

Inside FERC

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Long-term FTRs 'key ingredient' to MISO's energy-only approach to resource adequacy

While market participants in New England and the Mid-Atlantic continue slugging it out over resource adequacy proposals based on capacity payments, Midwest Independent Transmission System Operator is charting a different course. At a meeting last week, MISO's advisory committee was briefed on a draft white paper that touts an energy-only market built on long-term forward contracts tied to long-term financial transmis-

sion rights.

"I don't think that there is a single topic that is more important with regard to wholesale electricity markets" than resource adequacy, Ron McNamara, MISO vice president of market management, told *Inside FERC* prior to the presentation to the committee.

ISO New England and PJM Interconnection are pursuing proposals that offer capacity payments to ensure that units

needed for reliability stay on line and new generation is built. FERC has approved the framework of ISO-NE's controversial locational installed capacity proposal, but it recently agreed to hear oral argument on an initial decision addressing crucial components of the plan (*IF*, 15 Aug. 5).

PJM's reliability pricing model (RPM) differs from LICAP in some respects but also is based on ensuring a steady revenue

(continued on page 13)

Navy protests Weaver's Cove LNG project; sponsor stands firmly behind plan

The U.S. Navy asked FERC last week to reconsider its authorization of the Weaver's Cove liquefied natural gas terminal in Fall River, Mass., throwing up yet another potential roadblock to the increasingly contentious project.

Claiming it was left out of the loop during FERC's review process, the Navy said in a motion to intervene that the commission failed to adequately evaluate the impact of the project on the testing of shallow-water prototype weapons, under-

sea vehicles and sonar testing in the Narragansett Bay. If the project is built, an estimated 50 to 70 LNG import tankers would traverse the bay yearly on their approach to the terminal, requiring security zones extending up to two miles and complicating normal operation of the military program, the filing said.

The Navy urged the commission to reopen the public record and accept new evidence regarding the impact on military operations (CP04-36). The LNG traffic,

according to the Navy, would "significantly impact cost, schedule, program development risk, as well as fleet delivery of these critical Navy programs."

Located in the East Passage off the coast of Newport, R.I., the Shallow Water Test Facility includes testing ranges that permit prototype underwater weapons systems, including torpedoes, to be exposed to "real environments." All of the Navy's in-water test runs would be subject

(continued on page 12)

Kinder Morgan, Sempra unveil mega-pipeline project

Addressing in grand fashion gas pipeline constraints in the Rocky Mountain region, Kinder Morgan Energy Partners and Sempra Pipelines & Storage last week unveiled plans for a \$3 billion, 2 Bcf/day mega-pipeline from Wyoming to Ohio.

Houston-based Kinder Morgan and San Diego-based Sempra said they have signed a memorandum of understanding to jointly develop the 42-inch-diameter line connecting gas-producing areas of the

Rockies with consuming regions in the upper Midwest and eastern U.S.

Kinder Morgan and Sempra would share responsibility for development activities, with Kinder Morgan owning two-thirds of the equity and Sempra owning the remaining third. The companies said they anticipate phasing the 1,500-mile pipeline into service beginning in late 2008 and continuing through 2009.

Along with providing gas producers much-needed takeaway capacity from the

Inside this Issue

Legislation

FERC wins confidence of industry, consumer groups as it implements energy law 3

Markets

OG&E joins ranks of utilities willing to drop market-based rates until markets change 5

Agreeing to settle spot refund, other cases, Reliant ends California crisis disputes 7

Energy Projects

FERC gives green light to Northern Border pipeline capacity expansion 9

Rockies, the system would feature multiple interconnections with other large pipelines, which should "create significant flexibility and more options for reaching other demand-anchored markets," the companies said.

"If built, the pipeline would maximize the value of growing Rockies production by creating unprecedented access by one pipeline to multiple markets and storage, while providing markets in the upper Midwest and eastern U.S. with direct access to reliable, long-lived domestic natural gas supplies to meet growing demand," said Scott Parker, president of Kinder Morgan's gas pipelines group.

For its part, Sempra "has evaluated multiple alternatives to move gas from the Rockies and believes this project represents the best long-term solution for the U.S. gas market," said George Liparidis, president of Sempra Pipelines & Storage.

The preliminary pipeline route begins at the Wamsutter hub in Wyoming and extends into eastern Ohio, "with an ultimate route to be selected based on shipper interest," the companies said.

A Kinder Morgan spokesman said that the two firms are "still trying to determine interest" in the project and, thus far, "there seems to be quite a bit." While "it's a little premature" to announce dates for an open season, he said one would likely take place by year's end.

Under the MOU, Sempra has agreed to bid on 200,000 Mcf/day of firm capacity during the open season for use in supplying local distribution companies on the East Coast.

The pipeline is "clearly an ambitious project," said Greg Schnacke, executive vice president of the Colorado Oil & Gas Assn. But "these companies are capable of making it happen."

Problems acquiring sufficient equipment and labor for such projects do tend to "have some drag on being able to produce more gas," Schnacke told *Inside FERC*. "It takes some financial

wherewithal to get these things done," but Sempra and Kinder Morgan "have got the resources."

Kelliher: post-PUHCA era to spur investment in electric, new statute vitiates LNG case

Chairman Joseph Kelliher last week again raised the prospect that more players in the financial sector and energy firms with non-electric holdings could emerge as new entrants in the transmission and generation markets.

In the post-energy bill era, as FERC draws up regulations to replace the Public Utility Holding Company Act, he said the Energy Policy Act of 2005 removed barriers to entry into the electricity market, especially by the financial sector.

"With PUHCA repeal, you might see more entry by the financial sector—you've seen significant entry by the financial sector up to this point, but you might see more of it," Kelliher said in an interview with Bloomberg TV. "You might see more foreign entry. You might see entry by companies that are in the energy business but not in the electricity business."

The repeal of PUHCA and potential entry of mega companies, including giant integrated gas and oil producers like ExxonMobil or investors with diversified interests, could help feed the capital-intensive electricity and gas transportation sectors. "We need a lot of investment in transmission, in generation, we need investment on the gas side in pipelines," Kelliher said. "I think entry is a good thing and it'll result in more investment."

Kelliher sought once again to address concerns about whether FERC has enough enforcement weight to prevent market manipulation or market power abuses. "We can review generation acquisitions, something we didn't used to be able to review in the past," he said. "The new law also provides an

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express prohibition of market manipulation, and it gives us significant civil penalty authority, something that we didn't have in the past. So, we have a greater ability to prevent wrongdoing and to sanction it with very significant civil penalties."

On natural gas, Kelliher proffered that a provision in the new law that grants the commission exclusive authority to permit liquefied natural gas terminals "vitiates" a pending federal case challenging that authority. The California Public Utilities Commission is before the 9th U.S. Circuit Court of Appeals in an effort to clarify whether the federal or state government has preeminent authority to permit projects. Notwithstanding the chairman's take on the matter, the court has not yet ruled on the case.

"That was an area that I personally thought was settled 30 years ago with some other litigation," Kelliher said. "But there was a pall cast over our authority to approve LNG import facilities by the lawsuit. What Congress really did was vitiate the lawsuit. They clarified that we have exclusive authority to approve LNG import facilities," he insisted.

FERC gets votes of confidence from industry, consumers groups as it implements energy law

Energy industry associations and a group of major industrial end-users last week expressed considerable confidence in FERC as it begins implementing new electric reliability standards and prepares for a possible wave of corporate mergers and heavy investment in energy delivery infrastructure.

Speaking at a Washington briefing sponsored by *The Energy Daily*, a panel of electricity and natural gas executives said the Energy Policy Act of 2005 sets the stage for a healthier supply-and-demand balance, a less congested transmission grid and lower prices. Much of the activity necessary for those outcomes will run through FERC, which Congress provided with a stronger hand to regulate and police an expanding marketplace.

"We think this is a step forward," said John Anderson, president of the Electricity Consumers Resource Council. In particular, Anderson cited new "backstop" authority allowing FERC to push through transmission projects stalled at the state level, along with the decision by Congress to give the commission more power in the areas of market manipulation and merger review.

Signed into law two weeks ago, the bill repealed the Public Utility Holding Company Act (*IF*, 1 Aug. 1). Repeal of the 70-year-old law—viewed by some as a critical consumer protection but by others as a needless barrier to investment—garnered broad discussion. Most on the panel predicted additional mergers would result, and most felt FERC was in a strong position to fill the void with robust merger reviews.

Thomas Kuhn, president of the Edison Electric Institute, predicted that FERC and "a bevy of federal regulators" will diligently scrutinize merger deals. "Mergers are only going to happen if they're in the best interest of the customers," he said. "If they're in the best interest of the customers, then we

have to support them."

Utility mergers are scrutinized more than any other category of corporate mergers, Kuhn argued. As to whether, and to what extent, non-utilities will enter the power market, he cited the emergence of Warren Buffett, whose Berkshire Hathaway investment company recently filed to assume control of MidAmerican Energy in the wake of PUHCA repeal (*IF*, 8 Aug. 7), as potentially a key investor in transmission. "They're welcome," he said of outside investors, "because they bring capital to the industry. It is probably the most capital-intensive industry."

But Kuhn's flat assertion that customers will always benefit from mergers held little water with Anderson. "I sincerely hope that Tom is right that the mergers will only take place if they benefit customers, but I'm not sure if history will back that up."

The "good news," Anderson said, is that FERC will take the lead on merger review, instead of the Securities and Exchange Commission. "The SEC was on record saying that they wanted PUHCA repealed, and they've been consistent the entire time in wanting it repealed. They demonstrated their desire to have it repealed by not enforcing it."

Repeal of PUHCA will result in mergers and could result in less competition, Anderson said, but the regulatory shift to FERC will strengthen the overall review process. "It will bring about some mergers, and every merger has the potential of reducing one competitor from the marketplace," he said. "FERC gets merger review authority, and that's very important. More importantly, it has new authority to deal with market manipulation."

