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Global Power Report

October 30, 2008

Maryland PSC to rebid RFP after rejecting bids; monitor cites financial crisis premiums

The Maryland Public Service Commission will re-issue a solicitation for 1,000 MW after finding no acceptable bids for the procurement of 855.1 MW of residential standard offer service supply for Baltimore Gas and Electric or for 144.9 MW of SOS supply for Delmarva Power's residential and small commercial customers.

It accepted bids for 1,982 MW but said the financial crisis resulted in "substantial premiums" in the prices.

Regulators would not say why they rejected the other bids, but in testimony released on October 27, the procurement monitor said all bids were affected by the credit crisis, and that bid prices were well beyond what was anticipated.

"The key question before the auction, 'will the crisis be mirrored in the bid results?' was answered with an unequivocal 'yes,'" said the bid monitor, Richard Mazzini of Liberty Consulting Group.

BGE said it could not comment on the results from the auction. A PSC spokeswoman and the bid monitor also said they were not at liberty to comment on the results.

(continued on page 3)

Pink sheets company thinks big with plans to construct a fleet of nuclear power plants

Alternate Energy Holdings Inc. trades on the pink sheets along with a host of other small, unregulated stocks – though it soon expects to move up to the Over-the-Counter Bulletin Board – but there is nothing small about AEHI's plans.

The Eagle, Idaho, company plans to build at least three nuclear power plants on a merchant basis.

Current estimates for the cost of a nuclear power plant run between $5 billion and $8 billion, but those numbers could be low because there is no recent data. A nuclear power plant has not been built in the United States for about two decades.

AEHI, formed by nuclear industry executives, has a market capitalization of between $11 million and $17 million on its 75 million outstanding shares, depending on whether the bid or ask price is used for the calculations. AEHI's recently quoted bid price on the pink sheets web site was 15 cents a share. The asking price was 23 cents.

In a filing with the Securities and Exchange Commission earlier this month, AEHI reported that it had no revenues in 2007 and incurred expenses of $4.4 million during the year. Overall, the company reported a net loss for the year of $3.9 million. As of the end of June, the company reported assets of

(continued on page 4)

FPL Energy, citing economic turmoil, cuts its capital spending plans by $1.3 billion

FPL Group on October 27 said that because of the nation's economic turmoil, its FPL Energy independent power subsidiary will reduce its 2009 capital spending by $1.3 billion, including a cut of nearly $1 billion in its spending on new wind projects.

FPL Group Chairman and CEO Lew Hay and CFO Armando Pimentel said during an earnings conference call with energy analysts that while FPL Energy had planned to place 1,500 MW of new wind capacity online in 2009, the company has trimmed that plan to 1,100 MW. They suggested that additional cuts are possible if economic conditions worsen.

Pimentel added, "At this time, we are not adjusting our target to add between 7,000 to 9,000 MW of wind from 2008 to 2012, but we will continue to monitor the market and will update you on our fourth-quarter earnings call."

Hay explained FPL Energy's current situation: "Although our project pipeline remains very attractive, we are not immune to the credit crisis affecting the markets. We expect that the banks and other financial institutions that have been terrific partners in financing our growth that FPL Energy may need some time to

(continued on page 2)

INSIDE THIS ISSUE

Company News
- Constellation reveals story of acceptance of MidAmerican proposal 5

Finance
- Tenaska closes $2.4 billion fund for power sector purchases 7
- Industry Funds Management of Australia is expanding in the US 8
- Southern Company will still spend $13 billion in capex by 2010 8
- Calyon report sees increased power sector M&A activity in 2009 9

Asia/Pacific Rim
- India's Suzlon nixes rights issue and acquisition of REpower 12

Europe
- Credit crunch, turbine supplies crimp EU offshore wind plans 14
- Belgian group plans 600-MW offshore wind farm in North Sea 15
- Drax, Siemens plan three biomass plants in $3 billion venture 15

Latin America
- Colbun wins permit for 144-MW run-of-river project in Chile 17

North America
- Federal appeals court denies EnviroPower permit for Illinois project 18
- Santee Cooper signs 20-year PPA for 50-MW biomass project 19
- Pace says credit crisis delaying sale of 1,750-MW Texas project 20
- Progress Energy Carolinas seeks proposals for renewables 20

FPL Energy, citing credit crunch, cuts capex by $1.3 billion ... from page 1

recover from the recent turmoil."

He continued, "Although we believe that both public and private financing for good projects will continue to be available, it appears that the number of financial intermediaries with the appropriate risk appetite for project financing has declined in the short term. Until confidence returns to the credit markets, we believe financing will be available for only the best projects, and even for those, the cost of credit will be higher than we have seen in the recent past."

Neither Hay nor Pimentel provided specifics about which wind and other non-utility power projects would not advance in 2009 because of FPL Energy's plan to scale back its capital spending next year. The independent power subsidiary had indicated previously, however, that it would be delaying some wind projects in West Texas because of transmission-related concerns (*GPR*, 2 Oct, 14).

FPL Group, which also is the corporate parent of Florida Power & Light, said that it earned $774 million, or $1.92 cents/share, on revenue of $5.387 billion in the third quarter, compared with earnings of $533 million, or $1.33/share, on revenue of $4.575 billion in the same period last year.

The parent company's, and FPL Energy's, third-quarter earnings included a net unrealized after-tax gain of $285 million associated with the mark-to-market effect of non-qualifying hedges. Their results for last year's third quarter included a net unrealized after-tax gain of $40 million associated with the mark-to-market effect of non-qualifying hedges.

The FPL Energy subsidiary posted third-quarter earnings of $483 million, or $1.20/share, compared with earnings of $220 million, or 55 cents/share, in last year's third quarter. The $263 million increase in earnings was tied in part to the addition of new wind projects and the addition of the Point Beach nuclear station to FPL Energy's portfolio in September 2007, as well as contributions from the subsidiary's NEPOOL assets and Texas fossil-fired assets, FPL Group said.

"The net weather impact in the quarter was poor," Pemintel said. "Although ... we had good hydro[electric] conditions for our Maine unit, the wind resource in virtually all of our regions was poor," and in fact was "the lowest recorded wind source in our data base dating back to 1973." He added that FPL Energy is "well-hedged for 2009 and 2010. For 2009, we are essentially fully hedged the first-order impacts of natural gas prices and are significantly hedged against other price movements, including spark spreads."

Pimentel noted that FPL remains on track to meet its previously issued adjusted earnings/share expectations of $3.83 to $3.93/share for 2008, but noted that FPL now expects its earnings this year to come in at "the lower end" of that range. He also reaffirmed FPL's expectation of adjusted earnings of $4.05 to $4.25/share in 2009 and $4.50 to $4.90/share in 2010.

Hay and Pimentel emphasized during the conference call that, even with the ongoing turmoil in the credit markets, FPL Group retains a strong balance sheet, excellent credit ratings, continued access to the commercial paper markets, and significant lines of credit.

Still, they said that FPL Group has decided to reduce its planned 2009 capital spending to $5.3 billion from the $7 billion it had been planning for, with FPL Energy accounting for $1.3 billion of the $1.7 billion cut and FP&L the remaining $400 million.

Most of the cuts at the regulated utility are tied to projects

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associated with system growth that is no longer expected because of Florida's economic downturn. FP&L has not made any changes so far, however, in its plan to build five 1,250-MW gas-fired plants.

Hay said FPL Energy's scaled-down plans for 2009 "will reduce our forecast wind capital expenditures for next year by close to $1 billion ... Do these changes reflect a loss of confidence in the renewable energy business? Not at all ... Over the long term, we expect to see tremendous demand for renewable energy and we intend to be the company best positioned to meet that demand."

Hay added, "One of the reasons we want to be vigilant on capital expenditures is to be in a position to seize market opportunities should they arise. The fact is some of the weaker competitors in the renewable energy space are likely to face great difficulties. They will not only have trouble accessing the capital markets, which will drive up their costs, but they will also have trouble finding buyers ... given the uncertainty they will likely face in bringing projects to completion."

That, he said, "will leave competitively stronger companies well-positioned to potentially pick up market share ... It wouldn't surprise us if some truly interesting opportunities come down the pike" to either acquire assets or even an entire company. Hay quickly added, however, that his company's focus is on maintaining what he asserted are its very strong financial situation and liquidity, and that this "would not be the time to stretch our balance sheet."

Any possible acquisition would have to "pass the strategic test," he said, noting that he "would expect that most things that we would find interesting would be at the asset level instead of the company level. Still, I wouldn't rule anything out."

FPL Energy owns 16,128 MW of capacity in the US, including 6,636 MW of gas-fired plants, 5,574 MW of wind, 2,544 MW of nuclear, 798 MW of oil-fired plants, and 359 MW of hydro. — *Housley Carr*

Maryland PSC rejects bids, plans to rebid RFP; cites credit crisis premiums ... from page 1

The bid monitor had recommended that the reserve procurement be delayed until January. "Maryland needs time to convene stakeholders and solicit input on how to SOS process can best deal with the prospect of inflated risk premiums," Mazzini said. Among the questions that should be discussed are whether an alternate procurement scheme should be considered as a back-up.

Quote of the week

"The key question before the auction, 'will the crisis be mirrored in the bid results?,' was answered with an unequivocal 'yes,'" — bid monitor Richard Mazzini of Liberty Consulting on the financial crisis' effect on recent results of a Maryland Public Service Commission solicitation (see story, page 1).

It is unclear why the BGE and Delmarva bids were unacceptable, but sources close to the bidding said there are procurement rules for determining legitimate bids. "It ties into the overall process," he said.

Mazzini said the procurement results include a substantial premium that has never appeared in Maryland procurements of the past. "It is logical to add that this premium flows from the pressures of this global financial crisis," he said.

The magnitude of the premium was consistent over all bids, Mazzini said.

The premium is a reflection of the financial crisis, the perceived cost of doing business and heightened sensitivity to risk, Mazzini said. "It could be characterized as a natural market response to today's turmoil," he said.

Mazzini noted that the bidding was conducted in the midst of the most severe financial crisis in generations. The PSC, Liberty and others raised concerns before the auction, but the only way to determine the impact of the crisis was to proceed with the auction and hope that market forces would produce a positive result despite the threats, he said.

A reserve solicitation for the 17 blocks of residential power for BGE that were not filled and the three blocks of combined residential and Type I commercial power that were not filled will be held November 10.

There were winning bids for Type II, medium commercial SOS blocks for all Maryland investor-owned utilities, for BGE's Type I small commercial SOS blocks, Allegheny Power's residential SOS blocks and Potomac Edison's combined residential and Type I SOS blocks. Those bids were acceptable and awarded, the PSC said.

Because of the high premium included in the bids, the PSC considered whether to disapprove the award of the contracts for the bids found acceptable, the PSC said. The Office of the People's Counsel recommended that the PSC reject the winning bids for Pepco's combined residential and Type I commercial SOS load and suggested the PSC consider rejecting the winning bids for the two blocks of Allegheny Power's residential SOS load with a contract date of June 1.

The PSC ultimately decided the bids could be finalized and contracts awarded. The commission did not elaborate, but said in an order released late on October 24 that it would issue a further order to provide its reasons for its decision "in the near future."

Overall, there were 256 bids by 14 bidders and nine winning bidders, Mazzini said. There were 68 unacceptable bids for the 17 BGE residential, 24-month blocks. There were 21 unacceptable bids for the three blocks of combined Delmarva Power residential and small commercial customers, which also had 24-month terms.

The residential bids accepted for Allegheny Power will result in an 8% increase in rates and the accepted bids for Potomac Power will result in a 7.7% increase in rates, Phillip VanderHeyden, the PSC's director of electricity, said.

The average rate increase for Allegheny Power medium commercial customers is expected to be 1%, BGE's increase will be between 7% and 17%, Delmarva's increase will be between 5% and 12% and Pepco's increase will be 8%, VanderHeyden said.

Small commercial customers will have the smallest increases.

Pepco's rates will increase 0.6% while BGE's rates will increase 2.9%, VanderHeyden said.

The reserve procurement bid block targets for the November 10 solicitation will be released November 3. Reserve procurement price proposals are due November 10 with awards expected to be made the same day. A public hearing for the PSC's review of the results will be held November 13 with commission approval scheduled for November 14. — *Mary Powers*

Pink sheets company thinks big with plan to build a fleet of nuclear plants ... from page 1

$489,757, about 86% of which was cash equivalents.

AEHI made its October 8 SEC filing as part of its effort to move from the pink sheets to OTC Bulletin Board. Stocks that trade on the pink sheets have no regulatory restrictions. Stocks traded on the OTC BB must post financial statements with the SEC, but do not have to comply with the market capitalization or corporate governance restrictions that apply to stocks traded on the NASDAQ system.

To date, AEHI has funded its operations by selling stock or through private placements, raising a total of about $8 million. That may be a lot for a small company with a handful of unpaid employees and no revenues, but it is a drop in the bucket compared with the cost of building a nuclear power plant. It is not even half of the estimated cost of filing a single combined construction and operating license with the Nuclear Regulatory Commission.

Donald Gillespie, AEHI's CEO, readily admits the disparity. Filing a COLA can cost anywhere from $30 million to $50 million, he said in an interview. But he has a plan.

His plan is to secure the land, water rights, and various government approvals needed to build a nuclear power plant. The permitting process would cost about $65 million, but once the COLA is issued, the owner of the permit is worth between $1 billion to $1.5 billion, said Gillespie.

