardless of their normal responsibilities," are assisting with restoration efforts, an Entergy attorney in Washington wrote in the Sept. 6 filing (ER91-569, *et al.*).

Gas producers struggle with Katrina impact; condition of undersea pipes still in question

About 40% of Gulf of Mexico natural gas production knocked out by Hurricane Katrina was still off-line late Thursday, while gas pipelines and processing plants reported damage but were making gradual progress toward restoring capacity.

DOE reported that natural gas transmission pipes "survived with minimal damage." But questions remained last week about the status of the web of undersea gathering and transportation pipelines in the Gulf, with reports yet to come in on the most difficult underwater facilities to inspect.

With the Gulf of Mexico accounting for more than 20% of U.S. natural gas production, cumulative losses by since Aug. 26 had equaled 2% of yearly Gulf production by Thursday.

Gas production mustered only marginal gains during the past week. The Minerals Management Service said Thursday that 56 companies reported 4.02 Bcf/day of gas production, nearly identical to production levels two days prior, and still less than half of the 10 Bcf/day of estimated Gulf production.

Production is nearly restored in the western three districts of MMS' Gulf of Mexico OCS Region, has slowed in a fourth district and has barely restarted in the largest and easternmost New Orleans district. More than 3.3 Bcf/d of New Orleans district production was shut-in in advance of Katrina's passage and roughly the same amount remained shut-in Thursday, MMS reported. By comparison, in the Lake Charles district further west, 1.32 Bcf/d was shut in for Katrina and by Thursday all but 42,260 Mcf/d, or 97%, had been restored to production.

El Paso's Tennessee Gas Pipeline, which moves 7 Bcf/day, toward week's end still had throughput reductions of 700,000 Mcf/day upstream of the Port Sulphur Compressor Station. Tennessee had confirmed leaks on the 26-inch-diameter line at Ship Shoal 157 and Ship Shoal 144 offshore Louisiana and had isolated the 26-inch and 36-inch-diameter lines between Ship Shoal 198 and Station 523 in Cocodrie, La., according to a company spokesman.

Tennessee also incurred damage on lines in the South Timbalier offshore area south of Houma, La., with leaks confirmed on the 524C-100 and 524C-600 lines. Meanwhile, mainline valve 528 remained shut in because of high water at Port Sulphur, which was hampering the pipeline's ability to assess overall damage in the area.

El Paso's 3 Bcf/day Southern Natural Gas system also reported supply reductions of 550,000 Mcf/day as its *force majeure* continued upstream of the Toca Compressor Station. On Thursday, the company said on its Web site that flood waters had receded at Toca and assessments of compressor units, liquids handling and piping were expected to begin by week's end.

Southern Natural had planned to finish aerial assessments of its onshore and offshore facilities by Friday. An El Paso spokesman said Thursday the company is starting underwater assessments, particularly to equipment connected to third-party platforms. So far, the most serious damage appeared to be to ris-

ers on producers' platforms that had been destroyed at West Delta 133, Main Pass 306 and South Pass 62, the company said.

"We still need to get to Olga, Toca and Port Sulphur," the spokesman said, adding that they're "getting close to putting personnel in [the stations] using small boats."

The El Paso spokesman said the company is concerned about getting hit with a second wave of storms, as Tropical Storm Ophelia threatened Florida's east coast and another storm system threatened Mexico's Bay of Campeche.

Most of the Gulf's gas processors reported light damage to their facilities after the storm and, by Tuesday, were either back online or awaiting restoration of electric power. Four processing plants accounting for about 5.5 Bcf/day were not operating as of Thursday, DOE reported. "These plants can potentially be bypassed for a period of time while repairs are made with an acceptable impact on natural gas specifications," the agency said.

But, in an attempt to clean up a public relations snafu, a Dynegy spokesman recanted Chief Executive Bruce Williamson's comments indicating repairs to the company's natural gas processing plants in Louisiana would keep them off-line for three to six months.

"We're not confirming" three to six months of repairs, the spokesman told *Inside FERC*, blaming the media for misinterpreting Williamson. "We're still assessing the damage."

Williamson's estimates of \$15 million to \$20 million worth of repairs keeping Dynegy's Yscloskey and Venice, La., plants off-line for three to six months were merely hypothetical cases to better inform analysts, Byford said. The two plants account for 3.1 Bcf/day of processing capacity; the entire Gulf Coast has a total of 11.4 Bcf/day of processing capacity for its 10 Bcf/day of normal production volume.

Based on Williamson's remarks, several news services and the Energy Information Administration reported it would take Dynegy three to six months to complete repairs to the damaged plants.

The 5.7 Bcf/day Texas Eastern Transmission system was able to flow 30,000 Mcf/day on the 175,000 Mcf/day Main Pass leg of its Venice system, impacted in part by problems at a Dynegy gas processing plant, said a spokesman for the Duke Energy subsidiary early in the week.

Gulf South Pipeline also suffered from supply cuts of 300,000 Mcf/day primarily because of processing outages at the Dynegy gas processing plant. Enbridge Offshore Pipelines' fifth corridor, the 800,000 Mcf/day Mississippi Canyon Gas Pipeline, remained out of service because of ongoing problems at the Venice gas processing plant.

"If production can come back before [the Venice plant] resumes and the bottleneck is at Venice, there won't be a bottleneck on our entire system," an Enbridge spokeswoman said. "If all goes well, the pipe is OK and the production comes back on, that production can probably bypass Venice and get processed elsewhere." Enbridge's four operational pipelines on Thursday were flowing 1.6 Bcf/day including about 550,000 Mcf of storage and header gas on Destin. The system normally flows 2.7 Bcf/day through its five pipeline corridors.

Williams' 8.1 Bcf/day Transcontinental Gas Pipe Line system

continued to experience throughput reductions of 150,000 Mcf/day due primarily to producer shut-ins last week. Meanwhile, Transco was not accepting due-shipper imbalance transactions and planned to restrict pool scheduling tolerances to 1% effective with Wednesday's evening nomination cycle. Transco put the restrictions into effect to prevent the need for an operational flow order.

