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Electric Power Daily

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Utilities

ICE STORM KILLS POWER TO MORE THAN A MILLION MIDWEST CUSTOMERS

Utility officials were settling in for a long siege in ice-ravaged portions of Oklahoma, Kansas, Missouri, Indiana and Michigan where well over a million customers were affected by a massive ice storm. At least half remained without service Thursday afternoon.

Utilities in Oklahoma, Missouri and Kansas reported total outages of 989,000.

Among the major systems hit: Kansas City Power & Light reported 285,000 customers were affected at the peak of the storm, with 195,000 still out Thursday afternoon. The company reported calling in 230 outside repair crews from Georgia to Colorado and Minnesota to Texas. Transmission damage was severe, but not yet quantified. KCPL estimated seven days for repairs, compared to five days for restoration from the previous benchmark ice storm in 1996, when 175,000 customers were out.

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International

THREE WEEKS AFTER PRICE CAP, BRAZIL DECIDES IT WAS A MISTAKE

Brazil Thursday unexpectedly reversed a three-week-old policy that would have maintained price controls on electricity generated by federal or state power plants, saying the earlier decision was a mistake that would have chased away much-needed private investment in new capacity.

Brazil's currency and share prices of government-controlled power companies rose on the news, signaling investor relief over the shift in policy.

Under the new rule, government-owned generators—most of them fully-depreciated hydro facilities that supply nearly 90% of Brazil's electricity—will beginning next year sell be able to auction off any power not committed under long-term contracts. Those volumes will grow by 25% a year from 2003 through 2006, when all existing purchased-power agreements in Brazil will be opened up to the free market.

Private power companies were stunned by the Jan. 9 policy statement and complained

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NORTHEAST'S GROWING DEMAND WILL FORCE REGULATORS TO GRAPPLE WITH TOUGH ISSUES

The Northeast U.S. will continue to need new electric capacity, but state and federal regulators must first make some knotty choices on how best to meet growing demand. Gas pipelines can serve new power plants, or electric transmission can be expanded, but none of the choices would be easy, because a wider circle of stakeholders is getting involved, and more issues—financial, social and environmental—must be considered.

That's the picture that emerged during Thursday's "Northeast Energy Infrastructure Conference," sponsored by Federal Energy Regulatory Commission in New York (AD02-6).

Because of the slow economy, electric demand is not projected to increase in the region this year or the next, but by 2010, the region's appetite for power should increase by 20%, Mary Novak, managing

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CALIFORNIA UTILITY REGULATORS, GOVERNOR DAVIS REACH DEAL TO REPAY STATE FOR POWER BUYS

The California Public Utilities Commission and the Gov. Gray Davis have broken a nearly four-month deadlock over a key component in the debate over how to repay the state for money it spent buying power, clearing the way for an expected \$12.5-billion bond sale to replenish money drawn from the state's general fund since early last year.

The PUC draft on the Dept. of Water Resources rate agreement would also allow for the repayment of a \$4.3-billion bridge loan taken by the state last year to staunch the flow of money from the general fund to pay for power.

The PUC set a schedule for review of the agreement with a final draft to be brought up at its Feb. 21 business meeting. Comments on the draft will be accepted until Feb. 5 and a proposed decision will be released Feb. 12.

In the draft, DWR costs would be paid with two separate utility

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MIRANT SAYS IT WILL CUT BACK CAPITAL SPENDING TO ONLY ABOUT \$5-BILLION OVER NEXT FIVE YEARS

Citing the current soft energy market, Enron's collapse and Moody's decision to cut its rating to below investment grade, Mirant Thursday announced further cuts to its capital spending over the next five years.

In a conference call, company officials said they are canceling a number of plant projects outside of Asia and Europe while it continues its plans to sell \$1.6-billion in assets, including its \$900-million share of Germany's Bewag.

In an interview Thursday, Mirant Global Risk Officer Mike Smith said that the company will be completing around 5,700-MW in North America in 2002-2003, but will mothball its expansion projects at its Contra Cost plant in California and its Bowline plant in New York. He said any projects in the development stage for 2004-2005 have been postponed.

Mirant plans to remain in California despite ongoing changes in the

state's wholesale and retail power markets, Smith said. The producer has one power sales contract with the state for 500-MW through this year, which it does not plan to renegotiate, he said. "We are interested in signing other contracts. We are just determining what is the right time to do it," he said.

Mirant in December said that due to Moody's action and current market conditions, the company was cutting its capital spending to \$2.6-billion in 2002 and \$3.4-billion in 2003 with over \$12-billion spent over the next five years. Mirant CEO Marce Fuller Thursday said that after meeting with Moody's to ascertain what was needed to return the company to an investment-grade rating, it would further scale back its spending and is projecting \$1.8-billion in spending for 2002 and \$1.1-billion in 2003 with only \$5-billion spent over the next five years. On the call, Ray Hill, Mirant CFO, said that the power producer would have \$700-million in cash and credit liquidity by the end of this month with around \$1.1-billion available by the end of this year.

Smith said that Mirant would be concentrating on its financial health in the next few years as it attempts to convince investors it is not headed the way of Enron. "Mirant is very much an asset-oriented company," he said, emphasizing that the company uses short-term mark-to-market accounting. "Our books [of unrealized asset value] are of relatively short duration.... We turn unrealized profits to cash on a short-term basis." Mirant also will not be investing in Enron's assets, Smith said. "Given our current liquidity, we never really entertained going after their stuff.... We were not excited about their stuff and do not consider it a missed opportunity," he said.

Mirant late Wednesday posted 2001 operation earnings of \$683-million, or \$1.95 per diluted share, with fourth quarter earnings of \$93-million or 27 cents per diluted share. It estimated 2002 earnings to be between \$1.60-\$1.70, a reduction of its December \$1.90-\$2 guidance as a result of lower commodity prices and reduced business activity in North America.