AEHI's vehicle for this strategy is Reactor Land Development LLC, a 99% subsidiary of Idaho Energy Complex Inc., which in turn is a wholly owned subsidiary of AEHI.

Reactor Land Development will own the land, water rights and permits for the Idaho Energy nuclear project. Gillespie says he has already raised $1 million through its private placement of Reactor Land and, he says, he is headed to China where he hopes to raise more funds.

Gillespie's plans, like the plans of many other entrepreneurs, have been undermined by the unfolding credit crisis. In fact, he says that he had a $3.5 billion commitment letter from a major financial institution, but that was before the credit crisis began and the economy began to unravel. "I'm not sure that [commitment] is still valid." He now figures his best shot at raising the capital he needs is to head east.

Gillespie's sales pitch is that a nuclear power plant can throw off profits of $2 billion a year. By investing in Reactor Land, he says an investor can secure a share of those future earnings by taking an equity stake in the much lower, $65 million price tag of securing the COLA.

In a way, it is like buying an option on the possible future earnings. Gillespie says that he has been told by the Nuclear Regulatory Commission that the current estimate for securing a COLA is 42 months.

Eventually, some of the investors in Reactor Land may decide to cash out, but Gillespie is hoping that most will hold on to their investment. The money that Reactor Land raised would then be upstreamed to Idaho Energy Complex Corp. and serve as the collateral to fund AEHI's Idaho nuclear project. Idaho Energy Complex is the project company for the planned Idaho nuclear plant and is a wholly owned subsidiary of AEHI.

Gillespie says that he has been told by "every financial institution in the country — before the wheels came off [the economy] — that once you have a COLA, they would lend [him] money" to build a nuclear plant.

Gillespie said AEHI intends to use the same formula for all three of its planned nuclear power plants. In short, raising money through a series of subsidiaries and private placements and then possibly spinning off the subsidiaries.

The first nuclear project in Gillespie's sights is on a 1,400-acre site near Mountain Home, Idaho. According to the SEC filing, the 1,600-MW Idaho project would cost about $4.5 billion and has a target online date of 2016.

In addition to producing electricity the plant would also produce biofuels. The biofuels portion of the project would use waste heat from the nuclear reactor to "cook the mash" that goes into making biofuels.

The feedstock for the biofuel would come from a cooperative Idaho Energy Complex hopes to set up with local farmers. The co-op would also buy the biofuels the plant produces, as well as some of the electricity.

Gillespie says he did not pick Idaho for his first project, "Idaho picked us." He said he was approached by a group of farmers looking for a cheap and reliable source of energy to pump water for their operations. Gillespie says the project could produce power for 1 to 2 cents/kWh.

According to the SEC filing, AEHI is in the due diligence phase of forming a joint venture with another energy company and some large investors. AEHI would be the majority owner in the new company, which would have up to $50 million in funding from a large international investor, and would operate the Idaho nuclear plant.

AEHI is also looking at projects in Colorado and in Mexico. Gillespie says he is "drawing up the papers" for a possible project in Colorado on a 21,000-acre site. The site has ample room for the five reactors he wants to build, so he says he could lease or rent the remaining land. He said he is in talks with two developers who might want to use the land for solar projects.

In Mexico, Gillespie says the government is in the process of selecting a site for the project, which he expects to be decided in first-quarter 2009. The project, mostly likely, would be on the eastern shore of the Sea of Cortez and would primarily use the nuclear reactor to desalinate and then pump water.

Gillespie says the Mexican project, which is being done by International Reactors Inc., another AEHI subsidiary, could progress more quickly than the Idaho project because the regulatory process in Mexico is not as time consuming.

But AEHI still faces considerable hurdles to success, chief among them raising the capital that its project would require. In the SEC filing, the company warns that "AEHI has limited funds and such funds will not be adequate to carry out the business plan without borrowing significant funds."

The filing goes on to say that AEHI has "not investigated the availability, source, or terms that might govern the acquisition of additional capital and will not do so until it determines a need for additional financing." And if additional capital is needed, the filing says, "there is no assurance that funds will be available from any source or, if available, that they can be obtained on terms acceptable to AEHI." And the result could be that AEHI fails.

Gillespie says that since the credit crisis, he has begun to look outside the United States for funding, in particular, he says he is courting investors in China and in the Middle East, where a nuclear-desalination project could be attractive.

He also said that he has been contracted by "half a dozen states," mostly representatives of non-nuclear states or businessmen in those states that are interesting in bringing nuclear power to their states. He declined to name the states or their representatives.

He did say he was in negotiations with Entergy about a possible investment. An Entergy spokesman said the company is in discussions with a wide range of parties interested in nuclear power, but that if discussions become serious, they sign confidentiality agreements. The spokesman went on to say that Entergy could not comment at all on AEHI. However, an industry source said that Entergy had broken off discussions with AEHI.

Gillespie said that Entergy did break off negotiations, but has since resumed them.

Aside from capital or access to capital, the other requirement for building nuclear plants is credibility. Nuclear power plants are more complicated and potentially dangerous than fossil fuel-fired plants and have commensurately higher regulatory scrutiny.

Prior to founding AEHI, Gillespie helped start a management consulting business, the Institute of Nuclear Power Operations, in Atlanta, and a nuclear operating company, Nuclear Management Co., in Hudson, Wisconsin. He also worked in the nuclear operations of Boston Edison, Duke Power and Westinghouse, and says he was instrumental in the turn around of the Pilgrim nuclear plant in Massachusetts.

According to the company's web site, AEHI's vice president, Greg Kane, was previously general manager at Virginia Power's North Anna Nuclear Plant. Rick Bucci, is AEHI's CFO, also owns and operates a certified public accounting firm licensed in New York State.

AEHI's web site also lists as board members Leon Eliason, formerly president of the Public Service Electric & Gas' nuclear business, James Taylor, former chief operating officer of the US Nuclear Regulatory Commission, Ken Strahm, Sr., a past president of the nuclear industry watchdog Institute of Nuclear Power Operations, Ralph Beedle, a past senior vice president of the Nuclear Energy Institute, and John Franz, a past vice president of a nuclear utility. — *Jenny Weil and Peter Maloney*

COMPANY NEWS

Constellation proxy statement reveals story behind acceptance of MidAmerican proposal

Constellation Energy Group faced a two-notch downgrade by at least one credit rating agency and the possibility of bankruptcy if it did not accept the merger agreement proposed by MidAmerican Energy Holdings, the company said last week.

The back-story behind the frenetic few days that led up to the Baltimore-based holding company signing an agreement on September 19 with MidAmerican was described in a preliminary proxy statement filed by Constellation with the Securities and Exchange Commission last week.

On September 17, Constellation, parent of Baltimore Gas & Electric, signed a letter of intent with MidAmerican after MidAmerican, majority owned by Warren Buffett's Berkshire Hathaway, offered an immediate infusion of $1 billion in cash and $26.50 a share for Constellation's common stock (*GPR*, 25 Sept, 1).

Only one day earlier, MidAmerican's Chairman David Sokol telephoned to say that MidAmerican was interested in a possible transaction. Constellation was in a liquidity crisis and was negotiating an additional equity investment of up to $500 million with EDF Group, which is its largest stockholder. The two had not reached an agreement before Sokol's call. Constellation also received calls from other companies and private investment firms interested in making an investment in the company, Constellation said.

On the day of Sokol's call, September 16, the trading price of the company's common stock declined to an intra-day low of $13 before closing at $30.76. The decline was driven by speculation over Constellation's credit exposure to Lehman Brothers, which was filing for Chapter 11 bankruptcy protection, and rumors that the Royal Bank of Scotland and UBS Finance were withdrawing their commitment for a $2 billion credit facility, Constellation said. Constellation's stock had closed at $58.37 on September 12. Its one-year average was $87.24.

On the evening of September 16, Constellation's management team advised the board of directors at an emergency meeting that the company needed to move immediately to arrange for a substantial additional equity investment. The RBS/UBS $2 billion credit facility was not an immediate source of liquidity and without immediate additional equity the rating agencies were likely to further downgrade the company's debt ratings, which would trigger additional collateral requirements. The likely result would force Constellation to seek bankruptcy protection. Morgan Stanley, Constellation's financial advisor, said the company needed $750 million to $1 billion in immediate additional liquidity to avoid a credit rating downgrade.

On September 17, Constellation CEO Mayo Shattuck described in the SEC filing his telling MidAmerican he was not satisfied with the $26.50/share offer. He told MidAmerican that Constellation was interested in a financing transaction that did not involve a merger.

That same day, Constellation continued its discussions with EDF, but the company's offer of an equity investment was conditioned on EDF receiving assurances from Standard & Poor's Ratings (a unit of The McGraw-Hill Companies) and Moody's Investors Service that the investment would keep them from further downgrading Constellation's debt. Moody's told Constellation it could not comment on whether a transaction with EDF would alter its decision to lower the company's credit rating. Constellation, therefore, could not provide EDF with the assurance it required. The other companies that had expressed interest were backing away, Constellation said. Constellation's shares closed that day at $24.77.

The night of September 17, Shattuck decided to execute the letter of intent because MidAmerican's proposal was the only alterative available that would avoid substantial risks of an immediate ratings downgrade and a likely near-term bankruptcy, even as early as the following Monday, September 22. The aggregate equity value for its common stockholders would likely be less than $26.50 a share if the company filed for bankruptcy, Constellation said.

Shattuck expected that at least Moody's would immediately downgrade Constellation if the agreement were not signed with MidAmerican on September 19.

On September 18, Constellation's board of directors approved the letter of intent. Constellation's stock closed that day at $24.20. A final definitive agreement was to be signed at 5 pm, September 19.

The afternoon of September 19, EDF Group revised its original proposal and submitted an unsolicited, non-binding proposal to Constellation together with Kohlberg Kravis Roberts and TPG Capital for an immediate $1 billion investment that would match MidAmerican's offer. But its offer to purchase outstanding shares at $35 each contained no details but the purchase price, Constellation said. The proposal did not explain the ownership interest among members of the group or address potential regulatory considerations, and no information was given concerning the sources or availability of funds to finance such a transaction.

Shattuck asked MidAmerican to waive the contractual exclusivity right in the letter of intent so that Constellation could talk to EDF and its partners to clarify the proposal. MidAmerican refused and reiterated that if a definitive agreement was not signed by 5 pm September 19, MidAmerican would terminate all further discussions.

Constellation would have been forced to decline the MidAmerican offer in order to pursue the EDF offer. EDF's competing offer did not assure the company, its shareholders, its business partners and counterparties, its creditors and the rating agencies that a transaction would be completed quickly and would take the place of the MidAmerican equity investment, Constellation said.

The board of directors approved the MidAmerican agreement with the expectation that it would be completed quickly based on its belief that there would be less regulatory risk than other possible transactions, Constellation said.

EDF continued to discuss the possibility of a competing take-over bid for Constellation until October 15, when it said that current conditions were not conducive to pursuing a new offer.

Constellation's shareholders must approve the MidAmerican agreement. It also must receive various regulatory approvals.
— Mary Powers

Calpine settles disputes about 2005 sale of oil, gas business to Rosetta spin-off

Calpine on October 22 said it had reached an agreement with Rosetta Resources that resolves all claims related to Calpine's July 2005 sale of substantially all of its oil and gas business to Rosetta, a Calpine management spin-off.

Calpine said that under the deal, Rosetta would pay it $97 million and convey "certain residual oil and gas properties" it still holds to the producer.

Calpine said the settlement resolves disputes that were the subject of litigation in the US Bankruptcy Court for the Southern District of New York, including Calpine's fraudulent conveyance claim against Rosetta and Rosetta's claims against Calpine.

Rosetta was formed by Calpine in June 2005 as a $1.05 billion management buyout and spin-off of its US oil and natural gas operations in California, Texas, the Gulf of Mexico, and the Rocky Mountains. But after Calpine filed for bankruptcy protection in December 2005, the new management team claimed that Calpine was underpaid in the Rosetta spin-off.

Calpine said that as part of its plan to emerge from bankruptcy it wanted to "claw back" $400 million more from Rosetta. The management team brought in to run the company in bankruptcy told the court that their investigation into the sale determined that it was done at a fire-sale price and did not represent an arm's-length deal.

Rosetta officials at the time called Calpine's claims baseless.

In announcing the settlement, the two companies also said they have agreed to extend by 10 years a dedicated reserves gas purchase agreement for Rosetta's California production located near Calpine's CPN Pipeline.

"This is a win-win settlement," Calpine CEO Jack Fusco said in a statement. "Our disputes over past events have been amicably resolved, and we have entered into a mutually beneficial 10-year gas supply agreement that assures Calpine of a continued relationship with Rosetta and a reliable supply of natural gas for our California plants through 2019."

Calpine also said the settlement means that the 2,717,654 shares of Calpine common stock, which had been specifically reserved for the claims asserted by Rosetta in Calpine's bankruptcy case, will become part of the general reserve of Calpine common stock established under the generator's confirmed plan of reorganization, which, if not required to satisfy unresolved claims remaining in the bankruptcy case, would be available for further distributions to Calpine's general unsecured creditors. *— Jeff Barber*

Goldman Sachs and Blue Source form alliance to market carbon offset projects

Goldman Sachs Group and Blue Source announced a strategic alliance on October 27 to capitalize on greenhouse gas reduction projects by marketing carbon offsets in the portfolio of Blue Source, a company developing carbon capture and storage projects and other carbon offset efforts.