Despite the losses, industry officials and independent analysts surmised that natural gas shortages caused by Hurricane Katrina will be offset by losses of industrial, commercial and electric demand caused by the same storm (see story on page 8).

"There is no doubt that the Street will fixate on just supplies, but one needs to consider the demand effects," Merrill Lynch's John Herrlin wrote in a note to clients Thursday. "It is our supposition that demand loss in the hurricane ravaged states will mitigate some of the current supply issues the industry is facing."

A Gulf South Pipeline spokeswoman agreed, saying that an extended outage at Dynegy's Venice processing plant isn't an immediate concern because demand remains low in Gulf South's service area, in large part due to power plant reductions. "When they come up, they are going to start looking for supply. If we were still in the merchant business and buying gas ourselves, it would be more of an issue," she said.

Some pipelines reported relatively good news, though, as they waited for Gulf production to pick back up. Southern Union's Trunkline Gas Terrebonne offshore system was flowing 250,000 Mcf/day into its market area on Tuesday, far short of its full system capacity of 1.5 Bcf/day. "For the most part, the system is up and running; we're just waiting for flow to come in," the spokeswoman said.

Midweek, Southern Union's Sea Robin Pipeline also was awaiting the return of Gulf production as it was flowing about 350,000 Mcf/day, or about one-third of its 1 Bcf/day capacity.

Projections about the short- and long-term impacts of the storm varied throughout the week.

Analyst Frank Bracken of the investment bank Jefferies & Co. said in a note to clients over the weekend that conversations with his industry contacts indicate that "damage to infrastructure [is] likely worse than any of us know, and repairs may extend well into 2006."

But a senior administration official told a Senate panel in Washington Tuesday that the "vast majority" of the Gulf's production is expected to be back on line in a matter of days or weeks rather than months. Facilities accounting for 90% of Gulf production did not suffer significant damage during Katrina, Rebecca Watson, deputy secretary of the Interior Dept., told the Senate Energy and Natural Resources Committee. The hurricane destroyed 37 of the roughly 4,000 production platforms in the Gulf, but all were in shallow waters, she noted.

That said, four deepwater platforms accounting for 10% of Gulf production were heavily damaged "and could take up to three to six months to bring back online," Watson added.

Interstate Natural Gas Assn. of America officials said few of its members reported pipeline damage but noted that much of

the Gulf's pipeline infrastructure is owned directly by producers that were not members of the trade group.

"We still don't have a good read on what was damaged offshore," INGAA Vice President for Legislative Affairs Martin Edwards said Tuesday. Gas processing "potentially could be the bottleneck" added INGAA President Donald Santa Jr.

As for the producers, Shell said all of its western Gulf facilities had been returned to service, as had its eastern Gulf operations such as Fairway and the Mobile Bay gas processing plant. The company continued to assess any damage to deepwater rigs Mars, Ursa and Cognac, he said.

ExxonMobil on Tuesday said its gas output actually fell by 41,000 Mcf/day to 309,000 Mcf/day, or 28% of its normal 1.1 Bcf/day of Gulf production, but the company gave no reason for the decline. Apache reported that 76% of its 5.65 Bcf/day of gas production was flowing Tuesday, with another 1.5 Bcf ready to ship as soon as pipeline operators are prepared to take it.

To help fill in gaps in gas supplies, Canadian officials said that country may decide to forgo any storage injections and ship the gas south of the border, Alberta minister counselor Murray Smith told reporters in Washington on Tuesday. A Canadian Embassy energy official said his company's government has "canvassed the industry to make sure that production stays up."

Demand destruction brought on by hurricane should offset gas supply shortfalls, officials say

Even though 8% to 16% of daily gas supplies have disappeared in Hurricane Katrina's wake, markets across the country have managed to stay whole largely because of a significant drop in demand, particularly in the Gulf Coast region, industry officials said last week.

But as winter approaches and heating demand returns, any lingering supply curtailments in the Gulf of Mexico could pose problems for local distribution companies and their customers.

"LDCs and most businesses in the Gulf region are not drawing anything right now" as recovery efforts continue in a region that typically consumes large volumes of gas for power generation this time of year, noted Martin Edwards, vice president of the Interstate Natural Gas Assn. of America.

In addition, since Katrina slammed into the coast on Aug. 29, the weather across most of the U.S. "has turned nice and mild. It's not a heavy-demand period," Edwards observed. "But three or four months from now it will obviously be a very different demand period. Having systems and production back up by then will be critical."

Storage inventories also are helping to fill the gap in a few regions where utilities' requirements are greater than what they are receiving through the interstate pipeline grid, officials said. As of midweek, roughly 4.1 Bcf/day of Gulf production was curtailed due to Katrina, while pipelines were reporting that 6.3 Bcf/day was still not flowing (see story on page 1).

"If 4 Bcf is not going into the marketplace, that's 8% of sup-

ply, and that matters," said Chris McGill, managing director, policy analysis at the American Gas Assn. "We know that price rationalizes the distribution of supply. But I have no idea how that may have rippled through the industry or what we may see in the way of changes in gas going into the power generation or industrial sectors."

But McGill noted that even though gas storage inventories are behind where they were this time in 2004, they are still above the five-year average, which is providing a cushion for the market as producers ramp up in the Gulf.

"Our view is that we don't see a problem delivering gas to customers in the heating season—particularly for core customers," McGill said. "For consumers, if it doesn't show up as a restriction in volumes, it will likely show up in an upward pressure on gas prices. But from a volume standpoint, I get no sense of panic" from AGA members.

"Ask me again on Oct. 15 and see what I feel about it, but right now I think customers will get the gas, and our companies will continue to their supply-building. They may have to adjust their sources and prices may go up," McGill added. "Storage is always key. We will watch those numbers in the next few months, what is going in and coming out of storage. We still have nine weeks in the traditional refill season, and we've had net injections into storage even in December."