IPPS PUSH WIS. REGULATORS TO ALLOW COMPETITIVE BIDDING FOR NEW PLANTS

A group of independent power producers wants Wisconsin regulators to consider IPP proposals as part of Wisconsin Electric Power's plan to increase capacity in the state by 2,800 MW, a trade group representing merchant generators said Thursday.

The Midwest Independent Power Suppliers Coordination Group wants the state Public Service Commission to consider new generation proposals using a competitive bidding process, which the PSC has so far declined to allow.

At issue is WEPCO's proposed 10-year plan to increase generation in the state. WEPCO is expected to apply today for a certificate of public convenience and necessity (CPCN) that would allow the utility to build 2,800 MW of instate generation, including two 500-MW, combined-cycle, gas-fired units at the company's existing Port Washington plant site and three 600-MW advanced-technology, coal-based units at its Oak Creek plant site. Under the plan, WEPCO would spend \$3-billion on the new generation, \$1.3-billion upgrading existing facilities and \$2.7-billion improving the distribution system.

As part of their effort to get the PSC to allow competi-

tive bidding, MWIPS has submitted sealed proposals for the projects to a trust agent. MWIPS members include Aquila, Calpine, Mirant, and PG&E National Energy Group.

The trust agent will submit the confidential proposals to WEPCO and the PSC after WEPCO has finalized the economic details of its CPCN application, MWIPS Executive Director Freddi Greenberg said. MWIPS also is calling for an independent evaluation of the WEPCO and IPP proposals, she said. Because the bids were confidential, Greenberg could not say know how many bids there were or which IPPs made them.

Filing the IPP proposals with the trust company prevents all parties from seeing the confidential details of other parties, Greenberg explained. Once WEPCO's proposal is finalized, MWIPS wants the PSC to compare the utility's plan to the IPP bids and accept the best offers for new generation, Greenberg said. MWIPS has not yet approached the PSC or WEPCO about its plan, but expects to do so soon, she said.

In October, without endorsing specific details, the PSC gave general approval to WEPCO's plan, which allowed the utility to create W.E. Power, a subsidiary to design, build and own the proposed power plants. Once WEPCO files for the CPCN, the PSC will consider the details of the plan, a process that could take months.

ALJ RECOMMENDS ILLINOIS REGULATORS APPROVE CILCO'S RESTRUCTURING PLAN

Central Illinois Light's proposed restructuring of its electric generation business won a key victory when an administrative law judge recommended the Illinois Commerce Commission approve the plan.

The Peoria-based subsidiary of AES wants to transfer almost all of its electric generating assets to a newly formed, unregulated subsidiary, Central Illinois Generation (CIGI), which would operate as an exempt wholesale generator under federal law. CILCO and CIGI would enter into a power-supply agreement under which CILCO would purchase capacity and energy from CIGI through 2004.

CILCO would transfer the Duck Creek and Edwards coal-fired baseload generating stations to the subsidiary, which would have more than 1,130 MW. After completion of the transaction, CILCO would continue to own and maintain a natural gas-fired cogeneration plant and 26 MW provided by 16 diesel-fueled power modules currently located at various CILCO substations, which would be managed by CIGI.

The proposed restructuring comes amid an attempt by AES to sell CILCORP, the parent company of CILCO. AES received formal offers—it would not say how many—for CILCORP in January. The company hopes to announce a prospective purchaser in March.

Led by the city of Peoria, several central Illinois communities currently served by CILCO are campaigning for CILCORP to be sold to a group of local investors. They claim CILCO's service and community involvement have deteriorated under AES ownership, a charge refuted by AES and CILCO.

In his findings, Donald Woods, the administrative law judge, said CILCO "will continue to own its existing transmission and distribution systems" after restructuring. "As a result...the proposed transfer will not affect CILCO's ability to deliver electric power and energy." Woods noted that

CIGI would be required to provide CILCO with sufficient capacity and energy to supply its native load and firm load customers under the PSA. After the power agreement expires, "CILCO plans to acquire power and energy from market sources."

The ICC will begin deliberations in February and issue a final order by March 5, according to a commission spokeswoman.

FERC STAFF TO CONGRESS: WESTERN PRICE CAP IS NOT TO BLAME FOR UTILITY LOSSES

The Federal Energy Regulatory Commission's June cap on Western wholesale power prices did not cause utilities in the region to lose money selling surplus power from their long-term contracts into the spot market, commission staff said in a report sent to Congress Wednesday.

Congress asked FERC for the study after a number of Western utilities argued that the soft price cap, which took effect June 21, caused them to lose money when they were forced to sell surplus power into the spot market at prices below what they paid.

The report, however, found that the eight Western utilities surveyed, resold power in the spot market at an average price of \$35/MWh, well below the \$92/MWh cap that was in effect from June 21 through the end of the year.

The staff said a "wide variety of factors other than the price cap, such as conservation efforts, a downturn in the regional economy, and adequate supply given low demand, affected sales prices in both the spot and non-spot markets."

The study added that despite the fact that the Western utilities were forced to sell excess power from long-term contracts at prices below what they paid, the utilities' customers benefited from the resale of surplus energy from long-term contracts at the average \$35/MWh level because "the revenues from the resales offset the sunk costs of the long-term resources."

CALIFORNIA ISO ORDERED TO SCRAP MARKET CHANGES IT MADE WITHOUT FERC'S ASSENT

The Federal Energy Regulatory Commission has ordered the California Independent System Operator to throw out changes it made to its market operations without first seeking commission approval.

In the same ruling, FERC also upheld and confirmed a significant aspect of a December order requiring the ISO to allow out-of-state generators to set, or otherwise influence, the state's daily market-clearing price.

The Jan. 30 ruling builds off a complaint filed in December by generators alleging the ISO made substantial changes to two operating procedures before it sought FERC approval (EL02-42).

According to the complaint, the ISO unilaterally implemented a new redispatch policy to manage intra-zonal congestion that takes effect when it determines a generator's bids would not result in a competitive outcome. In addition, the ISO established new policies for out-of-state suppliers by essentially creating a separate 60-minute market for external supplies, an option not available to instate generators.