FERC is directed by the Federal Power Act to consider the interest of consumers, Anderson said. "We certainly intend to work very closely with FERC to try to ensure the consumers' interests are taken into account."

Kuhn and Anderson also addressed problems associated with joint ownership of transmission and generation. Couching the issue as an "economic disincentive to build transmission," Anderson said until joint ownership is dealt with, "we're going to have a real problem."

"Well, I think it is being dealt with," Kuhn responded. "There are regional transmission organizations that are being formed along with the regional regulatory entities that are essentially ensuring there is open access to transmission. I think that's a major priority that [Chairman Joseph] Kelliher and FERC want to make sure is addressed."

On the gas side, an industry official believes that for security and price reasons, Congress should look for more ways to create incentives for domestic production. The upcoming winter, which forecasters indicate could be harsh, will add to the price pressure, they said.

"We anticipate high prices again," said David Parker, president and chief executive of the American Gas Assn. "We're concerned about the kind of pressure that puts on natural gas utilities. If people can't pay their bills it causes us huge problems." As a result of the continuing price pressures, he said, "many of our companies are now considering going into rate cases."

Parker said he was pleased with the energy bill, but asserted that Congress and industry had to work toward a "better energy

policy down the road.”

Better access to the Rocky Mountains and the Outer Continental Shelf is critical to increased domestic supply, he said, and a gas pipeline from Alaska’s North Slope and more liquefied natural gas could also help bring prices down.

Beyond that, market stability is important as more LNG supplies enter the market. The Alaska pipeline could serve as an incentive for utilities to begin looking at longer-term supply agreements, Parker said, though he stressed it was a “real steep climb” to get utilities to actually make such agreements.

INGAA reaches emissions accord with EPA on compression, avoiding heightened monitoring

Gas pipeline operators will not have to install expensive nitrogen oxide emissions monitors on the bulk of their gas turbines as part of a settlement reached last week by the Environmental Protection Agency and Interstate Natural Gas Assn. of America. The new rule will allow for existing monitoring procedures already approved by federal and state authorities—namely periodic testing—to remain in place.

According to a notice in the Aug. 15 *Federal Register*, EPA agreed to clarify its rules for turbine emissions monitoring so that turbines made after 1977—or that did not use water from steam injections to control nitrous oxide—do not require continuous monitoring as the agency had proposed.

“We never had a fundamental disagreement with the EPA,” INGAA Director of Environment and Construction Policy Lisa Beal told *Inside FERC*. “We felt [the rule] just wasn’t clear; they felt it was clear.”

INGAA filed suit in 2004 in D.C. Circuit Court of Appeals, arguing that the EPA rule was too costly and environmentally unnecessary because gas is the cleanest-burning fossil fuel. Pipeline companies use more than 300 gas turbines nationwide for compression purposes, making the pipeline industry the largest operator of gas turbines outside the power-generation sector, according to Beal.

The suit’s primary intent was to clarify the rule under the Clean Air Act for all gas turbine operators nationwide. “Otherwise we end up fighting on a state-by-state basis,” Beal said.

In exchange for EPA’s decision to not require continuous monitoring for all gas turbines, the pipeline industry has agreed that turbine users will report to federal, state or local officials excess emissions “for all units of unit operation, including start-up, shutdown and malfunction.”

The EPA has until Oct. 15 to take public comments on the settlement, after which it would revise the regulation.

Growth of LNG imports should link U.S. gas industry to global market, study says

As imports of liquefied natural gas soar over the next decade, such growth figures to create closer ties between the U.S. gas industry and the global market, according to a new report.

Released last week, the study by Wachovia Securities said

domestic receipts of LNG “should lower prices, but only to a point of equilibrium with world markets.” The firm projected a long-term base price of \$5.00/MMBtu to \$6.00/MMBtu.

The U.S. “will likely be forced to accept the realities of a global market in yet another commodity: natural gas,” Wachovia said. “Henry Hub [prices] may be in the \$8-\$9/MMBtu area, but the United States has already been outbid for brief periods when European prices spiked.”

According to the report, domestic LNG regasification capacity, which currently stands at about 2 Bcf/day, “should easily grow to 10 Bcf/day and likely more as existing terminals are expanded and new ones already under construction are completed later this decade.”

Declining U.S. gas supplies “may briefly reverse as high prices, advanced technology and a record rig count coax new gas from the ground,” the report said, citing the growing percentage of production coming from long-lived onshore gas plays.

However, any such increase “will come at a very high marginal cost that ultimately won’t be able to compete with cheaper imports as LNG capacity into the U.S. grows post-2008,” it said. “We think the near-term U.S. supply response will be temporary. In our view, LNG will be needed by the end of this decade, when most new terminals are due to enter service.”

As LNG assumes a bigger share of the U.S. gas market, and the global price of gas begins to exert a greater impact on U.S. prices, market conditions will change to reflect the new dynamics, the report said. For example, increased volatility could occur, particularly in peak winter months, and the linkage of gas prices to crude oil prices “may strengthen, but it may not be a perfect correlation.”

Wachovia also speculated that the construction of new LNG import terminals on the East and West coasts could have a dramatic effect on local gas prices where the LNG comes ashore. However, “this impact should be somewhat muted by the likely concentration of LNG imports in the Gulf of Mexico.”

And as LNG imports rise, new opportunities in the fields of energy marketing, trading and hedging should follow. “The complexities and disruptions LNG will likely bring about should drive a need for more intermediation, allocation and risk-management services,” the study said.

Increased LNG imports also are expected to create downward price pressure on other fuels, particularly coal, Wachovia predicted. “Coal could relinquish some of its competitive advantage as efficient gas-fired power generation becomes more economically attractive.”

The report also said abundant LNG supplies could spark a renewal in the construction of gas-fired power plants. “Coal and nuclear plants are running at or near full capacity, coal prices have risen sharply, and there are not any new plants on the immediate horizon,” Wachovia said. “Power could be an early LNG adopter.”

The report said growth in U.S. imports of LNG “appears to be inevitable,” and energy market players are lining up to get a

piece of the action. "Most of the world's natural gas is in places that do not have a ready market. That stranded, low-cost gas should find its way to our market."

Although environmental concerns have stymied several LNG import terminals and have stalled others, Wachovia said most people would find the construction of an LNG terminal in their community preferable to that of a coal plant, nuclear plant or wind farm. "None of these are popular, but LNG appears best suited to deliver energy where and when it is needed, in our view, with minimal environmental externalities, and most important of all, soon," the authors wrote.

Similarly, the report downplays the safety concerns frequently raised in connection with new LNG proposals.

"Yes, LNG is flammable, and gas vapor can explode under certain conditions," it said. "The same things are true of gasoline, which we park in the garage every night. All forms of energy have inherent dangers that must be managed, and the LNG industry's clean safety record is virtually unmatched."

MARKETS

OG&E joins ranks of utilities willing to drop market-based rates until markets change

Many utilities seem willing to sit out the power supply competition until changes in the marketplace are approved down the road by FERC. Oklahoma Gas and Electric is the latest on a growing list to propose a mitigation plan rather than pursue retention of market-based rates.

OG&E and affiliates packed it in for the moment but the utility is likely to reapply for market-based rates in its home control area if there are changes in the market dynamic in the Southwest Power Pool region and/or FERC policy, according to an Aug. 8 filing (ER98-511). Earlier mitigation proposals in the same region by Empire District Electric (ER99-1757), Westar Energy and affiliate Kansas Gas and Electric (ER03-9), and Aquila (ER03-1079) also are pending.

Having failed FERC's interim screening process, Westar deemed cost-based mitigation a practical way to continue with its business, a spokesman said Thursday. "Our primary objective is to continue to sell to wholesale customers. This seemed to be the most efficient way to achieve that goal," he said.

Westar in May proposed adopting the Western Systems Power Pool Agreement, which entails incremental costs and a cap, for sales of one year or less. It would individually propose long-term agreement terms to FERC. Notwithstanding Westar's position that it doesn't have market power, "we would like to proceed," the spokesman said.

Though many utilities continue to fight to retain market-based rate authority, several others have thrown in the towel in the face of full-blown investigations. Among those that have recently proposed mitigated pricing are Xcel Energy Services,

MidAmerican Energy and Entergy (*IF*, 8 Aug, 1).

FERC's standard step after a market power screen failure is to give an applicant three choices: file a delivered price test analysis to rebut the presumption of market power, propose mitigation tailored to its particular circumstances to eliminate any ability to exercise market power or adopt either the commission's default cost-based rate mechanism or propose other cost-based rates.

OG&E and OGE Energy Resources responded to the commission instituting a Federal Power Act section 206 hearing on whether the affiliates can exercise market power in the utility's home control area by opting to adopt the commission's default cost-based rates. The default would apply to sales of one week or less and the OGE Companies would not enter into any sales between one week and one year in the control area at all.

OG&E does not make sales between one week and one year in duration so "it does not make sense" to devote any resources proposing mitigation for that type of deal, it explained. The short-term mitigation would be based on total incremental cost plus a 10% adder. For long-term deals, the utility would file separately with specific cost information, it said.

But OG&E does not view the filing as the end of market rates. "By electing to adopt cost-based rates, . . . the OGE Companies do not concede that they have market power or that they can or have exercised market power" in the OG&E control area. Instead, the filing was made to "avoid the burden" of an evidentiary hearing.

The OGE Companies reserved the right to submit changes to market-based rate tariffs "as factors in the Southwest Power Pool region change," if commission policy changes or as any other elements change. For example, SPP's proposed market power mitigation measures are pending and the applicants indicated they would seek market-based rate authority again "when these changes," or other potential changes in the landscape, occur.

SPP is phasing in regional transmission organization functions and plans to implement a centrally dispatched real-time imbalance market in March (*IF*, 27 June, 6). OG&E is joined in the SPP footprint by Empire District, Westar and Aquila. Empire District in May proposed tailored mitigation similar to that of Westar, and Aquila in June informed FERC it would adopt the default cost-based rates.