AGA spokeswoman Daphne Magnuson noted that gas storage reports in the coming weeks from the Energy Information Administration and EIA's winter fuels outlook to be released next month will give an indication of what the industry faces this winter. "We expect companies to draw on more imported gas from Canada, and that liquefied natural gas imports will play an important role," she said, adding that price-induced conservation may also be key to the supply/demand picture.

At the American Public Gas Assn., post-Katrina efforts have been focused on damage assessment and recovery for its many small, municipally owned members in Louisiana, Mississippi and Florida.

Staging from Mobile Gas' relatively unscathed system in Alabama, the Gulf Coast region has received assistance from other municipalities such as Pensacola, the Municipal Gas Authority of Georgia and Philadelphia Gas Works, noted APGA President and Chief Executive Bert Kalisch. In the meantime, some of the municipal systems have shut off gas at their city-gates while repairs are conducted, he said.

Merrill Lynch's top exploration-and-production analyst last week agreed that much of the gas supply shortages caused by Katrina will be offset by losses of industrial and commercial demand caused by the same storm. "There is no doubt that [Wall Street] will fixate on just supplies, but one needs to consider the demand effects," John Herrlin wrote in a note to clients Thursday. "It is our supposition that demand loss in the hurricane-ravaged states will mitigate some of the current supply issues the industry is facing.

"Conceivably, there could be 15% to 30% of demand curtailed for a couple of months, which represents 10% to 20% of

current supply shut-in in the Gulf of Mexico. This isn't a long-term panacea since the GOM needs to be onstream in winter time," Herrlin said.

"But, we still expect storage to be above 3 Tcf. The issue for natural gas this winter will remain infrastructure recovery and weather demand, which is no different than last year."

ELECTRIC POWER

DOE seeks industry input for study on the benefits of economic dispatch

On a fairly fast track, DOE has launched its study on the benefits of economic dispatch in the electricity industry. Letters sent out to stakeholders earlier this month, with responses due back Sept. 21, ask a series of questions about how economic dispatch currently is conducted and how it might be changed in the future.

Alison Silverstein, aide to former Chairman Pat Wood III and now a private consultant, is working with Lawrence Berkeley National Laboratory's Joe Eto to conduct the study. The Energy Policy Act of 2005 requires DOE to submit a report, with recommendations, to Congress and the states by Nov. 7.

In the cover letter attached to the questionnaire sent to Midwest Independent Transmission System Operator, David Meyer, acting deputy director of DOE's Office of Electricity Delivery and Energy Reliability, acknowledged the schedule "allows little time for gathering and submitting this material." However, EPACT requires the study be updated every year, "so it is likely that issues not fully addressed in this initial study will get more attention in the future," he wrote.

DOE posed six multipart questions and encouraged stakeholders to file supporting materials "such as studies or testimony that was filed in state or federal regulatory proceedings."

The first question asks: What are the procedures now used for economic dispatch in your region, and who is performing that function (utility, ISO, regional transmission organization or others) and over how large an area (geographic scope, load, number of generation resources, number of retail customers)?

Noting that EPACT defines economic dispatch as the "operation of generation facilities to produce energy at the lowest cost to reliably serve customers, recognizing any operational limits of generation or transmission facilities," the second question asks if this definition is appropriate. Over what geographic area should economic dispatch be practiced? Are there factors other than cost and reliability that should be considered?

The third question gets at operational considerations. Do economic dispatch procedures differ for different classes of generation, including utility-owned vs. nonutility generation? Do actual practices differ from formal procedures required under tariffs or federal or state rules, or from the EPACT definition?

Looking forward, the fourth question asks what changes in

procedures would lead to more nonutility generator dispatch. "Do you think changes are needed in your area to better enable economic dispatch participation by nonutility generators?" If so, explain such changes.

Fifth, if more nonutility generation ended up being dispatched, "what effects might this have on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts?" Would this affect retail customers in particular states or nationwide?

Finally, are there reliability implications—good or bad—from greater use of economic dispatch? If there are, how should the process be modified or enhanced to protect reliability?

Comments may be sent to Economic.Dispatch@hq.doe.gov.

PJM plan to use stated rates to recoup administrative costs is found deficient

PJM Interconnection's use of abbreviated filing procedures to seek to change its rate design for recovering administrative costs has been ruled "patently deficient." The order issued late last month recognized "PJM's desire to avoid the full expense of a rate proceeding," but said FERC also could not take the proposed alternative route of accepting the filing and allowing PJM and its finance committee to further review and negotiate the matter.

If the grid operator believes further talks could eliminate the need for a full rate case, it is "free to withdraw this filing and pursue further discussions with the finance committee and its members," the Aug. 31 order added.

The proposal to switch from formula to stated rates to recover administrative costs (ER05-1181) was met with a storm of protest from market participants that complained it was not supported by cost-of-service data (*IF*, 1 Aug. 6). Responding to those protests, PJM reiterated its view that the switch would allow it to provide the highest quality service at the lowest possible price, and bring greater cost transparency and accountability to the process.

But sharing the concern expressed in protests, FERC requested more information and rejected PJM's use of the abbreviated procedures, which are meant for filings that do not involve a rate increase. While the proposed stated rate of 39 cents would be a penny less than the current formula rate, "this is not necessarily a rate decrease but a rate design change in which the stated rate simply happens to be lower than the product of the formula rate at a particular time," the order explained.

"There is no way, in the instant case, to know whether a stated rate is, per se, lower or higher than a formula rate because the formula rate produces varying rates over time as costs change, while a stated rate, by definition, applies that same rate," it continued. "The commission requires cost-of-service data with which to evaluate whether the proposed stated rates represent a just and reasonable projection for the future years."

FERC identified several issues that it said were raised but not supported by the filing. For example, why does PJM believe for-

mula rates "do not align well with control mechanisms that help measure performance," but stated rates will "enhance management discipline" and provide "significant benefits" through improved productivity and other management objectives?

The commission also sought more detailed budget support for a one-page table showing projected revenues and expenses for 2006-10. And how would the proposed mid-year switch to stated rates, which PJM wanted to take effect the first of this month, be reconciled with the calendar-year budget on which the current formula rates are based?