Although the ISO argued that the changes were minor, the commission disagreed, saying they mark major

changes in the state's market and must be filed at FERC before they could be implemented.

FERC said the new policies for out-of-state suppliers could affect the rates under the ISO's open-access transmission tariff. "Although we agree with [the ISO] that it possesses authority under...[its tariff] to ensure that it can meet dispatch objectives, we find that this authority does not extend to making revisions to its tariff when the revisions...have an impact on rates," FERC said in the order.

Further, the commission reaffirmed that its Dec. 19 order that covered several California market-related issues also barred the ISO from excluding out-of-state suppliers from setting the market-clearing price.

Generators applauded the decision, claiming that it "confirms that [FERC] has leveled the playing field" for all suppliers in the state, one lobbyist said Thursday.

Officials at the ISO were still contemplating the order at press time and would not speculate on whether it would affect their operations.

CALIF. GOVERNOR ASKS FERC TO PROBE WHETHER ENRON MANIPULATED MARKET

California Gov. Gray Davis Thursday asked the Federal Energy Regulatory Commission to investigate whether bankrupt energy marketer Enron and others suppliers may have manipulated the wholesale power market during the state's energy crisis that began in late 2000.

"The governor has asked federal regulators for a year and a half to look into this issue and the feds have been unresponsive," a Davis spokesman said. "Considering the new facts about Enron's influence, now more than ever these issues need to be looked at."

The governor's request was prompted by testimony delivered Tuesday to the Senate Energy and Natural Resources Committee by Robert McCullough, an Oregon-based consultant, who claimed Enron may have used its market dominance to set the forward prices in the region. McCullough's assertions would support California's contention that long-term contracts the state signed this year were "artificially high."

McCullough told the committee that West Coast forward prices fell 30% Dec. 3, the day after Enron filed for Chapter 11. "The clear implication is that Enron may have been using its market dominance to 'set' forward prices," he said.

"I am extremely concerned about revelations made in the past few days concerning possible manipulation of energy prices by Enron Corporation," Davis said in a Jan. 31 letter to FERC Chairman Pat Wood. "California has a special interest in getting to the bottom of such charges, since this state bore the brunt of the marketers' price gouging.

"If there is any doubt in your mind about whether an investigation is warranted, the latest revelations should answer that question," Davis said in his letter. "Clearly, an investigation is needed."

Davis said he was also making the request on behalf of both of California's senators, Feinstein and Barbara Boxer (D) "I ask that you expedite your investigation into Enron's role in California's energy market. But I ask that you not stop there. You should seek to uncover manipulation by any and all marketers and generators."

Wood earlier this week said the commission would if asked, conduct an investigation into whether Enron manipulated wholesale prices.

SENATOR SAYS ENRON FAILED TO PROVIDE 'CRITICAL' DOCUMENTS ON PARTNERSHIPS

Enron has failed to provide Congress with documents "critical" its investigation into the company's financial collapse, despite repeated requests, North Dakota Democratic Sen. Byron Dorgan charged Thursday.

Dorgan, chairman of the Commerce subcommittee on consumer affairs, has scheduled a hearing Monday into Enron's problems and expects the company's former Chief Executive Officer and Chairman Ken Lay to testify.

Meeting with reporters yesterday, Dorgan said Lay's attorney, Robert Bennett, told committee staff Lay would answer questions, "and that commitment continues." It will be Lay's first appearance before Congress since the company filed for bankruptcy Dec. 2.

Dorgan said his panel was continuing to seek information about Enron's partnerships and sent another request to the company Thursday. At least several of Enron's partnerships were allegedly used to keep debt and bad investments off Enron's books and played a critical role in the company's financial demise.

"We must pierce the veil of secrecy" surrounding Enron, Oregon Democratic Sen. Ron Wyden, who join Dorgan at the news conference. "Without this information about the partnerships, it is simply impossible for Congress to engage in its oversight role."

Dorgan said that Enron, which has provided 41 boxes of documents, had not refused outright to provide the information about the partnerships, but "when we get information, it's not the critical information we requested."

There also has been "some suggestion" from Enron officials that the records requested were not available "because these are partnerships and not really Enron," Dorgan said, adding that he rejects that claim.

Enron had 2,832 subsidiaries, including 872 offshore subsidiaries, most set up in the Cayman Islands, Dorgan said. General Motors, with 316 subsidiaries, 14 of which were offshore, was a distant second in terms of partnerships among U.S. companies, he added.

The House Financial Services Committee also expects that Lay will appear and answer questions during two days of hearings set for Monday and Tuesday, a panel spokeswoman said.

In addition to Lay, the committee's will hear testimony from Arthur Andersen CEO Joseph Berardino, SEC Chairman Harvey Pitt and Enron director William Powers.

Dorgan also revealed that former Enron CEO Jeff Skilling had agreed to testify before the Senate Commerce Committee, at a later date.

"Skilling's legal representatives have now told us that he is willing to appear before our committee and testify," Dorgan said. "We intend to schedule another hearing following Monday's testimony from Ken Lay so that we will be able to take Skilling's testimony."

Meanwhile, Skilling, and Enron's ousted Chief Financial Officer Andrew Fastow are scheduled to appear before a House Energy and Commerce Committee subcommittee Feb. 7, committee Chairman Bill Tauzin (R-La.) and Oversight and Investigations Subcommittee Chairman James Greenwood (R-Pa.) said Thursday.

Tauzin and Greenwood also said Michael Kopper, a former Enron officer, had been subpoenaed to appear before the subcommittee Feb. 7; Skilling and Fastow are appearing voluntarily.

FPL ENERGY CONSIDERS BUILDING 332-MW, GAS-FIRED PEAKING PLANT IN SOUTH CAROLINA

FPL Energy said Thursday it is the early stages of developing a 332-MW, gas-fired peaking plant near an existing 80-MW, gas-fired cogeneration plant that the Juno Beach, Fla.-based company and Caithness Energy co-own in Cherokee County, S.C.