Financial terms of the agreement, in which Goldman Sachs has purchased an equity stake in Blue Source, were not provided.

The companies said Goldman Sachs will structure, market and off-take a broad range of verified emission reductions from certain GHG reduction projects in Blue Source's portfolio, including those associated with methane management from coal mines, wastewater treatment, landfills and animal waste, energy efficiency and carbon capture and storage projects.

Goldman Sachs said it can bring emission reductions to a market increasingly eager to engage in a low-carbon economy by helping clients manage GHG emission-related risks through voluntary efforts and in compliance with carbon reduction measures.

"This unique agreement is the next step for Blue Source as the US carbon market evolves from voluntary to compliance," said Bill Townsend, CEO of Blue Source, in a statement. "We have been able to develop a high-quality portfolio of independently verified emission reductions from projects based in North America, and this new alliance creates an exceptional opportunity to reach a broad range of offset buyers through a highly experienced and well-trusted institution."

Blue Source, which is based in Salt Lake City and has offices in the US and Canada, is funded by First Reserve, a private equity firm that is a major equity partner in the company, and investment funds of Och-Ziff Capital Management Group. In August, Och-Ziff committed up to $500 million for new GHG emission reduction projects to be managed by Blue Source, in addition to an equity investment in Blue Source. *— Staff Report*

FINANCE

Tenaska Capital Management closes fund, $2.4 billion, dedicated to power sector assets

Tenaska Capital Management LLC on October 29 said that it closed a $2.4 billion power-related fund after raising money from both existing and new investors from across North America, Europe and Asia.

An executive said the fund has already bought four US power plants with 2,899 MW of combined capacity.

TCM, an affiliate of the Omaha-based development firm Tenaska Inc., said its new fund is a follow-on to its $838 million Tenaska Power Fund LP, which closed in 2005. The new fund, TPF-II, was launched in May 2007 and is being managed by the same team that oversaw the investing of the earlier fund, according to the announcement.

Paul Smith, senior manager, said TPF-II's investment strategy will follow that of the earlier fund, focusing on power generation, including renewables, natural gas storage, pipeline and other gas midstream assets, and natural gas and power infrastructure goods and services.

Smith noted that TPF-II, which had an original capital raising target of $1.5 billion, announced October 13 the acquisition, for an undisclosed sum, of the 1,100-MW gas-fired Covert facility in South Haven, Michigan, from MachGen (*GPR*, 16 Oct, 18). In August, TPF-II agreed to pay Dynegy $368 million for its 815-MW Rolling Hills natural gas-fired peaker in Wilkesville, Ohio.

In March, 2008, TPF-II secured a $165 million senior secured term loan, due 2014, and a $40 million revolving credit facility to help it buy the 656-MW Lincoln gas peaker in Manhattan, Illinois, and the 328-MW Crete gas peaker in Crete, Illinois, from DTE and ArcLight Capital. It arranged financing for these two deals from Lehman Brothers and Calyon. Smith, in an interview, contended that both financings "are in good order," despite Lehman Brothers September bankruptcy filing.

On August 7, TCM said it funded the formation of a natural gas asset development and acquisition company in Houston, Voyager Midstream LLC.

According to Smith, TCM's first fund, TPF-I, bought a total of 11 power plants with approximately 5,300 MW of capacity, but has sold five of those facilities. TCM currently has more than $3 billion under management, which includes the assets it holds plus the debt the firm has issued on the backs of those assets. Smith says that TCM is "not a typical leveraged buyout firm" in that TCM does not seek to issue debt in all deals. He said TCM "comes at it more like a strategic investor," and will not burden an asset with debt "if it isn't appropriate or prudent." He said there are instances when TCM will buy "with all equity and no debt, even when debt is available."

Despite the challenging current financial environment, several TPF-I investors "increased their commitments to TPF-II," according to Smith. He said that the new fund also attracted several first time investors. Investors in TPF-II include leading global financial institutions, endowments and public and private pension funds, said Smith.

Saying that the Tenaska funds do not publish results, Smith argued that it is generally felt that the firm's first fund did reasonably well. He argued that the performance of the first fund led to a high rate of investors "re-upping" for the second fund.

The amount of money in the second fund, $2.4 billion, most of it raised, he said, in 2008, is "an important feature." He said the fund had to be "up-sized" to accommodate investor interest. Smith says the amount raised was "plenty of capital to execute the firm's business plan." Smith said he believes the focus of TCM is the key. He said TCM offers "a value based opportunity for investors." He says the fund buys assets that produce "critical services in the real world, electricity."

He says it is a market where the value of the assets is "clear and long-term." "Chaos in the market always creates uncertainty," Smith said. But, he argued, investors take comfort, "especially in troubled times," in focusing on hard asset sectors. "We had no trouble raising our fund," he says.

Moreover, with several companies in the sector in distress or looking to raise cash and improve their balance sheets by selling segments of their business, investment funds such as TPF-II could see an increase in opportunities and deal flow.

Smith argued that companies in distress are more likely to sell assets, "or partner on investments" than when credit is more available to them.

Smith said that while TCM works "in close coordination" with parent firm Tenaska, it holds its own, separate portfolio. He said that those working with the funds are from the same group of individuals who started Tenaska 20 years ago as a private firm dedicated to power and gas sector. Smith noted Tenaska Power Fund was originally conceived to provide the parent company capital it could not otherwise raise in the capital markets.

Tenaska says it has developed, over the past 20 years, a total of 9,000 MM of greenfield generating capacity in the US, and currently operates, manages and owns in partnership with other companies eight power plants in six states totaling approximately 6,800 MW of generating capacity. *— Jeffrey Ryser*

Industry Funds Management of Australia expands in advance of push into the US

Industry Funds Management, the Australian infrastructure investment fund that bought six power generating facilities from Consolidated Edison in June, said on October 28 that it was adding three senior executives in its New York office to support new investments in North America.

Melbourne-based IFM said it is adding two new executive directors for the US. They are Alec Montgomery, formerly the head of infrastructure finance at the Royal Bank of Scotland, and Michael Thompson, an IFM executive director formerly based in Melbourne.

IFM also appointed Mauricio Melzi, formerly a director of the energy commodities group at Merrill Lynch in New York, as senior investment director. Melzi will be working with current investment directors Lars Bespolka and Jeffrey Mouland, according to the statement.

IFM, founded in 1995, says it has a total of $14 billion under management. It is owned by 37 Australian retirement funds but has recently begun raising money from US institutional pension funds.

The firm has $5.9 billion invested outside of Australia, with roughly half of that invested in Europe and half in the US.

Dunia Wright, head of IFM's US and European operations, said that the firm is recruiting in the "current crisis because we think there will be new opportunities for an open-ended fund."

In June, a newly created IFM entity, North American Energy Alliance, bought six power generating facilities, with combined capacity of 1,706 MW, from Consolidated Edison Development, a subsidiary of New York's Consolidated Edison, for $1.47 billion (*GPR*, 26 June, 18).

Included in that acquisition were the 525-MW natural gas-fired combined-cycle Newington Energy facility in Newington, New Hampshire, the 185-MW Con Edison Energy Massachusetts facility in West Springfield, the 96-MW CEEMI Expansion facility in West Springfield, the 352-MW Rock Springs, Maryland, gas-fired peaker, the 246-MW gas or oil combined-cycle Lakewood Cogeneration facility in New Jersey, and the 351-MW gas-fired Ocean Peaking Power plant in Lakewood, New Jersey.

In 2007, the investment firm took a 16% stake in the US's third-largest refined petroleum products pipeline, the Colonial Pipeline. IFM bought $427 million of equity.

In 2006, IFM bought a 23% holding, for $251 million, of Duquesne Light Holdings. IFM was part of a consortium of investors in Duquesne Light that was led by one of IFM's competitors from Australia, Macquarie Infrastructure Partners.

Macquarie Infrastructure, unlike IFM, is publicly traded and its stock price has been battered over the past several months.

IFM says it specializes in the "management of diversified investment portfolios across the infrastructure, private equity, publicly traded equities, and debt investment sectors." The firm has made 47 investments over the past 13 years in infrastructure assets, totaling $5.9 billion.

IFM launched its international infrastructure fund in 2004. It says that the "investment universe" for IFM International Infrastructure is "physical facilities for the delivery, generation and transportation of energy, information, people and products." That fund's "exposure" by sector is 23% electricity generation, 9.1% electricity distribution, 6.9% generation and heating, and 4% gas distribution. Some 20% of the balance is represented by water projects. *— Jeffrey Ryser*

Southern Company, despite economic turmoil, says it will still spend $13 bil in capex by 2010

Southern Company on October 23 said that despite the nation's economic turmoil, its Southern Power wholesale generation subsidiary and four regulated utilities have not made any changes in their 2008-2010 capital spending plans, which total $13.3 billion, including $2.5 billion for new generating capacity.

Southern posted third-quarter earnings of $780.4 million, or $1.01/share, on revenue of $5.43 billion, compared with earnings of $762.0 million, or $1/share, on revenue of $4.83 billion in the same period last year. The Southern Power unit earned $60 million on revenue of $516 million in the third quarter, up from $51 million in earnings on revenue of $348 million in the previous year's third quarter.

Southern did not post any special gains or charges in its third-quarter results this year or last, but its results from the same period last year included 1 cent/share in earnings for synthetic fuel.

During a conference call with energy analysts, Southern CFO Paul Bowers said that as of September 30, Southern's consolidated liquidity totaled $2.5 billion, including $800 million in cash. He noted that Southern has issued $2.4 billion in long-term debt so far this year at interest rates averaging between 4% and 4.5% and expects to issue another $750 million to $800 million by year end without undue difficulty. He added that Southern has not drawn on any of its committed $4.3 billion in credit facilities.

Regarding Southern's equity requirements, Bowers said, "We are continuing to raise approximately $500 million of new equity each year through our existing employee and dividend reinvestment programs." But Southern will need additional financing for Georgia Power's planned Vogtle nuclear expansion and Mississippi Power's planned Kemper County integrated gasification combined-cycle project. "To address these needs, we began work early this year and are continuing to work to establish a continuous equity offering program, also called an equity dribble program," Bowers said.

"The amount we issue will depend primarily on the level of capital expenditures required for growth, new generation, reliability, environmental compliance in our traditional operating companies as well as potential new growth opportunities for Southern Power." Bowers said that under the program, Southern each quarter will issue new equity "to track the needs of our business relative to the targets that we have for a credit rating. It is dribbled out, if you will, similar to our dividend reinvestment program or employee savings program that ... matches the needs of our company from an equity issuance standpoint to maintain our credit quality. So it's really flexible, it's just not a one-time standard issue that you go into the market with."

Southern Chairman, President and CEO David Ratcliffe said Southern still expects to begin commercial operation of the two new nuclear units it is planning at Vogtle in 2016 and 2017, respectively, but acknowledged that the company "may be able to slow that down a bit." The time table for the IGCC project is more flexible, he said, and Bowers added that Southern's utility units could decide to delay natural gas-fired combustion-turbine and combined-cycle projects it is planning for the middle years of the next decade if economic and load-growth conditions warrant.

Southern's $13.3 billion 2008-2010 capital spending plan includes $4 billion associated with transmission and distribution projects, $3.9 billion with environmental-compliance projects, and $2.5 billion with new-generation projects, mostly gas-fired projects planned by Georgia Power.

Bowers and Ratcliffe did not provide specifics about Southern Power's capital spending plans, but when asked about how the wholesale-generation unit was faring, Bowers said the unit has been "successful on a few [requests for proposals]" with Santee Cooper and Georgia electric cooperatives.

Southern Power currently provides a total of about 500 MW to 10 Georgia co-ops under existing agreements that expire either at the end of 2009 or 2012. The deal extensions agreed to earlier this year run to either 2031 or 2034 and call for Southern Power to provide more than 1,400 MW to the co-ops in the deals' later years (*GPR*, 7 Aug, 15).

Southern Power, Bowers said last week, is "very active in the market in terms of responding to [additional] RFPs, but we have seen RFPs in the area of 2013 [and] 2014 being postponed for a year or so. So we have seen that in terms of outward years, but for the short term they have been pretty active in that marketplace."

Ratcliffe noted during the conference call that its "appetite for a federally mandated renewable portfolio standard has not changed. I really believe that the best policy is to leave that decision to the states, who know most about their ability to achieve any kind of renewable standard." He added, however, that it "is clear that the Democratic-led Congress ... is pretty adamant about the desirability of trying to pass a federal mandate with regard to renewable energy. So I don't think the issue will go away and ... it is likely to be part of whatever energy legislation is considered by the Congress."

Bowers also revealed during the call that Southern expects to earn 25 cents/share in the fourth quarter, which would put the company's full-year-2008 earnings at $2.36/share, "performance at the very top of the guidance range" that Southern has been providing. — *Housley Carr*

Calyon report sees increased M&A activity in the electricity sector in the coming year

Equity analysts at Calyon Securities said that they believe current market turmoil will "ultimately spur, not hinder, large-scale merger and acquisitions" in the power sector, with "increased activity likely" in 2009.

