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Electric Utility Week

August 1, 2005

Fire is gone, but NARUC still asserts state authority, not federal, on resource adequacy

After weeks of debate and pressure from neighboring regions, New England regulators last week dramatically altered a resolution that, in earlier drafts, emphatically urged the Federal Energy Regulatory Commission not to impose a capacity-market system for ensuring generation adequacy in states.

The capacity-market question has turned into an enormous political fracas between New England public officials and FERC, with members of Congress in the mix as well.

The resolution, approved by the National Assn. of Regulatory Utility Commissioners at its summer meetings in Austin, Texas, now endorses more communication and collaboration between states and FERC over generation resource matters. Although it still says that resource adequacy is strictly a state function, observers who attended the meeting were surprised to see the sudden change in the resolution's tone.

"Whatever happened to the fiery … resolution," one NARUC attendee said. The finished product "does still indicate that" resource procurement is a matter of "state jurisdiction, but it was

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Energy bill heads to Bush, with PUHCA repeal, more FERC authority, lots of industry approval

Legislation packed with the biggest incentives in more than a decade to boost a variety of sectors in the power industry was poised for President Bush's signature after House passage by 275-156 Thursday and the Senate's 74-26 approval Friday.

Bush had pressed hard to get the broad, multisector bill, H.R. 6, in time for signing by Aug. 1. After years of delay for some key provisions — notably establishment of a mandatory grid reliability system — legislative leaders were able to put together enough compromises to get a package through. They even neutralized last year's huge roadblock, a provision shielding producers of the gasoline additive MTBE from liability stemming from storage-tank leaks.

One casualty of the House-Senate conference on the measure was the Senate's provision requiring utilities to meet a renewable portfolio standard. House bill leaders would not accept the mandate.

House Energy and Commerce Committee Chairman Joe Barton, R-Texas, who shepherded the bill through negotiations

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Independent transmission coordinators seem to catch on; Duke, MidAmerican offer plans

Industry observers predicted earlier this year that if the Federal Energy Regulatory Commission approved Entergy's proposal to establish a transmission entity that would be far less than a regional transmission organization, other utilities queasy about or skeptical of joining an RTO would quickly follow suit.

FERC approved it in March. Nearly four months later, it appears the predictions were right.

In separate developments, Duke Power and MidAmerican Energy now have both filed plans similar to Entergy's: to hire third parties to oversee, but not operate, their transmission grids. Although both have pending mergers awaiting FERC approval — Duke is seeking to acquire Cinergy and MidAmerican is looking to buy PacifiCorp — neither grid proposal is contingent on their respective acquisitions.

And Entergy last week officially declared that it had hired the neighboring Southwest Power Pool to act as its so-called "independent coordinator of transmission." The move ends months of discussions between the two parties and should solidify final FERC approval of the ICT proposal. FERC's March approval of the plan was contingent on SPP's being hired (EUW,

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MARKET DESIGN

Market critics glad FERC 'listening'; market advocate Hogan says it's too early to give up

Municipal utilities and industrial customers, still voicing concerns that organized electricity markets are in need of an overhaul, expressed optimism last week that federal and state regulators were heeding their concerns.

"I'm confident that the politics are coming together and that it will get fixed," said John Hughes, vice president of technical affairs at the industrial group Electricity Consumers Resource Council.

"We believe" new Federal Energy Regulatory Commission Chairman Joseph Kelliher "is going to [fix] this, because he said so," said Sue Kelly, general counsel and vice president of policy analysis for the American Public Power Assn.

Hughes and Kelly, speaking at the National Assn. of Regulatory Utility Commissioners' summer meetings in Austin, Texas, reiterated reports both of their organizations released over the past several months that organized markets — like those operated by the PJM Interconnection and Midwest Independent Transmission System Operator — are not providing benefits for end-use customers.

FERC-approved organized markets have "failed to be a viable" solution for customers, Hughes said.

Although both Hughes and Kelly endorsed FERC's open-access platform and still want to see competitive wholesale markets throughout the country, neither is convinced that the *status quo* is working. Hughes recommended that forward and spot markets be integrated, asserting that "nodal market designs are prone to failure" if the transmission system is inadequate.

It is "time to return to the basics," Hughes said. "We urge further debate on what is the outcome of what we want to do" with competitive markets.

Kelly said the "spiraling costs" of regional transmission organizations continue to be a major concern for APPA membership, but said she is heartened by Kelliher's public comments that addressing RTO costs will be a top priority. "We very much appreciate that FERC is listening," she said.

While neither group is advocating a return to cost-of-service ratemaking — for now — one panelist from the Cato Institute said that may not be a bad idea. Jerry Taylor, director of natural resource studies at the libertarian think tank, said that to date, electricity competition has not been worth the trouble. The "rationale [for moving to competitive markets] is far less compelling than when we started this journey," he said.

Cato, he said, supports competitive markets completely free of regulation. But echoing themes Cato articulated in its own report late last year (EUW, 6 Dec '04, 2), Taylor said it was a misnomer to call the *status quo* a marketplace. "I'm not endorsing old-style regulation," Taylor said. Thus far, though, restructuring "is hardly" real restructuring, he said.

In particular, panelists said the onset of installed capacity markets as a means to encourage new generation is simply another form of regulation. "It seems to me that ICAP is all the rage," Taylor said. "It seems to me this is a rollback to old-style regulation."

Kelly called ICAP the "no-generator-left-behind" program. Many critics of capacity markets say the systems reward generators for locating in certain areas but do not really add anything but cost to an area's power supply.

But Harvard University's William Hogan, a chief architect of

platts *Electric Utility Week*

August 1, 2005
ISSN: 0046-1695

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Electric Utility Week is published every Monday by Platts, a division of The McGraw-Hill Companies. Registered office Two Penn Plaza, 25th Floor, New York, NY 10121-2298

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organized markets operated by the PJM Interconnection and proposed in FERC's failed standard market design plan, said it was too soon to say the *status quo* has not worked. While admitting some shortcomings in organized markets, Hogan said simply trying new things or scrapping the current system was not the way to move.

"No markets create frailty in the transmission system," he said. Markets "reveal it," he said. "Revealing it doesn't make it worse," but rather it provides an opportunity to make it better.

SMD-like markets have been tried and tested around the world and, if an entity embraces open access, "there's no other way to do it," he said.

Still, Hogan said that while he does not agree with everything APPA and ELCON said in their reports, he welcomed them as a necessary and important piece to what he called the "post-post Enron phenomena." In this stage of market development, "everyone is looking at what's working," he said.

The reports have raised a broad concern about the markets — that the benefits seen from restructuring so far have been small, he said. "I think they are small so far," Hogan agreed. But "successful market design … is a real challenge" and it is far too early to give up, he said.

There needs to be better demand response and longer-term financial transmission rights to improve the situation, Hogan said. "Is SMD necessary? Yes," he said. "Is it sufficient? No."

Entergy gives up market-rate sales in service area; Southern chooses to keep up the effort

Southern Company says it will continue to fight the market-power battle at the Federal Energy Regulatory Commission as it tries to retain the right to sell at market-based rates in its service territory. It plans to maintain its position even as Entergy Services, also under a market-power cloud at FERC, has decided to bow out of the battle.

"We continue to believe we have no generation dominance," said Wayne Moore, director of regulatory affairs and energy policy for Southern Company Generation.

Although Entergy said it was not admitting to having generation market power, it withdrew its request for market-based-rate authority July 22 and told FERC that it intends to charge cost-based rates for transactions within its control area. "Entergy has made this decision to avoid the uncertainty and delay of continued litigation over market-based rates in its control area…," Entergy said in its notice of withdrawal.

Moore at Southern said he was surprised at Entergy's withdrawal of its market-based-rate renewal application. "I'm not sure what their motive is," he said. But as far as it having any impact on Southern's own decision to renew its market-based-rate application, "It has no impact on us at all," Moore said.

Entergy said its decision would allow the company and FERC to "focus on more productive endeavors" such as implementation of an independent coordinator of transmission in its area. In March, FERC conditionally approved Entergy's proposal to have Southwest Power Pool oversee, but not operate, its grid.

Moore said Entergy's use of an ICT may help avert a FERC finding that the company has transmission market power, but the ICT does not affect the other three prongs of FERC's market power prongs, which examines a utility's generation market power, affiliate abuse, and barriers to entry. "An ICT is pertinent to the transmission market power prong," Moore said. "It's not pertinent to the other prongs."

Entergy, like Southern, had been investigated using all four prongs, although the transmission investigation has been put on hold pending the outcome of Entergy's ICT plan. Last week Entergy formally contracted with the Southwest Power Pool to act as the ICT, although other issues remain (see story, page 1).

As for its July 22 decision to withdraw its market-based-rate authority, Entergy said it will now be able to focus elsewhere. An Entergy spokeswoman said withdrawing the renewal request helps avoid the "distraction" presented by such a proceeding and allows the company to refocus its resources.

In late 2001, FERC proposed, in something of a thunderclap of an order, to revoke the market-based-rate authority of three major utilities—American Electric Power, Southern, and Entergy—for possessing generation market power. The decision, which FERC did not follow through on, was a strong move to push these big utilities into regional transmission organizations.

The commission made the proposal as it proposed a new generation market power test and determined the three utilities, which had not joined RTOs, all failed the test. As a consequence, they would be forced to sell wholesale power within their service territories at cost-based rates if they did not join an RTO.

And although the commission last April revised its controversial generation market power test, the penalty for failing the screens remained the same—revocation of market-based-rate authority.

After AEP joined PJM Interconnection on Oct. 1 last year, Entergy and Southern were the last two major utilities that would not yield to FERC, until now. Still, Entergy declared it was not, "by submitting cost-based rates, in any way conceding that it has market power in its control area."

Southern plans to go through with its evidentiary hearing because it feels "comfortable" that it does not have market power and is willing to prove that, Moore said.

FERC began an investigation last December to determine whether Entergy and Southern had generation market power. After the two companies failed FERC's two-step generation market power analysis, FERC launched an investigation under Section 206 of the Federal Power Act.

Under the process, the companies can either mitigate their perceived market power, undergo a more thorough analysis, or go through the 206 hearing. Wholesale sales made during 206 investigations are subject to refund, and if a company is determined to have market power, it may be forced to sell power at cost-based rates.

Merchants would reap profits under LICAP, S&P says; 'disincentive' to build capacity

Merchant generators stand to make huge profits — even if they do little more than they are doing now — under New England's planned locational installed capacity pricing plan, Standard & Poor's said in a report last week.

LICAP would allocate capacity payments to all generators without any guarantee that new entrants will arrive, noted Director Dimitri Nikas, so existing generators would get higher payments but provide no incremental value or service.

"To make matters worse, it is not clear why generators would ever want to build enough capacity in any region to receive anything less than the maximum potential capacity revenues," he added in the July 25 report.

The report is certainly timely as the LICAP issue has been front and center in recent weeks. New England's congressional delegation sent blistering letters to Federal Energy Regulatory Commission Chairman Joseph Kelliher last month urging FERC to at least delay LICAP's January implementation date, and state regulators debated a resolution at last week's National Assn. of Regulatory Utility Commissioners dealing with capacity market issues (see story, page 1; also see EUW, 18 July, 1).

According to S&P, while ISO-NE's methodology tries to balance capacity revenues with energy revenue, avoiding duplicate payments, this could act as a disincentive for merchant generators to build new capacity — frustrating the intent of LICAP, Nikas pointed out.

Also, LICAP does not address barriers that prevent development of new capacity in areas that need it the most, so it is possible new capacity will continue to be built away from load, in places where development is relatively easy, S&P warned.

Since the plan is likely to boost power prices, utilities will have to do considerable work to avoid a public backlash, but the substantial increase can have far-reaching repercussions, as consumers, who will eventually pay for the experiment, may express the largest dissatisfaction, Nikas said.

"If the capacity prices rise so significantly so that immediate recovery is politically unpalatable, it is possible that utilities may have to defer a portion of the costs and recover them at a later point in time. Under this scenario, a long recovery period could adversely affect credit quality.

"Yet another risk is that even under the currently supportive regulatory environment of states such as Massachusetts, the qualitative impact of the potential capacity cost increases can be significant. This is because the electric utilities are the customers' first contact with the industry, and many, if not most customers, are still unable to fully understand the impact of the electric industry restructuring. For such customers, an increase in capacity costs is viewed as an increase on their bill, irrespective of how the increase originates and who receives the actual revenues. As a result, such utilities face a public relations uphill battle, and must prepare their customers accordingly," S&P continued."

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In related news, New England state regulators last week asked FERC to hold an oral argument on LICAP before the new market is implemented in the region next year.

In a motion Thursday, the New England Conference of Public Utilities Commissioners claimed LICAP will cause a significant increase in rates for certain states without any guarantee that generators will build new supply.

LICAP "will, if implemented, impose immediate and enormous costs on electricity consumers in New England without the promise of adequate capacity over the long term," the regulators said.

According to the states, FERC needs to hold an oral argument to give parties one more chance to debate the merits before allowing the plan to go into effect. "[O]ral argument is warranted in this proceeding," the states said, noting that LICAP has been "unanimously and vociferously opposed by all six New England governors, New England's entire congressional delegation, all of the state regulatory commissions and other representatives of 'load' in the region."

Separately, merchant generators who support LICAP told FERC last week that the plan will improve reliability and lower costs over the long run. In a response to a series of missives by New England's congressional delegation, EPSA said that LICAP is "not only necessary from a reliability standpoint, it is just and reasonable from a regulatory and economic standpoint."

The Federal Energy Regulatory Commission should listen to its own administrative law judge — not to a group of congressmen — when deciding whether to employ a locational installed capacity pricing plan in New England, the Electric Power Supply Assn. said in a letter to FERC late Tuesday.

"The LICAP proposal is not only necessary from a reliability standpoint, it is just and reasonable from a regulatory and economic standpoint," EPSA's letter said. "ALJ [the Honorable Bobbie J.] McCartney concluded that the [New England Independent System Operator] proposal produces a just and reasonable result."

EPSA argued that capacity markets are consistent with competitive markets, but competitive markets must allow for the recovery of investments. "The energy market mitigation and cost-capping measures that have existed in New England since 1999 will not allow for the recovery of investment without a capacity market," EPSA said in its letter. "If investment cannot be recovered, reliability will be threatened by the lack of adequate and available generation capacity."

EPSA, which represents the country's power suppliers, said failing to act now to "fix New England's dysfunctional capacity market" would harm the region and neighboring regional transmission organizations.

PJM's proposed charges for administration too high, utilities say, seeking justification

The PJM Interconnection's proposal for changing the way it figures administrative charges is meeting a good deal of skepticism. Some utilities think the new method is wrong while others think the method is fine, but the proposed rate is too high.

Even the PJM Finance Committee told the Federal Energy

Regulatory Commission that PJM's "stated rate" of 0.39 cents/kWh is too high, and that a figure between 0.33 cents and 0.36 cents would be sufficient to recover the regional transmission organization's administrative costs. The committee, which would get a larger advisory role under PJM's new tariff revisions, said it did not get enough information from PJM to justify the fees.

"The Finance Committee's initial view is that the stated rate should be lower, based on, among other things, PJM's cost in the last two quarters, the load growth that can be expected to occur in the next few years, and preliminary consideration of major capital component business case rationale," the panel said (Docket No. ER05-1181).

Public Service Electric & Gas believes PJM has neither demonstrated that the 0.39-cent rate is "just and reasonable" nor shown that it adhered to an "open and collaborative stakeholder process" to determine the rate.

"PJM appeared to be rushing through the stakeholder process and ignoring the opportunity for stakeholder advice and guidance," PSEG said in its filing. "... [T]he commission should not authorize PJM to skip through this rate process without fully demonstrating the justness and reasonableness of its proposed rate and ensuring that adequate processes are in place to hold PJM accountable to its membership going forward."

PSEG said that while it supports PJM as an RTO and believes the RTO model helps build competitive markets, "we are not supportive of granting PJM free rein or our unfettered trust, and unfortunately it appears that this is exactly what PJM is asking for in its filing," PSEG said.

PJM filed revisions to its open-access transmission tariff on July 1, proposing the 0.39-cent rate, which would be static for five years. The grid operator said it had to reduce its costs by more than $100 million over the next five years.

Further, PJM said in its filing that the formula rates it currently uses produce revenue of $200.6 million. The new, stated, rates would produce revenue of $192.4 million, according to its calendar year 2004 test period. PJM said formula rates, according to its projections, would not yield enough revenue to cover its costs in light of its recent expansion.

PJM said using stated rates would create more transparency and make PJM more accountable to both FERC and PJM members.

"The stated rate filing proposes an entirely new rate and rate design," FirstEnergy Corp.'s utility subsidiaries said. FirstEnergy said FERC should require PJM to make a "complete and comprehensive Section 205 [of the Federal Power Act] filing" that would include "supporting documentation" that PJM did not provide in its July 1 filing.

PPL Electric Utilities Corp. and PPL EnergyPlus LLC said they agree with the Finance Committee that the proposed stated rate could be in the range of 0.33 cents to 0.36 cents.