"Our intention is to own and operate the plant, and sell its' output under a long-term power-sales agreement, probably with a single customer," a spokeswoman for FPL Energy said.

The companies had not yet determined whether FPL would retain full ownership of the plant, or sell a partial interest to New York City-based plant developer Caithness or another party.

The spokeswoman said the generation subsidiary of FPL Group wanted to secure the long-term power sales pact with a utility or other power buyer later this year, and begin commercial operation of the facility's two 161-MW combustion turbines by June 2004.

She acknowledged that South Carolina's state Legislature is currently considering a bill that would place a moratorium on any new merchant-project approvals by the state Public Service Commission until July 2003, but expressed confidence the bill would not affect FPL's plans.

Among other things, the bill exempts projects that hold agreements to sell at least 75% of their output for 10 years or more, and the bill may be amended to further limit the number of projects subject to the ban.

MERCHANT TRANSMISSION ADVOCATES FACE UP TO REGULATORY, FINANCIAL CONCERNS

Merchant transmission advocates were optimistic Thursday that the business soon would find a warmer financial climate and growing understanding from regulators allowing merchant transmission projects to flourish.

The merchant transmission business is at the "dawn of a new era," according to Ed Krapels, chief financial officer and board member of the Neptune Regional Transmission System. Right now, the financial community "has a bigger appetite for transmission projects than generation projects," he said in remarks at InfoCast's Transmission Summit 2002 in Washington, D.C., yesterday.

When completed, the Neptune project would be a 4,800-MW, underwater transmission cable network with three lines from New Brunswick, Nova Scotia and Maine connecting to Boston, the Connecticut Shore and New York City. The Federal Energy Regulatory Commission has signed off on the project, valued at between \$2-billion and \$3-billion, which is expected to be completed in 2006.

In the wake of Enron's collapse, energy companies are concerned about their balance sheets undergoing more vigorous scrutiny from ratings firms and are pulling back on long-term generation projects, Krapel noted.

"There will be a lot less generation than there would have been had Enron not collapsed," Krapels said. "As a result, the value of transmission is going up. Transmission assets are more valuable in this climate."

On the regulatory side, public utility commissioners are gaining a better understanding about the independent entities seeking to build merchant transmission and sell capacity rights, he said. "We have accomplished a lot in the

last year from a public policy point of view," said Krapels, adding that informal responses from state utility commissions have been "overwhelmingly positive."

Michael Naeve, an attorney in private practice and a former FERC commissioner, said FERC had been encouraging merchant transmission in its RTO orders but had expressed concerns, including whether merchant entities might have market power or withhold capacity.

To guard against such potential problems, buyers of transmission rights could be required to use rights to schedule in the day-ahead market or risk having a regional transmission organization sell them in the hourly market. But such a provision would make for an inflexible market and stifle creative bidding, Naeve said. Banning affiliates from buying transmission rights during "open season" also could hurt the market, he said. "There will be less participants available, less capital for projects," he said.

Still, FERC has said merchant transmission can collect "negotiated rates," which are, according to Naeve, "market-based rates with distinction."

Jose Rotger, regulatory strategy manager for Transenergie US, said his firm plans to have its 330-MW Cross Sound underwater line between New York and Connecticut operating by June. "Market-based transmission is for real. It is financeable. It is buildable."

DUKE ENERGY SELLS BULK OF ENGINEERING AND SERVICES UNIT TO FRAMATOME ANP

Duke Energy Thursday said it had agreed to sell the bulk of its Duke Engineering & Services (DE&S) unit to Framatome ANP, the French nuclear giant. Financial terms will be released when the deal closes in the second quarter of this year.

The Duke Energy unit specializes in energy and environmental projects in the U.S. and overseas, and posted 2001 revenue of about \$280-million. DE&S's large nuclear group provides, among other things, comprehensive design, engineering, procurement and construction management services.

DE&S is one of three companies providing engineering services to six Midwestern nuclear power plants operated by Nuclear Management, a joint venture of Xcel Energy, Alliant Energy, Wisconsin Electric Power, Wisconsin Public Service and Consumers Energy.

It also is a partner with Washington Group International on a project to replace the steam generators at AmerenUE's Callaway nuclear plant in Fulton, Mo., and is involved in several major nuclear projects overseas.

Charlotte, N.C.-based Duke Energy said it is selling its DE&S unit so it can focus on its wholesale electricity and gas businesses. It noted that it would retain two parts of DE&S: the power-delivery services component, which will be named Energy Delivery Services.

The deal with Framatome calls for about 1,250 of DE&S's more than 1,500 employees to become employees of Framatome. CIBC World Markets is Duke Energy's financial advisor in the deal.

AVISTA HAS 64% DROP IN 2001 INCOME, BUT HYDRO CAPACITY RETURNING TO NORMAL: CEO

Avista Corp. has begun to turn the corner on financial problems that plagued the company during the last year, Gary Ely, chairman, president and chief executive said

Thursday.

The Spokane, Wash.-based company ran into financial trouble last year when severe drought diminished its hydropower capacity at a time when replacement power on the market was expensive. Recent abundant rain has been restoring hydro levels to normal, Ely told analysts in a conference call.

The company awaits a ruling by Oct. 31 on whether it can create a power cost adjustment mechanism that will allow rates to fluctuate to reflect power costs. Meantime, it is seeking an interim rate hike and expects sufficient financing to bring on-line by summer the 280-MW Coyote Springs-2 plant in Oregon, Ely said.

Despite dramatic swings in power prices, the company's restructured power marketing unit delivered positive earnings for 2001, Ely said. But earnings were down significantly relative to the previous year.

The marketing unit had fourth-quarter pre-tax income of \$3.7-million compared to \$117.6-million in fourth quarter 2000. Revenues were \$781.4-million in last year's fourth quarter compared to \$1.9-billion in fourth quarter 2000. For the year, pre-tax income was \$94.7-million, compared to \$250.2-million in 2000, and revenues were \$5-billion compared to \$6.5-billion in 2000.