PJM's filing also proposed to revise its operating agreement to make certain changes to the finance committee. FERC accepted those revisions subject to a further filing that explains why the committee members would be required to represent the interests of their market sector rather than the overall interest of the PJM market and why the chairman must be the PJM representative on the committee.

Finally, the commission encouraged the parties to address other finance committee-related issues that were raised in protests.

With Potomac plant still out, OMTR asks PJM, Pepco and Mirant about reliability, restart

Following up on an urgent petition by the District of Columbia Public Service Commission to restart a Mirant power plant, FERC staff last week posed several questions about reliability planning.

Seeking to get a handle on the actual potential for a service outage in the nation's capital, staff asked Potomac Electric Power and PJM Interconnection to detail what transmission improvements are needed to avoid load shedding if vital lines were to go down. The PSC late last month sought to avert the Aug. 25 shutdown of Mirant's 482 Mw Potomac River Generating Station in nearby Alexandria, Va., citing fears about reliability.

Mirant revisited the topic with FERC in a Sept. 1 filing (EL05-145), reiterating the need to cease operations in the face of emissions concerns of the Virginia Dept. of Environmental Quality while expressing interest in restoring output at some acceptable level. The company also refuted an allegation by the City of Alexandria that the company wasn't really interested in keeping the plant running (*IF*, 5 Sept. 5).

FERC staff asked for information on the specific short- and long-term plans for transmission support for the city without the plant. With regard to the transmission lines identified as key contingencies, staff asked about the likelihood of one or both lines going out.

Jamie Simler, deputy director of FERC's Office of Markets, Tariffs and Rates, also asked how Pepco can reconfigure its system to serve load in the area from other substations and what reliability impacts such reconfiguration would have. She asked for responses by Friday (Sept. 9).

Turning to plant operations, Simler asked Mirant what would be the required stack height to meet National Ambient Air Quality standards and what is the maximum height allowed

by the Federal Aviation Administration. She also asked when the company would finish an analysis of changes to the plant.

In addition, Simler wanted a detailed walk-through of what it would take to get the plant up and running and how long the process would be.

The District of Columbia amplified its position, while environmentalists decried “illegal excess emissions.” The Potomac Riverkeeper, Anacostia Riverkeeper at Earth Conservation Corps and Patuxent Riverkeeper moved on Aug. 31 to oppose continued operation of the plant.

The DCPSC petition offered no plan to cut emissions at the plant and the relief sought would “require the commission to order Mirant to continue operating the station in violation of both federal and Virginia environmental laws, at the expense of both the public health and the health of the Potomac,” the Riverkeepers said.

But District of Columbia Mayor Anthony Williams warned that the plant’s “closure poses an unacceptable risk to the people of the nation’s capital.” The plant should be restarted immediately, he said in a press release filed with FERC last week.

“In the post 9-11 era, we must always be prepared for anything. After watching Hurricane Katrina devastate the Gulf Coast, we know how tenuous the supply of electricity can be,” he said, also harkening back to outages in California and the 2003 Northeast blackout. “The Potomac River plant is one of our primary backups in case of an emergency. Closing it puts lives and the well-being of hundreds of thousands of people at risk.”

NYISO seeks to make DSR programs permanent, files new credit provisions

In filings earlier this month, New York Independent System Operator proposed to eliminate the sunset provisions for two demand-side resource (DSR) programs and to provide new options for investing cash collateral deposits. Both proposals were said to have the support of market participants.

The day-ahead demand response program and emergency demand response program are due to end on Oct. 31. After “extensive analyses,” however, NYISO “concluded that both programs should continue to be an integral part of its market design for the foreseeable future,” said a Sept. 1 filing. In calling for an end to the sunset provisions, NYISO said the need “to seek repeated short-term extension of the programs creates uncertainty that reduces their effectiveness.”

With regard to the day-ahead program, NYISO recalled that over the years the market participants have “carefully examined possible alternatives and decided not to adopt them.” The program has provided quantifiable economic benefits, the filing continued, including reducing price volatility in the market.

For example, when supply was tight in 2002, the program provided an estimated “\$2.2 million in benefits, relative to program costs of approximately \$200,000.” NYISO and the market

participants also looked at the costs and benefits of removing the program “and concluded that this option should be rejected out of hand,” the filing related.

Likewise, the emergency program “provides substantial benefits to the market and helps preserve system reliability in the event of reserve shortages or significant emergency conditions,” said NYISO. The program “is critical to ensure a functioning grid if an emergency occurs that results in the need for demand reductions.”

Moreover, annual evaluations of the ISO’s demand response programs have shown that participants “are quite satisfied with the performance” of the emergency program, the filing added. “No matter what market design features are ultimately developed for DSRs, there will always be a need for an emergency program to address critical conditions,” it concluded.

In a Sept. 2 filing (ER05-1433), NYISO proposed giving market participants the option of electing to invest some or all of their cash collateral deposits in one of two bond funds. This revision “will allow market participants the potential for realizing greater returns on their collateral deposits as compared to the only investment option currently provided by the NYISO, a money market fund,” it said.

The proposal was approved unanimously by NYISO’s business issues and management committees in June, and was approved by the board in mid-July, the filing noted.

Last February, market participants asked the ISO to investigate alternatives to its use of the Victory Gradison Government Reserves money market fund, which consists of government securities with maturities of about 30 days and has a 2005 year-to-date return of 1.66%. NYISO said it considered the possible alternatives with four criteria in mind: safety of principal, liquidity of funds, earnings and ease of administration.

NYISO eventually selected the Low-Duration Bond Fund and the Core Bond Total Return Fund administered by BlackRock, the investment banking arm of PNC Financial Services.

The low-duration fund is a short-term fund (average maturity 2.19 years) and the total return fund is an intermediate-term fund (average maturity 6.7 years). Credit ratings for the underlying investments are AAA or government-backed for 96% of the short-term fund and 91% of the intermediate-term fund, and the funds met all four of NYISO’s criteria, it said.