PJM's expansion was "costly" enough, PPL said, but it was supposed to bring long-term benefits, including an increase in transactions and in turn a "steady reduction in the rate produced by the PJM formula," the companies said. "The stated rate unfairly takes that reduction expectation away."

BRIEFS

Regulatory commissions of 13 states and the District of Columbia have formed the Organization of PJM States, Inc., and elected Pennsylvania Public Utility Commission Chairman Wendell Holland as its first president. The group will help the states share information and "ensure that the voice of state regulatory commissions is heard at the PJM regional level and at the Federal Energy Regulatory Commission," Holland said.

...U.S. utilities generated 95,259 GWh in the week ended July 23, an all-time record weekly high and an 11.4% increase over a year earlier, the Edison Electric Institute reported. The previous all-time high of 90,468 GWh was set in the week ended Aug. 3, 2002. The largest rise in output was reported in the "central industrial" region, where output rose 17.2% to 16,760 GWh over the previous year's period. In the mid-Atlantic region, generation rose 17.1% over a year earlier, to 11,366 GWh. Generation for the week did not fall in any region.

...The Long Island Power Authority in New York is considering another transmission line to the PJM Interconnection, Chairman Richard Kessel said last week. Speaking at the Long Island Energy Summit, Kessel said, "adding to our ability to tap into off-island supplies" is key to the energy future of the state authority, which serves 1.1 million customers and faces 3% annual load growth. LIPA already buys power from New England through a 330-MW line owned by Cross Sound Cable, and has a 20-year contract for all the transmission rights on a 660-MW line to New Jersey, being developed by Neptune Regional Transmission Co. (EUW, 25 July, 25). Kessel provided no other details about the third line plan, but the authority attracted the Cross Sound and Neptune projects through competitive bidding. He also said LIPA would increase efficiency spending in 2006, targeting commercial, industrial and municipal customers.

...Vectren, parent company of Evansville, Ind.-based Southern Indiana Gas & Electric, is partnering with U.S. aluminum giant Alcoa by investing approximately $400 million to upgrade the 750-MW Warrick coal-fired power plant along the Ohio River in southwestern Indiana. For years, the aging baseload coal plant has been a lightning rod for criticism by environmentalists who say it is one of the most polluting generating stations in the country. A report released by the Environmental Integrity Project earlier this year backed up those claims, ranking 40-year-old Warrick third nationally in sulfur dioxide emissions. Valley Watch, an Evansville-based environmental group, had called on Alcoa/Vectren to either shut down or clean up the power plant. Last week, the companies chose the latter option. Alcoa plans to spend about $330 million and Vectren almost $70 million to cut SO2 emissions 98%. Most of the money will be earmarked for installation of scrubbers on all four operating units, boiler modifications to provide greater fuel flexibility and construction of new coal-handling facilities.

...The United States joined four Asian nations and Australia in a technology-based agreement to reduce emissions of greenhouse gases, which are believed to cause global warming. Four of the nations — the United States, China, India and Australia — are the world's largest coal consumers. With South Korea and Japan, the

BRIEFS (continued)

six account for about half the world's greenhouse gas emissions; the United States accounts for about half of that portion. The new pact allows each country to set its own emission goals and provides no enforcement mechanism, although, separately, Japan must meet its targets under the Kyoto Protocol. Deputy U.S. Secretary of State Robert Zoellick, in disclosing the pact last week, said it is "a complement, not an alternative" to Kyoto. But Philip Clapp, president of the National Environmental Trust, said the pact has "no agreements, actions or timetables for accomplishing anything" and the Bush administration may be "organizing a group of nations to try to block a new set of [post-2012] emissions reduction targets."

...The Compete Coalition last week disclosed a roster of 68 member companies and associations, including some utilities, power trading companies and generators, major retailers like Big Lots Stores and Federated Department Stories, and smaller companies. "Electricity is a substantial cost to our business operations and ultimately impacts our 46,000 associates and Americans as a whole," said Jeff Dummermuth, director of energy and engineering for Big Lots. "We recognize that success at the retail level ... requires robust competition at the wholesale level." The coalition is headed by Wexler & Walker Public Policy Associates, with former Oklahoma Sen. Don Nickles' Nickles Group (EUW, 25 July, 2).

...Weather forecaster WSI said weather across all the United States would be warmer than normal during August. And with the exception of the Great Lakes, the Northeast and the Mid-Atlantic states, that forecast holds for September and October as well. The Andover, Mass.-based company singled out Mississippi, North Dakota, Minnesota, Texas, Washington and Oregon as states where the warm forecast is particularly pertinent. Energy Security Analysis Inc., a Wakefield, Mass., energy markets analysis firm that provides market-impact analysis of WSI data, said the forecast prompts "concern that generator failures may be more prevalent in August after going through extended operations in July."

...FirstEnergy wants to give competitive energy suppliers another opportunity this fall to submit successful bids to serve the company's approximately 9,100-MW retail load in northern Ohio in 2007 and 2008. If the Ohio Public Utilities Commission approves the application FirstEnergy filed last week, a "Dutch-style" descending-clock auction would be held Nov. 8. The commission would have two business days to accept or reject the results. FirstEnergy's maiden auction on Dec. 8, 2004, proved unsuccessful when the PUC rejected the bids (EUW, 13 Dec '04, 18). The commission said the clearing price of 5.45 cents/kWh was "inadequate in comparison to the price available through FirstEnergy's rate stabilization plan." That plan was thus allowed to go ahead, starting January 2006, under much opposition from consumer advocates. But now bidders will have a second chance to beat FirstEnergy prices, and the November auction will have "some small differences" that might help increase its success, a spokeswoman said.

Fire is gone, but NARUC still asserts state authority on resource adequacy... from page 1

certainly not what we thought it would be."

Initially, the resolution, offered by Connecticut regulators, was a response to the proposed locational installed capacity market plan set to be implemented in the ISO New England market in January. The Federal Energy Regulatory Commission has approved aspects of the plan, but must rule on the financial aspects before LICAP can be implemented.

LICAP is touted by ISO-NE and generators as necessary to improve reliability because it seeks to encourage new plant capacity through market signals. A FERC administrative law judge in June said the pricing plan "appears to provide the proper incentives to build the right amount of capacity at the lowest possible cost to consumers" (EUW, 20 June, 22).

But consumer groups and Connecticut state officials have railed against the plan, calling it only a windfall for generators that will increase rates. Southwestern Connecticut, as a troubled load pocket, will see the largest impact. Officials have enlisted the New England congressional delegation, which peppered FERC Chairman Joseph Kelliher with a blistering series of letters urging FERC to, at the very least, postpone LICAP's implementation date (EUW, 17 July, 1).

The delegation won a provision in the energy bill urging FERC to consider New England views when deciding on LICAP, after having lost an effort to get stronger language.

[At the same time, Standard & Poor's released a report supporting critics' view that LICAP will give generators higher payments but offer no guarantees that new generation will be built. And the New England Conference of Public Utilities Commissioners asked FERC to hold oral arguments on capacity market issues before it lets LICAP go into effect. See story, page 4.]

In one of its early drafts, the NARUC resolution did not mince words against LICAP and other measures to guarantee resource adequacy through competitive markets instead of traditional state mechanisms. Federal law, the resolution said, specifically left resource adequacy to state jurisdiction, and FERC cannot allow regional transmission organizations or independent system operators to set capacity measures through the marketplace (EUW, 18 July, 1).

"The FERC may not rely upon RTO or ISO tariffs as a jurisdictional bootstrap to assert jurisdiction over activities such as generation resource adequacy and reliability," the early version said.

By imposing LICAP, FERC "is requiring New England states' consumers to pay for capacity up to the levels set by ISO-NE," the resolution said.

But after another week of debate and intense negotiation, the resolution's chief architect, Connecticut Dept. of Public Utility Control Commissioner Anne George, dramatically scaled back the language when she brought it for a vote in front of NARUC's electricity committee last Monday. George offered to change the tone and content after commissioners in New York and Michigan said the initial draft could hamper NARUC's communications with FERC.

New York Public Service Commission Chairman William Flynn, for example, said the earlier language "could jeopardize all the good work done before" in establishing an informal working group with FERC earlier this year. Flynn referenced a resolution that had similar intent that NARUC passed at its winter meetings in March that called for a forum between FERC and states to address resource adequacy. That forum, held in May, resulted in the creation of the informal working group to discuss related issues (EUW, 23 May, 7).

Michigan Public Service Commission member Laura Chappelle also applauded the revised resolution. "I think we are dealing with a much better version," she said.

Flynn and other state commissioners, NARUC meeting attendees said, were uncomfortable with the initial language because capacity markets have seen some success in some places, like New York and the PJM Interconnection.

"Bill Flynn took a lead role in making sure the resolution addressed everyone's needs," another NARUC attendee said.

In its final version, the resolution still asserts that "generation resource adequacy is a matter committed to state, and not federal, jurisdiction under applicable law; that state jurisdiction over generation resource adequacy should not be exercised in such a manner as to undermine FERC jurisdiction over wholesale electricity sales" and vice versa.

It declared that although some states have opted to allow market functions to incentivize resource adequacy, many have not. "These regional differences could reasonably lead to the adoption of differing approaches to generation resource adequacy issues by state commissioners," the resolution said.

Those states that have chosen to retain "their long-standing jurisdiction" over resource adequacy should be left alone, the resolution said. Also, though, states considering a market approach should feel free to do so, according to the resolution.

"The FERC and state commissions should exercise their respective jurisdictions in a complementary manner in order to assure that each body is able to adequately protect the wholesale and retail consumers of electric power," the resolution said.

The final version of the resolution kept the "jurisdictional bootstrap" idea from the earlier draft, but reworded it to cite a federal court ruling in April, concerning Columbia Gas, that FERC may not rely solely on the inclusion of something in a tariff to assert jurisdiction over that thing, if it would not normally have it.

The Electric Power Supply Assn. applauded the revised resolution. "The fact that the electricity committee agreed to a resolution acknowledging: 1) the need for bilateral state-federal cooperation between resource adequacy and wholesale electricity sales; 2) that state resource adequacy standards can be enhanced with assistance from" FERC, regional reliability councils and regional transmission organizations, "and 3) the need to coordinate regional resource adequacy planning, bodes well for consumers because the shared expertise on these technical issues will help ensure that consumers receive needed

FINANCE

International Transmission parent's IPO completed at higher-than-expected price

Common stock of ITC Holdings, parent company of International Transmission Co., soared $3.40 (14.8%) to $26.40 in its first day of trading July 26, after trading between $26.25 and $27.25. Earlier that day, the company's 12.5-million-share initial public offering was priced at $23/share, up from ITC's previous estimated range of $19 to $21.

On July 28, the stock traded as high as $29.12 before closing up 13 cents at $28.15. The underwriters have an overallotment option for another 1.875 million shares that can be exercised over the 30 days ending Aug. 25.

In the IPO, ITCH itself sold 2.5 million shares, for estimated net proceeds of about $49.8 million. Ten million were sold by International Transmission Holdings Limited Partnership, ITCH's immediate parent.

At March 31, about 90.65% of ITCH's diluted shares were owned by ITH LP. Following the IPO — and before the overallotment option — ITH LP owns 54.67%, management and employees 10.5%, and IPO investors 34.83%.

Most of ITH LP is owned by two groups of investment partnerships: one managed and advised by affiliates of Kohlberg Kravis Roberts & CO. LP (68.11% limited partner interest), and the other by affiliates of Trimaran Capital Partners LLC (29.19%).

The other 2.25% limited partnership interest is held by Stockwell Fund LP, formed to make investments for State of Michigan retirement funds.

Ironhill Transmission LLC is the manager and general partner, with a 0.45% general partnership interest in ITH LP. Its only member is Lewis Eisenberg, an ITC Holdings director who is co-founder and co-chairman of Granite Capital International Group, an investment management company. Prior to co-founding Granite Capital, he was a general partner and co-head of the equity division of Goldman, Sachs & Co.

On Feb. 28, 2003, ITCH acquired ITC's predecessor from DTE Energy and began operating what was Detroit Edison's transmission system as a stand-alone company. Payments from Detroit Ed, billed by the Midwest Independent System Operator, are expected to provide most of ITC's revenue for the foreseeable future.

EARNINGS

AEP more than doubles profit in Q2 on sales, lower operation, maintenance

American Electric Power, turning a triple play of increased retail sales, higher margins on off-system sales and lower operation and maintenance costs, more than doubled its second-quarter profit. The nation's largest electric generator reported quarterly earnings of $221 million, or 58 cents/share, up from $100 million, or 25 cents/share, a year ago.

Revenue declined, however, from $3.4 billion in the second quarter of 2004 to $2.8 billion for the three-month period ending June 30, 2005.

"Earnings are considerably better than we thought they might be. It's reflective of growth we're seeing throughout our service territories," Michael Morris, president, chairman and CEO of the Columbus, Ohio-based company, told financial analysts during a Friday webcast.

AEP accomplished the earnings growth without much help from the weather or fuel costs. Traditionally, the third quarter and its corresponding spike in summer air-conditioning load is a key driver for the company's overall profitability. Likewise, fuel costs — mainly coal — are crucial for AEP's 11-state system that burns more than 70 million tons of coal annually, the most among U.S. utilities.

Despite the rosy second-quarter results, AEP, at least for now, is holding fast to its previous earnings outlook of $2.30 to $2.50/share for 2005. It is sticking to that guidance even though the company earned $1.49/share, easily more than halfway to meeting the forecast, in the first half of the year.

AEP's stance, therefore, might be viewed as overly conservative, acknowledged Morris, who nevertheless insisted the conservatism is grounded in hard reality.

"Mild weather in the third quarter can quickly offset the year-to-date improvements," he cautioned. "We also see the potential for continued pressure on fuel prices because of transportation issues for Western coal."

Indeed, coal costs this year have climbed above AEP's projections. The company had predicted a 10% escalation in such expenses for 2005, but "that isn't going to maintain ... on the Eastern side we're probably 2-4% higher," observed Morris.

Morris was asked by an analyst if he ever thought AEP would welcome mild summer weather in the Midwest, where the usually steamy months of June, July and August can resemble the climate at the equator. Morris, no doubt not totally in jest, replied, "We're interested in comforting our customers, and the more uncomfortable they are the happier we are ... hot and sticky is really good."

Aside from the possibility of cooler-than-normal temperatures across AEP's service area in August and September, which weather forecasters are not predicting, Morris conceded there is nothing on the horizon to dim the company's earnings outlook through the balance of the year. AEP is preparing for rate filings in several states where its subsidiaries operate.

It also intends to maintain an aggressive maintenance strategy, prompting Morris to quip, "If you're a tree and you're in our right-of-way, look out, here we come." In Oklahoma, he noted, AEP's Public Service Oklahoma subsidiary won approval from regulators to automatically recover tree-trimming costs from customers.

"We're responding with as much vigor as you can get," he said, adding AEP also wants to make sure "we don't overspend."

PNM Resources Q2 net plunges 90.8% on outages and $11M of one-time items

PNM Resources second quarter net income plunged $15.3 million (90.8%) to $1.5 million. It had previously warned that results would be significantly impacted by unanticipated plant outages that slashed availability of low-cost generation and led to lower wholesale volume, but there were also $11 million of one-time charges.

They included $4.2 million of refinancing costs, $2.8 million for integration of TNP Enterprises, acquired June 6, $2.7 million to write off software, and $1.4 million to write off a regulatory liability.

Before those, due mainly to the outages at the Palo Verde nuclear plant and San Juan coal plant, what PNM calls "ongoing" net was down 25.2% to $12.6 million.

Total operating revenue rose 9.4% to $405.2 million, up 9.4%. Earnings per share slumped from 28 cents to 2 cents.

"Ongoing" EPS were 20 cents. The company would not provide average shares outstanding for 2005. In second quarter 2004 they were 60.4 million (basic) and 61.1 million (diluted). At April 29, 2005, there were 64.39 million outstanding.

However, citing the TNP acquisition, PNM boosted expected 2005 "ongoing" diluted EPS by 10%, to $1.55-$1.70.

PNM estimated that the outages slashed EPS by 10 cents, by cutting power available for wholesale, and boosted Public Service Company of New Mexico purchased power costs by 6 cents/share.

Revenue in the PNM Electric Wholesale segment fell 13% to $142.3 million.

TNP Enterprises, acquired June 6, was a "strong contributor to earnings" but PNM did not say by how much, though it did note that from June 6 to 30, Texas-New Mexico Power revenue was $19.2 million and gross margin $12.5 million, on sales of 618.4 GWh. Revenue from TNP's Texas retail electric provider First Choice Power was $43 million and gross margin $8.9 million, on sales of 372 GWh.

Company-wide operating expenses were up $45.6 million (13.3%) to $387.2 million, led by a $24.7 million (11.5%) hike in cost of energy sold, to $238.2 million. Administrative and general rose 23.2% to $52.4 million, and non-income taxes 27.9% to $10.6 million.

That left pre-tax operating income down 37.4% to $18 million. Income tax benefits were $1.2 million, versus year-before costs of $6.5 million.

Net "other income and deductions" sagged 20.9% to $5.4 million. Interest charges jumped 73.9% to $21 million. Preferred stock dividends soared from $146,000 to $2.1 million.