Calyon, in an October 27 report, said that seven of the last nine companies bought out by better-capitalized companies had been "a bottom-20 worst performer both on a 6- and 12-month basis relative to its peers." It said "this trend" has continued in 2008 with the pending acquisition of Constellation Energy, a bottom-20 worst performer in both categories, by MidAmerican Energy Holdings. It noted that Exelon's offer for NRG Energy also would qualify, "but NRG has not accepted — or denied — its interest in the deal at this point."

Calyon analysts said, "When you mix one of the most capital-intensive industries, energy, with the worst credit crisis in recent history, opportunities are created for large-scale acquirers with steady cash flows and an investment-grade credit status." They said that Warren Buffett's MidAmerican Holdings, and Exelon, are "cases in point."

Calyon said in its report that its third quarter updated analysis "comes at an important juncture." It noted that an estimated $1 trillion of capital is "needed globally" for power generation and transmission additions, but that, "ultimately, large scale expenditures are best reserved for only the best capitalized companies with strong cash flows, credit ratings and with scale."

Calyon noted that many utilities have seen their valuations destroyed due to liquidity concerns, declining energy prices, and a "general rotation out of energy" stocks. It said, as well, "We do not believe underperformance in-and-of-itself will lead to takeovers."

The analysts added, though, "We do believe investors should be cognizant of which stocks have underperformed relative to their peers as they are highly susceptible to takeovers in the future." The analysts did not say who they thought buyers would likely be.

A stock screen for what Calyon called "the bottom-20 worst-performing utilities" on a total return basis for the trailing six months from March 28, 2008, to September 26, 2008, were Constellation (-71%), Dynegy (-49%), Reliant Energy (-47%), Mirant (-42%), NRG Energy (-31%), Allegheny Energy (-23%), AES (-23%), Sierra Pacific Resources (-17%), Edison International (-17%), PPL (-17%), Entergy (-15%), Exelon (-15%), PSEG (-11%), FPL Group (-9%) ,AEP (-7%), Unitil (-6%), Black Hills (-5%), Great Plains Energy (-5%), Ameren (-5%), and Southern Union (-3%).

On a 12-month basis, from September 28, 2007, to September 26, 2008, Entergy, Exelon, FPL and Unitil were no longer on the list. However, there were four additional companies: PNM Resources (-48%), Central Vermont Public Service (-32%), CMS Energy (-22%), and PG&E Corp. (-17%).

The Calyon report noted that nine companies were new to the "combined lists" that were put together at the end of the third quarter, versus when the list was last published in the second quarter. The nine new companies are Constellation, Allegheny, AES, Edison International, PPL, PSEG, AEP, Great Plains Energy and Southern Union.

Calyon noted that large-scale M&A transactions have averaged 2-3 per year for the past several years. It said that it looked at nine deals done between February 2006 and the MidAmerican offer for Constellation, announced in September.

Calyon said that seven of the nine companies that had been bought showed up as one of the "bottom-20 worst performers in both a six-month and 12-month trailing period on a total return basis prior to the acquisition announcement date."

Calyon said those seven companies were Keyspan, Duquesne Light, Peoples Energy, Aquila, Energy East, Puget Energy and Constellation Energy. *— Jeffrey Ryser*

Fitch shifts its outlook to stable from positive on Dynegy, Mirant on weaker wholesale prices

Fitch Ratings on October 24 revised its outlook on Dynegy and Mirant to stable from positive, citing weakening wholesale power prices and difficult capital market conditions that offset their improving credit profiles and Fitch's long-term favorable view of competitive generator sector fundamentals.

Additionally, Fitch affirmed Dynegy's issuer default rating at B and Mirant's at B+. It also affirmed Dynegy Holdings' senior unsecured debt at B+ and Mirant North America's at BB-.

Uncertainty from tightness in credit markets, changing risk appetites regarding the merchant energy market, and increased merger-and-acquisition activity precludes favorable rating actions in the immediate term, Fitch said. "Any possible favorable rating actions would be beyond the normal time period associated with the previous outlook," it said.

"Environmental policies from a new administration will also factor into future rating actions," Fitch said. "Importantly, based on stress testing utilizing various commodity price assumptions, liquidity at both should be adequate to satisfy near-term hedging related collateral requirements."

Long-term industry fundamentals continue to favor competitive generators — as limited new capacity comes online, narrowing reserve margins will result in wider spark and dark spreads.

An economic slowdown should weaken demand growth, it said. Rising construction costs, uncertainty about state and national energy policy and carbon dioxide rules remain major deterrents to generation development, Fitch noted. *— Paul Carlsen*

Outlook for merchant power companies is stable, say reports from Moody's, S&P

The ratings outlook remains stable for merchant generators, despite recent economic turmoil, Moody's Investors Service and Standard & Poor's Ratings said in reports issued this week.

"The freezing of the credit markets made it extremely difficult, if not virtually impossible, for power companies to issue or refinance debt or raise fresh liquidity. Still, the merchant sector, with the exceptions of Constellation Energy and Reliant Energy, weathered the storm quite well," said S&P, which, like Platts, is one of The McGraw-Hill Companies.

"Notwithstanding negative developments, the fundamental outlook for the merchant wholesale power sector remains stable at this time," said Moody's.

In the Moody's report, Angelo Sabatelle and Natividad Martel said that "liquidity is strong among both investment-grade and speculative-grade issuers, and the declining commodity price environment, while a detriment to near-term profitability, enhances near-term issuer liquidity as it reduces the calls on collateral."

"Also, credit metrics for the wholesale power sector remain strong as profitability and operating cash flows are not expected to drop off precipitously as all issuers have some degree of hedged margins in place through 2009," they added.

Power demand is going to fall with the economic slowdown and more user conservation, but there is still an "inherent demand for electricity relative to other services," and demand has tended to rebound strongly following previous recessions, said Moody's.

"Independent power producers fall at the riskier end of S&P's business risk profile scale ... extreme volatility in natural gas prices and a sharp run-up in eastern [US] coal prices have hurt gross margins for many companies [and] a faltering economy and seasonal weather patterns lowered power demand," S&P analysts said.

But "some key factors that contributed to a strong merchant power sector outlook earlier this year are still present, like the elevated cost of construction of new power plants, difficulty in permitting any new assets, volatility in fuel prices that result in high supply premiums, transmission congestions, and declining reserve margins (albeit at a slower pace now)," they added.
— Paul Carlsen

Entergy reports modest earnings, warns spin-off of nuclear unit might be delayed

Entergy on October 28 reported a modest increase in third-quarter earnings, and sought to assure energy analysts and shareholders that it remains in strong financial shape despite the battering inflicted by the nation's ongoing economic crisis and back-to-back hurricanes.

It also warned that the planned spin off its non-utility nuclear operations into a new company called Enexus Energy could be delayed by what it called the "unprecedented turmoil in the financial markets."

Entergy posted third-quarter earnings of $470.3 million, or

$2.41/share, on revenue of $3.964 billion, compared with earnings of $461.2 million, or $2.30/share, on revenue of $3.289 billion in the same period last year.

Entergy said its utility subsidiaries and corporate-parent operations reported third-quarter earnings of $286 million, or $1.47/share, compared with earnings of $305.7 million, or $1.52/share in last year's third-quarter.

Entergy Executive Vice President and CFO Leo Denault noted during an earnings conference call that hurricanes Gustav and Ike reduced the parent company's third-quarter earnings by about 14 cents/share.

Entergy's non-utility nuclear operations, which it hopes to spin off into a separate company next year, earned $205.3 million, or $1.05/share, in the third quarter, compared with $160.9 million, or 80 cents/share, in the same period last year. The company said that the earnings increase was tied primarily to higher power prices.

Entergy's non-nuclear wholesale generation unit, in turn, posted a third-quarter loss of $21.0 million, or 11 cents/share, compared with a loss of $5.5 million, or 2 cents/share, in last year's third quarter.

Denault said during an earnings conference call, "as a result of the unprecedented turmoil in the financial markets, it is uncertain whether or not financing fundamental to the spin-off transaction can be effected in the near term on a cost-effective basis."

"As we assess the conditions of the market against our options for Enexus, we remind ourselves that we are in the enviable position of being able to simply wait. We believe the market will ultimately improve," he said.

Denault said that Entergy is "not tied to a specific time line to effect the transaction and we believe the value proposition remains intact. We will not take the financing into market when conditions are clearly unfavorable," he said but would be prepared when market conditions improve.

Denault noted that Enexus already has secure bank commitment letters in excess of $1 billion, which he said reflects "the interest and support in the financial community for a business that is truly one of a kind." Entergy announced last November that it plans to spin off its non-utility nuclear unit into a independent, publicly traded company. In addition, Entergy and Enexus said that they intend to enter into a 50:50 nuclear services joint venture called EquaGen LLC (*GPR*, 31 July, 21).

Entergy said that its four non-utility nuclear plants in the Northeast have sold forward about 92% of their capacity for the remainder of 2008 at an average price of about $53/MWh, as well as 83% of their 2009 capacity at an average price of about $61/MWh, and 59% in 2010 at an average price of about $58/MWh.

Denault noted that Entergy has "ready liquidity of $3.9 billion," and that the company expects to have $2.4 billion of cash at the end of this year, even after spending some $1 billion on hurricane recovery. Further, he said that Entergy does not need to access the capital markets "any time in the near future."

Meanwhile, in Mississippi, Hinds County Chancery Judge Dewayne Thomas on October 27 heard initial arguments from Entergy Mississippi and representatives of Mississippi Attorney General Jim Hood on the lawsuit that Hood filed last month.

In the suit, Hood alleged that Entergy sells power and power-plant fuel to its Mississippi subsidiary at artificially inflated prices and asked the state court to order the Entergy subsidiary to turn over years of detailed information about the utility's fuel purchases, requests for proposals, and purchases, sales and exchanges of power, as well as information about plant dispatch.

Judge Thomas did not rule on Hood's request from the bench, and instead gave Entergy 10 days to submit a detailed filing on its response to the lawsuit. Hood then will have five days to respond. Thomas did not indicate when he would issue a ruling in the matter. — *Housley Carr*

TransCanada's earnings rise 12% in the quarter on high water volumes and addition of N.Y. plant

Higher water volumes benefiting generation and the addition of a 2,480-MW natural-gas fired plant in New York helped push earnings for Calgary-based TransCanada up 12% for the third quarter, the company said October 28.

The pipeline and power plant operator reported third-quarter earnings of C$390 million (US$303 million), or 67 cents/share, up 12% from C$324 million, or 60 cents/share, for the 2007 period. Much of that improvement was attributable to the company's energy operations including power generation and natural gas storage.

The company's energy operations posted a posted income of $200 million in the quarter, up from $156 million a year ago. The improved earnings came from increased water flows, generation volumes and sales prices from Bruce Power. TransCanada owns or has rights or stakes in about 10,900 MW of generation in Canada and the US.

TransCanada saw 50-year water levels in its hydro facilities this year, said Alex Pourbaix, president of TransCanada's energy division during a conference call with analysts.

Additionally, incremental operating income of $9 million from the Ravenswood Generating Station in New York was included in the energy division's revenue. TransCanada purchased the natural-gas fired plant from National Grid for $2.9 billion in August. The plant provides about 25% of the New York city's power.

The company's Eastern Power operations posted operating income of $10 million, up from $52 million a year earlier. Operating income at its Western Power operations rose to $126 million from $120 million a year ago. — *Pam Radtke Russell*

Spain's Gamesa reports net profit of $184 mil in first nine months of 2008, up 67% from 2007

Spain's Gamesa Corp. posted a net profit of €143 million ($184 million) for the first nine months of 2008, up 67% year-on-year, the Spanish renewables company reported October 22.

EBITDA rose 36% to €367 million and revenues by 40% to €2.890 billion, while net financial debt at September 30 totaled €387 million.

Factors affecting the result included higher wind-turbine production, sales and prices and increased operating efficiency more than offsetting higher raw material costs and the sluggish performance of its wind farm construction division.

EBITDA by key business division was wind-turbine manufacturing, up 48% to €336 million and wind farm construction and sales down 38% to €21 million.

Gamesa added that it sold 2,853 MW of wind turbines in January through September, up 22% compared with the same period of 2007. About 37% of sales were in Spain, 24% in the US, 16% in the rest of Europe, 13% in China, and 10% in other countries.

The company noted that it currently has orders for more than 11,500 MW of wind turbines. — *Henry Cybulski*

Iberdrola net rises 53% in first nine months of 2008, spurred by international expansion

Spanish utilities group Iberdrola reported a 53.8% rise in net profit to €2.481 billion ($3.172 billion) in the first nine months of 2008, reflecting its expansion in international and renewable energy activities, Iberdrola said October 23.

This was also reflected by a similar jump in turnover, rising 56.5% to €17.808 billion and net operating profit, which rose 31.5% to €3.316 billion, Iberdrola said.

Earnings before interest, taxation, depreciation and amortization (Ebitda) rose 29.1% to €4.922 billion, with two thirds coming from the company's renewable energy subsidiary, Iberdrola Renovables, and its international activities. These include British utility ScottishPower, which the company bought in 2007, and Energy East, the US utility it acquired in September of this year.

Ebitda at ScottishPower was €1.373 billion in the first nine months of 2008, which was 28% of the Iberdrola group total and much higher than projected.