While offering the potential for increased earnings, bond funds “have more volatility than the money market funds,” the filing continued. For example, 2004’s annual return for the short-term fund was 1.35% and for the intermediate-term fund was 4.31%, but through the first quarter of 2005 the returns were -0.05% and -0.23%, respectively.

“In recognition of that volatility and in order to ensure the preservation of underlying principal, market participants agreed that a ‘premium’ of additional collateral should be required for cash collateral invested in such bond funds,” NYISO’s filing said. Market participants electing the short-term fund would pay 5% additional collateral; those choosing the intermediate-term fund would pay 10% additional collateral.

MISO begins to address questions about resource adequacy plan . . . begins on page 1

mactic," with stakeholders saying "this is exactly what they talked about for the last four, five months."

The new draft paper addresses some key issues highlighted by a raft of questions sparked by the original white paper. In that document, MISO staff laid the groundwork for an energy-only market approach to ensuring resource adequacy that is built on long-term forward contracts tied to long-term financial transmission rights (*IF*, 22 Aug. 1).

Laying down more detail, the new draft recognizes the importance of "facilitating the correct economic response" to capacity needs through new generation, new transmission and/or demand response, which in many cases could be "much more beneficial socially and commercially," McNamara said.

MISO sees demand response as an important part of the mix. "The goal here would be to establish a market," McNamara said. "How can we facilitate a real, true demand response, which I don't think you've seen too much of across the country."

Primarily, the latest draft seeks to address the need to sort out jurisdictional issues, delineate scarcity pricing from abuse of market power, revise MISO's planning role and address the "free-rider problem" of market participants "leaning on the system" rather than maintaining capacity to meet their load.

In addition, "one of the things we are trying to disentangle . . . is this issue that resource adequacy is a catchall phrase for many, many different things," McNamara said. "We've tried to put a stake in the ground and say that, from our perspective, capacity is about long-term investment, and it's about getting correct price signals."

At an Aug. 24 meeting on the white paper, operational issues was one of several topics probed in seven pages of detailed questions from the Organization of MISO States, the state regional committee for the regional transmission organization's footprint. In the context of the paper, MISO sees operational issues as a short-term reliability matter, McNamara explained.

"Reliability is first and foremost, but reliability is about real-time dispatch and making sure that we have the right amount of capacity on line in order to keep the lights on," he said. But from a resource adequacy perspective, "let's not confuse the difference between operating reserves and planning reserves. What we are talking about is largely planning reserves."

Obviously the two converge at some point, and "we clearly need to identify how . . . what happened seven years ago flow[s] into what is happening tomorrow," McNamara said. "We acknowledge the need to address that, but the primary effect here is to really go down the path of what are the obstacles that are preventing long-term contracting now." The intent is to provide "the right signal to get iron in the ground," he added.

"You have to bifurcate the two," agreed John Bear, MISO chief operating officer. "The concept we are putting forward here will accommodate a tailored approach" within each state to address the reserve margin issue. MISO does not profess to know the answer "for our entire footprint for operating

reserves," he said. "This will allow the states to push this issue and do what they think is appropriate in their particular area."

"Our goal is not necessarily to manage price volatility," McNamara said. "That will be done by market participants as they manage their own affairs and manage their own risk."

Commenting further on state jurisdiction, McNamara said MISO is examining "just what are their jurisdictional responsibilities, and whether or not they do have the jurisdiction to set or impose reserve margins, and whether those are enforced."

Turning to market power concerns raised by OMS and other stakeholders, McNamara sought to dispel a notion that MISO's plan to create proper price signals relies, in effect, on permitting abuse of market power. "Nothing could be further from the truth," he asserted. "There is a difference between true scarcity allowing prices to flow to where they should in terms of scarce resources and abusing a market power position. What we are going to do in this white paper is discuss what is it that we're trying to mitigate."

Parties were concerned the original draft spoke of relaxing bid caps and altering market mitigation. "We are not proposing, and there was some confusion out there, . . . getting rid of market mitigation and market monitoring," he said. "Hopefully we can address some of the OMS' concerns on that and say what is it that we need to tailor our market monitoring plan to reflect how we are going to ensure that abuse of market power doesn't occur."

The paper also will promote a broader planning process. "We do intend to include within the MISO planning process a view of the situation with regard to new builds" of both transmission and generation, McNamara said. "What we'd like to be able to say is, 'We are seeing from our index that long-term price signals are going up. The reason for that is we are getting no builds in these areas or you have a load pocket that people are nervous about.'"

By tagging these situations early, MISO would hope to propel projects to meet the need. It would glean information from the marketplace as well as from long-term contracts submitted to obtain long-term FTRs in the capacity market. "We are going to say how we intend to do that and what kind of information would be transferred to the marketplace and to the regulators," McNamara said.

He added quickly that this new approach "has to be accomplished in partnership" with market participants and state regulators. "This will only work if all three of us work as partners."

The free-rider problem is one that needs further discussion, McNamara said. The question is: "How do you protect people that did a very nice job of contracting" from real-time load cutting because "somebody's short out there?" He sees two issues. First, how does a load-serving entity avoid getting cut off in a real emergency? Second, how does an LSE insulate itself from price impacts of other participants going short?

As to the second issue, market participants need to make sure they are hedged. "If I'm hedged, I really don't care what the price does," McNamara reasoned.

With regard to the first issue, "obviously, the ideal state would be that you are cutting off people that are short if you

have to do that.” But something the new draft addresses in greater detail is the “need to ensure that we get demand response in this market” to, perhaps, avoid cutting load, he asserted. “I don’t think we need 50,000 Mw of demand response, but if John [Bear] had at his disposal between 2,000 and 8,000 Mw of potential demand response” that could be called on in real time, the problem of someone being capacity short could be mitigated.

In fact, “we had 2,000 Mw this year” in demand response, Bear added. While MISO doesn’t call on it, “the balancing authorities do, and they did on our peak day and it worked very well.” Once again, the key is “you’ve got to show them the price signal,” he said.