POWER INDUSTRY 2Q 2005 INCOME

REPORTED WEEK ENDING JULY 29 (in millions of $)

Company	Revenue $	Revenue %	Net Income $	Net Income %	Basic EPS $	Basic EPS %
Allegheny Energy*	$714.6	+17.3	-18.4	LNL	-0.12	LNL[1]
Allete*	186.8	+0.3	-40.3	LAP	-1.48	LAP[2]
Ameren*	1,590.0	+38.4	185.0	+56.8	0.93	+43.1
American Elec. Pwr.*	3,400.0	-17.6	221.0	+121.0	0.58	+132.0
Avista*	272.8	+20.8	18.6	+84.6	.38	+80.9
Central Vt. P.S.	75.1	+11.0	2.0	-38.4	0.17	-37.0
Cinergy*	1,114.3	+5.7	50.7	-13.3	0.25	-24.2
Constellation E.G.*	3,535.5	+26.8	121.7	-5.1	0.69	-9.2
DPL Inc.	293.4	+3.0	34.5	-61.2	0.18	-57.4
DTE Energy*	1,945.0	+29.6	29.0	-17.1	0.17	-15.0
Empire Dist. Elec.	87.9	+13.7	3.2	+52.0	0.12	+50.0
FirstEnergy*	2,929.3	-2.1	178.0	-12.8	0.54	-12.9
Hawaiian Elec. Ind.	522.3	+13.1	27.6	+145.4	0.34	+142.9
NiSource*	1,418.7	+8.3	39.0	+12.7	0.15	+15.4
Northeast Utilities*	1,551.0	-1.7	-27.7	LAP	-0.21[3]	LAP
NSTAR	692.0	+6.5	33.1	-11.7	0.31	-11.4
PNM Resources*	405.2	+9.4	1.5	-90.8	0.02	-92.9
Pinnacle West Cap.*	755.8	+7.1	26.7	-63.2	0.28	-65.0
Progress Energy*	2,333.0	+9.9	-1.0	LAP	-0.01	LAP
Southern Co.*	3,144.0	+4.5	387.0	+9.9	0.52	+8.3
TECO Energy*	719.0	+7.5	95.2	PAL	0.46	PAL[4]
UGI Corp.	22.0	+4.8	2.7[5]	-15.6	NA	NA
Unitil	51.4	+5.8	1.5	-3.2	0.27	-3.6
Vectren	326.2	+17.9	13.4	+306.1	0.18	+350.0
Wisc. Energy*	793.0	+10.9	62.0	+59.0	0.53	+60.6
Xcel Energy*	2,067.0	+17.2	82.3	-3.4	0.20	-4.8

** see accompanying story this issue*

1. LNL=lower net loss than Q2 04
2. LAP=loss after profit in Q2 04
3. diluted, basic EPS not reported
4. PAL=profit after loss in Q2 04
5. electric utility results only
6. NA=not available

Ameren second-quarter income up 57% on plant performance, higher sales margins

With no key power plant outages and higher margins on electric sales to other utilities, Ameren Corp. second-quarter net income jumped 57% to $185 million, or 93 cents/share, from $118 million, or 65 cents/share in the year-ago period.

Second-quarter revenue climbed to $1.6 billion from $1.1 billion in the second quarter in 2004, the St. Louis, Missouri-based company said July 28. In the second quarter last year, Ameren's earnings were depressed by 22 cents/share due to an extended outage at a nuclear power plant.

Illinois Power Co., acquired in September 2004, boosted Ameren's income by $15 million on $268 million in electric revenue and $73 million in gas revenue in the second quarter.

Ameren's electric revenue increased about $13 million due to hotter-than-normal weather in the quarter, the company said.

Interchange power sales increased by 39% in the second quarter to 4,051 million kWh. At the same time, power prices rose 27%, averaging $38/MWh in the second quarter, up from $30/MWh in the same period last year. Revenue from the interchange sales jumped 75% to $154 million in the quarter. Increased plant availability and the new Midwest Independent Transmission System Operator market also boosted interchange sales compared to last year, Ameren said. The capacity factor for Ameren's power plants increased to 78% in the second quarter, up from 72% in the same quarter last year, which included an extended outage at the company's Callaway nuclear plant. Ameren expects to increase the overall capacity factor for its fleet by 1% a year for the next several years, officials said Thursday during an investor conference call.

With expectations for increased earnings from interchange power sales, Ameren raised its 2005 earnings guidance to $3/share to $3.20/share, up from the previous range of $2.90/share to $3.10/share.

The current slowdown in coal deliveries from Wyoming will push up coal and coal-transportation costs in the next two years, which in turn will put pressure on power prices, Ameren officials told analysts Thursday (see story, page 29; also see EUW, 25 July, 1).

Ameren, which buys 85% of its coal from the Powder River Basin, believes coal and coal transportation costs will increase 3% to 5% in 2005, 5% to 10% in 2006 and 10% to 15% in 2007, said Gary Rainwater, Ameren chairman, president and CEO. There are a lot of indications that the forward prices for power will be solid, including high natural gas prices and rising coal prices, he said. "It's reasonable to believe that future prices will be affected by coal," he said. About 86% of Ameren's generating capacity is coal-fired.

In an effort to conserve its PRB coal, Ameren is buying coal on the spot market, raising the price at which it will sell power from its coal units and working with the rail companies to ensure adequate supplies, Rainwater said. "We believe these strategies will allow us to operate our coal fleet reliably and economically for the rest of the year," he said.

Ameren has hedged all its coal supply needs for 2005 and expects to soon be fully hedged for 2006, Rainwater said. Ameren is 90% hedged for 2007, he said. Average power sale prices rose 27% in the second quarter, averaging $38/MWh, up from $30/MWh in the same period last year, according to the company.

Ameren is planning a refueling and maintenance outage at the company's 1,143-MW Callaway nuclear plant in Callaway County, Missouri, Rainwater said. During the outage, Ameren will boost the plant's capacity by 60 MW.

Power Company 2nd Quarter 2005 earnings schedule

(As of July 29, 2005)

Aug. 1 (Monday):
■ Entergy ■ Otter Tail ■ Public Service Enterprise Group

Aug. 2 (Tuesday):
■ Cleco* ■ *NorthWestern ■ PPL Corp. ■ Puget Energy* ■ Sempra Energy ■ TXU Corp.

Aug. 3 (Wednesday):
■ *Calpine ■ Dominion ■ *Duke Energy ■ Great Plains Energy* ■ OGE Energy ■ PG&E Corp. ■ Reliant Energy

Aug. 4 (Thursday):
■ Aquila ■ CMS Energy ■ Energy East ■ *IDACORP ■ KeySpan ■ WPS Resources ■ Williams

Aug. 5 (Friday):
■ Alliant Energy

Aug. 7 (Sunday):
■ UniSource Energy

Aug. 8 (Monday):
■ CenterPoint Energy ■ *Duquesne Light Holdings ■ Dynegy ■ Pepco Holdings

Aug. 9 (Tuesday):
■ *Edison International ■ NRG Energy ■ Sierra Pacific Resources ■ Westar Energy

***before stock markets open**
after* stock markets close

Northeast Utilities loses $27.7M in Q2 with more 'mark to market' charges

Northeast Utilities lost $27.7 million in the second quarter — versus year-before net income of $24 million — again due mainly to "mark to market" impacts from higher forward power prices on derivative wholesale energy pacts that NU Enterprises Inc. is trying to divest as it gets out of wholesale energy marketing and services (EUW, 9 May, 16).

"NUEI's earnings are expected to be volatile until these contracts expire, are sold, or are restructured," the company warned in the July 26 press release.

In second-quarter 2004 NU had a $2.4 million (after tax) charge on the lower value of its investment in Acumentrics, a developer of fuel cell and power quality equipment.

The $39.8 million (after tax) of second-quarter 2005 MTM charges brought the total to $172.4 million for the first half, versus zero last year, and resulted in a second quarter net loss of $43.6 million on merchant energy operations, versus year-before income of $5.9 million.

For the first half, merchant energy lost $182.4 million — versus 2004 net of $25 million. Second-quarter restructuring and impairment charges were $700,000, versus zero last year, but down from $5.3 million in the first quarter.

But even without the charges, merchant energy lost $3.1 million in the quarter, versus year-before income of $5.9 million.

NUEI continues to try to shed 60 million MWh in power pacts and has received 15 indicative bids, which are being negotiated. NU also reached buyout deals on five long-term municipal contracts and is negotiating terms with 10 other munis.

The company also is reviewing bids for its energy services company, and hopes to recover the full $50 million book value.

NU's goal is to have buyers in place by the end of the year

(continued on page 12)

EARNINGS BRIEFS

■ **Allete** lost $40.3 million in the second quarter, versus year-before net income of $36.7 million, due to the previously announced $50.4 million (after-tax) ($1.84/diluted share) charge on the April 1 transaction in which the Rainy River Energy subsidiary assigned its power purchase agreement with LSP-Kendall Energy, LLC, the owner of an energy generation facility located in Kendall County, Illinois, to Constellation Energy Commodities. RRE paid CEG $73 million in cash. The PPA runs through mid-September 2017. Allete expects to book tax benefits on the deal in the first half of 2006. It lost $1.48/share for the quarter, versus earnings of $1.29, on 27.2 million average basic shares, down 4.2%, as revenue went up 0.3% to $186.8 million. Year-before net included $34.2 million from discontinued operations, mainly automotive services unit Adesa, which was divested in September 2004, and a $3.2 million impairment charge on investments in emerging technology companies.

■ **Avista Corp.**, reporting strong performances by its regulated utility operations, July 27 said it earned $18.6 million (38 cents/diluted share) in the second quarter, $10.1 million above the $8.5 million (17 cents/share) it reported in the same period of 2004. The Spokane, Washington-based company said Avista Utilities contributed $18.4 million to net income in the quarter, a $9.1 million increase over the year-ago period. The company attributed the improved results to general rate increases that took effect in the second half of 2004 in Washington and Idaho, lower electricity costs from improved hydroelectric generation, and a $3.2 million pre-tax gain from the sale of the unit's South Lake Tahoe natural gas distribution properties. The company said that while retail loads were lower than expected, the company was able to increase its wholesale power sales. Avista said its energy marketing and resource management operation reported a net loss of $300,000 in the quarter, compared with earnings of $1.5 million in the prior-year period.

■ **Constellation Energy** reported lower second quarter earnings on Friday, due to special items. The Baltimore-based company reported net income of $121.7 million (68 cents/share), compared with $128.2 million (76 cents/share) in the same period of 2004. The 2004 figures were boosted, however, by a synfuels credit that contributed to a $14.9 million income tax benefit. Without that in the second quarter of 2005, Constellation incurred income tax expenses of $33.2 million. As a result, net income from continuing operations before income tax was $152.2 million (66 cents/share) in the second quarter, compared with $113.3 million (54 cents/share) in the second quarter of 2004. Operating revenues rose to about $3.5 billion, compared with $2.8 billion, largely due to growth in the competitive wholesale and retail businesses. Non-regulated revenues exceeded $2.9 billion, compared with $2.2 billion in 2004. For the first six months of 2005, earnings ran $242.4 million ($1.35/ share) compared with $194.4 million ($1.15/share). Utility electric sales totaled about 7.5 million MWh in the second quarter, compared with 7.8 million MWh in 2004. During the second quarter, Constellation made a major investment in natural gas production, putting $233 million in Texas and Alabama properties with reserves of 216 Bcf. The company plans to build a gas merchant business equivalent to its power business, said Thomas Brooks, president of Constellation Energy Commodities Group.

■ **DTE Energy** second quarter net income slid $6 million (17.1%) to $29 million, as better electric and gas utility profits were more than offset by unfavorable non-utility results. Company-wide revenue rose 29.6% to $1.94 billion. Earnings per share fell from 20 cents to 17 cents, on 174 million average basic shares and 175 million diluted, both up 0.6%. Detroit Edison net leaped from $8 million to $43 million, on revenue of $1.03 billion, up 23.9%. With cooling degree days soaring 76%, sales were up 7% to 14,393 GWh, led by a 25% jump in commercial, to 3,820 GWh. Residential and industrial both rose 8%. Results reflect the $336 million rate hike effective Nov. 24, 2004. Expenses rose 26.6% to $896 million, led by a 71.5% hike in fuel and purchased power, to $343 million. That left operating income up 51.1% to $139 million. Interest dipped $2 million to $69 million. Income taxes surged from $5 million to $21 million.

■ **NSTAR** earnings fell 11.7% for the second quarter compared to the same period last year as the company grappled with increased operating and maintenance expenses associated with an unfavorable court decision and an employee strike in May. The Boston-based utility reported net income of $33.2 million, or $0.31/share for the second quarter of 2005, compared to $37.5 million, or $0.35/share for the same period in 2004. "Results for the quarter were generally in line with our expectations," said Thomas May, chairman, president and CEO. The company saw an increase in distribution sales and transmission and incentive revenues, despite a 0.6% decline in electric sales primarily driven by mild weather early in the second quarter. But the gains were more than offset by higher than expected O&M costs created when the Massachusetts Supreme Judicial Court (SJC) reversed an earlier lower court ruling on an environmental issue surrounding subsidiary Boston Edison. As a result, the company increased its environmental reserve for the liability by $5 million. The court decision had a $7 million negative impact on the quarter. The other negative impact on earnings was a three-week long strike by 1,900 members of the Utility Workers Union of America AFL-CIO, Local 369. The strike cost the utility about $2.3 million, primarily for outside staff and security.

■ **Pinnacle West Capital Corp.** July 27 said its second-quarter net income plunged to $26.7-million (28 cents/share) from $72.6 million (79 cents/share) in the same quarter of 2004, largely because of a loss related to the sale of a power plant. Phoenix-based Pinnacle West's revenue climbed to $755.8 million in the quarter, up from $705.6 million in the year-ago period. Earnings from ongoing operations increased to $86 million from $54 milliion in the second quarter last year. Pinnacle West took an after-tax loss of $59 million (61 cents/share) on the pending sale of its share in the unregulated 570-MW Silverhawk power plant near Las Vegas, Nevada, the company said. The company's results were boosted by a recent rate hike, higher sales due to customer load growth and lower depreciation expense. Those factors were partly offset by an increase in operating costs mainly related to generation, customer

EARNINGS BRIEFS (CONTINUED)

service and benefits costs, the company said.

■ **Wisconsin Energy** July 27 reported second quarter 2005 net income jumped to $62-milliion (53 cents/share) from $39-million (33 cents/share) in the same period last year, largely due to the company's ability to recognize state tax operating losses at the parent company level, the Milwaukee, Wisconsin-based electric and gas utility company said. The tax issue accounted for a 14-cent/share gain in the quarter. Revenue climbed to $793 milliion in the quarter, up from $715 million in Q2 2004. Residential electric use jumped 11.9% in the second quarter, reflecting warmer summer weather compared with last year. Commercial and industrial use climbed 2.3%, the company said.

Northeast loses $22.7M in Q2 ... from page 10

for both its wholesale contracts and energy services operations.

Utility Group net sagged 18.4% to $22.1 million, led by a 35.8% drop, to $11.1 million, at Connecticut Light & Power, due mainly to a $4.4 million charge for a refund to street lighting customers ordered by the Dept. of Public Utility Control.

Net fell 33.3% to $2.4 million at Western Massachusetts Electric, and Yankee Gas Group lost $400,000, versus net of $200,000. Those more than offset a 50% gain, to $9 million, at Public Service Company of New Hampshire.

Company-wide revenue went up 1.7% to $1.55 billion. The loss per diluted share was 21 cents, versus earnings of 19 cents, on 129.52 million average shares, up 1%.

Operating expenses rose 7.6% to $1.54 billion, including $62.6 million of MTM charges and $2.3 million of restructuring and impairment charges (both pre-tax and up from zero). Fuel and purchased power increased 2.7% to $937.2 million.

That left operating income down 86% to $13.4 million. Net interest was up 15.9% to $73 million. Other income jumped 216.7% to $9.1 million. Income tax benefits were $24.3 million, versus costs of $10.5 million.

While NU is selling off its wholesale marketing and energy services business, it is retaining competitive retail marketing and generation.

Retail marketing arm Select Energy is showing strong growth, said Lawrence DeSimone, president of NU's competitive group. It is bidding on 50% more business than in 2004 and winning 20% of the bids, up from 13% last year.

DeSimone expects NU's 1,400 MW of generation to perform strongly because of New England's tightening capacity market — whether or not the Federal Energy Regulatory Commission okays Locational Installed Capacity (LICAP) pricing.

He projected that NU's hydro and fossil-fuel plants would get $50 million in capacity-related revenue in 2006 if LICAP begins Jan. 1 as planned, or just under $30 million if it does not.

But capacity revenues will continue to grow either way, reaching $120 million by 2009 with LICAP and $90 million without LICAP, he predicted.

Southern Q2 net goes up 9.9% to $387M, though cooler weather cuts sales 1.8%

Southern Co. second quarter net income rose $35 million (9.9%) to $387 million — despite cooler weather that pushed down power sales 1.8% — due to customer growth, utility rate hikes and higher profits from "competitive generation."