Aquila views the cost-based rate option, which is limited to its home control area, as having little impact. Overall, it will take a minor financial hit in Kansas and the issue is basically irrelevant in Missouri where the utility has a handful of bundled contracts that are grandfathered from before order 888, explained Carl Huslig, vice president of transmission for Aquila.

"We did not put ourselves at risk at all," he said. Plus, the hope is the SPP will be a full-fledged RTO next year, which would mitigate any market power concern, so Aquila considers cost-based rates as "kind of a one-summer deal," Huslig added.

Also, when Aquila ran preliminary numbers for the delivered price test, the outcome was "iffy," he said. Cost-based rates were the "easiest way to go" for now and with SPP development,

"this issue goes away anyway."

Lou Jahn, Edison Electric Institute director of wholesale market policy, noted that many of the companies proposing mitigation or the default cost-based rates are in SPP, where the bind appears temporary. "As soon as SPP goes to Day 2 markets," he said, "they should be able to get [market-based rates] back."

But another SPP member, Kansas City Power & Light, looks to retain market-based rates. The utility argued earlier this year that a delivered price test for it and affiliate Great Plains Power successfully rebutted a presumption of market power.

KCPL also argued that because SPP is on its way to becoming a fully operational RTO, the utility should not be dinged in the meantime. "Given KCPL's commitment to the SPP RTO, it would be counterproductive and send the wrong signal to others, if KCPL's market-based rate authority in its control area was restricted for the short time period until SPP becomes fully operational," the utility said in the Feb. 15 filing (ER99-1005). It added that the presumption of market power was based on "very limited indicative screen failures" and "false indicators" from using a "grossly" exaggerated amount of uncommitted capacity under one of FERC's DPT analyses.

It is not clear how much the proposed SPP imbalance market would ameliorate market power concerns. It is possible and is "the utopian dream of some" that the imbalance market will be robust enough to make a difference, a market observer said last week.

Utilities also may temporarily go with cost-based rates until some other alteration in the landscape takes place, such as the structural change proposed by Duke Power for retention of an independent entity to oversee its transmission, the observer said. FERC revoked Duke's market-based rate authority after the utility failed to persuade the commission its DPT rebutted the market power presumption and Duke complied with a cost-based rate filing on July 28. Duke, Entergy and MidAmerican all have independent transmission proposals pending.

On the other hand, some utilities may find that "the piece" of their business from wholesale power sales "is just too small" to bother fighting to retain market-based rates, the market observer said. Yet another possibility is that of utilities forgoing protracted litigation because they calculated that they do possess market power, she added.

Public Service Co. of New Mexico falls into two categories. In a July 15 compliance filing (ER96-1551), the utility submitted additional DPT analyses along with historical data the utility claims rebut a presumption of market power. While it requested market-based rates, it also proposed mitigation in case FERC disagrees with it and finds there is market power. The mitigation "incorporates price caps based upon prevailing market prices at well-recognized and liquid trading hubs" and upon the WSPP agreement pricing mechanisms, PNM said.

For its part, Southern Company remains one of the largest utility companies to push full-bore for keeping its market-based rate authority. "We haven't changed our position at all," a spokeswoman said on Thursday.

The company declined to describe how the loss of market-

based rates could impact revenue except to say it would in the short-term have an immaterial impact on shareholders. However, it would "adversely affect" retail customers with which Southern operating companies share wholesale sales margins, the spokeswoman said. Southern's chief executive remarked earlier this summer the real hardship could be on competitors that may not be able to beat its cost-based rates (*IF*, 1 Aug. 1).

Still, "we believe we're in the right and we're going to pursue this," the spokeswoman said. In that vein, Southern Co. Services argued in an Aug. 8 rehearing request (ER97-4166, *et al.*) that its DPT calculation was correct, including its use of forward-looking figures, and that FERC had "no basis" for setting a hearing on issues related to internal constraints.

Chairman Joseph Kelliher earlier this summer partially dissented from the commission's decision to require a trial-type evidentiary hearing to include consideration of constraints within the Southern system, arguing that there was no evidence that anything but the entire control area should be viewed as the relevant market (*IF*, 18 July, 13). Southern argued that the change in course introduced a "new factor for consideration" without a "rational explanation."

Meanwhile, other utilities continue to pass the indicative pivotal supplier and market share screens. Allegheny Power and affiliates claimed in a triennial market report filed Aug. 11 (ER98-1466) that they pass in the relevant PJM Interconnection RTO market.

Allegheny also stated it lacks transmission market power, complies with affiliate codes of conduct and cannot otherwise present barriers to entry through control of generation build sites or limited gas distribution facilities that do not serve pivotal generation. "Accordingly, the applicants respectfully request the commission to authorize them to continue to sell power at negotiated market-based rates in all markets."

At the same time, commission staff pressed others for more information. In an Aug. 12 letter to Tampa Electric and affiliates (ER99-2342, *et al.*), Steve Rodgers, director of the Division of Tariffs and Market Development-South, informed them their submittals were still deficient. Their last filings contained available transfer capability data from a different time period than the generation data, he wrote.

The Pinnacle West Companies told staff in an Aug. 8 filing that additional generation either owned by or under contract with affiliates had no bearing on the market power analyses, nor did the forced outage of a generator. They maintained that affiliate Arizona Public Service passes the screens in the combined market of APS and Salt River Project and, despite "marginal violations" of the screening in the APS-only control area, should be able to sell at market rates.

The new generation resources were added to serve regulated native load obligations, Pinnacle West told staff. "There is enough oversupply and import capacity to allow the companies to meet or only slightly exceed" the market share screen's threshold, but the violations "do not raise competitive concerns," Pinnacle West added.

In that regard, the applicant recalled that Kelliher late last

year expressed disdain for treating the 20% market share threshold as a bright-line test (*IF*, 20 Dec, 1). If no utility can overcome such a screen failure through in-depth analysis, then it is in effect a bright-line test, he said.

"The Pinnacle West Companies believe that they fall within the very category Chairman Kelliher addressed in his comments." The companies exceed the 20% threshold "in only a few of the seasons" in the APS-only market and some of the newly acquired power is for peaking, which is not economic to run all the time, Pinnacle West added. —*Katharine Fraser*

Agreeing to settle spot refund, other cases, Reliant ends disputes from California crisis

Reliant Energy last week said it will pay nearly a half-billion dollars to "resolve all civil litigation and claims" stemming from the Western energy crisis of 2000-01 against the company by three states, three large utilities and other parties. If it passes muster with FERC, the deal will clear Reliant's deck of commission dockets from the chaotic period and its aftermath.

The focus of the settlement is the California electricity spot market refund proceeding pending at FERC. In an Aug. 8 order refining the scope of that four-year-old case (EL00-95, *et al.*), the commission strongly urged holdouts to settle (*IF*, 15 Aug, 7).

Those agreeing to the deal include FERC staff, the states of California, Oregon and Washington, and California's investor-owned utilities. It covers the refund proceeding, appeals of FERC orders related to the crisis, all market price investigations by the attorneys general of the states, electricity class actions, an electric market power antitrust case in California and certain gas pricing claims.

Houston-based Reliant also agreed to continue with operational conditions meant to restore trust in its power generation practices, including an independent audit of outages and must-offer obligations, which originated in earlier settlements.

The new settlement marks a "critical step forward in resolving a number of issues arising from the California energy crisis," proclaimed Joel Staff, Reliant's chairman and chief executive. "Today, Reliant is a very different company than it was in 2000 and 2001. Our new board of directors and management team are fully committed to delivering the benefits of competitive markets to consumers while maintaining the highest standards of conduct throughout the organization."

FERC described the deal as being worth \$460 million, but the figures given by different parties ranged from \$445 million as stated by Reliant to \$525 million as stated by Pacific Gas and Electric, which expects to receive a \$230 million share. The final settlement is expected to be filed with the commission in September.

In addition to FERC, the agreement is subject to approval by the California Public Utilities Commission and various courts where litigation is pending. Reliant previously settled other aspects of the crisis in FERC-approved agreements over market manipulation allegations and staff investigations which, accord-

ing to an Aug. 16 commission statement, totaled \$65 million.

Chairman Joseph Kelliher applauded the deal. "Without pre-judging this settlement, I congratulate commission staff and the other parties for reaching an agreement with Reliant to resolve issues still outstanding from the Western energy crisis," he said last week.

Kelliher also noted the Reliant deal comes close on the heels of a \$1.5 billion settlement Enron recently entered into with FERC staff, California state agencies and the utilities (*IF*, 18 July, 1). "These settlements reflect the solid work of the commission's staff and bring to nearly \$6.3 billion the amount of settlements relating" to the energy crisis, he said.

"This settlement is great news for California," said Gov. Arnold Schwarzenegger. "The people of California deserve affordable and reliable energy supplies. I will continue to fight for justice from companies that took advantage of California residents and businesses during the energy crisis."

In addition to the California attorney general, other parties from the states are the California Electricity Oversight Board, PG&E, Southern California Edison and San Diego Gas & Electric.

Standard & Poor's Ratings Services called the agreement "a favorable event" for the company's credit quality because it "significantly eliminates legal and regulatory uncertainty for Reliant. The settlement also eliminates the associated time and costs to defend the company against these allegations."

The total cash impact of the settlement "will be about \$150 million pretax, which, while not insignificant, can easily be met with the company's available liquidity, either cash on hand or available credit facilities," S&P said. Reliant said it will record an estimated \$350 million pre-tax charge in the third quarter.

The FERC statement dubbed Reliant the "last of the big five" California power suppliers to settle. The others, Mirant, Duke Energy, Dynegy and Williams, each wrapped up global settlements previously. In the recent order in the spot refund proceeding, the commission urged parties to settle within two months as it prepared to push toward final calculations of costs, refunds and offsets.

Similarly, to put an end to the ongoing manipulation proceeding, Chief Administrative Law Judge Curtis Wagner Jr. recently urged Enron and parties besides the California agencies and investor-owned utilities to settle so a trial in that case can be avoided (*IF*, 25 July, 6). Like former Chairman Pat Wood III, Kelliher wants to clean the slate of crisis cases and Congress has explicitly called for FERC to accelerate the processing of California refunds (*IF*, 8 Aug, 3).