In the fourth quarter, Avista had \$1-billion in revenues, compared to \$2.3-billion in fourth-quarter 2000 and net income of \$5.8-million, compared to \$67.4-million in fourth-quarter 2000. For the year ending Dec. 31, 2001, revenues were \$6-billion compared to \$7.9-billion in 2000. Net income for 2001 was \$23.9-million, compared to \$67.9-million in 2000, a drop of about 64%.

The company said the reduced net income reflects mainly the effect of poor hydro conditions during 2001, a write down of telecommunications assets and reduced retail and wholesale sales.

Avista executives said they hoped improved financial performance, stemming partly from a rate surcharge granted last fall, would lead to improved bond ratings.

Dimitri Nikas of Standard & Poor's, a division of the McGraw-Hill companies, said the rating agency does not think the lower earnings figure will result in any change in Avista's credit quality from BB+. S&P is monitoring upcoming events, including the outcome of a general rate case, he said, and all these events must have reasonably favorable outcomes for credit quality to be maintained at current levels.

Avista plans to fight a Montana initiative that may be on the November ballot which would allow a new state agency to condemn hydropower dams and pay market value to the owners, as this could affect its 525-MW Noxon Rapids dam.

CONECTIV SCALES BACK PLANS TO BUILD 'MID-MERIT' MERCHANT CAPACITY IN PJM

Citing a softer market, Conectiv Thursday said it is scaling back its plans to build "mid-merit" merchant power plants in the PJM Interconnection.

Conectiv, based in Wilmington, Del., plans to bring online five plants totaling about 3,300 MW in the next five years, officials said in an investor conference call. The company had planned to build eight facilities totaling about 4,000 MW by 2004. The build up would have cost about \$2.6-billion. Conectiv serves parts of Delaware, Maryland, Pennsylvania, New Jersey, and Virginia.

The company intends to complete its Hay Road site expansion in June 2002, bringing it to 550 MW, officials said. Also, it recently started building a 1,100-MW facility in Bethlehem, Pa., with 330 MW slated to come on-line in late 2002 and the rest in 2003. Conectiv expects to fund its midmerit strategy from internally generated funds, leasing, external financings, and proceeds from the sales of electric generating units. The company is selling its fossil generating plants in favor of natural gas-fired, mid-merit facilities, a company spokesman said.

Conectiv also said it expects to close on the sale of 794 MW in generating assets to Minneapolis-based NRG Energy in February, officials said. Under the deal, NRG will buy from Atlantic City Electric, a Conectiv subsidiary, the BL England and Deepwater Generating Stations as well as additional partial ownership interests in Conemaugh and Keystone stations. In late June 2001, NRG bought 1,081 MW of baseload electric generating plants from Delmarva Power and Light, a Conectiv subsidiary. Proceeds from the sale will go into Conectiv's mid-merit investments.

Also, Conectiv officials said they see no barriers to closing its pending merger with Potomac Electric Power in the first quarter. The merger remains on track, with settlement agreements awaiting in Maryland and Delaware, officials said. The merger has been cleared by the Federal Energy Regulatory Commission, the Pennsylvania Public Utility Commission, the Virginia State Corporation Commission, the Federal Trade Commission and the Dept. of Justice. The utilities are seeking approvals in the District of Columbia, New Jersey, and from the Securities and Exchange Commission.

TXU NET INCOME FALLS 27.5% TO \$655M, ENTERGY IMPROVES 6.9% TO \$726.2M

TXU Corp. Thursday reported 2001 net income of \$655-million, down 27.5% from 2000, on operating revenue of \$27.93-billion, up 26.9%. Earnings per share fell from \$3.43 to \$2.52, on average shares of 259 million, down 1.9%. "Other deductions" were \$117-million, versus year before "other income" of \$238-million, mainly from the sales of TXU Processing, TXU Europe's metering business, and TXU's share of the Mexico City natural gas distribution system. Last year's net was cut \$325-million—\$274-million in the fourth-quarter—for unusual items.

Largest was \$154-million in the fourth-quarter on U.S. electric operations for separating power delivery from what are now unregulated merchant energy operations, and, settle all issues related to the start of retail competition on Jan. 1.

Another \$88-million was the net loss, including transaction and refinancing costs related to the planned sale of the "low growth, mature" Eastern Electricity (United Kingdom) network operations to London Electricity. That includes TXU Europe's 50% share of 24seven, the network operating company, and the 2,000-MW West Burton power plant.

Another \$43-million was charged for European restructuring and related costs; \$22-million for Enron-related write-offs of European assets; and \$18-million to write off U.S. Electric wholesale regulatory assets.

On U.S. Electric (utility) operations, with the charges, net fell 18.8% to \$717-million, on revenue of \$7.61-billion, up 2%. Operating expenses were up 2.5% to \$5.88-billion, led by a 16.4% rise in non-income taxes, to \$646-million.

Purchased power and fuel dipped 2.1% to \$3-billion.

There was a fourth-quarter net loss of \$62-million, down from net income of \$158-million, as revenue dropped 22.4% to \$1.5-billion. But the charges were somewhat offset by a 23.2% slump in expenses, to \$1.27-billion, led by a 52% plunge in power and fuel, to \$441-million.

Power sales dipped 1% to 105,560 GWh, led by a 15.5% slide in wholesale, to 2,747 GWh. And with the average price down 46.9% to 2.04 cents/kWh, wholesale revenue plunged 55.2% to \$56-million. Residential sales rose 0.3%. Commercial fell 1.4% and industrial 0.9%. Cooling degree days were down 15.6%.

The U.S. Gas (utility) segment lost \$16-million, versus year-before net of \$49-million, on revenue of \$1.23-billion, up 11%. Operating expenses rose 19.9% to \$1.21-billion, led by a 51% jump in non-income taxes, to \$95-million. Purchased gas was up 26.5% to \$764-million. Distribution volume rose 4.3% and transportation fell 9.2%.