It was the best second quarter in company history, except for $432 million in 2003 which included an $83 million (after tax) gain on termination of all wholesale power pacts with Dynegy.

Company-wide revenue rose $135 million (4.5%) to $3.14 million, also a second quarter record. Basic earnings per share went from 48 cents to 52 cents, on 747 million average shares, up 1.2%.

Power sales were 47,714 GWh, down 1.8% from the quarterly record of 48,585 GWh set last year, led by a 5.2% slide in residential, to 11,204 GWh. Commercial fell 0.9% and industrial rose 0.2%. Southern adjusted 2004 figures to reclassify some Georgia Power industrials to commercial rates, under a new structure effective this year.

Wholesale dipped 1.8% to 9,262 GWh, but revenue was up $41 million (11.9%) to $385 million.

"Competitive generation" net income improved $13 million (28.3%) to $59 million. This included the Southern Power unit, where net went up $3 million (12.6%) to $25 million, though revenue slid $54 million (18.3%) to $149 million.

Power constructs, owns and/or manages Competitive assets — including some capacity owned by regulated utilities — and sells at market-based rates in the wholesale market.

Net from the Retail Business (utility retail operations) rose $17 million (6%) to $301 million — a quarterly record — as revenue went up $77 million (3.1%) to $2.55 billion.

Alabama Power saw the biggest dollar improvement, with net up $17 million (16.5%) to $121 million — another record — as revenue increased 2.6% to $1.09 billion. It benefited from the rate mechanism to recover costs with environmental laws and similar mandates, starting Jan. 1. That hiked rates $33 million (1%), with another 1% ($30 million) expected next year.

At Georgia Power, Southern's largest unit, net rose $2 million (1.2%) to $158 million, on revenue of $1.46 billion, up 7.8%. Results reflect the $194 million (4.2%) rate hike, effective Jan. 1, under a three-year retail rate plan.

Combined net from Gulf Power, Mississippi Power, and Savannah Electric was up $7 million (14.6%) to $55 million, on revenue of $597 million, up $32 million (5.7%).

Net from Southern's synthetic fuels investments, which stems from federal tax credits, rose $2 million to $23 million. Leasing Business net was up $1 million to $8 million. Both were second quarter records. The "parent company and other" net loss was down $2 million to $4 million.

Company-wide operating expenses were up $112 million (4.8%) to $2.43 billion, led by a $55 million (23.6%) hike in depreciation and amortization, to $288 million. Fuel and purchased power rose $48 million (4.4%) to $1.14 billion.

That left operating income up $23 million (3.3%) to $718 million — also a record, except for $801 million in 2003 which synfuels credits as well as tax reductions at Alabama under the 2004 order. Interest and preferred dividends went up $14 million (7.8%) to $194 million.

TECO Energy has $95.2M profit in Q2, with gain on sale of merchant plants

TECO Energy had $95.2 million of net income in the second quarter, up from a $108.2 million year-before loss, thanks mainly to a $76.5 million gain (in discontinued operations) from the May 31 transfer of the Union and Gila River merchant power projects to project lenders.

That was partially offset by a $45 million (after tax) charge for the June redemption of 10.5% senior notes. With that, the net loss at the "parent company and other" level jumped 228.6% to $65.4 million.

In 2004, net was slashed $98.7 million for a valuation adjustment on Texas Independent Energy projects, sold in August 2004, $19.3 million for income taxes on cash repatriated from Guatemala, and $6.7 million for a debt extinguishment charge on refinancing the San Jose plant there.

Company-wide revenue was up 7.5% to $719 million. Basic earnings per share were 46 cents and diluted 44 cents, both up from a 57-cent loss, on 206.7 million average basic shares, up 9.8%, and 208.9 million diluted, up 10.9%.

With the Union and Gila River gain and year-before charges, discontinued operations net was $82.7 million, versus a $26.3 million net loss.

Continuing operations' net was $12.4 million, versus an $81.9 million net loss — but all of the income came from minority interests, with net up 28% to $23.6 million. Before that, the net loss on continuing operations fell 88.8% to $11.2 million. All the following amounts are from continuing operations:

Tampa Electric net dipped 7.4% to $38.8 million, as revenue fell 0.9% to $425.4 million, on sales of 4,711 GWh, up 0.1%, led by a 27.2% jump in sales for resale, to 204 GWh. With combined heating and cooling degree days down 15%, residential fell 2.1%. Industrial — phosphate dropped 4.2%, and other industrial 3.4%. Commercial rose 1.3% and "other" 2.5%.

Peoples Gas System net went up $100,000 to $6 million, as revenue rose 6.9% to $113 million, though volume fell 12.4% on the milder weather.

TECO Coal net soared 60.4% to $28.4 million, on revenue of $128.2 million, up 55%, due to a 40% jump in coal prices.

TECO Guatemala — now reported as a separate segment — had net of $7.9 million, versus a $16.3 million net loss, though revenue fell 64.6% to $1.7 million.

TWG Merchant's net loss plummeted from $113.1 million to $8.6 million. Revenue fell from $1.6 million to $100,000.

Cinergy profits decline by 13% in Q2; company revises 2005 earnings outlook

Profits slipped 13% during the second quarter at Cincinnati-based Cinergy, with continued weakness in the company's unregulated gas operations leading the decline.

For the three months ended June 30, the parent company of Cincinnati Gas & Electric and PSI Energy reported net income of $51 million, 25 cents/share, on total operating revenues of $1.114 billion, down 13% from income of $59 million, 32 cents/share, on revenues of $1.053 billion for the year-ago quarter.

Consequently, Cinergy revised downward its 2005 earnings outlook from the previous $2.70 to $2.85/share to $2.50 to $2.65/share on an adjusted basis. The company is not releasing projections for 2006 at this time.

Earnings from the company's regulated businesses remained strong, accounting for 27 cents/share, up from 22 cents/share in the second quarter of 2004. The increase largely was attributed to improved electric gross margins resulting from the Indiana Utility Regulatory Commission approval's of an electric rate hike for PSI Energy, the state's largest electric utility, in May 2004.

But gas was another matter.

Cinergy's commercial gas segment's adjusted earnings dropped to 9 cents/share from 23 cents/share a year ago, reflecting a decline in gas marketing, trading and origination.

"Our gross margin was break-even and, consequently, did not cover our cost," said James Rogers, Cinergy chairman, president and CEO. Rogers said Cinergy lost some gas customers to competitors and "curtailed our activities and reduced our market position."

Michael Cyrus, formerly executive vice president and CEO of Cinergy's regulated businesses, said the commercial gas group "clearly missed our expectations this quarter." Cyrus, who has been reassigned to direct the commercial businesses, said the Cincinnati-based company is "moving quickly to restore the success of this business by making necessary organizational changes, attacking operating costs by consolidating support functions and again executing on our strengths in the physical and financial markets."

Despite the company's disappointing gas results, there is no reason to panic, said Rogers, who, at least temporarily, is running the regulated businesses. "One bad quarter doesn't totally change your strategy in driving the [gas] business," he told financial analysts during a July 28 webcast. "Over the last 12 quarters, the gas business has been very good for Cinergy. It's prudent for us to review the business, but it's been a good business for us."

Results from regulated businesses and other core electric generation activities, he added, "continue to meet our expectations." In addition to the gas segment's underwhelming performance, Cinergy said higher fuel costs and maintenance expenses also reduced earnings.

Quarterly results also included costs related to Cinergy's proposed $9.1 billion merger with Duke Energy (EUW, 16 May, 1). The companies hope to complete their corporate combination in the summer of 2006.

FirstEnergy Q2 net down 12.8% to $26M on write-off of deferred Ohio tax benefits

FirstEnergy second quarter net income fell $26 million (12.8%) to $178 million, due primarily to a $71.7 million (after tax) charge to write off Ohio deferred tax benefits that it does not expect to realize due to changes in the state tax system effective in June.

That more than offset a $16.4 million gain on Jersey Central Power & Light rate settlements okayed by the New Jersey Board of Public Utilities May 25, and year-before one-time items that cut net $17.6 million.

A year before there was a $10.6 million (after tax) charge on settlements of securities and shareholder derivative lawsuits, and a $7 million (after tax) loss on the sale of the 50% interest in Great Lakes Energy Partners, an oil and natural gas developer.

Company-wide revenue was down $62.9 million (2.1%) to $2.93 billion, but that mainly reflected a shift to "net" reporting of wholesale sales and related purchased power costs in the PJM Interconnection starting this year, and had no impact on earnings.

Earnings per share fell from 62 cents to 54 cents, on 328.06 million average basic shares and 329.88 million diluted, both up 0.2%.

Also July 27, FirstEnergy raised projected 2005 EPS (before nonrecurring items) from $2.70-$2.85 to $2.85-$3.00, citing strong generation performance, favorable Ohio and New Jersey regulatory rulings, and lower operating, benefits and depreciation costs. It also projected 2006 EPS for the first time, at $3.40-$3.60 (before unusual items).

FirstEnergy has "significantly improved our financial strength and flexibility through the retirement of more than $3 billion in debt" during the past three years, said President and CEO Anthony during a Webcast.

It usually does not issue following-year guidance until late in the year. But it did so in July "to improve transparency … a lot of folks were looking for guidance earlier and we're trying to be responsive to that," said Richard Marsh, senior vice president and chief financial officer.

Asked about potential investments, Marsh said FirstEnergy has been searching for generation in PJM but has found nothing. "We're probably not going to find anything in that area for the time being," he said. "So, cash will be invested in the regulatory portion of the business."

In FirstEnergy's business segments:

Regulated Services net improved 14.4% to $267.1 million, as power sales revenue went up 3.5% to $1.16 billion, on deliveries of 26,274 GWh, up 2.4%, led by a 9.5% hike in residential, to 8,453 GWh. Commercial rose 2.9% and industrial fell 3.8%. Cooling degree days were down 8.6% but heating degree days rose 25.7%. Other revenue increased 21.9% to $186.2 million.

This segment includes utility transmission and distribution and American Transmission Systems, Inc.

Results reflect the JCP&L settlements, which FirstEnergy expects to boost 2005 net income about $36 million, including about $19.7 million from higher revenue.

Operating expenses rose 4.7% to $879.2 million, led by a 13.1% hike in amortization of regulatory assets, to $306.7 million. But that was mostly offset by $120.2 million (up 75.9%) for deferral of new regulatory assets — tied to accelerated JCP&L tree trimming costs expensed in 2003-04 — booked as a cut to expenses. That added $16.4 million to second-quarter net.

With that, operating income rose 6.5% to $551.6 million. Net interest dropped 12% to $95.2 million, reflecting debt retirements and refinancings, and dividends on preferred stock 30.7% to $3.7 million.

Power Supply Management Services (formerly Competitive Electric Energy Services) net slumped 71.3% to $10.7 million, as power sales revenue fell 13.5% to $1.31 billion, though generation sales rose 1.5% to 30,681 GWh. Other revenue jumped 112% to $64.9 million.

This segment includes FirstEnergy Solutions, FirstEnergy Generation Corp. and FirstEnergy Nuclear Operating Co., which sell in deregulated markets and operate plants owned by FirstEnergy's utilities in Ohio, which has deregulated generation.

Expenses were down 8.5% to $1.35 billion, led by a 27.8% slide in purchased power, to $652.4 million. Fuel jumped 46.3% to $280.2 million.

That left operating income down 63.9% to $26.4 million. Net interest was down 16.3% to $8.3 million and income taxes 71.3% to $7.4 million.

Facilities (HVAC) Services lost $2.8 million, versus year-before net of $1.5 million, though revenue rose 12.1% to $56.4 million.

Other Operations' net plunged 85.6% to $5.3 million, on revenue of $136.8 million, up 15.3%. This includes MYR (a construction service company) and telecommunications services. They formerly included FES natural gas operations, sold in December 2004.

Progress Energy loses $1M in Q2 on job cut and tax allocation costs

Progress Energy lost $1 million in the second quarter, down from year-before net income of $154 million, due mainly to $87.1 million (after tax) of costs for job cuts that began in February.

Net was also cut about $61.5 million for intra-period federal income tax allocation, but this does not impact net for the year. Tax regulations require Progress to adjust quarterly tax rates to be consistent with the expected annual tax rate.

Company-wide revenue was up $210 million (9.9%) to $2.33 billion. The per-share loss was 1 cent, versus earnings of 63 cents, on 246 million average shares, up 1.6%.

The main impact of the job cuts charge was at Progress Energy Florida ($56.2 million), plus $27.7 million at Progress Energy Carolinas, $2.6 million at Progress Fuels, and $600,000 at Competitive Commercial Operations.

However, the $145.2 million (pre-tax) amount was less than the $180 million Progress predicted in the first quarter Form 10-Q. Most of the cost is for postretirement benefits that are to be paid over time to employees who chose the voluntary enhanced retirement package.

Progress, as did Xcel Energy (see story, page 16), warned that it could see a "material impact" if the Financial Accounting Standards Board adopts as proposed its July 14 exposure draft "Accounting for Uncertain Tax Positions—an Interpretation of

FASB *Statement No. 109—Accounting for Income Taxes*."

The Internal Revenue Service a year ago challenged synfuels tax credits taken on Progress' Earthco facilities, and the situation remains unresolved (EUW, 26 July '04, 10). Through March 31, 2005 the company used or carried forward about $1.1 billion of credits generated by Earthco. If they were disallowed, the one-time exposure for cash tax payments would be $300 million, and earnings and equity would be reduced by about $1.1 billion to reverse the tax credits (both excluding interest), Progress estimated in the first quarter 10-Q.

By segment, Carolinas net income slid 29.9% to $68 million, as electric operating revenue dipped 0.1% to $860 million, due to the job cuts and income tax costs, and milder weather. Heating degree days were up 31.3% but cooling degree days slid 36.5%, so power sales fell 2.5% to 13,492 GWh, led by a 6.8% drop in residential, to 3,285 GWh. Commercial fell 2.7% and industrial 1.5%. Wholesale rose 7.3%.

Florida net plunged 88.1% to $10 million, though revenue rose 5.6% to $908 million, for much the same reasons, partially offset by a $25 million (pre-tax) gain on the sale of the Winter Park distribution system to a new municipal utility (EUW, 2 May, 4). With CDDs down 6.5%, sales fell 3.2% to 10,777 GWh, led by a 3.6% drop in residential, to 4,341 GWh. Commercial fell 1.8% and industrial 1%, but wholesale jumped 20.6%.

Progress Ventures' net slid 59% to $9 million (excluding synfuels), with Progress Fuels down 29.4% to $12 million and CCO losing $3 million, versus year-before net of $5 million. CCO was impacted by lower margins due to expiration of tolling pacts, and lower power sales at market prices, partially offset by earnings from new full-requirements pacts.

Synfuels net dropped 36% to $23 million, due to lower sales and higher production costs.

The net loss at Other Businesses fell from $31 million to $2 million, due to the 2004 $29 million charge for the contract settlement between the defunct Strategic Resource Solutions unit and San Francisco's school district.

Company-wide operating expenses were up $291 million (15.8%) to $2.22 billion, led by a $171 million (46%) leap in operation and maintenance, to $543 million, due to the job cut costs. Diversified businesses' cost of sales rose $151 million (38.9%) to $539 million.

That left operating income down $171 million (59.6%) to $116 million. "Other income" jumped from $1 million to $23 million, due to the Winter Park sale. Net interest rose 5.8% to $164 million. Tax benefits jumped 83.3% to $22 million.

In discontinued operations, Progress booked an additional $7 million loss on the March 24, 2005 sale of Progress Rail, due to adjustments to working capital and the estimated loss. A year before Rail net was $8 million.

Allegheny Q2 net loss down $21M to $18.4M on lower loss at Generation & Marketing unit

Allegheny Energy's second quarter net loss narrowed $21 million to $18.4 million, as a lower net loss in the Generation & Marketing segment more than offset a profit slump in Delivery & Services.

The per-share loss fell from 31 cents to 12 cents, on 156.73 million average shares, up 23.4%, reflecting the April tender offer for $295 million of Allegheny Capital Trust I 11 7/8% Mandatorily Convertible Trust Preferred Securities. For each $1,000 tendered, a holder got 83.33 common shares and $160 in cash, booked as interest costs. The offer slashed net by $29.8 million (after tax).

D&S net slid $13.8 million (57%) to $10.4 million, on revenue of $663.2 million, up 7%, as sales rose 0.6% to 11,369 GWh, with cooling degree days down 1%. Operating expenses rose 2.2% to $604.3 million, led by a 2.8% hike in purchased power and transmission, to $436 million.

That left operating income down 12.2% to $58.9 million. Interest and preferred dividends jumped 46% to $47.3 million, due to the tender offer. Income taxes slumped 76.5% to $3.2 million.

But the loss on discontinued operations soared from $1.2 million to $6.5 million.

G&M's net loss was down $34.9 million to $28.8 million, on revenue (before eliminating intra-company amounts) of $404.5 million, up 26.2%, on sales of 11,052 GWh, up 8.2%.

Expenses dipped 1.7% to $351.3 million, led by a 24.3% slide in operation and maintenance, to $103.3 million, due to 2004 unplanned outages at the Pleasants and Hatfield's Ferry plants (EUW, 9 Aug '04, 11). G&M also got $6.7 million this year from insurance on the Hatfield's outage. Those were somewhat offset by a 17.7% hike in power plant fuel, to $166.1 million, due to higher coal prices and consumption.