"The commission aims to speed resolution of the refund proceeding and other administrative matters still pending" from the crisis, Kelliher added in his statement. "But settlements promise to end the regulatory uncertainty remaining" from the crisis, "which is serving as a disincentive for the investment in power plants and transmission lines needed to prevent the next crisis," he said.

Settlements are "in the best interests" of consumers, indus-

try and “the success of California’s power market redesign effort,” Kelliher said.

Entergy customers balk at request for market power probe to die out with cost-based rates

Entergy is willing to sell power at cost-based rates to avoid further scrutiny of whether it can exercise market power in some areas, a set of customers recently argued. FERC should not terminate investigations in exchange for a cost-based rate schedule because problems and potential refund obligations remain, argued the Users of Entergy Transmission.

Entergy late last month suggested that FERC need not examine further the market power question because the company has withdrawn its request for market-based rates in its home control area (*IF*, 1 Aug. 1). The transmission users asserted in an Aug. 12 response (ER91-569) that that is tantamount to asking the commission to “simply ignore the ever-increasing accretion of Entergy’s market power.”

Countering Entergy’s steadfast denial of market power, the transmission users argued that adoption of cost-based rates would not address allegations of transmission constraints within the control area that FERC noted in a June 30 order may block customers’ access to generation (*IF*, 4 July, 11). Nor would Entergy’s proposal confront the “credible concerns” about transmission market power the commission highlighted in a May 5 order establishing a separate Federal Power Act section 206 proceeding, which is currently being held in abeyance (*IF*, 13 June, 8), the customers said.

“In fact, it is telling that Entergy has taken the extraordinary measure of abandoning its market-rate authority to avoid a hearing that would shed light on its congestion management practices,” the transmission users said. The customers include Calpine, municipal utilities such as Lafayette Utilities System, the Mississippi Delta Energy Agency, the Arkansas Cities and Cooperatives, Dow Chemical and Cottonwood Energy.

When it comes to concerns about transmission access, FERC may be pinning hope to Entergy’s independent coordinator of transmission, but the transmission users have little faith in that proposal, they said. The ICT plan took a beating recently from customers opposed to a proposed reassessment of network upgrade costs (*IF*, 15 Aug. 8).

The transmission customers accused Entergy of not keeping up its system to meet demand growth to discourage generation competitors and asserted that the ICT would not improve matters. Entergy “has proposed a rather toothless ICT, which (if approved by this commission) will be forced to acquiesce in the ongoing ‘rust down’ policy” of avoiding improvements, the transmission customers said.

Entergy has also taken advantage of transmission challenges by buying former merchant plants that “have been prevented from obtaining transmission rights to reach any load on or off the Entergy system,” the customers added. In the short term “this monopsony policy (and market power)” may benefit

Entergy’s retail customers, “but in the long run, this is the antithesis of a market envisioned by” the Energy Policy Act of 1992, order 888 and their progeny, they added.

The transmission customers asked FERC to find that Entergy is not meeting its obligations under the order 888 open-access transmission tariff and should not have market-based rates outside of its control area because of possible cross-subsidization from within the home footprint. They also asked for the “creation of a meaningful ICT” that could direct transmission planning and for transmission credits for grid enhancements, which “Entergy has resisted.”

In addition to continuing the generation market power investigation, FERC should lift its holds on the transmission market power probe and another hearing on how well Entergy gauges available flowgate capacity (AFC), the transmission users said. They claimed they are “being harmed with the passage of every single day Entergy is allowed to continue its discriminatory practices.”

For its part, Entergy rebutted the filing in an emailed response to a reporter’s query, stating that the decision to revert to cost-based rates was made to focus on ICT “so as to provide better market development and access” to the transmission system. In response to the charge of a toothless ICT, Entergy noted that FERC has “agreed in principle” to the plan and that the company has adopted “several critical aspects” to respond to needs and concerns of merchant suppliers and municipal utilities, including giving transmission scheduling, AFC calculation and open-access same-time information system administration to the ICT (*IF*, 28 March, 1).

Also, the “so-called Rust Down Policy is a fantasy made up by the merchants,” an Entergy spokesman wrote, adding that the company has “consistently invested significant capital” in its system. Entergy is on track to invest \$200 million in the grid by the end of the year and has committed to that level of annual investment through 2007.

ENERGY PROJECTS

Proposed WIC Rockies expansion receives FERC staff nod on environmental issues

In a final environmental impact statement released earlier this month, FERC staff endorsed Wyoming Interstate Co.’s proposal to build and operate a 142-mile pipeline capable of moving 341,000 Mcf/day from the Piceance Basin of the central Rocky Mountains to an interconnection with Colorado Interstate Gas in Wyoming. Both WIC and CIG are affiliates of Houston-based El Paso Corp.

FERC staff said that with mitigation steps proposed by the company, the \$120 million project (*IF*, 7 Feb. 3) would have limited adverse environmental impact because, among other things, 82% of the line would be located adjacent to existing

pipeline, utility and road rights-of-way. In addition, staff said the company has agreed to use horizontal directional drilling to avoid disturbing the beds and banks of the Little Snake, White and Yampa rivers.

The new line (CP05-54) would run from the existing CIG Greasewood compressor station in Rio Blanco County, Colo. and CIG's Wamsutter compressor station in Sweetwater, Wyo.

Now's the time to change your mind, says FERC in approving pipe upgrade for Freeport LNG

FERC on Wednesday approved a plan to beef up the sendout pipeline for the Freeport LNG Development terminal under construction in Brazoria County, Texas.

Approved by the commission in June 2004 (*IF*, 28 June '04, 4), the original project design featured a sendout capacity of 1.5 Bcf/day through an associated 9.6-mile, 36-inch-diameter pipeline running from the terminal on Quintana Island to the Stratton Ridge meter station.

But the sponsor of the fully subscribed project soon received additional requests for capacity to meet future market demand. In April it filed with FERC for authorization (CP03-75) to install 42-inch-diameter pipeline stock to increase the operational reliability and flexibility of the line.

In approving the request, the commission noted that the larger pipe "will increase system pressure and thus improve the deliverability" at Stratton Ridge, "where there would otherwise be a pressure drop between the delivery point and interconnected pipeline systems." Hiking delivery pressure to interconnected pipelines by as much as 13% figures to produce a significant increase in linepack and increased working volumes, "enabling Freeport LNG to respond to larger hourly swings in demand on its system," said the Aug. 17 order.

What's more, the change in pipeline diameter will not change the construction footprint or procedures, FERC noted, adding that upgrading the pipe at this point in the process "will obviate the need to construct an additional pipeline or compression in the near future, which could result in additional environmental impacts." The in-service target for the project is the 2006-07 winter heating season.

The Freeport project targets Texas markets, including local distribution companies, large end-users and intrastate marketers. Houston-based Cheniere Energy holds a 30% interest in Freeport LNG, while Freeport LNG Investments holds 60% and Contango Oil & Gas the remainder.

The terminal project includes one unloading dock with the capability of receiving up to 200 ships/year and two storage tanks with total capacity of 7 Bcf.

Stressing its planned focus on the intrastate market, Freeport LNG noted in its March 2003 application that the proposed pipeline would not interconnect with any interstate pipeline systems. The intrastate systems of Houston Pipeline, Kinder Morgan Texas Pipeline, Texas Utilities Pipeline and Dow Pipeline all are in close proximity to the Stratton Ridge meter station.

FERC gives green light to Northern Border pipeline capacity expansion for Chicago Hub

FERC last week cleared the way for Northern Border Pipeline to increase its pipeline capacity by up to 130,000 Mcf/day on its system from Harper, Iowa, to North Hayden, Ind., boosting service to the Chicago Hub.

Aside from equipment modifications and replacements at two existing compressor stations in Iowa and Illinois, Northern Border proposes in its Chicago III Expansion Project to install a new compressor unit to expand capacity on the eastern end of its system (CP05-88). The system transports gas originating from production areas in Canada and the Williston and Powder River basins.

Northern Border conducted an open season for capacity agreements in July 2004, resulting in quality bids from four shippers. Ultimately, the pipeline entered into long-term agreements with BP Canada Energy Marketing, Basin Electric Power Cooperative and Tenaska Marketing Ventures for the total capacity expansion. The agreements for the \$20.7 million project range from five to 10 years and include firm rate schedules at fixed negotiated rates.

The commission accepted negotiated rates and fuel retention provisions in customer agreements, but it did not grant Northern Border's request for a pre-determination of rolled-in rate treatment based on its in-kind fuel value. To get the rolled-in rate treatment, the commission said, a pipeline usually must demonstrate that revenue generated by an expansion project will exceed project costs.

"Northern Border has failed to adequately support its assertion that the value of fuel to be provided by expansion shippers will be adequate to offset the shortfall of other project revenue as compared to project costs," the commission concluded. FERC added that even if it were to accept a Northern Border assertion that service to the expansion shippers would involve no fuel, "we question Northern Border's valuation of the fuel to be provided by the expansion shippers."

Rolling the costs of the proposed expansion into system rates could result in a subsidy of the expansion by existing customers, the commission said.

Growth of gas transport grid slowed in 2004, capacity to rise as LNG imports grow, says EIA

The expansion of the U.S. natural gas pipeline network slowed by about 20% in 2004 in terms of completed projects as compared with 2003, the Energy Information Administration reported last week. But pipeline builders are expected to pick up the pace of capacity and mileage expansions to accommodate more imports and demand in the coming years.

The pipeline network saw record additions in 2002. Yet while the general expansion continued in 2003 and 2004, total mileage increased only marginally, EIA said in its assessment. In 2004, total mileage increased by less than 1% year-

on-year while overall system capacity increased by slightly more than 4%.

But in describing the temporary lull in pipeline development, EIA suggested it won't be a prolonged slump. "While the amount of incremental pipeline capacity added in 2004 was the least since 2000, the current inventory of new project proposals indicates that a major growth in new pipeline capacity can be anticipated. In fact, perhaps as much as 44.4 Bcf/day of pipeline capacity could be added to the national network between 2005 and 2007 based upon current proposals."