Iberdrola Renovables, owned 80% by Iberdrola and 20% by public shareholders, doubled its Ebitda to €768 million. It installed 1,389 MW of new capacity between January and September taking its total capacity worldwide to 8,487 MW. Iberdrola said 90% of its growth in the first nine months of the year came from the renewables and international divisions while the "traditional" Spanish business brought in just 37% of Ebitda (€1.817 billion), compared with 99% of income in 2000.

Its Spanish business benefited from the move to market tariffs from regulated tariffs for industrial consumers, which had accounted for 50% of the market. Regulated tariffs had typically been much lower than market rates, leading to a "tariff deficit" that Iberdrola and Spain's other utilities have to claw back gradually through higher distribution tariffs in the future.

Output from the group's power plants rose 23% to 106,442 TWh between January and September 2008, compared with the equivalent period of 2007, with half of this coming from power plants outside Spain.

Iberdrola said the higher profits had come on the back of major investments; it has invested €30 billion in 2007 and 2008, but also greater efficiencies. — *Paul Whitehead*

ASIA/PACIFIC RIM

India wind vendor Suzlon nixes rights issue and acquisition of REpower of Germany

Indian wind turbine manufacturer Suzlon Energy Ltd. has been swept up in the global credit crisis, prompting it to cancel plans for a $363 million share-rights issue and the planned acquisition of German renewables company REpower Systems AG.

Suzlon cited weak market conditions in canceling its plans to rights issue to existing shareholders. The proceeds of the issue would have been used to complete the acquisition of REpower.

Suzlon currently owns a 67.22% stake in REpower through its SE Drive Technik GmbH subsidiary.

In an October 27 news release, REpower said a syndicate of banks planning to lend money to the company had insisted that REpower not transfer technology and profits to Suzlon as previously agreed.

Suzlon did not specify its strategy for REpower in light of the cancellation announcement, but said in a news release, "We will continue to pursue our strategy for sustainable growth." Suzlon officials were not available to provide more details.

The technology transfer could be a critical issue for Suzlon, which has suffered from a series of turbine blade failures.

Suzlon said a single V2 blade on a Suzlon S.88 turbine broke at a customer's wind farm in Illinois. "This is an extremely rare and unusual incident. The cause of this incident is presently under detailed investigation. Other turbines owned by that customer and our other customers at various locations in the US are operating without any interruption. Any reports of turbines being shut down in the US are baseless and speculative."

However, it is a problem that Suzlon has been struggling with recently. In June, Edison Mission Energy cancelled the second portion of an order for 300 wind turbines from Suzlon, citing problems with cracking blades (*GPR*, 12 June, 3). And earlier this year Suzlon said it would replace or strengthen 1,251 blades that it had sold in the US.

On another matter, Suzlon denied rumors it had defaulted on loan repayments. "The company's financial position has not changed and it continues to meet all its obligations to its lenders. All the borrowing lines with the lenders of the company continue to be available and the company continues to receive support from its lenders."

The company asked its shareholders not to believe the rumors and said the recent fall in the share price was the work of some stock market traders. "The company is contemplating necessary legal options in this regard."

On October 27, the company's share price was $0.94 on the Bombay Stock Exchange, down from the 2008 high of $9.29.
— S. Anuradha

Indonesia planning to offer geothermal projects as part of second 10-GW fast-track solicitation

After successfully launching its 10,000-MW coal-fired fast track program, Indonesia plans to bid out geothermal projects as part of its second 10,000-MW fast-track program.

An industry source associated with the program said the government was in the process of finalizing the conditions for bidding and an announcement could be made in 2009.

The bidding process would be launched once the first program is implemented in 2010.

Under the second fast-track program, about 60% of the projects would be geothermal and 30% coal-fired. Gas-fired power, hydropower and wind energy would comprise the rest.

The source said that under the scheme, a preliminary survey permit would be given to any interested party. The survey area would be around 200,000 hectares and the interested party would be given two years' time to prepare the feasibility study.

The projects would then be awarded on the basis of the lowest tender offered. A 10,000-acre concession area would be given to the developer for 30 years.

Foreign companies with local subsidiaries can bid for the project. One company would be given only one geothermal project. The government has not yet decided on the individual size of each of the projects. State-owned power utility Perusahaan Listrik Negara would be the main buyer of the power.

Indonesia has identified geothermal as a key source of power given the abundance of natural resources. Geological surveys have indicated that the country has the potential to develop 27,000 MW of geothermal capacity. Currently, Indonesia has just 800 MW of geothermal capacity and has targeted to increase this capacity to 9,500 MW by 2025. The Philippines has the highest operating geothermal capacity in Asia at 2,000 MW.

Under the first fast-track program launched in 2007, 10 coal-fired plants are being developed in Java-Bali and 25 are being developed in other parts of Indonesia at a total cost of $8.3 billion. Most of the projects in the second program are likely to be outside the Java-Bali region.

Indonesia's current capacity is 25,000 MW, mostly fired by oil and owned by PLN. In order to meet the growing demand and to reduce the dependence on oil, the government announced the 10,000-MW coal-fired fast-track project. Most of the plants under this program are being built by Chinese engineering companies. PLN would subsequently operate the plants. *— S. Anuradha*

CLP Holdings reports 7% revenue increase in the third quarter to $5.51 bil from $5.15 bil

Hong Kong-based CLP HoIdings Ltd. reported total revenues of $5.51 billion in the nine months ended September, up 6.9% from $5.15 billion in the year-earlier period.

Revenues from CLP's Hong Kong business rose 3.4% to $3.03 billion from $2.93 billion. The remaining revenue came from its businesses in the rest of Asia and Australia. The company does not provide the profit figure on a quarterly basis. Interim dividend was maintained at $0.20 per share.

The company said electricity demand fell in Hong Kong 0.4% in the nine months to September 30. The slowdown in the retail sector and the closure of some factories in the textiles and electronics industries lowered demand for power.

CLP said electricity sales to the residential sector fell 0.4%, infrastructure sales fell by 0.1% and sales to the manufacturing sector fell 1.9%. Sales to the commercial sector rose by 1.3%. Total electricity sales in Hong Kong and China in the nine months fell 1.9% to 25,787 GWh.

CLP said it was too early to assess the impact of the current financial market turmoil on the company's growth. However, the company said it is "well placed to not only to ride out the storm but to capture opportunities which may arise during a period of adjustment in the energy markets of our region." *— S. Anuradha*

China Datang reports loss of $63 million in the third quarter on higher coal prices

China's Datang International Power Co. reported a net loss of $63 million in the third quarter ended September 30, compared with a net profit of $124 million in the year-ago period on higher coal prices.

In the nine months to September 30, the net loss was $2.04 million compared with a net profit of $395 million in the year-ago period. In the first half ended June 30, the company reported a net profit, though it fell 75% to $81 million from $329 million.

Net loss per share in the third quarter was $0.0054 and in the nine-month period it was $0.0001.

The company did not provide any details on the revenue and operating costs, but said operating costs rose 44% in the third quarter and finance costs rose 76%.

Operating costs rose mainly because of the rise in coal prices.

Datang said it expects the full year net profit to fall 85% because of the higher coal prices. The company said China had to increase power tariffs further for the company's earnings to improve. So far this year, China has increased tariffs twice, raising them by a total of 10%.

Datang Power has an installed capacity of 22,896 MW.
— S. Anuradha

India's NTPC posts second-quarter profit of $426 million, up 9.5%, on lower taxes

State-owned Indian power producer NTPC Ltd.'s net profit in the second quarter rose 9.5% to $426 million, from $389 million, on higher sales and lower taxes. NTPC's financial year runs April through March.

Net sales rose to $1.95 billion from $1.62 billion. Fuel costs rose to $1.20 billion from $892 million and operating profit fell to $495 million from $533 million. However, net profit rose because tax payments fell to $26 million from $110 million after a refund of $107 million.

Second-quarter earnings were better than previous quarters. In the first quarter, net profit fell 27% and in the fourth quarter of the previous fiscal year, profit fell by 23%.

NTPC said during the second quarter a 500-MW plant was commissioned at the Kahalgaon super thermal power station. The company's total installed capacity is 29,894 MW.

The company did not provide any outlook for the rest of the year but earnings are likely to fall because of rising fuel costs and interest charges. — *S. Anuradha*

Reliance Power of India reports quarterly profit of $7.4 million on higher non-operating income

India's Reliance Power Ltd. earned a net profit of $7.4 million in the second quarter ended September 30 on higher non-operating income.

The company's non-operating income from treasury activities was $11 million. Without this income the company would have reported an operating loss of $3.92 million.

Total expenses in the second quarter were $3.92 million.

The company did not provide the previous year's figures because this is the first year of operation for the company as Reliance Power. The company's financial year runs April to March.

Reliance Power said, as of September 30, it has spent $484 million from the $2.32 billion it raised from the initial public offering in January. Of this, $274 million was spent on the development of the two 600-MW units of the Rosa, 300-MW Butibori, 4,000-MW Sasan, 1,200-MW Shahapur and 400-MW Urthing Sobla projects. The remaining funds were spent on the 4,000-MW Krishnapatnam, 700-MW Tato-II and 1,000-MW Siyom projects. — *S. Anuradha*

EUROPE/MIDDLE EAST

Credit crunch, tight turbine supplies crimp plans for European offshore wind capacity

The global credit crunch and turbine-supply constraints are jeopardizing European plans to build nearly 200 GW of offshore wind capacity by 2020, banking and renewables experts said at an industry event on October 22.

Speaking at the British Wind Energy Association annual conference in London, industry participants said 184 GW of installed wind capacity already are in the pipeline to be built by the end of the next decade, which will require yearly investments to increase to about €25 billion ($31.8 billion) in 2020 from around €10 billion this year.

But the limited availability of funding in the financial markets, as well as a shortage of wind turbines and vessels, is threatening to derail Europe's huge commitment to wind, they said.

"There are no shortages of projects, although government targets are ambitious," said Maartje van den Berg, senior associate at Dutch bank Rabobank International, which has already financed wind energy projects in Europe, "But vessel and turbine availability could be limiting factors for offshore wind growth, starting from 2013/2014," she added.

Although yearly unconstrained installation would see around 9 GW of offshore wind installed in just 2015 alone, the turbine capacity will only be able to accommodate around 4 GW of new installed capacity that year, with vessel capacity limited to around 5 GW, Berg said.

"The value chain won't be able to deliver anything more than that. There are currently only seven or eight suitable vessels to install offshore turbines worldwide and one ship having an accident will completely change the picture," she said.

Another constraint is the lack of funding available to finance the projects, with a near freeze on lending for anything other than smaller deals.

"Even the deals near to their financial close, the banks are waiting to see what conditions will be like next year," Berg said. "We need all the banks to participate; they're being very cautious right now. The terms are also going down. They're not lending on a 15- to 20-year basis now; they're decreasing their risk."

Peter Dickson, technical director at Fortis Investment's clean energy fund, agreed, noting that the cost of finance has already increased significantly since last year, with rising debt spreads and cover ratios having put an overall squeeze on the economics in the sector.

"Wind project debt spreads have increased, on average, by 20 to 25 basis points from the first half of 2008 to the corresponding period of 2007," Dickson said. "Also, debt finance for large wind portfolio buy-out deals is more difficult to arrange."

Adding to the problem for wind developers is the fact that it is increasingly a suppliers' market, with a huge backlog of orders on the books of the specialist turbine manufacturers.

"We've gone from asking for a reservation fee to wanting a full down payment," said Erik Sejersen, financial engineer at Vestas Wind Systems, a manufacturer of wind turbines. "Smaller developers are finding life difficult, and new, emerging markets are finding it difficult to attract interest," Sejersen said.

"The crunch means project financed deals may face problems to reach financial close, and banks are preferring club deals, which means working with the other banks, instead of syndicated arrangements," he added.

Finance for offshore wind is particularly tricky because there are only a few international banks — about 10 — focused on offshore wind, Sejersen said. "Finance for offshore is not 'mainstream' yet."

The speakers agreed, however, that over the medium to long term, the prospects of offshore wind will improve, providing the credit markets thaw out. "I've spoken to more banks in the last month than I have in the previous 12-month period," Sejersen said. "And the common denominator is that the banks are just constraining large deals over the short term, but they want to understand what the underlying situation is and want to see more cash coming through the system," before they start offering finance. "The expectation is that by the first quarter of next year … it will be a significantly improved situation, and a couple of years down the road it will be business as usual," added Sejersen.

"It's an interim problem," Dickson agreed. "Over the medium to long-term, the sector remains quite strong. The underlying drivers are there, government policy remains in place and that itself will create demand. Finance will become available again," he maintained.

"Although other worries remain, such as the supply of turbines, the sector is still relatively attractive."

Berg gave a cautiously optimistic appraisal of the wind sector over the longer-term, saying that if the credit crisis persists, governments could look at reducing the amount of money they spend on renewables.

"There's also the risk that, after buying out the banks, [European] governments will be squeezed for money and start to look at their renewable targets and maybe lower them," Berg said.

"I hope that such short-term panic measures won't be taken, but there is a chance that they will happen, and in that case I will be very negative," she added. "But, hopefully, this will pick up next year. The wind sector will continue to grow despite the credit crunch, but the sector needs money from other sources — not just banks," said Berg. *— James Allen*

Belgian consortium Northwester planning 600-MW offshore wind farm in North Sea

Belgian consortium Northwester has applied for a public property concession for the construction of a 600-MW offshore wind farm in Belgian North Sea waters, lead companies Econcern and Blue H Technologies said October 23 in a statement.