That left operating income of $53.2 million, versus a $36.9 million loss in 2004.

"Other income" soared from $300,000 to $12.9 million, thanks to $11.2 million of forfeited assets received from Daniel Gordon, former head of energy trading subsidiary Global Energy Markets. That boosted net $6.9 million.

Interest and preferred dividends jumped 37.6% to $82.4 million. The loss on discontinued operations rose 5.4% to $5.8 million, due mainly to an $8.9 million impairment charge on West Virginia gas operations and Midwest power plants.

NiSource Q2 net improves 12.7% to $39M, but only with gains tied to sold operations

NiSource second quarter net income went up $4.4 million (12.7%) to $39 million, but all of the increase stemmed from a $42.7 million (after tax) gain on adjustments to reserves for contingencies, and impairment charges, related to previously sold discontinued operations.

Without that, it would have lost $3.7 million, versus year-before net income of $34.6 million.

Revenue was up 8.3% to $1.42 billion. Basic earnings per share were 15 cents and diluted 14 cents, both up from 13 cents, on 271.2 million average basic shares, up 3.3%, and 273.1 million diluted, up 3.2%.

NiSource had $31.2 million of costs tied to the IBM outsourcing deal (EUW, 27 June, 1), for job cuts ($16.4 million), consulting fees ($3.9 million), and impaired obsolete software ($10.9 million). Most of that was at the Corporate level ($15.3 million) and the Gas Distribution segment ($11.2 million).

That cut net income about $19 million. Gas Distribution also wrote off $10.9 million (after tax) of "goodwill" at Kokomo Gas and Fuel (acquired in February 1992), which is operating under an earnings cap.

"We had a good quarter," President and CEO Robert Skaggs said during a July 28 Webcast. "Our business fundamentals continue to remain strong, cash flow is strong and our customer base continues to grow." He called 2005 a "base year" during which the company hopes to build a platform for sustainable growth, with outsourcing a key component.

"[We are] right on track with this process … IBM is on site and working at several of our operating units," Skaggs said. Under the program, more than 1,000 jobs were outsourced or cut.

NiSource expects IBM-related charges for the rest of this year of $40 million to $45 million. But it projects the 10-year deal will save up to $530 million.

Electric Operations segment operating income fell 25.6% to $61 million, on revenue of $282 million, up 5.5%. Cooling degree days jumped 36.6%, but sales fell 2.1% to 4,153 GWh, led by a 32.3% slide in wholesale, to 196 GWh. Industrial fell 6.1% to 2,185 GWh. However, residential rose 10.6% and commercial 9.9%.

Cost of sales rose 8.8% to $92.4 million, leaving gross margin (called "net revenue" by NiSource) up 3.9% to $189.6 million.

But operating expenses were up 28% to $128.6 million, led by $13.8 million of "other taxes," versus a $2.7 million credit in 2004, which reflected cuts in accruals for property and sales taxes. Also, operation and maintenance rose 17.3% to $69 million, including $1.8 million for IBM-related costs.

Gas Distribution operating income slumped 62.2% to $5.7 million, on revenue of $748.4 million, up 6.4%, due to IBM-related costs and the Kokomo charge. Though heating degree days rose 12%, volume fell 7.6% due to a 52% slide in off-system sales.

Gas Transmission and Storage operating income rose 4.5% to $76.8 million, on revenue of $195.8 million, up 0.6%. The "Other" segment, including assets held for sale, saw the operating loss rise 14% to $8.9 million, on products and services revenue of $192.5 million, up 33.2%.

With the IBM-related charge, the Corporate-level operating loss jumped 204% to $15.2 million.

The after-tax loss on discontinued operations still owned by NiSource soared from $900,000 to $11.6 million. These include the Sand Creek Golf Club, owned by the Lake Erie Land subsidiary, and "non-core" pipeline assets of Columbia Transmission.

Xcel Energy Q2 net dips 3.4% to $82.3M; warns of hit on FASB 'tax positions' rule

Xcel Energy second quarter net income fell $2.9 million (3.4%) to $82.3 million, as slightly better utility results were more than offset by much higher nonregulated losses and higher interest and taxes.

Regulated utility earnings from continuing operations improved 5.6% to $94 million, as electric utility gross margin improved $60 million (8.4%) to $777 million, including $25 million from non-weather-related sales growth and $22 million from warmer weather. Retail power sales increased 4.7%, led by an 8.2% rise in residential.

That was slightly offset by Jan. 21 sale of Cheyenne Light, Fuel & Power to Black Hills Corp.

But losses from continuing nonregulated operations and at the holding company soared from $500,000 to $13 million.

Also in the July 27 earnings release, Xcel warned that it would have to take a $350 million charge against this year's net income if the Financial Accounting Standards Board adopts as proposed its July 14 exposure draft "Accounting for Uncertain Tax Positions—an Interpretation of FASB *Statement No. 109—Accounting for Income Taxes*."

The draft would clarify accounting by requiring entities to recognize in financial statements the best estimate of the impact of a tax position only if it is probable of being sustained on audit based solely on technical merits. The comment period ends Sept. 12, 2005.

The Internal Revenue Service has challenged 1993-2001 income tax deductions for corporate-owned life insurance policies on current and former Public Service of Colorado employees. A hearing is set for Aug. 19, in U.S. District Court for the District of Minnesota, on motions for summary judgment by Xcel and the IRS in Xcel's April 2004 lawsuit seeking to establish its right to the COLI deductions.

Second-quarter operating revenue was up $303.9 million (17.2%) to $2.07 billion. Earnings per share dipped from 21 cents to 20 cents, on 402.2 million average basic shares and 425.5 million diluted, both up 0.7%.

Operating expenses rose $300.2 million (19.2%) to $1.86 billion, led by a $189.4 million (26.2%) hike in utility fuel and purchased power, to $912.4 million.

That left operating income up $3.7 million (1.9%) to $202.5 million. Interest and other income was $5.1 million, versus a $296,000 year-before loss.

But non-cash income from allowance for equity funds used during construction slid 33.8% to $5.4 million, interest and financing costs rose 4.6% to $109.8 million, and income taxes jumped 55.4% to $24.8 million.

That left net from continuing operations down 8.3% to $78.4 million. Net from discontinued operations jumped from $792,000 to $5 million.

ENVIRONMENT

A small number of plants in Northeast produce most CO2 emissions, report says

A small number of plants produce most of the carbon dioxide emissions in the Northeast U.S. power sector, so CO2 cuts at those units could significantly reduce the region's contribution to global warming, according to a new report by some environmental groups.

The Regional Greenhouse Gas Initiative (RGGI) could greatly improve the emissions situation, but that proposed cap-and-trade system must be designed carefully, they said.

"More Heat than Light" was released last week by Environmental Advocates of New York, the National Assn. of State Public Interest Research Groups, MassPIRG and the Clean Water Fund.

According to the report, 10 plants in the Northeast produced one-third of all CO2 during 2004. These are: Brayton Point, Mass., owned by Dominion, which emitted 5.7 metric tons or 1,757 pounds/MWh; Northport, N.Y., KeySpan, 5.2 tons, 1,727 lbs/MWh; Canal, Mass., Mirant, 4.2 tons, 1,680 lbs/MWh; Somerset, N.Y., AES, 4.1 tons, 1,608 lbs/MWh; Mystic, Mass., Boston Generating; 3.9 tons, 950 lbs/MWh; Ravenswood, N.Y., KeySpan, 3.7 tons, 1,711 lbs/MWh; Dunkirk, N.Y., NRG, 3.2 tons, 1,988 lbs/MWh; Roseton, N.Y., Dynegy, 3 tons, 1,774 lbs/MWh; Huntley, N.Y., NRG, 3 tons, 2,100 lbs/MWh; Linden Cogen, N.J., Newmarket Energy/MMC Energy, 2.8 tons, 1,180 lbs/MWh.

Christine Vanderlan, energy program associate at Environmental Advocates, said the CO2 figures were calculated by the Frontier Group, which obtained fuel consumption data for the plants from the U.S. Energy Information Administration, and then applied Dept. of Energy emissions factors for different fuels.

Those plants emitted twice as much carbon per unit of generation (1,570 lbs/MWh) as the regional average (850 lbs/kWh), according to the report.

Further, over 80% of all emissions from electricity generation came from 50 plants that produced 45% of the region's electricity. Those 50 plants produced 90% of the region's sulfur dioxide (SO2) and 81% of the nitrogen oxides (NOx).

Nine states in the Northeast are developing a carbon cap-and-trade plan under the Regional Greenhouse Gas Initiative (RGGI), which could begin in the fall (EUW, 6 June, 10). The environmental groups applaud that effort, but argue that the regulations "should not create a windfall for owners of dirty power plants" by giving them allowances for free. The sale of allowances should provide funding for renewable energy and efficiency, they say.

The groups also recommended that RGGI regulations reduce global warming emissions by 25% below current levels by 2020, and grow tighter over time. Reductions from outside the region should not be allowed for compliance with the initial cap, they added.

"More Heat than Light" is posted on the MassPIRG web site (www.masspirg.org) under "Reports."

RECs are scarce and costly, so Mass. agency proposes including old biomass in program

With renewable energy certificates (RECs) scarce and the cost high in Massachusetts, a utility and other companies recently came out in support of a controversial proposal that would allow more biomass projects to participate in the program.

Only newly built renewable energy projects can generate RECs in Massachusetts, but the state Division of Energy Resources has proposed making existing biomass plants eligible.

Companies that feel the impact of REC prices, such as utilities, wholesale and retail suppliers, and business energy users, say the plan will reduce certificate scarcity, drive down costs and create a well-functioning market. Wind energy supporters and other groups oppose the plan, saying older, more polluting biomass plants could flood the REC market and seriously deflate REC values, discouraging development of new renewable projects.

Massachusetts utilities and retail suppliers are required to purchase up to 2% of retail supply from renewables this year under the state's renewable portfolio standard. Because they are in short supply, RECS are selling in the low $50/MWh range in public auctions, close to the $53.19/MWh penalty utilities and suppliers must pay the state if they cannot secure the certificates. The penalty charge, known as an alternative compliance payment, goes into a state trust fund to develop more renewables.

Massachusetts Electric said it supports reasonable broadening and clarification of existing rules to create more market certainty. "In particular, Mass. Electric suggests that DOER accomplish these objectives so that additional renewable projects will be developed. This will help to reduce the current shortage of renewable energy credits, reduce the need to make alternative compliance payments, and drive down the cost of RECs for Massachusetts customers."

At the same time other renewable energy developers, such as those developing wind and new biomass, question the wisdom of allowing older plants into the program. Russell Biomass, which is developing a 50-MW biomass plant in Russell, Mass., says that allowing older biomass plants to generate RECs will destabilize the market. As a result, new biomass plants will find it more difficult to secure financing, since their success is heavily dependent on REC values.

If the proposal moves forward, about 400 MW to 600 MW of New England biomass would become eligible to generate certificates, according to Russell Biomass. At a 60% to 90% capacity factor, this represents over 3,000 GWh/year, which cuts significantly into the demand for RECs created by the Massachusetts and Connecticut RPS programs, the two states currently responsible for the largest certificate demand.

New biomass already appears to be at a disadvantage, according to Russell Biomass, which said that no new greenfield biomass plants have applied for a major permit in the two years that the Massachusetts RPS program has been in effect. The Russell project plans to begin permitting this year and start construction in 2007. But, the company added that it is "still not clear that we can obtain the long-term contract REC-purchase or floor guarantee commitments that will allow our project to achieve financing."

Massachusetts' RPS law says biomass must use "low-emission, advanced biomass power conversion technologies" but does not define those technologies. As a result, it's not clear if a plant that undergoes certain retrofitting meets the criteria and can be considered a new renewable. The DOER has been reviewing the retrofits on a case-by-case basis, but hopes to set clear policy to avoid this practice.

Air Force seeks 847,000 MWh of RECs for various sites; bids due Aug. 12

The U.S. Air Force is seeking 846,875 MWh of renewable energy certificates (RECs) for various sites. The solicitation (SP0600-05-R-0415) was issued last week by the Defense Energy Support Center (DESC).

RECs represent the green attributes and price premium of renewable energy, but are sold separately from the power itself. This allows buyers to acquire renewable energy if there are no facilities in the area, and the sale of RECs helps developers finance projects.

The Air Force is seeking RECs as part of the Environmental Protection Agency's Green Power Partnership program. It will not accept RECs created by hydroelectric power.

This solicitation will provide RECs for: Hill AFB in Utah; the Air Education & Training Command at Randolph AFB in Texas; the Air Combat Command, which has facilities throughout the country; and the Air National Guard, which also has multiple sites.

The RECs must be delivered by Sept. 30. They must be generated during the contract year of the delivery date, six months before the contract year, or three months after the contract year.

Verification of the RECs is required from an independent third party that has no stake in the sale. Bidders must also provide affidavits attesting that the RECs have not been sold to another party and are not being used to comply with any regulations.

Technical proposals (outlining qualifications) and price offers are both due on Aug. 12. The Air Force requires firm, fixed price bids.

The solicitation is posted at DESC's website (www.desc.dla.mil). Click on "Solicitations" then "Electricity."

Questions may be addressed to: Contract Specialist Leslie Simpson at (703) 767-8536 or leslie.simpson@dla.mil; Contract Specialist Lisa Robert at (703) 767-8533 or lisa.robert@dla.mil; or to Contracting Officer Andrea Kincaid at (703) 767-8669 or andrea.kincaid@dla.mil.

Ohio PUC staff supports IGCC technology but questions AEP financing for 600-MW plant

Ohio should encourage the development of coal gasification plants to prepare for a "carbon-constrained world" many believe is on the way. But American Electric Power's plan to construct a 600-MW integrated gasification combined cycle (IGCC) facility in Meigs County may not be the most consumer-friendly way to finance such expensive ventures.

That's the upshot of testimony filed with the Ohio Public Utilities Commission last week by the PUC staff. The commission is reviewing AEP's March request for upfront regulatory assurances the company's Ohio Power and Columbus Southern Power subsidiaries will be able to fully recover the cost of the estimated $1 billion IGCC project (Case No. 05-376-EL-UNC) (EUW, 14 March, 19).

AEP's financing proposal was portrayed by staff as the "traditional method of financing capital projects for the integrated public utility under traditional cost-of-service regulation." Ohio has had electric choice since Jan. 1, 2001. The General Assembly passed electric utility restructuring legislation in 1999.

The PUC staff, noting the state's newest coal plant is 14 years old and the average age of Ohio's coal-fired generation fleet is 44 years, said clean coal technology, in particular IGCC, should be pursued.

Kimberly Wissman, deputy director of the PUC's utility department, said the U.S. must "fulfill its strategic energy policy by displacing foreign dependency with self-supply, as well as accommodating efficient and effective use of its scarce resources."

But it is not clear AEP's preferred method of financing is the proper path, said Richard Cahaan, chief economist in the capital recovery and financial analysis division of the PUC utility department.

"Other methods are possible," he said. One possibility is "project financing ... in which a significantly lower equity ratio is used. For instance, there have been projects financed with 80% debt. Generally, one would expect that both the debt and equity rates would be higher with the increased leverage, but that the overall rate would be lower."

Cahaan said the issue of least cost extends beyond "the questions of technology and physical construction to the areas of financing and institutional arrangements. The problems which are being put to the Commission in this proceeding require innovative approaches and solutions, and the proposed cost recovery mechanism is an example of such thinking. There are no precedents here. If we are required to forge new ground, we should also examine possibilities for innovation in financing arrangements as well."

To the extent other funding options are available such as federal grants or loan guarantees, AEP "should further explore taking advantage of those," added Wissman.

An AEP spokeswoman said if an attractive financing option presented itself, "we would consider taking advantage of it." But she said the Columbus, Ohio-based company has no interest in partnering with another company or the federal/state government in building an experimental IGCC plant.

The PUC is expected to rule on AEP's application before the end of the year. The company wants to begin construction sometime in 2006 and place the facility in commercial operation around the end of the decade.

Push for U.S. greenhouse gas regulations seen as move to protect European business

State and regional greenhouse gas regulations in the U.S. are part of a European effort to extend non-scientific policies and protect its business, according to a new paper. Standards originating in Europe are affecting U.S. businesses by "regulation without representation," according to Lawrence Kogan, director of the Princeton, N.J.-based Institute for Trade, Standards and Sustainable Development (ITSSD).

Kogan makes that argument in a new paper entitled, "How Europe's New Regulatory Protectionism Imperils American Free

Enterprise." Recently released by ITSSD, the paper will be posted in the near future by the Washington Legal Foundation.

Kogan does not deny that climate change is occurring, but said in an interview that "The jury is still out" on whether the change is cyclical or due to human activity.

Meanwhile, many environmental, health and safety (EHS) standards are being based on "an evolving international legal norm" known as "the precautionary principle," which his paper calls a "non-scientific, 'better safe than sorry' risk-averse philosophy of regulation."

European regulators have adopted the approach, and want to impose it on the U.S., the paper says. In fact, these "hazard based" regulations are becoming increasingly popular in the U.S.