Liquefied natural gas is the driving force behind the projected upswing in pipeline development, said the report. If enough are built, import terminals and storage facilities along the Gulf Coast and new laterals for transporting gas to interconnections will push pipeline growth between now and 2010. EIA noted that only "a limited amount" of new capacity has been approved on portions of the pipeline grid on which LNG developers indicate they'll use. Moreover, few interstate pipeline companies have announced plans to expand to accommodate new LNG supplies, in part because some believe unused capacity might still be available.

But projects are in the works. EIA noted proposed pipeline expansions to upgrade segments serving the Trunkline Gas Lake Charles LNG facility and Excelerate's Louisiana Energy Bridge, as well as six lateral projects associated with new LNG projects.

Most likely, EIA concluded, as more LNG projects get the regulatory nod, interstate pipelines will start sponsoring open seasons for LNG shippers. "Consequently, it will not be surprising to see more interstate pipeline expansion proposals related to LNG development on the Gulf Coast over the next year or two."

The second key factor, the agency said, is increasing demand for more capacity to transport gas from the Unita/Piceance Basin in Colorado and Utah to markets in the Midwest and West. More than 6.7 Bcf/day of new pipeline capacity has been proposed, 56% of which would be directed toward Midwest markets.

More than 100 pipeline projects, coming to about 5,000 miles of pipe, have been proposed for development between 2005 and 2007, according to EIA, noting that only about one-third have achieved regulatory approval so far.

Looking back, about 1,450 miles of pipeline and 7.7 Bcf/day of gas pipeline capacity were added to the national gas pipeline network in 2004 compared with 2,243 miles and 10.4 Bcf/day in 2003. EIA predicted that capacity additions will increase again in 2005, despite fewer miles of installed pipe.

Last year "appears to have been a temporary low in the development cycle for the natural gas pipeline grid, which has grown significantly over the past decade," the report said.

Growth in pipeline import and export capacity between the U.S., Canada and Mexico "slowed substantially." Only one import expansion project was completed in 2004, the Iroquois Eastchester Marine expansion of a pipe that crossed the Canadian border to serve New York power generators. Despite some

significant hurdles, five import/export projects are in the works through 2007.

U.S. pipeline projects completed in 2003 and 2004 were markedly different from one year to the next. For example, the average pipeline project finished in 2004 averaged 36 miles as compared to 46 miles per project a year earlier, EIA reported. After a growth spike in 2002, the installation of new gas pipeline capacity dropped 19% in 2003 and fell another 26% in 2004. Added mileage fell 35% in 2004 and pipeline construction expenditures also dropped by 40%, according to EIA.

Perhaps the most marked difference in 2004 was the completion of capacity additions to non-interstate pipelines. That contrasts with 2002, when capacity additions were primarily to the interstate system. Only five of the 41 natural gas projects finished in 2004 crossed regional boundaries, much of which went to the Southwest market, according to EIA.

In making note of major 2004 projects, EIA pointed to six new pipeline systems placed in operation in the deepwater Gulf of Mexico. They provided for 1.8 Bcf of new transport capacity to support deliveries from new production fields, accounting for 66% of total new capacity in the Southwest and 23% of the total U.S. added capacity. EIA also noted the Cheyenne Plains Pipeline extension in Colorado and Kansas, as well as an expansion of the El Paso Natural Gas southern leg in Arizona.

New gas infrastructure to cost at least \$60 billion, but delays cost more, EEA says

Necessary improvements to U.S. and Canadian gas infrastructure will cost roughly \$60.3 billion by 2020, according to a preliminary report released Thursday by Energy and Environmental Analysis. Close to half of that would be for new pipelines.

The Arlington, Va.-based firm said investments will be required for pipelines, storage facilities and liquefied natural gas terminals to provide outlets for new supply sources, as well as ensuring continued service along traditional corridors and integrating new consumers.

EEA projected costs of \$29 billion for new pipelines, \$16.4 billion for replacement pipes, \$9.4 billion for LNG terminals and \$5.5 billion for storage projects.

To facilitate infrastructure growth, EEA recommended long-term contracts as a means of "managing risks to all participants." However, the analyst noted that such contracts "are only one element needed for timely infrastructure projects," pointing to other issues such as attracting capital and dealing with gas interchangeability issues.

Delays of one to three years in improving infrastructure will result in increased costs to gas consumers of \$179 billion to \$653 billion between 2006 and 2020, "plus electricity price increases, plus economic dislocation," EEA said.

EEA prepared its report at the request of the Interstate Natural Gas Assn. of America for presentation to the National Assn. of Regulatory Utility Commissioners/Interstate Oil and Gas Compact Commission joint task force meeting held Thursday in

Washington. EEA said it would issue a full paper on its findings by the end of the month.

Overthrust, Texas Gas, Point Comfort solicit interest in new capacity on gas pipelines

Pipeline sponsors earlier this month set out to gauge customer support for new capacity in Texas and the Rockies, as Overthrust Pipeline, Texas Gas Transmission and Point Comfort Pipeline kicked off open seasons.

Questar's Overthrust is soliciting binding support for a project that would connect to the Painter Lateral, a Kern River Gas Transmission pipeline near Whitney Canyon in southwestern Wyoming. Some 200,000 Dt/day of firm transportation capacity would be available from receipt points on Overthrust such as Wyoming Interstate Co., Colorado Interstate Gas, Questar Pipeline at Kanda, Western Gas Resources' Granger plant and Clear Creek Storage for re-delivery to the Painter Lateral.

The project would target growing production areas in the area such as the Wamsutter, Green River, Piceance and Uinta basins. Service could be available by Jan. 1, 2006, Overthrust said.

The open season is set to end Aug. 26. For more information, contact Tom Myrberg at (801) 324-2978, Gaylen Haag at (801) 324-5133, or visit www.questarpipeline.com.

For its part, Texas Gas launched a binding open season for new gas transportation capacity from East Texas to Lebanon, Ohio, where the mainline system connects with the Columbia Gas Transmission, Texas Eastern Transmission and Dominion Transmission systems. The solicitation, which closes Aug. 24, is in response to interest expressed during a nonbinding open season earlier this year, the company said.

Through a proposed lease agreement with Texas Eastern, Texas Gas is offering shippers firm transportation rights to the Texas Gas interconnection at Sharon, La., and continuing on the Texas Gas mainline system to its terminus in Lebanon. The project is expected to be in service Nov. 1 subject to FERC approval.

For more information, contact Jim Martin at (270) 688-6927.

Finally, Gulf Coast LNG Partners announced that its affiliate, Point Comfort, is seeking shipper interest in capacity on a proposed 27-mile gas pipeline that would connect the proposed Calhoun LNG terminal in Port Lavaca, Texas, to the U.S. pipeline grid. The open season will run through Sept. 14.

The proposed 36-inch-diameter Point Comfort line is designed to move up to 1 Bcf/day of regasified LNG from the Calhoun project, which is awaiting FERC approval and is scheduled to begin operation by 2010.

The pipeline would connect to the local industrial markets and to major interstate and intrastate systems in the region, accessing more than 4 Bcf of takeaway capacity, the company said. Planned interconnections include the Channel/HPL JV Pipeline, Florida Gas Transmission, Kinder Mor-

gan-Tejas Pipeline, Enterprise (Valero) Pipeline, Gulf South Pipeline, Kinder Morgan Texas Pipeline, Natural Gas Pipeline Co. of America, Transcontinental Gas Pipe Line and Tennessee Gas Pipeline.

For more information, contact Robert Epps at (713) 439-0506.

PIPELINES

Canada's NEB finds shippers 'reasonably satisfied' with oil, gas pipelines for now

Canadian gas and oil transportation systems are "working very well at the present time," although a number of challenges remain, the National Energy Board said in a report last week. New demand as well as sources of supply could change the picture, it added.

"We have concluded that, overall, there is adequate capacity on the oil pipeline transportation system and adequate natural gas pipeline capacity in place on existing systems," said NEB Chairman Kenneth Vollman.

The board took a survey of shippers to determine their levels of satisfaction with pipeline company services and consulted with members of the investment community "to assess the financial viability of the industry."

Overall, shippers are "reasonably satisfied" with pipeline services, particularly with physical reliability of operations. However, shippers indicated that work is still needed on making rates more competitive, exhibiting an attitude of continuous improvement and innovation, and working collaboratively to find fair and reasonable solutions to problems, the NEB said.

On the financial side, NEB-regulated pipelines are generally seen as sound and "should have no difficulty in raising capital to finance most new major projects at this time," the board concluded.

However, to better meet the needs of producers and end-users, transportation systems "must be able to adapt to the changing needs of the market over time and expand to attach new sources of supply," the NEB said. "This can be particularly challenging for the pipeline sector because investments tend to be 'lumpy' and, given the long life of assets, investors have to be reasonably assured of the existence of supply and markets over a long time period."

In particular, the potential for market changes over time "is highlighted by the uncertainties around the number of liquefied natural gas terminals that will be built in North America and the potential effects that imported LNG will have on the supply and demand balance, and on the pattern of natural gas flows," the report said.

Moreover, the decision by the government of Ontario to remove 7,500 Mw of coal-fired power generation capacity from its system will likely trigger "a significant volume of net natural gas-fired generation." The precise impact of those additions will

depend upon where and how much new gas-fired generation comes on line, the board observed.

The flattening of gas production levels from the Western Canadian Sedimentary Basin and the construction of Alliance Pipeline in the late 1990s have "created challenges for a number of the older systems that are experiencing a sharp decline in the long-term contracts on their systems," the NEB said. "New toll design structures may need to be considered to effect a fair sharing of costs and to maintain the competitiveness of these systems."

The report marks the first time the NEB has examined the functioning of the Canadian gas and oil transportation system, Vollman remarked. "The board considers this report as a first step in assessing the effectiveness" of the gas and oil pipelines in Canada and will continue its monitoring efforts.