And that means letting the market work. “I don’t know how you incentivize that demand response while you simultaneously manage price volatility,” McNamara said. “Anything that dampens that price volatility really creates a disincentive.”

One topic for discussion at today’s meeting is a “program of analysis” for demand response. “What we need to show to the regulators is that, on the one hand, we need that price volatility and, on the other hand, this is how much demand response you are going to get” as a result of it, McNamara said. The analysis would consider “the benefits of going to a market-based mechanism vs. command and control.”

Also, “what kind of demand response can we expect in three years, five years, and so on? What kind of price elasticity can we expect to see from the demand curve? What sorts of investment become commercially viable in this environment that may not be viable in other environments?”

On the market side, participants are concerned about “regulatory bounce-back,” he said a reference to the fear that “regulators may back out on this . . . when the water gets a little hot.” But McNamara expressed confidence that “we can show regulators that we have a viable demand-response program and, moreover, that we are going to be tracking that program in terms of the investment being put in.”

The overall objective is to take “a whole package of things to the regulators and say, ‘Yes, you are going to allow more volatility [but] expect as a response to that volatility to get various kinds of investment including demand response,’ ” which is “absolutely key to making sure that people who are hedged don’t get their lights turned off.

Oversight agencies seek to dampen Katrina price gouging claims . . . begins on page 1

warned that consumers can expect high heating costs this winter due to natural gas supply shortages.

Lawmakers questioned officials from the Federal Trade Commission and the Commodity Futures Trading Commission on the precipitous rise in gasoline prices at the pump, which in some cases spiked by more than a dollar since the hurricane hit. Democrats pressed agencies to hold accountable gasoline retailers that hiked prices to reap profits after the hurricane,

rather than as a response to supply and demand fundamentals. Concerns about the impact of speculators in the futures markets for natural gas and oil were also expressed, as the October NYMEX gas futures contract remained above \$11.00/MMBtu throughout the week.

FERC escaped direct scrutiny during two days of hearings in House and Senate oversight committees. But through its Office of Market Oversight and Investigations, which came into existence in 2002 after market abuses led to the California energy crisis, the commission is playing a central role in federal efforts to monitor U.S. cash markets.

Stephen Harvey, deputy director of OMOI, told *Inside FERC* that no evidence has emerged that the natural gas spot market is behaving abnormally. Summer temperatures were hot and recent gas storage had been less than optimal. “We expected prices to be fairly high, and we recognized that a shock could happen that would push prices higher.”

Arguments can be made about where the price of natural gas ought to be, Harvey said, but the fundamental relationships between oil, coal and gas prices—and the tie between cash prices and futures contracts—were as expected. “Those are the relationships we have not seen breaking down at all,” he said.

John Fenton, CFTC deputy director for market surveillance, which coordinates with FERC on market oversight, offered a similar assessment. Natural gas is highly volatile right now, he said. Spreads between long and short trades appear reasonable and the relationship between futures prices and the underlying cash market appear to be within an acceptable range. No evidence has emerged to suggest the price discovery function of the market for futures contracts has not functioned as it should, he told *Inside FERC*.

But, Fenton asserted, the especially tight supply/demand balance and growing liquidity resulted in a more rapid surge in upward market pressures than had occurred after Hurricane Ivan hit energy production and transportation last year. In response to concerns about the volatility, the CFTC sent additional monitors to the floor of the New York Mercantile Exchange last week. Cooperation with FERC will probably increase in the coming weeks, he said. “They are far more expert on infrastructure.”

James Overdahl, CFTC chief economist, testified before the Senate Energy and Natural Resources Committee on Tuesday that conditions were ripe for price increases. “In U.S. energy markets, recent experience has shown that even small disruptions in production, refining capacity or transportation networks can significantly affect prices in the face of high demand for energy products,” he said. “Given the scale of disruptions caused by Hurricane Katrina, it is not surprising that current prices for energy products have risen significantly.”

Both FERC and the CFTC were buffeted by the storm of the 2001 California energy crisis, which resulted in sharp rebukes from Congress that oversight agencies failed to identify distortions in the markets and actively pursue abusers. But both Fenton and Harvey said things are different now.

While liquidity has rebounded since the falloff of the energy

marketing industry, there is far more transparency today than there had been in the past, both in the form of price reporting and a more open trading system, they said. "All of those are radically different," Harvey said. The other big change has come in the form of market behavior rules. "Five years ago OMOI didn't exist," Harvey added.

The dual experience of CFTC and FERC enforcement, coupled with "clarity" about the rules and greater concern that breaking the rules has a consequence, "are all powerful differences" between 2001 and today, Harvey said.

Any stepped up efforts in the aftermath of Katrina also come as the two market regulators firm up plans for future cooperation. The Energy Policy Act of 2005 recently passed by Congress requires the agencies to prepare a memorandum of understanding by early next year on how to coordinate and share information.

Congressional hearings last week focused primarily on the price of gasoline at the pump and the behavior of retailers. A number of states considered price controls to stem the upward climb in gasoline prices.

But the impact integrated oil and natural gas companies have on market prices did not escape scrutiny. Both Democrats and Republicans raised concerns about record profits, industry consolidation and the companies' claims that oil and gas production has fallen short of expectations despite heavy investment.

At a Wednesday hearing of the House Energy and Commerce Committee, Rep. John Dingell, D-Mich., ranking member, asserted that during the 1970s, big oil companies "were the major violators of oil price controls then in effect and were required to disgorge billions of dollars in overcharges. Any examination of price gouging must begin with a review of their practices."

FTC Associate General Counsel John Seesel told the House panel that his agency was on "high alert" for price gouging. But, in responding to aggressive questioning, he said the commission does not probe prices charged by individual retailers. For the agency to pursue the issue of price gouging, it would first have to identify collusion within the industry.

In an interview with reporters on the sidelines of the day-long House committee meeting, Chairman Joe Barton, R-Texas, said he did not support a federal price gouging law and warned that a drive to cap energy prices could lead to shortage and misallocations. "I'm much more willing to monitor the market, but let the market operate," he said. "If there is no standard definition of what gouging is, it is hard to go out and be punitive."