"Greens have red underbellies," Kogan said in an interview. "After the fall of the Berlin Wall, communists needed to find a new vocation, so they embraced environmental issues." He added that "The U.N. is the best forum to spread the message" via the Kyoto Protocol, and that Europeans are determined to impact the U.S., despite the country's shunning of the Kyoto system.

Kogan asserts that European influences are helping to shape the Regional Greenhouse Gas Initiative (RGGI), a plan launched by New York Gov. George Pataki, R, to establish a carbon cap-and-trade system (EUW, 6 June, 10). Nine northeastern states are participating and two others may join RGGI, which could begin in the fall. RGGI is meant to be a model for the nation, and has already spawned a "clone" that would cover California, Oregon and Washington, Kogan notes. It may also link up with the European Union's Emissions Trading Scheme (ETS) through "mutual recognition agreements."

His paper asserts that "the seeds of RGGI had been sown" earlier by a Washington think tank called the Center for Strategic & International Studies (CSIS), "which has advised the EU to practically bypass the White House in favor of the states."

The effort is misguided, he says, because RGGI "will have no measurable scientific or environmental impact on global warming." Further, RGGI will interfere with interstate commerce because energy imported into the RGGI states will be subject to the initiative's rules. And RGGI stakeholder forecasts show that energy prices will rise for 10 years as a result of the program, partly due to the retirement of older coal and oil plants, Kogan says. These price hikes will be passed along by businesses, so that companies in the RGGI area "will be placed at a competitive disadvantage *vis-à-vis* their non-RGGI competitors (domestic as well as international)," the paper states.

Other initiatives are proceeding as well, including state restrictions on CO_2 and efforts by state pension funds to exert pressure on companies over GHG issues (EUW, 27 June, 2).

State attorneys general have also filed lawsuits, "hoping to move climate change policy from the elected branches to the courts," because "neither the Congress nor the Administration has chosen to address climate change issues in the manner advocated by European leaders and trans-Atlantic environmental groups," he adds. Kogan refers to a suit filed by eight state attorneys general aiming to force five utilities to reduce CO_2 emissions (EUW, 28 Feb, 9; 26 July '04, 1).

He also notes a number of efforts to impose climate change regulations through the comprehensive energy bill. Kogan favors the final bill's approach of providing loan guarantees and tax benefits for clean energy projects. These provide environmental benefits "without jeopardizing the American free market enterprise and legal systems and the American comparative advantage in international trade," the paper states.

The paper is posted on ITSSD's web site (www.itssd.org) under Library/White Papers.

Christopher James, director of the Connecticut Dept. of Environmental Protection, rejected Kogan's contention that RGGI is adopting European regulations. Rather, the EU based its ETS program on the U.S. Environmental Protection Agency's acid rain program and NOx budget program, he said. RGGI was also a "logical outgrowth" of the acid rain and NOx programs, James commented.

He also said Kogan took one of his comments "out of context" in a footnote, quoting James saying that each state in RGGI "is much like a member state in the EU — a sovereign state subject to its own processes and regulations." James said he was not equating the U.S. states with European countries, but trying to illustrate to people outside the U.S. that states do not necessarily act in the same way.

FEDERAL POLICY

Southern wins one rollover-rights conflict with FERC; its battle on the policy remains

Southern Company's recent court victory over the Federal Energy Regulatory Commission in a case involving transmission rollover rights is a small step toward the utility's goal of changing FERC's policy on rollover rights, a spokeswoman said last week.

"This is a small piece of the puzzle, but we still have a long way to go in challenging the policy," a Southern spokeswoman said.

The case involved a one-year transmission service contract Southern signed with Oglethorpe Power in October 2001, for service starting in December of that year. When Oglethorpe sought to roll it over the next year, Southern filed a rollover agreement with FERC on Dec. 20, 2002, explaining that it would allow a rollover provided it had enough transmission to serve its own native load.

FERC rejected the provision. It said that under its open-access rule, Order 888, utilities cannot put native-load limits on rollover contracts if the limits were not in the original contracts. Southern's agreement was thus not allowed and was a "collateral attack" on Order 888, FERC said.

But the U.S. Court of Appeals for the District of Columbia Circuit said July 22 that Order 888 or 888-A did not include that provision (Case No. 03-1252). FERC had argued that 888-A said the limitation on rollover rights had to be specified in the contract, and Southern should have known that meant the original service agreement. The court disagreed: "Regardless of whether rollover agreements are new contracts or extensions of the original, there is no doubt that they are themselves 'contracts'." The rule did not specify the "original" contract.

It was only later, in a case involving Nevada Power in December 2001, the court agreed with Southern, that FERC set the original-contract requirements. FERC offers "no rationale for applying the requirement to a rollover when the provider did not know of the requirement at the time it executed the original service agreement," the court said. "And they make no argument that system reliability can still be assured if the requirement was imposed without adequate notice."

Southern is fighting FERC's rollover-rights policy in other cases, some of which have more to do with the policy itself, unlike this one, which was decided on the basis of when FERC's policy was set. The Southern spokeswoman said FERC's policy on rollover rights should be changed so companies can negotiate their own contracts instead of being forced to offer rollover rights even in cases where they are not warranted or necessary. "We would like to negotiate our own contracts," she said.

FERC's rule is "just problematic" because it thwarts cost-effective transmission planning and construction, she said.

Energy bill heads to Bush, with PUHCA repeal, more FERC authority ... from page 1

between House and Senate, hailed the electricity title as the one he is "most proud of" with its provisions "to usher in innovations to the generation of electricity, to the transmission of electricity, to the distribution of electricity and to the consumption of electricity."

The title contains provisions to facilitate mergers and acquisitions by repealing the Public Utility Holding Company Act, six months after enactment, although also expanding Federal Energy Regulatory Commission authority to include review of utilities' generation-only acquisitions valued at more than $10 million and review of holding company mergers.

PUHCA repeal, which had been sought for as long as 15 years, is seen as a key to future merger activity and possibly diversification in the industry that some say could change the face of the power sector. Warren Buffett's Berkshire Hathaway, for example, is eager to buy more utilities after completing its proposed purchase of PacifiCorp; Buffett already owns most of MidAmerican Energy Holdings (EUW, 30 May, 3).

The merger-review section also requires FERC to complete action on a merger application within 180 days, although the time limit does not apply to mergers that have already sought commission approval. In fact, however, the commission has been acting on mergers within that time in recent years.

For transmission, the bill transforms the decades-old current voluntary reliability program into a mandatory organization to develop and enforce standards for users of the nation's power grid. The plan is one at least a few years in the making. The North American Electric Reliability Council has been working for some time already on the steps required to become the North American Energy Reliability Organization, with FERC as a backup federal authority.

The bill authorizes FERC to grant permits for critical transmission lines and allows utilities to use their transmission rights to protect their native load customers.

The bill imposes a broad ban on manipulation of the wholesale power market, allows but does not require FERC to issue rules to set up an electronic information system to provide public access to wholesale power prices and availability; while boosting civil and criminal penalties for violations of the Federal Power Act.

As part of its 10-year multibillion-dollar tax incentive package, the bill accelerates the depreciation period for transmission investment to 15 years, and allows utilities that sell their transmission assets to a FERC-approved independent company eight years to pay the tax on any gain. The bill provides the first production tax credit for nuclear power facilities and the first investment tax credit for low-emission advanced technology coal facilities.

The bill had the support of the principals of the 65-member House-Senate negotiating conference: Barton and his committee's ranking Democrat John Dingell of Michigan, and Senate Energy and Natural Resources Committee Chairman Pete Domenici, R-N.M., and ranking Democrat Jeff Bingaman of New Mexico. They signed the conference report in support of the compromise bill and credited the open process Barton employed in drafting the legislation to its broad support.

"This is not a perfect bill, but it is a solid beginning to developing an energy strategy for the 21st century. It is a balanced product that will serve the country well," Dingell said.

Just about all segments of the electricity industry said they were satisfied with the final product, which they called balanced and fair.

"The strongly bipartisan vote in the House today is a vigorous endorsement of this energy bill," said Tom Kuhn, president of the Edison Electric Institute. "A vote of 275-156 sends an important signal to the Senate that after a 13-year hiatus, the country wants and deserves an updated national energy strategy that will both expand our energy production infrastructure while also boosting efficiency and conservation."

The National Rural Electric Cooperative Assn. also lauded the process and the bill's inclusion of measures to allow co-ops to participate in the energy marketplace, and to invest in renewable energy, without losing their tax-exempt status or suffering other consequences.

The Electric Power Supply Assn. praised the measure's support for growth in competitive power markets. "The electricity title, especially, will create a new climate of regulatory certainty for many companies in the industry, and particularly their customers," EPSA President and CEO John Shelk said.

Despite the bill's repeal of PUHCA, the American Public Power Assn. said it "strongly" supported the bill for a number of provisions, including those that create renewable tax credit bonds, clarify that transmission-line "participant funding" plans are at FERC's discretion, streamline the hydroelectric licensing process and preserve long-term transmission rights for load-serving entities.

"When you get a bill that satisfies the IOUs, the munis and co-ops and merchant generators, that is a pretty good trick," said Joe Nipper, APPA senior vice president for government relations. The open markups and making the bill text available to the public "clearly was key to their success," he said.

The large customer group that initially had concerns with the bill came out in favor of it and said it was eager to see its final passage. John Anderson, president and CEO of the Electricity Consumers Resource Council, said the bill no longer ties the hands of FERC by mandating participant funding of transmission projects, will not raise power costs by requiring a renewable portfolio standard that the Senate endorsed but that was rejected by House conferees, and provides "substantial merger review provisions" for FERC as PUHCA's merger restrictions disappear.

"We are pleased that the electricity provisions have improved as much as they have," said Anderson.

Much of the criticism of the bill was aimed at its provisions and billions in tax breaks for the oil and gas industries and mobile sources. Many legislators bemoaned the bill's failure to include corporate average fuel efficiency standards for passenger vehicles.

The bill "is tipping U.S. consumers upside down and shaking money out of their pockets," said energy bill conference member Rep. Edward Markey, D-Mass., who deemed the legislation "socialism at its worst." "Right now Adam Smith is spinning in his grave so fast that he would qualify for a subsidy in this bill as an energy source."

One consumer group, Public Citizen's Critical Mass Energy and Environment Program, decried the provisions giving incentives for transmission infrastructure activity. "Rather than improving reliability (as is its stated purpose)," Public Citizen said, "this incentive-based ratemaking will simply act as a tax increase on consumers — with consumers receiving no guarantee that the higher rates they will be paying will lead to better service."

The group also criticized, among other things, the provisions adding to FERC authority to balance repeal of PUHCA. "In PUHCA's place, FERC would be given a virtually meaningless right to look at the "books and records" of conglomerates the size of GE, ExxonMobil, J.P. Morgan and Berkshire Hathaway in the off-chance that FERC could discover whether these vast conglomerates have affiliates whose activities have in any way affected their affiliated utility's rates," Public Citizen said. "State review of such huge companies, the adequacy of which review would clearly be absurd in any case, would have even more restricted rights to look at these affiliated books and records.

"In addition," the group's statement continued, "the Senate bill would give certain additional merger authority to FERC over generating plants and holding companies. However, without the structural merger standards of PUHCA, which limit the size and geographic scope of utility mergers in order to protect local management and effective regulation, FERC will presumably continue to approve all the utility mergers that it reviews."

Here is a roundup on the key electricity provisions, which appear in various sections of the bill:

- Streamlines the hydroelectric licensing process by allowing disputed issues raised by the licensee or any party to be considered in a single trial-type hearing process lasting no more than 90 days. Provisions also allow for consideration of alternative conditions and prescriptions in licensing a hydroelectric project.
- Allows, but does not mandate, FERC to consider "participant funding" plans to finance new generation interconnection or upgrades so that those that benefit from the projects are assigned costs. FERC already has the discretion to consider such plans, but the participant funding issue went through a number of contentious iterations and apparently simply ended up with this language as a compromise.
- Says FERC may issue rules to set up an electronic information system to provide public access to wholesale power prices and transmission availability to inject transparency in the market. This issue was also contentious, since some lawmakers wanted to require FERC to establish such a system.
- Bans filing of any false information involving wholesale energy prices or the availability of transmission capacity, and prohibits market manipulation.
- Gives FERC exclusive jurisdiction to determine whether utilities in the Western Interconnection that entered into wholesale power contracts before June 20, 2001, with a seller found to have manipulated the market — this alludes to Enron — must pay termination fees for power not delivered. The provision was promoted by Sen. Maria Cantwell, D-Wash., and Senate Democratic Leader Harry Reid of Nevada. Enron sued utilities in their states to collect contract termination fees of more than $500 million.
- Allows a state to give a tax credit or incentive to facilities that generate electricity within its borders from coal mined in that state.
- Creates a risk insurance plan through which the Dept. of Energy would pay 100% — up to $1 billion — of the costs related to delays during construction and gaining approval for full-power operation of the first two advanced nuclear reactors with designs approved after 1993. The department would pay half such delay costs — up to $250 million per contract — for the next four advanced reactors with licenses and construction started.
- Allows transmission property rated 69 kV or greater to be treated as 15-year property; the provision is expected to provide a $1.2 billion benefit over the 10-year period.
- Extends the placed-in-service date by two years — to December 31, 2007 — for renewable energy sources to qualify for a production tax credit; includes hydropower and Indian coal generation in the mix of wind, closed-loop biomass, open-loop biomass, geothermal, small irrigation, landfill gas and trash combustion as "Section 45" qualifying facilities. The renewable production credit was projected to cost $2.7 billion through 2015.
- Provides the first production tax credit for nuclear power

facilities with a 1.8-cent/kWh credit for electricity generated during an eight-year period. The value is projected at $278 million.

■ Provides a 15% investment tax credit for low-emission advanced coal facilities and a 20% investment tax credit for integrated gasification combined-cycle projects. The tax break for the 10-year period comes in at $1.6 billion.

■ Allows coal-fired generating units built after 1975 to amortize the cost of certified air pollution control equipment over seven years. That is a two-year extension from present law and is expected to provide a $1.1 billion benefit.

■ Allocates $411 million in tax credits to "clean renewable energy bonds" whereby Indian tribes, electric cooperatives or other qualified entities can issue bonds to pay for capital costs for Section 45 facilities.

■ Allows certain cooperatives, with a majority agricultural membership, to pass through any portion of the renewable electricity production credit to their members.

■ Makes permanent a rule change in the 85/15 test for the treatment of electric cooperative income to make it easier for co-ops to participate in a competitive market environment and open access to their transmissions facilities without financial loss. The 85/15 test required that co-ops get 85% of their income from members to provide them service.

■ Authorizes demonstration projects on technologies to address climate changes caused by greenhouse gas emissions and facilitates deployments of technologies to developing nations.

TRANSMISSION

Grid West start-up could run $133 million, BPA finds plan 'still has a long way to go'

Grid West will cost $133 million to start and $65.6 million in annual operating costs if it moves forward in September, estimates a report released by officials of the proposed Northwest transmission agency.

The region has awaited the cost estimate for years. The Bonneville Power Administration, a key player in the proposed agency, has long said costs could be a deal breaker. The cost report prompted a BPA spokesman to note, "things need work and we've still got a long way to go." BPA plans to make a decision on whether to join Grid West by late September. If Grid West survives it would start operating in 2007.

The controversial Grid West has taken a decade to shape. It includes 62,000 circuit miles owned by BPA, PacifiCorp, Sierra Pacific Power and Nevada Power, Idaho Power, BC Hydro, Avista, Puget Sound Energy, NorthWestern and Portland General Electric. It would cover Washington, Oregon, Idaho, Montana, Wyoming, Utah, Nevada, British Columbia and Alberta and manage the use and expansion of the grid.

Grid West would be regulated by the Federal Energy Regulatory Commission. But FERC, when it approved the Grid West concept, noted that it will not have jurisdiction over BPA if the entity decides it wants to leave. Still, the federal power marketing administration would turn its vast transmission grid over to Grid West to oversee, a cause of concern for some BPA customers.

"Over time, Grid West would be the dominant entity and FERC would have a lot more control over BPA," said Marilyn Showalter, former chairman of the Washington Utilities and Telecommunications Commission and current head of the Public Power Council. Showalter has largely opposed FERC's efforts over the last three years to establish an RTO in the region.

A cost-estimate workshop for Grid West will be held Aug. 11 in Portland, Ore., to discuss the cost-benefits study and other reports, said Steven Walton, head of the Grid West coordinating team.

A goal is for cost recovery to enable transmission owners to meet their revenue needs while offering new services at non-pancaked rates. Annual revenue requirements of $85.4 million a year would cover yearly operating costs, interest and amortization of start-up costs, the study said. Grid West's annual transmission load would be 291 million MWh and revenue requirements would add $0.29/MWh, said a report prepared by the Structure Group of Houston.

Grid West would operate from three leased facilities. BPA's Dittmer complex in Vancouver, Wash., would be the primary control center, leased at $460,000 a year. A Vancouver administrative facility would lease for $775,000 a year and a Reno backup facility owned by Sierra Pacific would rent for $410,000 a year. Furnishings, data and network, utilities and building services for the three facilities would cost $4.3 million.