Columbia Gulf seeks rehearing of order requiring interconnection for Tennessee

Columbia Gulf Transmission on Thursday sought rehearing and a stay of a recent interconnection order, claiming there is "compelling evidence" that Tennessee Gas Pipeline "is engaged in an ongoing effort to eliminate" it as a competitor in the offshore Louisiana area. FERC last month directed Columbia Gulf to construct the interconnection requested by Tennessee (*IF*, 25 July, 17).

The case involves Tennessee's March 2004 complaint (RP04-215) charging that Columbia Gulf unlawfully denied a request for a new interconnection for their jointly owned Blue Water Project (BWP) natural gas system located offshore Louisiana. Columbia Gulf responded by noting an existing interconnection at Egan, La., the same point targeted by Tennessee's complaint, and said the proposal was inconsistent with an existing operating agreement (*IF*, 12 April '04, 8).

But FERC's July 21 order affirmed an initial decision that found the proposed interconnection was consistent with commission policy and directed that it be constructed by Columbia Gulf.

The rehearing request maintained that Tennessee sought the meter "to further anticompetitive goals." Documents related to an agreement executed by Tennessee and a gas processing plant in early 2004 clearly demonstrate that Tennessee "is engaged in an effort to drive Columbia Gulf out of the business of providing transportation service in offshore Louisiana," it said.

Columbia Gulf cited as evidence Tennessee's effort to get a bi-directional meter at Egan in the Blue Water case, and its apparent attempt to "gain operational control" over a critical facility on the BWP.

In addition, Columbia Gulf said the commission "has no authority to order the interconnection requested by Tennessee in this case," arguing that doing so exceeds its power under Natural Gas Act sections 5, 7 and 16. The order "will permit Tennessee to escape its contractual obligations," Columbia Gulf said.

Navy protests Weaver's Cove; defiant builder to fight on . . . begins on page 1

to a Coast Guard prohibition on movement within the security zone as LNG tankers pass through the bay, the Navy asserted.

The testing facility is part of the Naval Undersea Warfare Center in Newport, which employs about 4,300 military and civilian workers.

"The applicant's proposal significantly impinges on the Navy's ability to conduct its mission and exercise its authority," the filing said. "As such, the Navy has a significant interest that may be affected by the outcome of this proceeding." In light of the potential impact on the Navy's ability to continue its mission in the area, "the Navy's participation in the proceeding is in the national and public interests," the filing said.

FERC approved Weaver's Cove on a 3-1 vote at its June 30 meeting, with Commissioner Suedeen Kelly the lone dissenter. But despite the federal endorsement, project developers have been unable to shake loose the fervent opposition of politicians at nearly every level of government in Massachusetts and Rhode Island. Opponents are concerned about the dangers of sending LNG tankers through waterways that abut urban areas.

Earlier this month, Rep. Jim McGovern, D-Mass., managed to place in the \$286 billion transportation bill, signed by President Bush Aug. 10, a provision prohibiting the use of federal funds to replace the Brightman Street Bridge in Fall River—a replacement seen as necessary to accommodate LNG tankers (*IF*, 8 Aug, 9).

Hess LNG, the parent company of developer Weaver's Cove Energy, has said 2009 is the probable startup date. The project would include a 4.4 Bcf LNG storage tank, vaporization equipment sized for a sendout of 400,000 Mcf/day and peak sendout of 800,000 Mcf/day, and two 24-inch-diameter pipelines.

It is unclear why the Navy did not submit comments during the long federal review process. The Navy asserts it was not made aware of the pending project's potential impact on its operations until FERC issued its paper order in July. Rhode Island officials first passed along the public information about the FERC approval of the project, the filing said.

The naval center in Newport was "not included in the applicant's scoping process for this proposal, nor was it invited to participate in any meetings or associated discussions." It also asserts that the FERC decision "evidences no substantive mention of the Navy's presence or activities in Narragansett Bay."

Although FERC rarely grants rehearing after an infrastructure project is approved—in part because of the open review process—the Energy Policy Act of 2005 could bolster the military's position in assessing LNG facilities. A provision in the law, supported by the White House, requires FERC to consult with the Pentagon on the siting of LNG facilities that "may affect an active military installation."

McGovern, along with Rep. Barney Frank, also a Massachusetts Democrat, jumped into the fray on Wednesday with a letter to President Bush, asking him to join with the Navy in requesting that the commission reopen the record. "We

believe this will lead to a reconsideration and reversal of FERC's decision."

McGovern and Frank said they "were struck to learn" that the Navy had apparently not been informed of the Weaver's Cove proposal. "At a time when all Americans are focused on the importance of our national defense," the letter added, "and when we are particularly concerned with the possibility of terrorist assaults through our ports, interfering with the Navy's ability to conduct underwater testing of this sort is obviously a grave error."

Gordon Shearer, president of Hess LNG, fired back in an interview with *Inside FERC* shortly before Weaver's Cove sent to the commission a formal response to the Navy's claim that it had not been informed about the project until recently. The Navy had "no procedural or factual basis" for its request for rehearing, he said. "They have participated in numerous security workshops," he said, adding the issues associated with the Naval Undersea Warfare Center were "fully and clearly discussed."

"I have no idea what motivated them to do this, but it is factually incorrect," Shearer asserted. "The Navy has been aware of this for months. It had two years to voice their objections."

Weaver's Cove is not in danger despite the recent barrage by opponents, Shearer asserted, because the bar is set high to get a FERC rehearing. "They have to demonstrate that they had no prior knowledge of this going on." On the Brightman Street Bridge snag, he stressed an agreement already exists to demolish the bridge due to its public safety hazard.

Shearer expressed a steadfast attitude toward the latest turn of events in the effort to bring more LNG imports to New England. Opposition is just part of the equation. "It's important to recognize that any significant public infrastructure will attract incredible opposition," he said. "There isn't any easy solution in New England; every solution has an ugly permit fight."

Rhode Island Attorney General Patrick Lynch, among the most vocal critics of the LNG project, has accused federal regulators of failing to "seriously consider" a threat assessment conducted by Richard Clarke, the former Clinton and Bush White House terrorism expert.

Lynch, Massachusetts Gov. Mitt Romney, Fall River Mayor Edward Lambert and the Boston-based Conservation Law Foundation, among others, have also reiterated opposition to the project or filed rehearing requests over the past two weeks, claiming FERC did not fully consider the environmental and safety implications of the project.

In an interview, Lynch lauded Navy officials in Newport for "breaking ranks" with the Bush administration on the issue, despite what he described as a general reluctance by the Naval War College to get involved in the dispute between state and federal authorities. "We need the Secretary of the Navy to see that the professionals underneath him have cited dramatic concerns," he said.

Lynch called it "regrettable and astonishing" that FERC would "exclude the Navy" from the environmental assessment

process. "FERC will be hard pressed to ignore the objections of the U.S. Navy with respect to the adverse impact of the Weaver's Cove proposal on critical naval programs and the security interest of the nation as a whole."

Shedding light on a strategy to use legal and bureaucratic avenues to kill the project—such as the new federal transportation law and high-profile rehearing requests—Lynch repeated his mantra of recent weeks: "We're in the land of a thousand paper cuts." —*Joel Kirkland*

Long-term FTRs 'key ingredient' to MISO's energy-only approach . . . begins on page 1

stream for generators. The proposal was the subject of a FERC technical conference in June and continues to be debated by PJM stakeholders, despite having been rejected by the grid operator's members committee last spring.

"The assumption in both New England and PJM is that, for a number of reasons, the forward market in electricity doesn't exist and it can't work," McNamara said. "It has not so far sent price signals that incentivize the appropriate amount of investment, so [they] need to kind of circumvent the market and create this artificial construct. That is what ISO-New England and PJM are doing."

MISO's energy market tariff doesn't include a capacity market or mechanism. In approving that tariff, FERC told the regional transmission organization to file a resource adequacy plan by June 1, 2006.

Laying the groundwork for that filing, MISO's supply adequacy working group issued the paper earlier this month. The group plans to take another crack at it in the coming weeks to develop a more "nuts and bolts" document that MISO likely "will allude to" in a Sept. 27 informational filing on its Day 2 market, McNamara said.

A final proposal could be in stakeholders' hands in October, allowing MISO to begin work on tariff language in November, he added. That could result in a filing before the end of the year; however, "we can't do anything if we don't get stakeholder buy-in."

McNamara explained the working group's decision to turn from the course of capacity payments taken by MISO's neighbors to the east. "Obviously, the LICAP proposal . . . has met with some heavy resistance," he noted, and "the PJM proposal has certainly met with some [internal] resistance." There is "no single thing out there that everybody looks at and says, 'there is nirvana if we can only get there.'"

McNamara offered three reasons why MISO has rejected the capacity market approach. "It's costly, it will incentivize decisions that last a very long time and it fundamentally changes the role of the RTO."

He related that ISO-NE President and Chief Executive Gordon van Welie recently estimated the LICAP approach will cost \$10 billion to \$12 billion over a five-year period starting in 2006. "That's a lot of money," McNamara said. New England needs new capacity, he acknowledged, "so we don't want to say

this proposal by itself" represents all those costs. "But what I look at . . . is: What if this proposal isn't right or what if there is a better one?"

If LICAP "induces 10% or 20% inefficiency we are . . . talking an order of magnitude of \$1 billion or \$2 billion or more, which is a lot of money to be paid by ratepayers," he said. Conversely, the white paper asserted that the "cost implications and risks associated with this [MISO] resource adequacy plan are dwarfed by comparison to PJM's or ISO-NE's proposed capacity market constructs."

A second driver for the MISO proposal is that a capacity market "is kind of like the gift that keeps on giving," McNamara said. "Once you have incentivized somebody to build generation in a specific area or have incentivized a certain type of generation or transmission solution, that physical asset is going to be around for a very long time." It will influence consumption, generation and investment decisions "for 20 to 30 years after that."