The U.S. Energy (trading and marketing) segment had net of \$6-million, versus a 2000 loss of \$88-million, on operating revenue of \$5.58-billion, up 1.3%. Operating costs fell 1.5% to \$5.54-billion, led by a 4.3% drop in purchased power, to \$5.19-billion. Income taxes were \$1-million, versus tax credits of \$47-million. Power volume rose 19% to 26,105 GWh, and gas fell 30.4% to 864 Bcf.

Fourth-quarter net was \$35-million, versus a \$48-million loss, despite a 36.2% slump in revenue, to \$1.13-billion. Power volume surged 76.4% to 12,384 GWh, though gas fell 31% to 199 Bcf.

With the charges, European net was down 26.5% to \$158-million, on operating revenue of \$12.7-billion, up 80.6%. Operating costs jumped 93% to \$12.3-billion, led by a 111.2% leap in purchased power and fuel, to \$10.4-billion. But income tax credits were \$263-million, versus 2000 costs of \$94-million.

Those results reflect: purchase of 51% of Germany's Stadtwerke Kiel (July 2000) and Norweb Energi from United Utilities (August 2000), and, sale of TXU's 50% share in Sweden's Elbolaget to Lunds Energi (November 2000), 19.2% of Spain's Hidroelectrica del Cantabrico to Adygesinval SL (a joint venture of Electricidade de Portugal and Spanish bank Caja de Ahorros de Asturias)(April 2001); and the British 1,000-MW Rugely plant to International Power (July 12, 2001).

Australian net was down 7% to \$53-million, on revenue of \$700-million, down 2.4%.

With the charges, there was a fourth-quarter net loss of \$76-million, versus 2000 net of \$156-million, on revenue of \$6.8-billion, up 0.2%.

TXU is "confident it can meet earnings expectations of \$4.35-\$4.45/share in 2002," including \$1.00-\$1.05 in the first quarter.

Entergy net improved 6.9% to \$726.2-million, on total revenue of \$9.6-billion, down 4%. Basic EPS rose from \$3.00 to \$3.29, and diluted from \$2.97 to \$3.23, on basic shares of 220,944,270, down 2.5%, and diluted of 224,733,662, down 1.7%. Net was cut \$13.2-million (6 cents/share) for costs of the canceled acquisition by FPL Group.

U.S. utility operational EPS fell from \$2.65 to \$2.46. Electric revenue was up 0.3% to \$7.24-billion, on power sales of 108,852 GWh, down 3.7%, led by a 9.2% slump in wholesale, to 8,896 GWh. Residential fell 2.9% and industrial 5.4%. Gas revenue rose 12% to \$185.2-million.

From Competitive Non-Regulated Businesses, EPS jumped from 40 cents to 95 cents, reflecting growth at Entergy Nuclear and better results at Entergy-Koch, the new trading, marketing, and development unit.

Nuclear EPS rose from 22 cents to 57 cents, due mainly to the acquisitions of the New York Power Authority's Indian Point-3 and FitzPatrick (Nov. 21, 2000), and, Consolidated Edison's Indian Point-1 and –2 (Sept. 6, 2001).

Commodity Services (Entergy-Koch plus Entergy Wholesale Operations) EPS surged from 18 cents to 38 cents. There was a \$33.8-million gain from the sale of the 1,200-MW Saltend plant in the United Kingdom to Calpine, on Aug. 27.

Fourth-quarter net was down 52.3% to \$20.6-million, on total revenue of \$1.88-billion, down 28.4%.

WPS Resources net improved 15.8% to \$77.6-million, on revenue of \$2.67-billion, up 37.3%. Basic EPS were \$2.75 and diluted \$2.74, both up from \$2.53, on average shares of 28.2 million, up 6.4%, due mainly to the 1.8 million new shares issued in April 2001 to acquire Wisconsin Fuel & Light Co. This cut EPS by 18 cents.

Electric utility net was down 3.1% to \$58.8-million, on revenue of \$675.7-million, up 5.1%. Gas utility net slumped 23.3% to \$8.9-million, on revenue of \$321.6-million, up 21.6%.

EPS were boosted 24 cents by higher electric utility margin and 25 cents by higher gas utility margin, reflecting the Jan. 1 rate hikes of 5.4% for power and 1.5% for gas at Wisconsin PS. Also, cooling degree days jumped 65.5%, though heating degree days were down 9%.

At WPS Energy Services, higher margins boosted EPS 22 cents for power and 10 cents for gas, due to higher sales, entry into new power markets, and exiting of unprofitable gas markets.

At WPS Power Development, lower margins cut EPS 4 cents due to higher purchased power costs and higher fuel costs at the 389-MW Sunbury plant, bought from PPL Corp. in November 1999. It had to buy coal at market prices due to the failure of WPSPD's supplier to deliver specified volumes. WPSPD is suing to recover part of those higher coal costs.

Results also reflect the September 2000 purchase of the 30-MW Westwood coal waste unit.

Net income from "holding company and other," including other nonutility operations, was \$1.3-million, versus a 2000 net loss of \$7.9-million, on revenue of \$1.3-million, up 8.3%. The 2000 was due to a \$3.8-million power contract entered into as hedge against potential loss of generation or high summer peak loads.

Company-wide operating expenses rose 39.7% to \$2.57-billion, cutting EPS by \$1.06. But EPS were boosted 28 cents by lower depreciation and decommissioning costs. "Other income" surged 85.2% to \$37.5-million, due to higher earnings on equity investments including Wisconsin PS' investment in American Transmission Co. This boosted EPS 37 cents.

With tax credits on WPSPD synfuels plants, income taxes fell 20% to \$4.8-million.

Fourth-quarter net jumped 51.9% to \$20.5-million, on revenue of \$583.8-million, down 18.8%, as heating degree days slumped 25.4%. But other income was \$24-million, versus other deductions of \$1.5-million, due to pre-tax gains of \$13.1-million on the sale of hydroelectric properties, and

\$2.2-million on the sale of part of the synfuels operations. WPS predicted 2002 EPS "from ongoing operations" of \$2.75-\$3.00, including 59 cents from additional synfuels divestitures.