Roughly 60% of the park will consist of floating turbines, reducing the costs and opening up opportunities for even deeper offshore locations, Econcern said.

The project site is in the furthest available zone north of Bligh Bank, in water depths ranging from 30 to 45 meters, the consortium said. The site is just north of Econcern's Belwind wind park, where construction is expected to start in 2009.

Blue H Technologies has developed the technology for floating wind turbines, adapted from the deepwater platform technology that has emerged in the oil and gas drilling industry over the last 25 years.

"A floating wind turbine costs less than a conventional fixed installation in terms of both initial investment and operating costs," the consortium's statement said. "For a conventional offshore turbine, the actual foundation work currently makes up … half the total cost."

Frank Coenen, managing director of Econcern unit Evelop Belgium, said construction of the first wind turbines could begin as early as 2013.

The Northwester consortium comprises Econcern's operating company Evelop and Blue H TTR, which is made up of Transcor Astra Group, TPF Group, Wagram Invest and Blue H Technologies. *— Henry Edwardes-Evans*

Drax, Siemens plan three biomass plants, each 300 MW, in $3.3 billion joint venture

UK coal-fired generator Drax Group plans to develop three 300-MW biomass-fired stations with Siemens Project Ventures of Germany in the UK, Drax said in a statement October 23.

Total cost of the program is put at about £2 billion ($3.3 billion). Construction of the first plant is targeted to start in late 2010, with the first plant expected to be operational in 2014.

Drax will own 60% of the projects' equity, with SPV holding the remaining 40%. Drax will manage and operate the biomass business and be responsible for biomass procurement and trading. It is proposed that the plants will use Siemens' turbine technology.

Drax said it had secured rights to port sites at Immingham and Hull for two of the plants. The company is looking at options for the third site, including land at the 4,000-MW Drax station in Selby, North Yorkshire. The planning application process for each of the two secured sites, including required consents, has recently begun, Drax said.

Each plant must meet a "mid-teens equity return hurdle" based on current market scenarios, Drax said, with less than a six-year payback period from start of operations. "No commitments to construction contracts or financing have been made to date and Drax expects to finalize these arrangements over the next 12-18 months," the statement said.

Based on current estimates, once all three plants are operational, Drax would be responsible for at least 15% of the UK's renewable power and up to 10% of total UK electricity, Drax Chief Executive Dorothy Thompson said.

Drax already produces power by co-firing biomass at the Selby station. It is in the process of increasing its biomass co-firing capability to 500 MW by mid-2010, making it the largest biomass co-firing plant in the world.

In a separate announcement, Drax published its interim management statement for the period from July 1, 2008, saying that, due to improving commodity markets, it anticipates its full-year results to be "modestly higher" than the current market consensus.

"This is primarily a consequence of low reserve margins in the UK electricity market for the last quarter of 2008 leading to improvements in dark green spreads. Our expectations for the year are based on our current contracted position as well as prevailing conditions in the commodity markets," the company said in a statement.

One banking source said October 22 that, given current power prices, Drax's "investment in biomass looks attractive for long-term valuation." The source added, "Certainly we'd see biomass as a renewables investment as more 'deliverable' than wind or wave in the near term." *— Henry Edwardes-Evans*

Italy's Enel and Eni plan joint CCS project, merging two separately planned projects

Italy's two largest energy companies, Enel and Eni, last week agreed to join forces to implement the country's first project for the capture, transport and geological sequestration of CO_2, according to a joint statement.

Power utility Enel plans to build a CO_2 capture and liquefaction plant at Brindisi, on the "heel" of Italy. At the same time, oil and gas company Eni said it would inject the liquefied gas into a depleted gas field at Cortemaggiore in Emilia-Romagna belonging to Eni subsidiary and gas storage operator Stogit.

The pilot project represents the integration of two projects that both companies launched independently.

Enel is completing Italy's first industrial CO_2 capture plant, capable of removing 2.5 tons/hour of gas, at its Brindisi thermal power plant. The pilot plant will be ready in fall 2009, the statement said.

Meanwhile, Eni has started its project to inject about 8,000 tons of CO_2/year at the Cortemaggiore reservoir.

The integration of the two projects involves the creation, in Brindisi, of a system for the capture and liquefaction of CO_2 and for its transport to the Cortemaggiore site. The underground injection is set to start in fall 2010.

To gain additional experience in the pipeline transport of CO_2, Enel and Eni have also decided to lay a pilot dense-phase CO_2 transport line at the Brindisi site. *— Eloise Logan*

CEZ, Vattenfall express interest in buying stake in Poland's 2,338-MW PAK plant

CEZ of the Czech Republic and Vattenfall of Sweden each said October 29 they were interested in buying a stake in Poland's 2,388-MW power generator Zespol Elektrowni Patnow-Adamow-Konin.

"CEZ is interested both in PAK and the two coal mines, which supply the plant," said Sebastian Wlodarski, a spokesman for CEZ Polska, in an interview.

Vattenfall also told Platts it would consider a bid. "We are interested in the PAK stake and we analyze every offer," said Lukasz Zimnoch, a spokesman for Vattenfall Polska.

The Polish government is seeking an investor to buy a 46% stake in PAK, one of the country's largest power generators. Treasury Minister Aleksander Grad told the business daily *Gazeta Prawna* on October 28 that negotiations had started with the private owner of the stake, Elektrim, owned by businessman Zygmunt Solorz-Zak.

The ministry wants to sell PAK's shares in a package with the generator's feeder lignite mines, Kopalni Wegla Brunatnego Adamow and Kopalni Wegla Brunatnego Konin, next year.

Gazeta Prawna reported October 28 that Polish state-owned power company Enea is also interested in acquiring the stake. "If there's a tender for the sale of PAK and the Konin and Adamow mines, we will take part in it," Pawel Mortas, Enea CEO, told the daily.

PAK, in central Poland, produces about 12% of the country's electricity. *— Adam Easton*

Polish oil and gas producer PGNiG in talks for as much as 1,600 MW of gas-fired plants

Poland's largest oil and natural gas producer, PGNiG, is in talks to build as much as 1,600 MW of new gas-fired capacity, CEO Michal Szubski said on October 24.

"We are talking to several companies, both domestic and foreign, about building between 400 to 800 MW and even in some cases 1,600 MW of gas-fired power plants," Szubski told reporters in Warsaw.

"We want to have some preliminary agreements over the amount of gas needed in the first quarter of 2009." Szubski did not name the companies that were in discussions with PGNiG.

In July, it was reported that PGNiG was holding preliminary talks with RWE to build two 400-MW gas-fired plants close to PGNiG's underground gas storage facilities in either Wielkopolska, western Poland, or in Podkarpac, south eastern Poland.

The cost of the projects is estimated at up to Zloty 6.3 billion ($2.1 billion). If it goes ahead, PGNiG could increase its gas sales by between 0.8 Bcm/year to 1.2 Bcm/yr, which represents a 6% to 9% rise.

The Polish company's share of the investment would be in the region of Zloty 1.6 billion, it was reported.

Currently, Poland has just five gas-fired CHP plants in the country. More than 90% of the country's electricity is produced from coal-fired plants, which causes Poland problems in meeting the European Union's climate change goals. *— Adam Easton*

Verbund-Sabanci joint venture to proceed with plans for three power plants in Turkey

EnerjiSA, a joint-venture between Austria's Verbund and Turkey's Sabanci, is proceeding with plans to build three power plants in Turkey, Verbund said in a statement October 22.

Simultaneous groundbreaking ceremonies were held for the 920-MW Bandirma gas-fired power project on the south coast of Lake Marmara in northwest Turkey and at hydropower sites for the 180-MW Kavasak Bendi plant in the Adana region and the 142-MW Hacininoglu project in the Kahramanmara region.

The Bandirma plant is expected to enter service in late 2010 and is being built by a consortium of Mitsubishi Heavy Industries and Austria's A-TEC Power Plant Systems.

Kavasak Bendi is due online at the end of 2011. Hacininoglu is expected to enter operation in 2010.

Verbund said Turkey was an attractive market for foreign investors because of the speed with which projects could be developed.

EnerjiSA already has an installed capacity of 450 MW from gas and hydropower plants. Its owners, Verbund and Sabanci, plan to build generation totaling at least 5,000 MW by 2015.

This summer they won a contract for the distribution grid in Ankara, supplying 6 million residents in and around the Turkish capital. *— Alex Froley*

Israel's Delek to build and own 55-MW plant for agricultural company in north of country

Delek Infrastructure has signed an agreement with Tnuva, Israel's largest agricultural marketing concern, for construction of a 55-MW gas-fired cogeneration plant at Alon Tavor in northern Israel.

The $63 million build-own-operate project would include a 30-year power-sales contract with Tnuva.

Delek Infrastructure already operates a private power plant at the Ashkelon desalination plant along Israel's southern Mediterranean coast. The company has also signed an agreement with Nilit Ltd. for construction of a 48-MW cogeneration plant in Migdal Haemek. The company is also active in Brazil and is looking at projects in India. — *Neal Sandler*

LATIN AMERICA

Colbun receives environmental license for 144-MW run-of-river project in Chile

The environmental commission for southern Chile's Los Rios region gave its approval on October 22 to Colbun's 144-MW San Pedro hydroelectric project.

The run-of-river plant is expected to produce 935 GWh annually after it begins operating in late 2011.

Plans to develop hydropower, including San Pedro, in southern Chile have faced opposition from environmentalists and local indigenous groups. Police had to clear the room of protesters before the commission could complete its evaluation process.

Commission chairman Ivan Flores highlighted that the project has undergone significant revision during the evaluation process to meet the requirements of government services and local communities. "The project approved today is not the same one originally presented by the company," he said.

Earlier this year, Norway's SN Power announced the suspension of plans to develop 260 MW of run-of-river capacity in the same area as the San Pedro project after a senior executive was shot near his home in Santiago. — *Tom Azzopardi*

Peru faces risk of power shortages during 2009-2010, says central bank

Peru's central reserve bank has given a gloomy outlook on the future of the country's power supplies, warning of increased danger of shortages over the next two years as generating capacity fails to keep pace with rampant demand for electricity.

In its latest inflation report, released on October 24, the bank said that the reserve margin in the electricity sector will fall to 20% by year end, from 30% in 2007 and 55% at the start of the decade in the face of growing energy consumption, which has risen by almost 50% in the last seven years.

The risk will be at its height during the coming winters (May-November) when snow builds in the Andes mountains, intensified by a sharp drop in water reserves.

Reserves during the first half of the year were down 16% from the same period of 2007.

In recent years, gas supplies from the Camisea field have led the increase in power supplies but limited pipeline capacity mean that the country's gas-fired power plants, with 1,200 MW of capacity, are running at just 70% of capacity.

Concession holder Transportadora de Gas del Peru is planning to increase pipeline capacity to 380 million cubic feet/day by next August, from 293 million cubic feet/day currently, and to 450 million cubic feet/day by the end of next year.

But the addition of 590 MW of new gas-fired capacity over the next two years is set to increase gas demand from the electric sector to 430 million cubic feet/day, leaving no extra gas for other sectors of the economy.

"Thus gas pipeline capacity will continue to be a restraint on the increased power supplies, even after the expansion work has been concluded," the bank warned.

The impact of restricted power supplies is already being felt, with marginal generating cost hitting a peak of $236/MWh in July this year.

A dry year or a sudden spurt in demand could push up "marginal costs to new highs and increase the risk of a grid failure," the bank said.

High commodity prices, rising personal incomes and free trade agreements are driving an investment boom in Peru, further lifting demand for power.

"In practical terms, the loss of supplies from just one 200-MW power plant could lead to temporary rationing at peak hours during these months," the bank said.

Looking further ahead, Peru will require an additional 550 MW of capacity each year over the next decade. But the bank warned that government disincentives to investment, including low maximum prices in power tenders and obstacles to new hydroelectric projects, had to removed to ensure this extra capacity is built. — *Tom Azzopardi*

Venezuelan power company Corpoelec to expand 150-MW power plant to 450 MW by year-end 2009

The Venezuelan government plans to expand its Termozulia-II plant to 450 MW by the end of 2009, the head of state power company Corpoelec said at the inauguration of the project on October 24.

The plant's first two units, with 150 MW of capacity, are operating on an open-cycle basis.

Corpoelec Chairman Hipolito Izquierdo said the company planned to close the first cycle by year end, doubling capacity to 300 MW.

The Termozulia-II plant is an extension of the 470-MW Termozulia-I plant, Venezuela's first combined-cycle plant, which began operating last year.

During the inauguration of Termozulia, Venezuelan President Hugo Chavez said the plant would help make the western province of Zulia self reliant in electricity. Venezuela has suffered numerous power cuts in recent months as demand has overtaken installed capacity.

Corpoelec and state oil company PDVSA plan to invest close to $14 billion over the next five years to expand installed capacity. *— Tom Azzopardi*

NORTH AMERICA

PROJECTS

Federal appeals court upholds denial of permit for 534-MW EnviroPower coal project in Illinois

A federal court has dealt a potentially lethal blow to EnviroPower's plans for a long-delayed coal-fired project in Illinois, and the Houston-based developer is not faring much better with a project in Kentucky.