Third, and "critically important to the industry," a capacity market changes the RTO's role, McNamara asserted. Traditionally, a utility ensured resource adequacy through integrated planning conducted in conjunction with regulators, who approved a plan that was executed by the company.

But proposals like LICAP and RMP put the resource planning responsibility on grid operators, McNamara explained. The RTOs "essentially represent future demand. They then hold an auction to determine who they are going to buy from, they set a price on behalf of future demand and then, essentially, a liability is imposed on future demand established by the RTO," he said.

That is a "really a big leap from the current role of the RTO," which is to: run short-term markets, day-ahead or real-time; dispatch existing resources to maintain reliability, and serve a "kind of advisory role in planning." A capacity mechanism puts the RTO in the role of "what I call the utilities' utility," McNamara said.

ISOs and RTOs "are not principals *in* the market but rather service providers *to* the market," the white paper said. However, implementation of a capacity market renders them "both a service provider and a principal. The creation of this new relationship raises important questions around market design, regulatory matters and commercial obligations," it said.

"Creating a forward-looking capacity construct is therefore potentially not just an incremental increase in responsibilities for an ISO or RTO, but rather it is a significant structural change to the role they currently perform," the paper said.

Instead of a forward-looking capacity construct, MISO wants a bilateral forward market in electricity that "people can optimize around—get in and out of their positions—and that, as it moves toward real time, actually goes physical," McNamara said. "You would think that in an industry where the assets are so long-lived we would see a tremendous amount of forward contracting, but we don't," he added. There is virtually no forward contracting and only a very limited, and "not a very robust, forward price."

In seeking to foster a flexible energy-only market, MISO is

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following certain guiding principles, including not usurping the right of states to set reserve margins. Under a capacity market, the RTO—a federally regulated entity—sets the resource adequacy requirement and then goes out and purchases against it, McNamara said.

That may work for other regions, but “we really want to maintain the ability of the states” to set reserve margins. “They have that responsibility now, and we don’t want to do anything to jeopardize that,” he said.

A second guiding principle is that “we don’t think mandating a single mechanism, a centralized procurement mechanism is appropriate,” McNamara continued. Market participants should be able to go out and bilaterally contract for capacity needs. “What is important is that we get the stuff built, and that we get the stuff built in the right places. So we need to get a price out there, and we think the market can deliver that price.”

Third, the approach must be flexible to accommodate diversity in MISO’s footprint owing to “a broad geographic range, as well as a broad political, regulatory, cultural and electrical range,” McNamara stressed. “One size fits all is probably not going to fly at the MISO,” he continued.

For example, this “umbrella” proposal can accommodate Mid-Continent Area Power Pool’s “iron in the ground” reserve requirement of 15%, McNamara asserted. While MISO already performs long-term generation and transmission adequacy assessments, “an energy-only market may require . . . short-term [analyses] as well, to ensure reliable grid operation,” the white paper noted.

Finally, the regime for ensuring resource adequacy “has to be relatively cheap to implement. Administration costs are an ongoing concern,” McNamara said. “We want to keep the cost of participation in our market down. So we want something that achieves the forward price signal without imposing a big cost on the participants.”

To accomplish its goal while meeting these principles, the paper says MISO should promote long-term energy contracting and perform an advisory role in transmission and resource planning, the paper said. And that contracting can be facilitated by “developing and offering a standardized forward energy contract and by creating the incentives for market participants to engage in such contracts by letting the Midwest ISO energy markets work through relaxation of the offer caps, an alteration of the market mitigation protocols and the offering of long-term FTRs.”

McNamara noted that the Edison Electric Institute already has developed a standardized long-term contract for capacity products that sets out boilerplate provisions, such as dispute resolution and credit requirements. All the parties must do is negotiate price and term, he said.

Currently, MISO has a \$1,000 cap on energy offers. According to the paper, “a balance must be struck between the political reality of necessarily lower offer caps and appropriately higher caps for investment incentive.” It suggested “a transition might be prudent to relax the existing \$1,000 offer cap by \$500 each

successive year under the new resource adequacy plan.”

Market mitigation also must be altered, the paper continued. It should not create or exacerbate a supply shortage by capping prices below the level needed to attract investment. Market power “conduct and impact tests can be developed that are tailored specifically based on whether resources are in rate base, have long-term contracts or depend significantly on revenues from the spot markets,” the paper added. “Cumulative price thresholds can be developed specifically for each resource.”

As for FTRs, the hedge provided by a forward energy contract “will be incomplete unless the parties . . . can also hedge the congestion costs to which they will be exposed,” the paper said.

But rights extending beyond one year just are not available. “We don’t see how you can have a true . . . forward energy market without saying you can buy your congestion hedge for longer than a year,” McNamara said. “What we would like to do is not only facilitate long-term [forward] contracting, but also say that if you have a long-term contract we will allow you to nominate for long-term FTRs,” which he called “a key ingredient to this proposal.”

An issue that MISO’s stakeholders will need to consider is how the proposal dovetails—or conflicts—with PJM’s proposal, assuming the RPM is filed at FERC. But McNamara sees no problem, again depicting the MISO proposal as an umbrella.

“What I envision is somebody could enter into a long-term contract. Now they may have to go through more hoops in terms of getting that qualified under the PJM rules,” he acknowledged. “I can’t assure them that they would necessarily qualify, but all the rules would be up front and [market participants] could know that before they entered into any contracts.” There is “nothing that we are proposing that is inconsistent with the PJM proposal,” McNamara asserted.

If there was a forward price “three years, five years or seven years out,” he said, “why wouldn’t the market work? Why wouldn’t capacity see that and build around that price?”

Once you start getting that, “then people have some liquidity around that price. You can hedge your risk, you can get in and out of positions, you can do things,” he said. “But right now, it’s if I build, I’m stuck.” —Craig S. Cano

ELECTRIC POWER

NOI sparks debate over need, format for reporting generator run status data

FERC lacks jurisdiction to compel utilities to report a broad range of information on the operating status of their generation, according to the Edison Electric Institute. Even if the commission could show a legal basis, a recent notice of inquiry on generation run data failed to demonstrate a need for the information and, moreover, could duplicate the collection efforts of other entities, EEI said in Aug. 15 comments.

FERC’s late-May NOI (RM05-16) provided a list of data ele-

ments that it might require be reported, including: the status of breakers; generating unit megawatts and megavolt-ampere reactive capability based on generator-tested performance capability data; Mw and MVAR net output; the status of automatic voltage control facilities; unit dispatch levels; unit outages or deratings, including the reasons for the outages or deratings; the date and time that a unit was taken out of service or derated and the estimated and, later, actual date and time when the unit was expected back online; and generator-tested performance capability data.

Last Monday's comments ran the gamut from EEI's argument that FERC lacks authority to compel the reporting of all that information, to the full support for such reporting expressed in a joint filing by consumer advocates in four states.

In its list of arguments, EEI asserted that much of the information identified by the NOI is already collected by third parties like regional transmission organizations. Nevertheless, consumer advocates from the District of Columbia, Illinois, Maryland and Pennsylvania observed that "from an enforcement perspective, if generator run status is routinely available to the commission, investigation of suspected generation output manipulation will operate from a more sound and empirical basis, and will thus produce results that are less subject to challenge."

Most comments fell in between the two extremes. Merchant generators said the need for the data must be balanced with the administrative burden sure to fall on both industry and FERC. Municipals were concerned about market impacts from real-time public disclosure of unit status. RTOs and independent system operators were reluctant to become middlemen in the reporting process. And there was broadly shared concern about the potential disclosure of sensitive business information.

The Electric Power Supply Assn. suggested FERC convene a technical conference to determine what generator run status information is currently available and how it is formatted. EPSA took note of Commissioner Nora Mead Brownell's questions about the need for and breadth of the data, expressed during discussion of the NOI at FERC's May 25 meeting.

"Competitive generators share Commissioner Brownell's concerns about balancing the responsibilities and burdens associated with information gathering efforts against the benefits of such efforts," said the merchant power trade group.

EPSA recommended that FERC create a template for data collection that is based on current collection efforts by RTOs, ISOs and their market monitors. It said the template should be maintained by market monitors in the organized markets and by individual generators in non-organized markets.

But the ISO/RTO Council cautioned that "the fact that RTOs and ISOs currently have a substantial amount of data related to generator run status does not mean it would be easy, or inexpensive, for them to function as clearinghouses for all of the information that the commission may find to be of interest." In the same vein, it added, "requiring RTOs and ISOs to reform or

recompile information they currently collect could impose significant new burdens and costs."

While expressing a desire to be helpful, members of the council pressed those concerns as well as others in their own comments. For example, Midwest Independent Transmission System Operator said it "is willing to cooperate with the commission in this important information gathering function; however, the Midwest ISO believes that the commission should consider making generators the primary reporters of their own data to avoid putting the Midwest ISO in the middle of a dispute between the commission and a generator."

Giving primary reporting responsibility to the grid operators "would also be undesirable from the commission's perspective as a market monitor, since ISOs and RTOs cannot vouch for the accuracy of generator data as effectively as generators can themselves," added New York Independent System Operator. Generators should be the guarantors of the accuracy of their data, PJM Interconnection agreed.

PJM went on to suggest, however, that RTO independent market monitors could be relied on to synthesize raw data and provide FERC with the desired information on an aggregated basis. ISO New England was open to forwarding to FERC the generator status data it already collects. But ISO-NE said it would be more efficient and cost effective for FERC to collect directly from generators any information not provided to the ISO.

Unlike EEI, the American Public Power Assn. found FERC's statutory duties require collection of jurisdictional generator run status information "in sufficient detail to deter attempts to exercise generation market power or to leverage control of generation into the creation of transmission market power." But APPA stopped short of supporting real-time or close-to-real-time disclosure of the data.

Some APPA members are concerned that immediate public disclosure could have severe adverse impacts on the price of replacement power when forced outages occur. "The primary direct effect of a forced outage of a baseload power plant, if immediately broadcast to the market at large, could be to trigger offer price increases by potential alternative sellers," it said.