Grid West's report, "Preliminary Report on Estimated Benefits," claims the agency would bring multiple benefits and cost reductions. It said the capacity cost savings with managed contingency reserves ranges from $20 million to $73 million a year. It would have $30 million to $412 million a year from production cost savings from managed real-time energy balancing redispatch. By avoiding cascading disturbances, the region could save $27 million to $83 million a year.

Avoiding outages from non-cascading transmission problems is valued at $17 million to $231 million a year. By removing pancaked rates, the region could save $3 million to $61 million a year, the report said. More efficient pre-scheduled use of transmission lines could save $18 million to $52 million a year.

The report said the cost of setting up regional transmission organizations across the country ranged from $55 million to $240 million. ERCOT start-up costs were $137 million, the PJM Interconnection $140 million; the New York Independent System Operator $82 million, ISO New England $55 million, the Midwest Independent Transmission System Operator $157 million, and the California ISO $240 million, the report said.

When the RTOs and ISOs first went into operation, annual costs ranged from $25 million to $75 million. But today, approximate annual operating costs, the report noted, are ERCOT $125 million, PJM $270 million, NYISO $125 million, ISO-NE $125 million, MISO $250 million, CAISO $225 million and IESO $125 million.

But Showalter questions whether Grid West will achieve the benefits. "Every region that created an RTO or ISO thought their proposal would work and every region has been disappointed with results," said Showalter. "Every region thought they could avoid the mistakes others made, but they only created new ones. We should build on what already works in the Northwest rather than create a new agency."

Showalter supports the creation of the so-called Transmission Issues Group, a loosely knit coalition of non-FERC jurisdictional utilities and a handful of investor-owned utilities. TIG would not create a new entity, rather it would be a forum for the West to plan and operate the transmission system independently.

The TIG alternative is gathering momentum, Showalter said, and some observers indicate that it has the potential to emerge this fall as BPA's preferred transmission entity.

TIG would not be FERC jurisdictional and no new operating entity would be created. TIG would work within existing agencies to handle needed functions such as reliability, security and market monitoring. TIG will release its strategy in early August. BPA and many utilities are participating in discussions for both TIG and Grid West to help shape what evolves.

Brownell vows FERC open to variety of ways to achieve independent transmission operation

Just because the Federal Energy Regulatory Commission officially scrapped its controversial standard market design rulemaking, the commission cannot be seen as "abandoning" competitive markets, Commissioner Nora Brownell said last week.

In comments at the National Assn. of Regulatory Utility Commissioners' summer meetings in Austin, Texas, Brownell said FERC recognized the regional nature of the transmission grid and would welcome different models for independent grid operation.

There are "different models and different solutions," she said. As long as transmission is operated independently, FERC will have an open mind, adding, "I think there are a variety of approaches to solve the problem."

FERC formally withdrew the SMD proposal about two weeks ago, after determining the progress made toward regional transmission organizations since SMD was unveiled in July 2002 rendered the rulemaking obsolete (EUW, 25 July, 1).

Brownell told the state regulators that FERC would focus on reforming its open-access transmission tariff regime, as prescribed under the 1996 rule, Order 888. New FERC Chairman Joseph Kelliher lists 888 reform as his top priority, and Brownell said she was solidly on board. "It's clear there is still discrimination" on the transmission system, she said. "It is clear there are still loopholes."

In an interview after her speech, Brownell said doing away with SMD was not only an act based on political reality, but also a chance to make progress. "What we're saying is, 'we have RTOs, and we're going to work with them, and work with those state commissioners who really invested huge amounts of time and leadership,' " she said.

"Recognizing [that RTOs] are not going to be everywhere, we still have an obligation to make sure that there's equal access, and we're maximizing use of the transmission system and it's fair."

Withdrawing SMD is "not an abandonment as much as a recognition of the reality," she said.

It is also a chance to build on relationships with state regulators, Brownell said, relationships that were strained for some after the issuance of SMD. "We need to stop treating transmission as a battleground, but as an enabler," she said.

Bangor-Hydro gets Maine okay to build line to open up transfers to Canada

Bangor Hydro-Electric has received approval from the Maine Public Utilities Commission to build a 345-kV transmission line to Canada. The Northeast Reliability Interconnect (NRI) will open power transfers between New England and the Maritime Provinces, BHE said.

The Maine PUC granted a Certificate of Public Convenience & Necessity (CPCN) for NRI, which will run 85 miles, from a substation in Orrington, Maine, to the New Brunswick border. New Brunswick Power will construct a similar line to Point Lepreau.

Gaining the CPCN is a big step in advancing the project, said a BHE spokeswoman, though the company still awaits approvals from the Federal Energy Regulatory Commission, the Maine Dept. of Environmental Protection and the Army Corps of Engineers. The company expects to begin construction in the winter of 2006 and complete the line by the end of that year, she said.

BHE won a big victory in 2004 when the Independent System Operator of New England declared the project to be a "pool transmission facility," allowing the $90.4 million cost to be spread among all New England ratepayers.

The only existing line linking Maine to Canada was built in 1970, and suffers from reliability problems. NRI will increase North-South transfers by 300 MW, and will connect some isolated parts of Maine with the rest of New England, BHE has said.

ISO-NE has said NRI would address the "ongoing, unacceptable reliability concerns" arising from tripping of the old Keswick-Orrington line. It will also ease line overloads and improve transient voltage response on the Central Maine Power System, according to ISO-NE.

Independent transmission coordinators seem to catch on... from page 1

28 March, 1).

While there remain a few big utilities that still have not proposed to either join an RTO or hire an ICT-type entity, utility observers say the recent events may change the dynamics for those companies. "This absolutely puts additional pressure" on utilities "that aren't doing anything, to do something — particularly on market power issues," one platts

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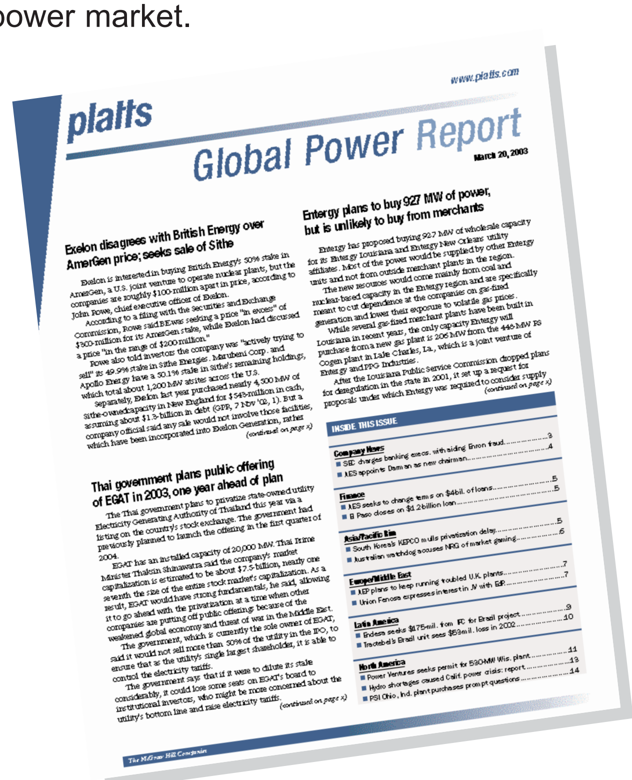
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Global Power Report

March 20, 2003

Exelon disagrees with British Energy over AmerGen price; seeks sale of Sithe

Exelon is interested in buying British Energy's 50% stake in AmerGen, a U.S. joint venture to operate nuclear plants, but the companies are roughly $100-million apart in price, according to John Rowe, chief executive officer of Exelon.

According to a filing with the Securities and Exchange Commission, Rowe said BE was seeking a price "in excess" of $300-million for its AmerGen stake, while Exelon had discussed a price "in the range of $200-million."

Rowe also told investors the company was "actively trying to sell" its 49.9% stake in Sithe Energies. Marubeni Corp. and Apollo Energy have a 50.1% stake in Sithe's remaining holdings, which total about 1,200 MW at sites across the U.S.

Separately, Exelon last year purchased nearly 4,300 MW of Sithe-owned capacity in New England for $543-million in cash, assuming about $1.3-billion in debt (GPR, 7 Nov '02, 1). But a company official said any sale would not involve those facilities, rather which have been incorporated into Exelon Generation.

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Entergy plans to buy 927 MW of power, but is unlikely to buy from merchants

Entergy has proposed buying 927 MW of wholesale capacity for its Entergy Louisiana and Entergy New Orleans utility affiliates. Most of the power would be supplied by other Entergy units and not from outside merchant plants in the region.

The new resources would come mainly from coal and nuclear-based capacity in the Entergy region and are specifically meant to cut dependence at the companies on gas-fired generation and lower their exposure to volatile gas prices.

While several gas-fired merchant plants have been built in Louisiana in recent years, the only capacity Entergy will purchase from a new gas plant is 206 MW from the 446-MW RS Cogen plant in Lake Charles, La., which is a joint venture of Entergy and PPG Industries.

After the Louisiana Public Service Commission dropped plans for deregulation in the state in 2001, it set up a request for proposals under which Entergy was required to consider supply

(continued on page x)

Thai government plans public offering of EGAT in 2003, one year ahead of plan

The Thai government plans to privatize state-owned utility Electricity Generating Authority of Thailand this year via a listing on the country's stock exchange. The government had previously planned to launch the offering in the first quarter of 2004.

EGAT has an installed capacity of 20,000 MW. Thai Prime Minister Thaksin Shinawatra said the company's market capitalization is estimated to be about $7.5-billion, nearly one seventh the size of the entire stock market's capitalization. As a result, EGAT would have strong fundamentals, he said, allowing it to go ahead with the privatization at a time when other companies are putting off public offerings because of the weakened global economy and threat of war in the Middle East.

The government, which is currently the sole owner of EGAT, said it would not sell more than 30% of the utility in the IPO, to ensure that as the utility's single largest shareholder, it is able to control the electricity tariffs.

The government says that if it were to dilute its stake considerably, it could lose some seats on EGAT's board to institutional investors, who might be more concerned about the utility's bottom line and raise electricity tariffs.

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utility observer said.

Still, although FERC has endorsed one ICT and continues to promote a flexible open-access agenda that does not require RTO formation in all regions, one federal official said the jury was still out as to whether Entergy's so-called "RTO-lite" approach is a long-term solution.

"I think ICTs are an interesting trial," FERC Commissioner Nora Brownell said in an interview last week. "I think time will tell if they get you where you need to go. … For me it's about, forget the issue of discrimination, what are the economic incentives? If my economic incentive is to maximize throughput on my transmission asset, my behavior is going to be different than whether I'm torn between doing the generation, doing the transmission. So what I'm looking at is, 'what's the most straightforward way to get the economic incentives aligned appropriately'."

In its proposal, Duke hired the Midwest Independent Transmission System Operator with a two-year contract to perform certain transmission functions independently. Duke filed its plan late July 22.

MISO CEO and President James Torgerson said in an interview that his RTO would handle Duke's transmission service requests, administer its open-access transmission tariff, operate its open-access same-time information system and calculate its available transmission capacity.

The agreement will start in March 2006, Torgerson said. This is "significant for us; we're very happy with the arrangement," Torgerson said.

Duke, whose merger partner Cinergy is a longstanding MISO member, has held open meetings with stakeholders over the past several months about whether and how it should turn over certain functions of its North Carolina- and South Carolina-based transmission system to a third party. It officially filed its merger application to FERC about two weeks before filing its RTO-lite plan.

The Cinergy merger, Torgerson said, played a big part in the agreement.

Under the deal, Duke will not be a full-fledged member of MISO and will not participate in the grid operator's Day-2 energy markets, Torgerson said. MISO already provides similar services to utilities in the Mid-Continent Area Power Pool, Torgerson said, so adding Duke to the mix should not present any difficulties.

The plan is different, though, because Duke and MISO are not directly interconnected, but Torgerson does not expect any complications. "We operate a pretty broad footprint to begin with," Torgerson said.

Duke, in its filing to FERC, said its primary goal is to "increase confidence in the independence and transparency of the operation of the Duke transmission system."

Further, the OATT amendments would preserve the jurisdiction of North Carolina and South Carolina regulators by not transferring control of a utility system that operates within those states' boundaries.

MidAmerican, meanwhile, detailed plans to hire its own RTO-lite entity called a "transmission service coordinator" (TSC). Although it has not disclosed who will run its grid, MidAmerican said MISO performs certain functions already because of the utility's membership in MAPP.

Some of the language in MidAmerican's filing is nearly identical to what Duke filed, as both proposals were made by the same law firm, Steptoe & Johnson. "The TSC proposal will enhance independent and transparent operation of the MidAmerican transmission system and serve to enable customers to be confident that the MidAmerican system will continue to be operated in a fair and reasonable manner," MidAmerican said.

Specifically, MidAmerican's TSC will calculate total-transfer capability and available transmission capacity for locations not under MISO's control. It will grant or deny transmission service requests, receive and process generator interconnection requests, manage the utility's generator interconnection queue, and interpret MidAmerican's OATT and related business practices, the company said.

Moreover, "MidAmerican is optimistic that the TSC role will expand and evolve over time to include non-jurisdictional transmission providers in states to the west of MidAmerican," the filing said. "This would lead to a broader scope for tariff administration and for the regional planning process that eventually may lead to the elimination of seams on the western border of MAPP."

For its part, Entergy officially hired SPP as its ICT last week. SPP's board of directors approved the business plan proposed by Entergy and authorized the negotiation of a contract which would be signed once the plan receives final FERC approval, expected in early 2006. The contract would be for two years, the length of time FERC approved for the ICT trial.

"The plan needs federal and state regulatory approval and unless something comes out of the commission that requires substantive changes, we wouldn't expect that [the agreement] will change," she said.

SPP generally would provide oversight of the operations of Entergy's transmission system. It also would provide a new process for assigning cost responsibility for transmission upgrades and it would implement a new weekly procurement process.

SPP will develop a separate department to carry out the ICT functions, and be paid nearly $12 million by Entergy for its services.

Among its duties, SPP will develop the base transmission expansion plan for Entergy. The plan will be used to optimize regional development for all members that choose to participate.

In its analysis of Entergy's proposal, SPP staff said its members would benefit from the enhanced coordination with Entergy both operationally and financially. By operating Entergy's system, the SPP will be able to improve reliability in the region and operating both systems should result in better transmission planning in both regions, SPP said.

SPP also would benefit from the experience of managing the weekly procurement process, the staff said.

SPP staff agreed that there are benefits and risks to performing the role of Entergy's ICT, but said the risks can be mitigated. It also said it is possible that FERC could assign additional functions to the ICT, which would require additional contract negotiations.

ACQUISITIONS

Little overlap means no market power problem, MidAmerican, PacifiCorp tell FERC of merger

MidAmerican Energy Holding's plan to buy PacifiCorp poses no market power problems and is all about building new infrastructure, the companies told the Federal Energy Regulatory Commission in their application for merger approval.

MidAmerican coupled the merger filing with a proposal for a transmission service coordinator, but said the TSC idea is not contingent of approval of the merger (see story, page 1).

A merger would "build on the expertise" of the two companies and result in "formation of a financially strong, diversified energy company that will help promote more reliable markets in the region," said the July 22 application (Docket No. EC05-110). Backed by Warren Buffett's Berkshire Hathaway, MidAmerican is "well matched to utilities, such as PacifiCorp, with a need for significant capital investment," it added.

Des Moines, Iowa-based MidAmerican would invest $1 billion annually for five years in the PacifiCorp system on transmission, distribution, pollution controls and wind generation. It also would retain the TSC for operations in the Mid-Continent Area Power Pool that could bridge its operations with Portland, Ore.-based PacifiCorp's pursuit of the Grid West plan in the Pacific Northwest (Docket No. ER05-1235).

Hoping to close the $9.4 billion deal during the first quarter of 2006, the companies asked FERC to approve it by Dec 15. MidAmerican is an exempt public utility holding company under the Public Utility Holding Company Act and, if the deal closes, will be required to be a registered public utility holding company, the application said. MidAmerican expects to pass muster with PUHCA, although with the energy bill's repeal of PUHCA last week, it seems unlikely the company will have to deal with that law at all. Buffett, who worked for years for the repeal, has said he is interested in buying more utilities.

The acquisition is in the public interest and will not have adverse impacts on competition, rates or regulation, the application claimed. There is hardly any horizontal market power threat from the combination in generation assets totaling more than 15,000 MW as evidenced by the companies' plan to reserve a 50-MW contract transmission path between their regions, it said.

An analysis of available economic capacity raises "no issues whatsoever" in any of the relevant markets, the companies said, as the resulting changes in the Herfindahl-Hirschman Index of market concentration are less than 50 points. "No conceivable horizontal competitive concerns arise" when looking at the economic capacity of the control areas, the filing said.

Actually, the deal would create a new competitor, it asserted, because PacifiCorp's current owner, ScottishPower, plans to keep PPM Energy, which owns generation in California, Colorado, Iowa, Minnesota and Oregon. Also, neither applicant has generation assets located on the other's transmission system.