Barton and Sen. Pete Domenici, chairman of the Senate panel, identified refinery shortages as chief among the underlying culprits causing high energy prices. The two said they would introduce legislation to encourage the construction of new refineries. Barton said he would reintroduce a "refinery revitalization" bill that would tap into enterprise zones. A similar bill failed to pass the Senate last year, in part because critics contend such a bill would ease federal clean air and water rules.

Domenici and other Republicans on the Senate panel called

for legislation to expand drilling in the OCS, which included a push to redraw the boundaries between Alabama and Florida to tap into Lease 181. —*Joel Kirkland*

SUPPLY & DEMAND

Industry officials ponder impact of gas-fired power plants on tight supply/demand balance

New gas-fired power generation capacity in eastern Canada and the U.S. Northeast will strain an already tight gas market over the next several years, although industry officials differed last week on just how great the impact will be.

Paul DuMaresq, director of marketing for Shell Trading, said the Ontario government's June 2004 call to reduce the province's reliance on coal-fired electricity has resulted in about 25,000 Mw of gas-fired replacement capacity being proposed. He said those plants' "potential" gas consumption is about 73 petajoules/year, or about 7 Bcf annually.

If all of those plants become operational, they would boost Ontario's yearly gas consumption by about 8.5%, DuMaresq told the Industrial Gas Users Assn.'s annual conference in Quebec City. "From an Ontario perspective, the gas demand from these projects is going to increase quite a bit," he said.

However, he stressed that 2,500 Mw of new gas-fired capacity would increase total Canadian gas demand by about 1.5% and overall North American consumption by just 0.25%, which he called "a drop in the bucket . . . compared to total demand."

"I am not trying to understate it by any stretch, but we are not going to see the 'off-coal' program in Ontario lead to gas price increases" in the broader market, DuMaresq proclaimed.

In fact, he said storage capacity at the Dawn, Ontario, hub, as well as current pipelines serving the region, should be able to serve the new power plants without any expansions. And from a supply standpoint, "these projects have access to huge volumes of supply" from several North American basins, he said.

But not everyone speaking at the IGUA conference was as optimistic. Haig Vejprava, director of marketing for EnCana Gas Marketing, said North American supply should increase by about 10 Bcf/day by 2014 due to liquefied natural gas imports and increased production of unconventional domestic gas.

"But our estimates show that demand will increase by about the same amount," in part because of new gas-fired power plants, which indicates little relief from the current tight supply/demand balance, he said.

Steve Acker, director of marketing and origination for BP Canada Energy's North American gas and power division, said growth in gas demand for generation in eastern Canada and the U.S. Northeast will average about 2.2%/year for several years and "the question is, where is this supply going to come from? Gas from traditional North American basins will not meet demand." He, like several other speakers, noted that the decline rate from conventional wells continues to rise as

basins are “played out.”

Acker said the placement of new LNG import terminals in New England and in the eastern Canadian provinces would go a long way toward filling the regional supply gap, and he predicted that enough import capacity will be built—despite resistance from local governments and residents.

“There is no shortage of import and regasification projects [proposed] for this region,” he told the conference. And “while there appears to be a lot of fear mongering in North America, the LNG industry has an outstanding record around the world . . . this technology has proven successful.” —Mark Davidson, Quebec City

ENERGY PROJECTS

With 235,000 Dt/day Jewell Ridge project, East Tennessee to add to regional capacity

East Tennessee Natural Gas last week filed for commission authorization to build a 32-mile, 20-inch-diameter pipeline to connect with CNX Gas’ Cardinal States Gathering System in southwestern Virginia. The sponsor asked for FERC approval by Jan. 19 so that it could place the Jewell Ridge Lateral in service before the cooling season next summer.

Before the open season was launched (*IF*, 8 Aug, 14), East Tennessee entered into a precedent agreement with CNX Gas for 210,000 Dt/day of firm transportation capacity. If CNX does not need the full amount of the contracted capacity and it is requested by others, CNX may drop its quantity no more than 25,000 Dt/day, according to the Sept. 8 application.

The 235,000 Dt/day, \$53 million project “will provide Appalachian natural gas producers a new outlet for their growing supply to support the growth” in the Tennessee, Virginia and North Carolina markets, said Guy Buckley, group vice president of Duke Energy Gas Transmission, parent of East Tennessee. Supply through the lateral would also be available to East Coast markets through interconnects with Texas Eastern Transmission, Transcontinental Gas Pipe Line, Tennessee Gas Pipeline and others, he added.

Jewell Ridge, in concert with recent expansions by East Tennessee, “creates an integrated energy hub that provides storage and transportation options for Mid-Atlantic producers,” Buckley said. Also, the lateral would serve as an alternative outlet for producers to steer gas supplies around repair outages associated with Dept. of Transportation pipeline integrity rule maintenance, the application added.

“At a time when energy supplies in North America are a critical concern, the Jewell Ridge Lateral will also provide markets attached to the existing East Tennessee pipeline grid with direct access to competitively priced and clean-burning natural gas to serve the growing demand of the surrounding region,” East Tennessee continued in the application. In addition, the lateral would provide access to gas for the first time

to certain areas in Virginia.

The project entails the lateral running from the Cardinal States system in Tazewell County, Va., to a point on the East Tennessee system in Smyth County, Va.; a meter station and launcher; and pressure regulation facilities with a receiver at the terminus of the lateral. East Tennessee asserted the project “will have limited residual adverse impacts on landowners and communities.” A full range of interested parties were engaged during the pre-filing process (PF05-3), the company added.

It offered mitigation measures to limit the impacts. “The benefits of the Jewell Ridge Lateral outweigh potential residual adverse effects,” East Tennessee said.

The pipeline also told FERC that the project would have no adverse effects on existing customers or on existing pipelines and their customers. The costs would be recovered through an incremental rate and would not have any negative impact on the existing East Tennessee customers, the sponsor added.