Until the day of unfettered competition in wholesale markets arrives, APPA continued, the immediate release of information is not appropriate. "This issue, however, is separate and apart from whether *the commission* should have access to such data."

Cogeneration groups, meanwhile, asserted that they should be exempt, regardless of what is required in a final rule. Because of their operational characteristics—electricity is a byproduct of the essential thermal generation—"physical withholding is not a strategy that is readily available to cogenerators," said largely identical comments by the Cogeneration Assn. of California, Cogeneration Coalition of Washington, Energy Producers and Users Coalition, and the Nevada Independent Energy Coalition.

Groups see need for more transparency, uniformity in transmission calculations

The calculation and posting of available transfer capability “sits at the pivot point among reliability, economic regulation and wholesale electric commerce,” the American Public Power Assn. said last week. Commenting on a notice of inquiry on information requirements for ATC, the trade group called the issue “an early test case” of the new relationship between FERC and the North American Electric Reliability Council under the Energy Policy Act of 2005.

In a May 27 NOI (RM05-17), the commission asked for comments on a NERC task force report addressing ATC and available flowgate capability. It also sought comment on the advisability of revising and standardizing ATC calculations, as well as the most expeditious way to obtain an industry-wide standard (*IF*, 30 May, 5).

APPA, the Edison Electric Institute and the ISO/RTO Council all recommended in Aug. 15 comments that FERC allow the ongoing NERC process on ATC standards to run its course.

“We have no formal response to the series of questions posed in the NOI, since we expect that industry experts engaged in the NERC process will appropriately address the commission’s questions,” said EEL. However, it urged FERC to formally endorse the process, saying “such support will send a clear message that allows the industry to focus its attention on the NERC forum with confidence.”

In its comments, NERC pointed out that it has had standards on ATC, total transfer capability (TTC), capacity benefit margin (CBM) and transmission reliability margin (TRM) since 1997. They were incorporated in NERC’s version 0 reliability standards that took effect last spring and were filed with FERC on an informational basis (*IF*, 14 Feb, 6). The reliability council will begin auditing compliance with the standards next year.

In addition, NERC’s long-term AFC/ATC task force has submitted two standard authorization requests (SARs) for revisions to the ATC and related standards, NERC said. The SARs were put out for a comment period that closed Aug. 8 and a drafting team will prepare a recommendation to the NERC standards authorization committee.

The task force also has proposed a business practices standard to the North American Energy Standards Board to enhance the processing of transmission service requests, NERC related.

Like EEL, the ISO/RTO Council said the SARs process should be allowed to continue, but it urged FERC to “take an active role . . . to ensure that the standards development process meets market designs and tariffs” already in place. The council sees “considerable merit” in efforts to promote standardized ATC and AFC methodologies; however, this “does not, by definition, require that identical software tools be utilized by each transmission provider.”

While APPA also backed the ongoing NERC/NAESB efforts on ATC and AFC calculations, it professed to be “less sanguine that an industry consensus in support of a reliability standard

regarding the calculation of CMB and TRM can be reached.” In prodding industry, NERC and NAESB to wrap up the revised reliability standards and corresponding business practices, FERC should make clear that withholding of ATC through “undocumented and uncoordinated adjustments” to CBM and TRM will not continue under new standards, it added.

The NOI defined CBM as the amount of firm TTC reserved by a transmission provider “so that load-serving entities, whose loads are located on that transmission provider’s system, can access remote reserve generation from interconnected systems.” TRM is the amount of TTC needed to ensure the interconnected grid will be secure under a range of uncertainties in system conditions.

“Additional clarity as to the regulatory treatment of CBM as well as heightened commission and industry scrutiny of TRM adjustments to ATC is appropriate,” APPA said. Among other things, CBM should be reserved and paid for by its beneficiaries and not third-party transmission customers with no access to the capacity, the trade group asserted.

The Transmission Access Policy Study Group also urged FERC action on CBM, which it called a “competitively significant tariff term.” The commission was on the right track in the now-defunct standard market design proposal when it suggested that CBM be reserved and paid for like any other reservation, TAPS said. As for TRM, the commission should require transmission owners, through NERC, to develop a standard that “leaves no discretion to the individual [owners] as to whether, where and how much capacity to set aside for this reliability purpose.”

Further, formation of regional transmission organizations should not be a prerequisite for calculating TTC and ATC on an independent basis, TAPS asserted. It noted the Mid-American Power Pool calculates ATC on a regional basis under its tariff. Although that specific calculation is not independent—key elements are provided by transmission owners—it shows one avenue available to get beyond individual transmission owner calculations of ATC, the group said.

In fact, it may even be preferable to find someone other than an RTO to perform ATC calculations, said the New York Public Service Commission. “One such alternative may be the establishment of a separate entity to oversee the calculation.”

While a move to standardization is proper, “the most urgent step is for the commission to insist that every aspect in the ATC calculation process be open, transparent and uniform,” said the Electric Power Supply Assn. With regard to TRM, “there is no legitimate reason for transmission providers to utilize different formulas,” it said. But while FERC should provide guidance to ensure adoption of a uniform formula, it should permit the use of different assumptions underlying the ultimate TRM value.

Like other commenters, EPSA was concerned about CBM, particularly in non-RTO regions. The “overarching concern is that transmission providers’ reliance on CBM not operate to limit competitive power suppliers’ market entry or otherwise disadvantage them,” it said.

International Transmission Co. said one problem with CBM

and TRM calculations is that "current descriptions are too vague and, as a result, there is a wide variety of interpretations." Without more prescriptive standards, ITC continued, "these problems will not be solved."

But Western parties, while endorsing greater transparency in the process, counseled against a one-size-fits-all approach to ATC. Coordination and calculation methodologies used in the West "are appropriate and should not be revised for the sake of creating national uniformity," said the Transmission Agency of Northern California.

ATC and TTC in the Western Electricity Coordinating Council region are developed through coordinated study efforts, TANC explained, and "these operating studies have long identified interregional power transfer relationships, models and study criteria." Conversely, the flowgate ATC model in the NERC task force report "does not adequately represent the nature of many of the transmission constraints in the WECC," it said.

The basic issue underlying the NOI is how best to optimize the availability of transmission capacity for others to use, said the City of Los Angeles Dept. of Water and Power. "That question should be reframed as: How far can we stretch the system without creating risk in reliability?" And standardization may be risky "if it ignores local system knowledge and judgment," LADWP said. "The alleged problems with the *status quo* are overstated."

The California Electricity Oversight Board focused on the need for standard TRM and CBM methodologies but, like TANC and LADWP, did not support a standard ATC calculation.

In other comments, Allegheny Power said FERC should require a transmission provider that discovers an ATC calculation error to retract the amount of firm service sold due to that error. MidAmerican Energy, meanwhile, suggested there may be a bigger issue than the extent to which AFC/ATC calculations are standardized and whether FERC should set those standards.

"The need for standardized definitions and calculations of ATC, TTC, CBM and TRM by individual transmission providers may be less important than the need for those transmission providers to coordinate their application of AFC/ATC with other providers," MidAmerican said. Further, there may be value in adding firm on-peak and off-peak transmission products, it said.

"This would be a significant aid in maximizing the use of the transmission system," MidAmerican maintained. "In many cases, the transmission system could support additional off-peak service, but service must be denied because AFC calculations are performed only for peak periods."

Montana co-op complains NorthWestern is ignoring order 2003 to charge it \$34 million

NorthWestern Energy is letting an affiliate generator keep its primary position in an interconnection queue so that the delayed project won't have to pay like lower-queue generators would for upgrades, an interconnection customer recently complained. The alleged order 2003 violation would unfairly cost Southern Montana Electric Generation & Transmission Coopera-

tive about \$34 million, it said.

The whole purpose of order 2003, the standardized rules for generator interconnection, was to avert this sort of affiliate favoritism and discrimination by laying down a prescribed format for studies and queuing, the co-op recalled in the Aug. 12 complaint (EL05-141). The conduct of NorthWestern "exacerbates the problems and thwarts the solutions identified by the commission" in the rule (RM02-1), Southern Montana said.

FERC held that delays and a lack of standardization "inherent" in the system before order 2003 served as barriers to entry for competitive generators, the co-op added. Former Chairman Pat Wood III remarked in introducing the notice of proposed rulemaking for the interconnection standards that the purpose was to put to rest complaints from interconnection customers (*IF*, 29 April '02, 1).

Order 2003 leaves some room for delay, but not the five years that NorthWestern's affiliate project has pushed back its in-service date, Southern Montana said. In the meantime, the co-op made its interconnection request last year for a 268 Mw generator near Great Falls, Mont., that would be located near the NorthWestern affiliate project, Montana First Megawatts.

Assuming both projects are using the system, about \$35.2 million in upgrades financing is needed, according to NorthWestern, which plans to assign \$34 million of it to Southern Montana, the co-op said. That's \$34 million beyond what Southern Montana would owe on a stand-alone basis, it added.

The five-year delay exceeds the threshold for a material change that should trigger a re-ordering of the queue under order 2003, Southern Montana claimed. In addition, NorthWestern has missed deadlines for studies, the co-op said.

The Montana First project also appears to be on the block, which may explain why NorthWestern would want to keep down the costs for a potential buyer of bringing it on line, Southern Montana suggested. Some equipment is for sale and what's left "appears to be little more than a priority position" in the NorthWestern interconnection queue, the co-op said.

The transmission owner's "persistent refusal to acknowledge, let alone, act on the material modifications of its affiliate amply demonstrate the advantage available to an entity that owns and controls the transmission infrastructure," Southern Montana said. As disclosed to the Securities and Exchange Commission, NorthWestern "is holding out in hopes of transferring" Montana First to another developer, the co-op said.

"Undisclosed to the SEC, but of great interest to this commission," Montana First has been delayed for 63 months before the original Nov. 1, 2001, commercial operation date, Southern Montana said. "Such behavior thwarts the core object of order 2003" to ensure that generators unaffiliated and affiliated with transmission owners are treated comparably, the complainant said.

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