EnviroPower has proposed virtually identical 534-MW pulverized coal plants in southern Illinois and eastern Kentucky. An Indiana coal project also was proposed but it was quickly jettisoned.

Over fierce opposition from environmentalists, EnviroPower secured air permits in Illinois and Kentucky but soon ran into problems over its apparent failure to begin meaningful construction by required regulatory time tables.

In a 3-0 decision on October 27, the 7th US Circuit Court of Appeals in Chicago ruled EnviroPower's permit from the Illinois Environmental Protection Agency, originally issued in July 2001, had expired years ago.

The appellate court affirmed an October 7, 2006, ruling by US District Judge J. Phil Gilbert, who determined the IEPA permit no longer was valid. EnviroPower appealed to the 7th Circuit.

EnviroPower had insisted it met the construction deadline provision of the state permit by performing limited earth work at the plant site near the Benton Airport in Franklin County. Bruce Nilles, national coal campaign director for the Sierra Club, a long-time critic of EnviroPower's plans, ridiculed those efforts. "They dug one hole and put fencing around it," he said. "The owner came back and filled the hole in, saying it was a liability. When IEPA began sniffing around, [EnviroPower] dug another hole ... they've just tried to skirt the law."

In its opinion, the 7th Circuit said the federal Clean Air Act is designed to prevent companies from building power plants with outdated equipment.

Several Illinois coal officials said they were not surprised by the ruling or EnviroPower's apparent demise. Bill Hoback, director of the Illinois Coal Office, said his office repeatedly tried to reach company officials about updating old information, but to no avail. "We couldn't reach them," he said on October 28. "I assume they disappeared."

Perhaps not totally.

Nilles of the Sierra Club said his group is fighting a similar permit battle in neighboring Kentucky over another coal plant, Kentucky Mountain Power, that EnviroPower had talked about building for several years. Ben Markin, an environmental control supervisor for the Kentucky Division of Air Quality, said EnviroPower has filed an administrative appeal to the division's refusal to renew a permit for Kentucky Mountain Power. "We're not going to give them a permit," Markin said.

Several phone numbers of previously listed EnviroPower officials, including at a Houston office, were no longer in service. A secretary at Dershowitz, Eiger and Adelson, the law firm EnviroPower hired to file the appeal, said that Alan Dershowitz, who is handling the case, was not available to comment. *— Bob Matyi*

California Energy Commission delays permitting for 255-MW NCPA project

The California Energy Commission on October 22 declined to start the 12-month permitting process for a 255-MW gas-fired, combined-cycle plant proposed by the Northern California Power Agency.

CEC staff found NCPA's proposal lacks adequate data in several areas, including air quality and transmission system design. The project would be located in San Joaquin County, California, and the developer hopes it will begin operations in 2012.

CEC member Jim Boyd said the agency expects to review the proposal in November, once all the required information is sent to it.

In other action, the CEC awarded about $2.4 million to the Center for the Study of Energy Markets at the University of California Energy Institute to conduct a four-year study focusing on, among other things, reliability and adequacy of supplies, and polices addressing demand response, and global competition. *— Lisa Weinzimer*

Ausra begins operation of 5-MW solar project near Bakersfield, selling steam to industrials

Ausra on October 23 inaugurated a 5-MW solar thermal demonstration project that the company says also has the potential for a new business model.

Instead of selling power from the project, Ausra is lining up deals to sell the steam from the project to industrial users.

The Kimberlina plant uses Ausra's compact linear fresnel reflector technology and is in the heart of oil country in Kern County, California, about 40 miles northwest of Bakersfield. The plant sells steam to the adjacent Clean Energy Systems facility that uses combustion turbines to generate power and capture CO_2.

Kimberlina also serves as a research and development facility for Ausra's 177-MW Carrizo solar thermal plant that is under review at the California Energy Commission.

Palo Alto, California-based Ausra has a power-purchase agreement with Pacific Gas and Electric and expects to begin initial commercial operation of the Carrizo facility by second-quarter 2010.

Perry Fontana, Ausra's vice president of projects, said the company is talking to oil companies about process steam projects. He said he hopes to sign deals soon. Ausra is looking to build solar facilities on a customer's site that would provide steam for enhanced oil recovery or for industrial processes. Solar steam generators are much easier to permit that gas-fired generators, said Fontana, adding that "Steam deals may get constructed before Carrizo becomes operational."

Fontana said Ausra is talking to utilities across the Southwest as well. In Arizona, it has started outreach on a project near Yuma and in Nevada it is looking at a Bureau of Land Management site north of Las Vegas. Both projects would be larger than Carrizo, he said.

Sean Kiernan, development director for Ausra, said the company is looking at two sales models: an equipment sale where an oil company would buy, own and operate the solar facility, and a steam sales agreement in which Ausra would build the facility, own it and contract to sell steam.

"We can do four lines of mirrors, on 10 acres," each approximately 1,000 feet long, said Kiernan. That size facility would produce 6 MW of thermal energy per line, or 1 to 1.5 MW of power per line. — *Lyn Corum*

CONTRACTS

Progress Energy Carolinas signs PPA for 20 years from 1-MW solar project

Progress Energy Carolinas on October 27 said it has entered into a 20-year power purchase agreement to buy the output of a 1-MW solar project that FLS Energy will build next year at the site of closed landfill in western North Carolina's Haywood County.

The solar photovoltaic panel project is expected to generate more than 1,600 MWh/year. Financial terms of the PPA were not released.

Progress spokesman Scott Sutton said the PPA is the third the utility has entered into involving North Carolina solar projects in past few months. The others were for a 1-MW SunEdison project to be constructed in New Hanover County and for a 1-MW SunPower project to be built in Wake County.

Sutton said that SunEdison, SunPower and FLS Energy were among the respondents to Progress' November 2007 solicitation for renewable energy projects. The three 1-MW solar projects will help Progress meet the requirements of North Carolina's year-old "renewable energy and energy efficiency portfolio standard." The REPS includes a solar "carve-out" under which utilities much secure at least 0.02% of their electricity needs in 2010 from solar projects and at least 0.2% of their needs in 2018 from such projects. — *Housley Carr*

Santee Cooper signs 20-year purchase deal for output of 50-MW biomass project in S.C.

Santee Cooper said it has signed a 20-year power purchase agreement for the output of a 50-MW waste-wood-fired plant that Rollcast Energy will build by late 2011 in Newberry County, South Carolina.

Mollie Gore, spokeswoman for South Carolina's state-owned utility, said that the PPA represents "a significant step" for Santee Cooper in achieving its recently announced goal of having 250 MW of renewable energy online by 2020 (*GPR*, 17 July, 20). She said the utility would not release specifics of the PPA, but noted that its value over the agreement's 20-year term is more than $500 million.

Santee Cooper, over the past several months, has been in talks with Rollcast and other, unidentified developers of biomass-fired plants in the hope of reaching PPAs, Gore said. She said that Rollcast presented "a strong business plan," and noted that the company already is developing a similar project in Georgia.

Rollcast has a 50-MW biomass project in Heard County, Georgia. The $170 million project is due online in 2010. Earlier this year, Georgia Power signed a 15-year PPA for the project's output (*GPR*, 14 Feb, 12).

Charlotte-based Rollcast is in earlier stages of developing a third 50-MW biomass-fired project in Barnesville, Georgia, and hopes to develop several more projects in the Southeast, said Rollcast President Penn Cox. He said that the company has discussed a possible PPA on the Barnesville project with several entities, but he declined comment when asked if MEAG Power, which secures power for Georgia' municipal utilities, was among them. Spokesmen for MEAG did not return telephone calls seeking comment.

Cox said that while Rollcast is not actively seeking project financing at this time, he does not anticipate that securing financing would be unduly difficult, despite the ongoing credit crisis. "Right now about the only [financing] getting done is project financing," he said, adding that because of the Rollcast projects' relatively modest size and the company's PPAs with credit-worthy counterparties that financing the projects would be "in the sweet spot for a lot of folks." — *Housley Carr*

Iberdrola Renewables reaches deal to sell 55 MW from Wash. biomass plant to SMUD

Iberdrola Renewables on October 27 said it will sell Sacramento Municipal Utility District 55 MW from a biomass cogeneration plant that is under construction at a Tacoma, Washington, pulp and paper mill.

Iberdrola acquired the output of the plant in April. The plant is being built and will be owned by Simpson Tacoma Kraft Co. It is expected online in July 2009.

"Simpson is building the cogeneration plant to maximize energy production from our existing operations that already involve burning sawmill and paper mill by-products, wood-building demolition waste and debris from logging," said Dave McEntee, Simpson's Energy and Environmental Manager.

He also said it might "mine" old lumber mill landfill sites to recycle wood waste buried at its mill years ago. According to the USA Biomass Power Producers Alliance, the facility will be the largest single cogeneration renewable energy project built in the US in the last 10 years.

"This transaction allows everyone to do what they do best. Simpson is using its extensive experience in wood products to provide biomass fuel and operate the plant. Tacoma Power's quality infrastructure will connect the plant to the grid. Iberdrola Renewables will provide transmission and manage logistics, and SMUD will distribute renewable power to Sacramento-area homes and businesses," said Peter van Alderwerelt, senior vice president of Iberdrola Renewables. He added, Iberdrola's " unique rights to otherwise scarce transmission resources" made the deal possible. *— Staff Report*

SECONDARY MARKETS

Pace says credit crisis delaying sale of 1,750-MW Cobisa project in Texas

Pace Global Energy Services said October 29 that the credit crisis has delayed its effort to find a buyer for a 1,750-MW gas-fired combined-cycle project that Cobisa Corp. has been developing northeast of Dallas in Greenville, Texas.

Pace Executive Vice President Bo Poats said the company, which was hired by Cobisa this past spring to coordinate a "structured sale process" for the project, has identified parties interested in purchasing it, but that credit markets need to improve and "settle" before a deal can be consummated.

Asked how long that might take, Poats said he believes conditions in credit markets will improve "in the first half of 2009." He noted that, in the meantime, Pace also has put on hold its efforts to line up potential off-takers for the project's output.

Houston-based Cobisa has said that it is open to the possibilities of selling 100% of the fully permitted Greenville project or selling almost all of it and retaining a small equity stake.

Cobisa, formed in 1987, has developed three gas-fired projects, including a 1,750-MW combined-cycle plant in Forney, Texas, that is nearly identical to the proposed Greenville project. Cobisa sold 95% of that project to FPL Energy. *— Housley Carr*

John Deere buys 70-MW wind farm in Michigan from Noble Environmental

John Deere Wind Energy has purchased an unfinished 69.5-MW wind energy project in Michigan's Thumb region from Noble Environmental Power.

Noble recently shuttered several wind projects in New York State, following the September bankruptcy of a key underwriter, Lehman Brothers (GPR, 23 Oct, 5). Deere's acquisition of the Noble Thumb Windpark near Ubly in Huron County closed on October 24, according to Brad Johnson, Deere's director of business development. Financial terms were not disclosed.

Following a series of delays, Noble began construction on the wind park earlier this year. Thirty of 46 wind turbines had been installed by the time the sale closed. Johnson said the wind park would be completed by year end. Consumers Energy has agreed to buy the wind park's entire output under a long-term contract.

"We bought it and stepped into it," Johnson said. "We had an opportunity to pick up an existing project under construction to add to our assets in Michigan." Deere developed the state's first commercial wind project, the 54-MW Harvest Wind Farm near Elkton, about 20 miles from the former Noble project. The power is sold to Wolverine Power under a long-term arrangement.

Johnson said Deere has submitted a permit application for a 90-MW expansion of Noble Thumb. "We're trying to work through the permitting right now," he said. "Potentially, that could be a 2009 project." Deere has been relatively unaffected by the financial turmoil. "All of our financing to date has been internal," he said.

Noble officials could not be reached for comment.
— Bob Matyi

Puget Sound receives antitrust approval for purchase of 310-MW Washington plant

Puget Sound Energy's plan to buy a 310-MW gas-fired plant in southwest Washington from Wayzata Opportunities Fund of Minnesota for $240 million received federal antitrust approval on October 23.

In an early termination notice under the Hart-Scott-Rodino Antitrust Improvements Act, the Federal Trade Commission said neither it nor the Department of Justice's Antitrust Division plan to take enforcement action against the deal.

On September 25, the utility said it had signed an agreement to buy the Mint Farm plant in Longview, Washington, from Wayzata Opportunities Fund, an investment fund managed by Wayzata Investment Partners.

The deal, which is part of an initiative to meet growing electricity needs in its service territory, is expected to close by year end. It must be approved by the Federal Energy Regulatory Commission, which is expected to issue a decision in the fall, PSE said.

In January, PSE issued a request for proposals for up to 1,340 MW of supply resources, which would have to be online by 2015. Mint Farm was one of four projects on PSE's shortlist.

That list also includes two planned 20-year power purchase agreements with wind farms in Washington and Oregon, together totaling 250 MW of power capacity, and one short-term, winter-only PPA.

The population of PSE's service territory is expected to increase by more than 1 million people over the next 20 years.
— Staff Report

SOLICITATIONS

Progress Energy Carolinas seeks proposals for renewables, its second request in a year

Progress Energy Carolinas said October 28 that it is seeking renewable and alternative-energy proposals, with a deadline of November 11 to be considered in the company's 2009 planning period, the company said in a statement.