CLECO net was up 8.3% to \$68.4-million, on revenue of \$1.06-billion, up 29%. Basic EPS rose from \$1.41 to \$1.52, and diluted from \$1.36 to \$1.47, on basic shares of 45 million, up 0.1%, and diluted of 47.76 million, up 0.2%. In 2000, net was boosted \$2.5-million (11 cents/share) from debt repurchases by a Cleco Midstream Resources subsidiary.

Last year, the combined loss on the discontinued operations, and disposal of, the Utility Construction and Technology Solutions LLC unit, sold March 31, 2001, was \$2-million, down 70.3%. At utility Cleco Power LLC, EPS dipped from \$1.29 to \$1.27, as retail electric revenue rose 0.6% to \$623.1-million, though power sales fell 4%. From Midstream Resources, EPS jumped from 22 cents to 31 cents, on energy marketing and tolling revenue of \$435.8-million, up 116.5%. Results reflect the first full year of operation at the 750-MW Cleco Evangeline plant, which began commercial operation July 8, 2000,

Operating expenses were up 35% to \$909-million, led by a 142% jump in purchases for energy marketing, to \$359.4-million.

Fourth-quarter net surged 216.3% to \$14.9-million, on total operating revenue of \$194.8-million, down 14.2%.

TXU ENERGY LOOKS AT NEW GENERATION; RETAIL GROWS FASTER THAN EXPECTED

TXU Corp. said Thursday its unregulated TXU Energy subsidiary had been more successful that expected in signing up 1-MW-plus retail customers outside the traditional service area of its regulated TXU Electric affiliate.

TXU Energy had been expecting to secure a market share among larger commercial and industrial customers in the Reliant Energy/HL&P and other Texas areas "in the high teens, and we find ourselves in the high twenties," said Rob McCoy, president of TXU Energy's retail business.

McCoy said TXU Energy's contracting rate for Texas C&I customers had been "about five times our goal in January," the first month of retail competition in the state. He noted that the electricity-supply contracts TXU Energy has been reaching with C&I customers range from three months to three years, with an average term of 20 or 21 months.

Finally, TXU Energy said it is open to the possibility of selling more generation assets in Texas, where it recently reached a \$443-million deal to sell 2,334 MW in gas-fired capacity to Exelon Generation. It also said it is considering buying or developing more capacity in the Northeast and Mid-Atlantic states, and in Europe's Nordic countries.

DESPITE CHARGES, CONSTELLATION AND PPL SHARPLY HIKE DIVIDENDS

Constellation Energy Group Wednesday and PPL Corp. late Tuesday sharply boosted dividends on common stock—despite major one-time charges that cut 2001 earnings.

As announced in October 2000, CEG in second-quarter 2001 slashed the quarterly dividend 71.4%, from 42 cents down to 12 cents (48 cents annually). It has been 42 cents

since it was raised from 41 cents in second-quarter 1998.

But Wednesday, CEG doubled the dividend to an annual rate of 96 cents—the biggest one-time hike by an electric power company in at least a decade. The new dividend is payable April 1 to shareholders of record March 11, 2002, and represents a pay-out ratio of 168.4% of 2001 reported earnings per share, or, 36.9% of EPS before one-time charges.

On Wednesday, the stock closed up 74 cents (2.8%) at \$27.13, down 32.9% in a year. At that price the dividend yield is 3.54%.

PPL hiked the quarterly dividend 35.8%, from 26.5 cents to 36 cents (\$1.44 annually)—also one of the biggest hikes ever by an electric power company. The last rise, from 25 cents to 26.5 cents (up 6%) was paid in second-quarter 2000, and was the first since it was cut from 41.75 cents in fourth-quarter 1998. In April 2001, PPL said the \$1.06 annual rate would be held for the "foreseeable future," but on Jan. 4 PPL said consideration was being given to a raise.

The new dividend, payable April 1 to shareholders of record March 8, will bring the pay-out ratio more in line with similar energy companies, PPL said. At the new rate the ratio is 118% of reported 2001 EPS share of \$1.22, or, 34% of EPS before one-time charges of \$3.00, also announced Tuesday. On Wednesday the stock gained 31 cents to \$32.83, down 21.3% in a year. At that price the dividend yield is 4.39%.

BRAZIL-CAPS (continued from page 1)

that the rule would put privately owned generation at a strong disadvantage and dry up future investment in new projects.

Most of those projects would be fueled by natural gas imported from Bolivia and have production costs well above those of the country's existing hydro generators. Brazil projects that it will need to add more than 4,000 MW of new capacity a year by 2009 to keep pace with demand.

The price caps were approved by government fears that retail electric rates would skyrocket next year, pushing up inflation.

Among the power companies that hope to develop new generating plants in Brazil are AES, El Paso Energy, Duke Energy, InterGen, Tractebel, Endesa Espana, Eletricidade de Portugal, and Electricite de France.

STORM-MIDWEST (continued from page 1)

UtiliCorp United's Missouri Public Service division reported 54,000 customers and 4% of its transmission capacity out. Of the municipal utilities in the area, the Kansas City, Kansas Board of Public Utilities reported peak outages affecting 10,000 customers, with 8,000 still out. Independence (Mo.) Power & Light was hard hit, but numbers were not immediately available.

AmerenUE reported a total of 51,600 customers affected. Fourteen Missouri electric cooperatives were affected, with up to 25,000 customers out. No major transmission damage was reported.

In Oklahoma, OG&E reported 191,000 customers out at the peak and 177,000 still without service Thursday afternoon. It had at least 60 miles of major transmission lines down, and estimated eight days for full repairs.

AEP Public Service Oklahoma reported peak outages in the 45,000 customer range, with 27,100 still out Thursday.

It had significant transmission damage, including a damaged line that left Elk City blacked out and isolated.

Oklahoma's electric distribution cooperatives estimated peak outages at 20,000, including all 11,800 customers served by Kingfisher-based Cimarron Electric Cooperative. Western Farmers Electric Cooperative of Anadarko had serious transmission damage, but details were not available.