The filing further maintained that MidAmerican's ownership of gas pipeline assets — Northern Natural Gas and Kern River Gas Transmission — does not pose any vertical market power problems. Kern River serves the Utah market within a portion of the PacifiCorp service territory, but "the relevant upstream gas transportation market is not highly concentrated" because there is "a significant competing" interstate gas pipeline and local distribution presence, the application said: Questar Pipeline and Questar Gas.

Competition for gas delivery into Utah and the upstream market further exists "as a result of the diverse ownership of firm transportation rights" on Kern River and Questar Pipeline, the application added. "Moreover, Kern River does not serve any gas-fired generation in Utah," other than an interruptible backhaul agreement with PacifiCorp for the West Valley and Currant Creek plants, it said.

"Therefore, Kern River has no ability to affect existing generators" and Questar provides alternatives for generators, the application added.

As for the regional grid plans, MidAmerican hopes to include under the TSC other transmission owners located between itself and PacifiCorp in South Dakota, Nebraska and North Dakota, "with the objective of promoting the construction of needed transmission upgrades in the region." The TSC proposal is modeled after Entergy's independent coordinator of transmission, which FERC has conditionally approved, and is similar to Duke Power's recently proposed independent transmission agreement with MISO.

The TSC would take on functions not currently performed for MidAmerican under a contract with Midwest Independent Transmission System Operator. It would manage the generation interconnection queue, while MISO would manage the transmission service queue through open-access same-time information system administration.

The TSC would calculate total and available transfer capability for flowgates and interfaces not otherwise determined by MISO. It also would grant or deny transmission service requests, perform system impact studies and oversee other functions, such as balancing authority and regional transmission planning coordination.

"Because of its westward focus," MidAmerican doesn't expect any MISO members to join the TSC. It would "not disrupt the strong seams coordination" between MISO and MAPP, and would hope to obtain a seams agreement with Grid West.

The TSC plan "will address any concerns" about transmission market power and standards of conduct, MidAmerican said.

CALIFORNIA

Consumer group TURNs tide; re-regulation proposition is back on California ballot

In a see-saw chain of events, the California Supreme Court last week reversed a lower court ruling and restored The Utility Reform Network's measure to re-regulate the state's power market to the Nov. 8 ballot.

Two days earlier, TURN petitioned the court to overturn the lower court's ruling and reinstate Proposition 80 — an initiative that would effectively re-regulate the state's electricity market. TURN said it asked for a quick court review so information on the measure could be included in voter pamphlets, which are due out next month.

While the Supreme Court revived Proposition 80, it ruled the validity of the measure could be determined after the election.

"It is usually more appropriate to review constitutional and other challenges to ballot propositions after an election rather than to disrupt the electoral process by preventing the exercise of the people's franchise, in the absence of some clear showing of invalidity," said the court.

TURN said the court's ruling was a victory.

"We are glad the Court saw fit to weigh in so quickly and so positively," said TURN Executive Director Bob Finkelstein. "California's voters have demonstrated they want this opportunity to vote on the folly of any electric deregulation, and the Supreme Court has now ensured they will have that opportunity."

The Independent Energy Producers Assn., which challenged the proposition along with the California Retailers Assn., expressed disappointment, but said it expects the proposition will be voided.

If voters approve Proposition 80, "the Supreme Court has agreed to hear the case after the election," said Jan Smutny-Jones, IEPA executive director. "The Appellate Court decision is a very strong decision. If we should need to take it to the Supreme Court, we will prevail," he said.

On July 22, a California Court of Appeal sided with IEPA and removed Proposition 80 from the ballot. The court said the initiative is invalid because it "usurps" the state Legislature's "plenary power to confer additional authority and jurisdiction" on the Public Utilities Commission.

Proposition 80 would prohibit expansion of direct access transactions, place independent energy producers under PUC authority, and require all retail electricity suppliers to meet the state's renewable goals.

Direct access was suspended in 2001, during the state's energy crisis.

Gary Ackerman, the Western Power Trading Forum executive director, worried that investor-owned utilities could get behind TURN's initiative if the proposition gains ground in the polls.

At this point, the proposition is not polling well, and IOUs are sitting on the sidelines. But that could quickly change, given the threat of rolling blackouts this summer, said Ackerman.

Of the state's three IOUs, Southern California Edison has been the most vocal opponent of direct access. The utility last year sponsored AB 2006, which aimed to re-regulate the electricity industry. Gov. Arnold Schwarzenegger vetoed the measure. This year, SoCal Ed opposed AB 1704, a bill that would have brought back retail choice. The bill was defeated in May.

Pacific Gas and Electric and San Diego Gas and Electric said they would support AB 1704 if the measure guaranteed that all customers pay their fair share for power supplies — a standard that is arguably hard to measure.

If Proposition 80 becomes law, the court could decide to keep the law in place, or reject all or part of it, according to Steve Levin, who is with the Center for Governmental Studies. The court could choose not to review the legal challenge if the measure passes, he added. The Center is a Los Angeles-based bipartisan research group.

Richard Martland, an attorney representing IEPA, said it is hard to predict the ultimate fate of the proposition.

"Anything is fair game for them," said Martland, referring to the Supreme Court. In the meantime, IEPA and other opponents are mounting what could be a costly campaign against TURN's proposition, Martland said.

"Our clients don't have any choice. Either they do nothing or campaign against it," he added.

"The money [for Proposition 80] came from union members. I don't know if they will go back to that well," said Martland, when asked whether TURN will also sink funds into an expensive fight.

TURN's proposition is backed by the Alliance for a Better California, a coalition of labor organizations that includes teachers, firefighters and health-care workers. The campaign aims to oppose Schwarzenegger's "wasteful" initiatives while offering alternatives such as TURN's proposition, said a spokeswoman for the campaign last month.

TURN did not respond to questions on the campaign by press time.

When the lower court pulled Proposition 80 off the ballot, WPTF's Ackerman expressed relief, saying "there is no cloud hanging over us."

But now, the Supreme Court has "reinstated the cloud," said Ackerman.

CEC report endores 'proactive' approach to transmission, backing ISO's commitment

A California Energy Commission report on the state's transmission outlook endorsed the California Impendent System Operator's recent message that it will take a more proactive role in transmission planning.

In June, ISO President and CEO Yakout Mansour said a "top priority" for the grid operator is to begin a long-term transmission plan, in which ISO will survey the entire transmission system within its control area and gauge improvements that need to be made. Mansour said the study will be delivered to investor-owned utilities. After that, ISO and transmission owners will determine the next steps.

The CEC report noted that the commission intends to work closely with ISO to coordinate the agencies' transmission efforts.

"A more proactive transmission planning process, coupled with changes in market design, could provide the appropriate signals so that generation is sited in locations enhancing the overall effectiveness of the electricity delivery system, "said the report.

"Just as the interties between California and the Western states allow each region to achieve planning reserve margins with collectively less native generation than would be required by each region on its own, a similar intrastate, inter-utility assessment may conclude that it is more cost-effective to upgrade the intrastate transmission system rather than increase the planning reserve margins to deal with deliverability issues," said the report, which was released earlier this month.

The report reiterated the CEC's belief that transmission corridor planning is a key way to upgrade the grid. Under this plan, which the commission first pitched last year, the CEC would designate suitable transmission corridor zones for high-voltage transmission lines. The aim is to increase chances transmission lines will be built, in part by preventing permitting delays and ensuring that optimal routes are chosen.

SB 1059 by Sens. Martha Escutia and Bill Morrow would authorize the commission to enact its transmission corridor plan. The bill has moved to the California Assembly as a two-year bill and will not be taken up until next year.

The report also acknowledged that Gov. Arnold Schwarzenegger's controversial reorganization plan is facing roadblocks. The governor's plan would subsume several agencies into a new Dept. of Energy. This new entity would take over transmission permitting from the PUC.

While the Little Hoover Commission "made many positive comments about the [governor's reorganization plan], they recommended that the legislature reject the proposal 'to avoid legal challenges.'…"In summary, there is widespread recognition that the current transmission permitting process is inadequate, and various methods have been proposed to address the problem. However, none of the solutions described above have yet been implemented," said the report.

Findings of the report will be included in the commission's annual Integrated Energy Policy Report, which is intended to provide policy guidance to regulators, lawmakers and the governor.

SUPPLY

Most of the East reaches record peaks before heat breaks; PJM cuts voltage

Most of the East reached new peak load records last week before the heat wave broke, in many cases beating records set the previous week several times (EUW, 25 July, 16).

The New York Independent System Operator and PJM Interconnection both set new records July 26, a day before ISO-New England did so.

On July 26, PJM was forced to cut 5% voltage in the mid-Atlantic region and Virginia, through 5:30 p.m.

On July 27, due to heat, humidity, and chronic transmission constraints in southwestern Connecticut, ISO-NE declared a "power watch" and had to call upon 220 MW of emergency energy resources secured through a 2004 request for proposals. They include emergency generation, usage cuts, and conservation resources. The watch ended at 6:30 p.m.

NY-ISO did not ask customers to conserve but did recommend various standard practices to cut consumption such

LATEST RECORD PEAKS SET SUMMER 2005

System	Summer 2004	Peak 2005	(Date)	Increase
EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT (ECAR)				
Cinergy	10,911	**12,001**	(7/25)	+10.0%
FLORIDA RELIABILITY COORDINATING COUNCIL (FRCC)				
Progress Energy Florida	8,519	*9,208*	(7/27)	+8.1%
NORTHEAST POWER COORDINATING COUNCIL (NPCC)				
New York ISO	28,433	**32,075**	(7/26)	+12.8%
Central Hudson G&E	1,043	**1,201**	(7/27)	+15.1%
Con Edison of N.Y.	11,327	**13,059**	(7/27)	+15.3%
New England ISO	24,116	**26,922**	(7/27)	+11.6%
NSTAR	4,254	**4,683**	(7/27)	+10.1%
PJM Interconnection				
PJM	120,367	**135,000**	(7/26)	+12.2%
Dominion Generation	14,856	**18,897**	(7/27)	+27.2%
PECO Energy	7,376	**8,695**	(7/27)	+17.9
PPL Electric Utilities	6,434	*7,024*	(7/26)	+9.2%
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL (SERC)				
Progress Energy Carolinas	11,192	**12,572**	(7/27)	+12.3%
South Carolina E&G	4,574	**4,820**	(7/27)	+5.4%
Southern Company (system)	36,317	**37,376**	(7/25)	+2.9%
Tennessee Valley Authority	29,966	**31,703**	(7/25)	+5.8%

All-time record peaks in boldface
Summer-only records in italics

Information is the latest available to *Electric Utility Week* as of July 29

as using major appliances only in the evening.

During the week ending July 23, U.S. power output hit a record 95,259 GWh, beating the August 2002 previous record of 90,468 GWh by 5.3%, the Edison Electric Institute reported.

Utilities cope with lower Powder River Basin shipments; do not forsee reliability problems

In spite of ongoing maintenance problems on the joint BNSF Railway/Union Pacific line in Wyoming, it appears as if most utilities have been able to cope with a shortage of Powder River Basin coal.

Last week, in response to a query by North American Electric Reliability Council President and CEO Michehl Gent, several NERC regions and utilities said they did not expect trouble meeting electricity demand.

Gent's query came after the Dept. of Energy began looking into the problem.

In a letter to NERC's regional managers July 21, Gent asked them to gather information by last Friday on problems the utilities were facing receiving coal deliveries because of two derailments in the PRB caused by heavy rainfall followed by a snowstorm in May (EUW, 25 July, 1). While the line has reopened, the railroads have said repairs and maintenance will last through the end of November.

A DOE spokeswoman said the department was not acting in response to a request from the White House, as Gent said in his letter. She said the department's Office of Electric Delivery and Energy Reliability constantly monitors electricity supplies.

Gent had sought to gauge coal deliveries, and how any shortfall would affect utilities' ability to meet electricity demand through Sept. 30 and Dec. 31. He also asked if the utilities had switched to alternative fuels, if their reliance on bulk power imports had increased or decreased as a result of reduced fuel deliveries, and other related questions.

During an earnings conference call last week, BNSF Chairman, President and CEO Matt Rose said shipments on the joint line for July month-to-date were up to 61 trains/day, 6% more than in July 2004 and only slightly below the 63.6 trains/day average the line saw through April of this year, before the derailments.

"So far from what we've seen, [utility response] seems to indicate there aren't any significant problems," Brantley Eldridge, executive manager of the East Central Area Reliability Coordination Agreement, said in an interview. He declined to discuss specific responses.

"We've surveyed our plants and it's not going to be an issue here," agreed Sam Jones, chief operating officer of the Electric Reliability Council of Texas.

Eastern regions are far less likely to depend on Western coal.

Several utilities addressed the rail problems in their earnings calls last week, and while some reported reductions in PRB coal deliveries of up to 30%, none were worried about meeting demand.

Wisconsin Energy Chairman, President and CEO Gale Kappa said the company had adequate coal stockpiles, but was bracing for a possible shortfall in PRB deliveries, adding the company had no reliability issues related to the deliveries.

The utility is setting inventory targets at its coal-fired plants, trying to lower the use of those plants in off-peak periods and shifting its coal supplies between plants, said Rick Kuester, executive vice president.

Ameren, which buys 85% of its coal from the PRB, has had to buy coal on the spot market, raising the price at which it will sell power from its coal units, and is working with the rail companies to ensure adequate supplies, Chairman, President and CEO Gary Rainwater said. "We believe these strategies will allow us to operate our coal fleet reliably and economically for the rest of the year." About 86% of Ameren's fleet is coal-powered.

Northern Indiana Public Service Co.'s PRB deliveries are down 30%, parent NiSource said. Despite the decline in shipments, NiSource officials told analysts it is confident it has sufficient coal inventories to get through the remainder of the year. In an attempt to manage its coal, a NIPSCO official said the utility has increased coal blending "and picking up other supplies when we could."

Unlike NIPSCO, Cinergy's Cincinnati Gas & Electric and PSI Energy subsidiaries do not burn PRB coal. "We use almost exclusively Eastern coal, and we have no plans to change how we dispatch our generating units for the remainder of the year," James Rogers, Cinergy chairman, president and CEO, told analysts.

Rogers said Cinergy was "fully hedged" on coal supplies for the final months of this year and is "prudently hedging" supplies for 2006 and 2007.

At Cinergy's inland power plants, the company has a goal of maintaining a 40-day coal inventory, he added. For generating stations on rivers, such as the Ohio, "we generally shoot for a 20-30 day inventory of coal at those plants." Rogers said Cinergy was meeting those goals.

RATES

TVA board approves 7.5% hike in rates, citing jump in fuel, purchased power costs

The Tennessee Valley Authority board of directors has approved a 7.5% increase in firm wholesale electric rates, which should net the federal utility $524 million in additional revenue for 2006.

Much of the rate hike will cover a projected 16% increase in fuel and purchased power costs in 2006.

The two-member TVA board at its July 22 meeting also approved a 2006 budget that projects $8.7 billion in revenue, $7.2 billion in operating expenses and $1.5 billion in interest expenses. The budget includes $340 million to reduce its $25.6 billion of long-term debt and other obligations, a TVA spokesman said.

The board also agreed to begin writing off the $3.9 billion past investment in the Bellefonte Nuclear power plant in Alabama at a rate of $391 million a year for 10 years. The plant was never completed and was mothballed in 1988. It is doubtful the plant will ever be completed, the spokesman said.

TVA will decide in September whether to pursue the construction of a new nuclear plant at the Bellefonte site, said Jack Bailey, TVA's vice president for nuclear asset recovery and strategic projects. TVA will need new capacity beginning in 2015, and must begin now if it is to have a plant up and running to meet that time frame, Bailey said. TVA has peaking capacity of 31,000 MW and expects growth of 300 MW to 500 MW a year, but it will lose a 1,500-MW customer in 2010 when United States Enrichment Corp. closes the Dept. of Energy's gaseous diffusion plant in Paducah, Ky.

The agency is in discussions now with possible partners in a project, including customers who are interested in becoming part owners of a plant.

TVA has several options, including working with NuStart Energy, a consortium of utility and reactor designers, which chose Bellefonte as one of six possible sites to build a next generation nuclear plant. NuStart is looking at utilities with strong support for building a nuclear plant in the region, Bailey said.

Louisiana Governor Kathleen Blanco last week welcomed NuStart to build a plant in St. Francisville, La., home of Entergy's River Bend nuclear plant, and the state public service commission on July 22 passed a resolution supporting the construction of a nuclear plant there. "I think you will see a similar response from the Bellefonte neighbors," Bailey said.

TVA and several partners, including U.S. Enrichment Corp. and Toshiba, are studying the cost and schedule of building an advanced boiling water reactor at Bellefonte. While NuStart would build a demonstration plant of next generation nuclear technology, the advanced boiling water reactor has been certified and built in Japan. Either a NuStart plant or an advanced boiling water reactor would add up to 3,000 MW of power to the system.

A third option for TVA is to complete unit two at Watts Bar nuclear plant in east Tennessee. Construction of the 1,180-MW unit was suspended in 1988 when it was 55% complete.

TVA will decide in September whether to initiate the NRC licensing process after it decides which nuclear route it will take.