Mackenzie, Alaska gas pipes needed to satisfy North American demand, says Canadian official

Gas pipelines from Canada’s Mackenzie Delta and from Alaska’s North Slope will both be needed to meet North American demand in the coming years, a Canadian government official said last week.

“The supply of that gas is going to be critical,” Murray Smith, Alberta’s minister-counselor to the U.S., told reporters at the Canadian Embassy in Washington.

Smith said negotiations among the various Mackenzie partners and stakeholders are ongoing, noting that the Canadian government “broke a major logjam” in July when it agreed to provide C\$500 million for a socio-economic fund to aid Mackenzie-impacted communities.

And because the route selected for that pipeline is largely flat, construction of the pipe “can happen fast once you get approval,” Smith noted.

LIQUEFIED NATURAL GAS

With favorable project report in hand, Maine LNG developers plan to move forward

Having received a favorable project feasibility report, developers of a liquefied natural gas terminal proposed for Maine’s Passamaquoddy Indian Reservation now plan to submit a permit application under FERC’s pre-filing process by the end of the year.

A safety, security and navigation study conducted by Houston environmental and security consulting firm TRC concluded that Quoddy Bay LNG’s proposed 500,000 Mcf/day terminal at Pleasant Point poses “no major issues, obstacles or concerns.”

Quoddy Bay LNG Project Manager Brian Smith said the company plans to file a full FERC application in eight to 12

months and hopes to start operating the proposed \$400 million facility by late 2009.

"The demographics of this area do not even fall into" the criterion for population density "both with regards to the route of the vessel transit or at the proposed facility site," the TRC report said. "Zone One, the measure with the most severe impact on the local population, does not even affect the shoreline anywhere along the vessel's route except slightly during the short transit time in the vicinity of the 'Old Sow' whirlpool."

Some Canadian officials opposed to the three planned terminals in northern Maine have said Canada could block the projects by denying LNG vessels permission to navigate Canadian waters before approaching the U.S. border. But Smith said that under international law, he expects Canada to authorize LNG vessels to navigate Canadian waters because the country is building its own LNG terminals north of Maine.

California sends skeptical safety report to FERC on proposed Long Beach LNG project

A catastrophic event at a proposed liquefied natural gas terminal in Long Beach could kill thousands in the area and cripple the nation's import capacity, the California Energy Commission warned in a report filed with FERC last week.

In suggesting that a catastrophe at the busy Long Beach port could temporarily halt crude oil and gasoline shipments to the California market, the CEC cited the impact of recent disruptions in the aftermath of Hurricane Katrina.

"There is no precedent on the West Coast for such a large temporary loss of crude oil and refined petroleum product supply on a temporary basis," the report said, "although we are now seeing impacts from Hurricane Katrina that could be used as a basis for evaluation of a supply disruption on the West Coast."

As required under the Energy Policy Act of 2005, the state of California sent to FERC a safety advisory report on the pending Long Beach project (CP04-58). The CEC urged the developer, Mitsubishi's Sound Energy Solutions, to relocate the proposed import terminal to a non-urban site.

Further, it pressed FERC to address why a more remote location cannot be developed, citing federal and state statutes that require authorities to consider alternatives to urban sites. FERC should address whether offshore projects such as the BHP Billiton proposal near Cabrillo Port and the Crystal Energy proposal at Platform Grace offshore of Oxnard are feasible alternatives, the California report said.

The report was filed as opponents and supporters of the contentious import terminal project await a joint draft environmental review by FERC and the Port of Long Beach. The review is expected out this month.

Long Beach officials do not have authority to stop the project. But a negative environmental and safety assessment could draw out opponents on the Long Beach City Council and further dampen the odds the project can withstand public opposi-

tion and get built (*IF*, 29 Aug, 12).

Using a Sandia National Laboratories analysis of LNG risks and a report by former White House terrorism expert Richard Clarke as central guides, the CEC pointed to a range of hypothetical disaster scenarios, including the hijacking of an LNG ship, a small-boat or grenade attack, aircraft attack or some form of sabotage. The report warned that flash fires resulting from vapor clouds could decimate the port and nearby neighborhoods.

In the report, the CEC called for a broader evaluation process under the National Environmental Policy Act and a more expansive FERC environmental impact statement due to public concerns about terrorism. "Even if probabilities cannot be quantified or identified, the EIS should provide as much information as possible" on terrorism risks, it said.

"FERC should identify all terrorist activities which, based on world history and projected future scenarios, could cause a release of LNG at the terminal. The state requests that the FERC consult with insurance companies in this regard."

The CEC also wants FERC to consider the economic impact of a disaster at the Long Beach port, focusing especially on petroleum. "Local refineries would reduce output as crude oil inventories decline or completely shut down if the marine terminals remained closed for an extended period of time." If petroleum facilities located near a spill were unavailable for days or weeks, "wholesale gasoline and petroleum product prices in Southern California would rapidly increase."

Turning to national security matters, California claimed that the U.S. Defense Dept. has indicated that operations of the terminal could potentially interrupt fuel deliveries to a Defense Logistics facility in the area.

The California report said FERC should identify land-use issues in areas surrounding the proposed project—some of which federal regulators already do—and the report should also take into account the potential for natural disasters in the region. Beyond that, safety issues raised by "sending up to 45 LNG-loaded trucks each day" from the port through the Los Angeles metropolitan area should be a consideration for FERC.

SES President and Chief Executive Thomas Giles could not be reached for comment by press time.

The California commission called on federal and state authorities to refrain from granting permits to the SES project in an urban setting until a "comprehensive risk, economic and fiscal impact assessment is complete."

The "foundational information" necessary to conduct a thorough analysis of the Long Beach project is not public yet, the report said. Any assessment, it maintained, must include impacts on the surrounding population, economy and transportation network in the event of a catastrophe; impacts on port operations as LNG tankers enter and leave the area; the ability of the U.S. Coast Guard and local police and fire departments to provide security and react to an incident; a worst-case scenario analysis; impacts on air traffic; identification of the fiscal impact on the city; impacts on the U.S. Navy and Defense Dept; and an assessment of the homeland security threat.



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