In Kansas, the storm knocked out service to an estimated 172,000 customers of Westar Energy. About 42,000 remained out Thursday afternoon. "We have a lot of transmission lines out, but don't have mileage figures yet," a spokeswoman said.

Seven of the state's 27 distribution cooperatives were impacted, with an estimated 30,000 customers blacked out. Westar transmission damage was hampering repair efforts, cooperative officials said.

In Indiana and Michigan more than 150,000 electric customers of American Electric Power, Detroit Edison and Northern Indiana Public Service were without power.

AEP said the storm caused damage to power facilities and left as many as 76,000 of its customers without power in northwestern Indiana and southwestern Michigan. The outages may increase, the Columbus, Ohio-based company said, as damage assessment continues. NIPSCO reported about 20,000 customers affected by the storm.

A Detroit Ed spokeswoman said at least 68,000 outages were reported in the southern portion of the utility's service area, in southern Wayne, Monroe and Washtenaw counties. And "the numbers are rising in the last couple of hours," Kessler said late Thursday afternoon.

More freezing rain was forecast for much of the region Thursday night and Friday morning, raising the possibility of additional outages.

Oklahoma Gov. Frank Keating declared 27 counties to be disaster areas, Kansas Gov. Bill Graves shut down or cut hours for state offices and a state of emergency was declared in Kansas City, Mo. Both Kansas City Power & Light and Oklahoma Gas & Electric said the storm was the worst in their 100-year-plus histories. There were growing reports of severe transmission system damage and repair estimates of eight days or more were common.

CALIFORNIA-AGREEMENT (continued from page 1)

ratepayer revenue streams called bond charges and department charges. The bond charges will go toward paying off the bonds, ensuring a dedicated portion of utility rates will go to bondholders, while the department charges will pay for DWR's operating expenses, including its long-term power contracts.

The PUC is set to rule Feb. 7 on another order critical to the bond issuance—DWR's \$10-billion revenue requirement. The PUC plans as part of the agreement to set the charges quickly for DWR's revenue needs. Under the agreement DWR in the future would be required to submit its revenue requirement to the PUC annually and the commission would will revise bond charges and power charges as necessary to ensure sufficient revenues to pay for DWR costs and bond-related costs as they come due.

The PUC said that it is working with the office of the governor and state Treasurer Philip Angelides on the details and amounts of the bond issuance, resolution of which will be provided to the PUC in a summary of financial terms

before the PUC will act on the proposed agreement.

The PUC in a 4-1 vote in October refused to pass a DWR rate agreement because of fear that it would lock the state into the expensive long-term power contracts. PUC and Davis aides have been working since then to come to a resolution to enable the bond sale.

As part of the draft DWR agreed to use its best efforts to renegotiate its long-term contracts. The PUC also is not limited in its ability to engage in litigation regarding the contracts under the settlement.

Davis in a statement called the agreement "a significant step in the right direction to get energy bonds sold. We look forward to approval of this agreement by the full commission at its next meeting." Angelides did not return calls for comment.

NORTHEAST-DEMAND (continued from page 1)

director, energy consulting, for DRI-WEFA, said. The Mid-Atlantic states will need about 15 GW of new capacity, while New England will need an additional 10 GW—both representing increases of about 25%, she said.

Although there is great interest in developing plants, "the picture is not that rosy in New England," said Steve Whitley, senior vice president for the ISO-New England, who added that "transmission is loaded to the limit," making it difficult to move more power around the region. Last summer, consumers incurred \$80-million in additional costs because the independent system operator could not move cheap power from Maine to southern New England, he noted. A troublesome area is southwestern Connecticut, a densely populated and affluent area where residents have the time and money to oppose new power projects, he said.

New England Gas Assn. President Craig Frew told the conference that gas supplies for power could also tighten, because merchant generators insist on buying only spot or short-term supplies. That makes it difficult to build or expand lines, because pipeline companies can more easily get financing if they have long-term contracts. He suggested that when state commissions approve gas-fired power plants, they should require long-term contracts. Alternatively, regulators could let local distribution companies (LDCs) sign long-term pacts, which could "underpin" the pipelines.

Ron Erd, an official with merchant generator Mirant, said "the merchant sector has delivered" for the region, noting that competitive power plants now account for one-third of total generation and 90% of new capacity. Erd, however, warned that "price controls are stalling the market, and private investment. Reliability is vital, but if we're going to attract private investment, we need payments that reflect the value of reliability."

Erd's argument was seconded by Christine Uspenski, electric analyst in Schwab's Washington, D.C., office, who said price controls are disrupting project financing. The financing of transmission is even more difficult because of regulatory uncertainty, she added. Traditionally, utilities sought transmission financing through "socialized" rate structures, where costs were passed along to ratepayers. Now, there are moves to build "leaner, just-in-time" merchant lines, which banks will also finance, "but you have to make up your minds," she said.

Maureen Helmer, chairman of the New York Public Service Commission, agreed that transmission is becoming more confusing. "A state agency can't just tell a utility to build a power line," he said, since that utility's customers will bear the costs, while others may benefit more from relieved congestion.

The picture grows even more complex when officials consider other factors. At the conference was a delegation from Mt. Vernon, N.Y., which wore arm bands to "mourn" the fate of their city, which was approved by FERC as the site for a terminal for the proposed Millennium pipeline. Noting that the city is mostly minority-populated, Councilman William Randolph called for "environmental justice," saying, "We want analyses of communities with the same diligence as financial and engineering analyses." Regulators must also consider alternatives to infrastructure projects, said Ashok Gupta, director of the air/energy program for the Natural Resources Defense Council (NRDC). Demand-side measures and distributed generation can eliminate the need for major, disruptive projects, he said.

Uspenski said the financial community welcomes this approach. "Wall Street wants all the cards on the table," she said. "We encourage [project developers] to look at alternatives before coming for financing because they're less likely to be sandbagged later."