The company is not identifying a specific amount of power, said Michael Hughes, a Progress spokesman.

The solicitation is in addition to an open-ended request in November 2007 for renewable proposals that resulted in a number of proposals for solar and biofuels energy projects, the company said.

"Although the request remains open, there are certain deadlines for submitting proposals to be considered in the company's renewable resource planning, which is updated at regular intervals and shared with state regulators annually," Progress said in the statement.

The company has signed contracts for two biomass projects and for three solar photovoltaic plants of about 1-MW each, including one in western North Carolina, one near Raleigh and one near the coast. Additional solar proposals and projects involving the use of wood waste and agricultural byproducts are being evaluated.

The company expects to purchase up to 1 million MWh of renewable energy when a 3% state renewable standard takes effect in 2012.

Bidders responding by November 11 will be notified by March of Progress Energy Carolinas' intent to enter further discussions.

Solar energy bids with capacity of 50 kW or greater and non-solar bids with capacity of 10 MW or less will be accepted. The latter category includes such technologies as wind, hydropower, geothermal, ocean current/wave energy, biomass, landfill methane or hydrogen derived from a renewable resource.

Priority will be given to those proposals that are expected to be operational before 2011. The request for proposals, including information on the process for submission, can be viewed in its entirety at: www.progress-energy.com/renewableRFP.

— Staff Report

Northern Indiana Public Service issues RFPs, one for up to 300 MW, one for renewables, DSM

Northern Indiana Public Service Co. on October 24 issued two requests for proposals, one seeking capacity and energy proposals for up to 300 MW to address the company's projected electricity supply needs for 2011-2016, and the other seeking supplies derived from renewable energy sources and demand side management resources.

The 300-MW RFP was issued to identify and negotiate contracts for firm electric capacity and associated energy from base, intermediate and/or peaking resources for a delivery period starting as soon as 2011 and no later than 2016. Nipsco will consider proposals that begin before 2011.

Nipsco projects a need by 2016 for up to 300 MW of incremental long-term resources, comprising supply-side base, supply-side intermediate and/or supply-side peaking resources.

The renewables solicitation is looking to identify and negotiate contracts for renewable energy and/or DSM resources for a delivery period starting as soon as January 1, 2011.

Based on its last-filed integrated resource plan in 2007 and the potential future passage of an Indiana renewable portfolio standard, Nipsco is projecting a future need for up to 300,000 MWh/year of incremental long-term renewable resources made up of renewable energy generation and/or DSM.

The company, therefore, anticipates that it will contract for up to 300,000 MWh of new, incremental renewable and/or DSM resources per year.

In the renewable/DSM solicitation, Nipsco said that it has a preference for in-state proposals and renewable energy delivery with the associated and certified renewable energy credits.

Both RFPs note that the utility will consider joint ventures, partnerships, power purchase arrangements with options to acquire and turnkey proposals.

Questions or communications related to both RFPs should be sent to Charles Adkins, RFP Contact Person, 801 E. 86th Avenue, Merrillville, Indiana 46410-6271, e-mail: nipsco2008rfp@ventyx.com, phone: 404-512-3584, fax: 770-989-4445 (confidential fax number).

All fax submissions must have either "Attn: NIPSCO 2008 Base, Intermediate, and/or Peaking Power RFP" or "Attn: NIPSCO 2008 Renewable and DSM RFP."

Proposals in response to the RFPs are due by January 15.

RFP documents are available at www.nipsco2008RFP.com.

— Paul Ciampoli

Kentucky's Owensboro muni looks to sell excess capacity from 416-MW coal station

Owensboro Municipal Utilities of Kentucky is seeking proposals from parties interested in buying excess baseload capacity and energy from OMU, beginning in June 2010 and extending through December 2012.

OMU noted in the October 22 request for proposals that it owns and operates the 416-MW Elmer Smith coal-fired station, which is the primary source of power and energy for OMU customers.

When OMU's current power supply agreement terminates as scheduled in May 2010, the muni will have excess generation available from the plant for sale to qualified counter parties.

The types of energy and capacity proposals being considered by OMU include, but is not limited to, system firm purchases of energy, unit firm purchases of energy, and reliability capacity purchases.

Notices of intent to respond to the RFP are due by November 7 and the bidding deadline is December 1.

The RFP contact is Jim Grise, director of finance, Owensboro Municipal Utilities, e-mail: grisejr@omu.org, subject line: BID 08-11-064.

For more information, go to www.omu.org/powerrfp.

OMU is the largest municipal electric and water system in Kentucky with more than 26,000 electric, 24,000 water and 3,200 telecommunications customers. *— Staff Report*

GSA seeking power supplies in Texas for facilities; deadline is December 9

The General Services Administration is seeking power supply proposals for various federal facilities in Texas.

In the October 23 solicitation, GSA noted that the facilities are in the service territories of CenterPoint Energy, Oncor and Oncor SESCO, and AEP Texas Central.

The GSA has issued the request for proposals for pricing of the supply of all electricity supply commodity components up to the delivery point, including energy, capacity, ancillary services, scheduling, balancing, fuel costs and network firm transmission necessary for the firm supply of electricity to the facilities.

The successful bidder will supply electricity for a term of 24, 36 or 60 full monthly billing cycles.

GSA noted that in order to facilitate the timely evaluation of proposals, the government will request and evaluate technical qualifications before the submission of price proposals. Evidence of technical qualification must be received by November 25.

All pricing received as a result of the solicitation will be submitted using an Internet-based reverse auction transaction platform administered by World Energy Solutions on December 9.

Respondents will be allowed to offer and reoffer pricing until the close of the auction time for each pricing group and accompanying contract term. Auction instructions are detailed on the World Energy Solutions web site at www.worldenergy.com.

Questions related to the solicitation must be submitted in writing and can be sent via e-mail to lindal.collins@gsa.gov.

The solicitation contact is Linda Collins, contracting officer, via phone: 202-708-9881, fax: 202-205-5049, or e-mail: lindal.collins@gsa.gov. — *Staff Report*

University of Houston issues solicitation for power; has peak demand of 30 MW

The University of Houston system, which has a non-coincident peak demand of 30 MW, issued a request for proposals on October 27 for electricity and related services. Proposals are due by November 26.

The university consumes 250,000 MWh a year. The system's existing electricity supply contracts expire on the regularly scheduled meter reads after March 31.

All questions or concerns related to the RFP should be in writing and directed to Don Whaley, Whaley Energy Consulting, 3638 Glen Haven Blvd., Houston, Texas 77025, e-mail: DBW@whaleyenergy.com. The deadline for questions is November 17.

The university system is the state's only metropolitan higher education system, encompassing four universities and two multi-institution teaching centers, the RFP noted. — *Staff Report*

WHOLESALE MARKETS

MISO is considering forming a task force to examine sharing of grid connection costs

As more wind generation is projected to be added in the Midwest Independent Transmission System Operator's footprint in the coming years, the ISO is looking at forming a task force on sharing transmission costs that will be incurred to accommodate renewable resources, a MISO spokesman said October 28.

"Everyone agrees that transmission costs should be shared," but different utility rules, state laws and other factors can make sharing of transmission investments very complicated," MISO spokesman Carl Dombek said.

The MISO advisory committee is expected to seek approval of a cost-sharing task force at its December 3 meeting. If approved, the task force would begin meeting in early 2009, Dombek said.

The transmission investment needed to support wind generation being added in the MISO area and other regions is significant, MISO CEO Graham Edwards told the Pennsylvania Public Utility Commission last week at a hearing on wholesale market operations.

The Joint Coordinated System Planning study, a collection of ISOs in the Eastern Interconnection, has worked with the Department of Energy to examine state renewable portfolio standards and grid impacts for a possible federal RPS.

While a 20% RPS at the national level would allow a variety of renewable resources to be added, the study noted that wind is the dominant renewable resource being added in the Eastern Interconnection. It projected some grid impacts for MISO and other system operators

Democratic presidential candidate Senator Barack Obama supports a 25% federal RPS.

Under a 20% national RPS scenario, about 90,000 MW of wind generation would be added in MISO's territory over the next 20 years, creating the need for $45 billion in transmission investments to connect the facilities and bring the power to customers, Edwards told the Pennsylvania PUC last week.

Much of the wind generation would be added in remote areas removed from load centers, according to the JCSP study.

Transmission cost allocation is being addressed not only by MISO, but also by the Organization of MISO States, a group of state regulators. It is a major factor that utilities and others in the Midwest will have to deal with over the next year or so, Edwards said. "Until we get that resolved, I don't see a lot of transmission being added." — *Tom Tiernan*

ISO New England CFO says FERC is eyeing creating credit policies across all RTO areas

The Federal Energy Regulatory Commission is exploring the idea of regional transmission organizations working together to develop a national credit policy for power markets, ISO New England CFO Robert Ludlow said October 24.

Ludlow told members of the New England Power Pool's Budget and Finance Subcommittee that ISO management recently met with FERC officials to discuss concerns about the grid operator's credit policies.

FERC is "sufficiently concerned on how the credit and financial assurances are designed throughout the country. It is an important topic for them," Ludlow said at a subcommittee meeting. During the talks, he said, FERC officials asked whether all ISOs could work to develop a national credit policy.

Ludlow said that such an effort would be a huge task and that he believes each ISO should be allowed to proceed with its own policies while a nationwide approach is being formulated.

In response to the global financial crisis and the default of Lehman Brothers Commodity Services in all organized markets, all ISOs have moved to re-evaluate their credit policies.

Also at the subcommittee meeting, ISO-NE management proposed adopting NYMEX and the Chicago Mercantile Exchange's credit practices, and eliminating the unsecured credit and parent guarantees that are now available to market participants.

The proposal drew quick opposition from the region's utilities, which said eliminating the secured credit guarantees would increase their costs of doing business.

Ludlow said that because the grid operator serves a market-clearing function like that performed by NYMEX and CME, it looked to the exchanges for best practices. Based on a review of them, ISO-NE managers proposed three main changes to the existing credit policy.

Under the first, ISO-NE would eliminate unsecured credit available to market participants. Unsecured credit is granted based on a company's credit rating and net worth, and cannot exceed $75 million for any single entity.

The second part of the proposal calls for limiting the list of banks eligible to issue letters of credit to those approved by NYMEX and CME.

The last part of the proposal includes a limit on how much of the trading activity could be supported by a letter of credit. Following the commodity exchanges' practices, ISO-NE wants to split the financial assurance provided by members to 50% cash and 50% letter of credit, meaning that a letter of credit would not be accepted as a financial backup for more than 50% of a company's transactions. To be adopted, the proposal must win approval from a number of ISO-NE committees.
— Milena Yordanova-Kline

PJM members reject proposals to limit availability of unsecured credit in market

Members of the PJM Interconnection on October 27 rejected a package of proposals to limit the availability of unsecured credit in its markets, after voting against the individual proposals in the package October 16.

Unsecured credit in PJM is granted based on the company's credit ratings and tangible net worth and can not exceed $150 million to any one member.

At a meeting of PJM's Credit Risk Management Steering Committee Group, PJM made another attempt to push forward the concept of limiting the risk of unsecured credit by bundling three individual credit proposals into one package. PJM proposed to eliminate unsecured credit in the financial transmission rights markets, to lower the maximum amount of unsecured credit allowed to each member and to establish a cap on unsecured credit available to a group of affiliated members. Under the current policy, each member of an affiliated group of companies is eligible to apply for the maximum amount of unsecured credit.

At the last committee meeting on October 16, in a sector vote where members are divided into five sectors with equal voting power, 4.28 out of 5.00 voted to support the continuation of unsecured credit in general. The proposal to remove unsecured credit from the FTR market also failed, with only 1.76 of the votes in support. The suggestion to eliminate the available unsecured credit by 50% only got 2.99 of the possible 5.00 votes. The committee also rejected the idea to cap the amount of unsecured credit available to a group of affiliated companies.

October 27, PJM combined the three of these failed proposals and asked members whether they would conceptually support changes in the unsecured credit policy and agree to work on the details later before a final proposal goes for approval at the Member's Committee. According to PJM's CFO Suzanne Daugherty, the grid operator put the unsecured credit package again for a vote because it believed that it had conceptual support among members.

At the sector vote, the members rejected the package proposal with 3.19 voting for and 1.81 voting against. The proposal needed 3.335 out of the 5.00 possible sector votes to pass.

However, the members supported with a slight margin a proposal in favor of setting a cap on the dollar amount of letters of credit provided by any one financial institution that issues letter of credit to PJM members. The details surrounding the implementation are to be agreed upon later.

Currently, about 47% of all letters of credit posted with the grid operator are issued by only two financial institutions that are A graded. The largest provider of letters of credit in PJM supports over $400 million in letters of credit, while the second largest supports over $300 million. Members had different reactions to this proposal, some suggesting that only letters of credit from institutions with AA of higher rates should be accepted by PJM, others encouraging PJM to look at NYMEX's credit policies with regards to acceptable letters of credit. *—Milena Yordanova-Kline*

New York ISO sees no significant losses from the recent spate of credit defaults

The New York Independent System Operator's CFO last week said the grid operator does not expect to sustain any significant loss from three recent defaults and said it holds sufficient collateral to cover most of the money that is due to the grid operator.

Earlier, NYISO said Lehman Brothers Commodity Services, Pro-Energy Development and Quark Power failed to meet their payment obligations and were considered to be in default. LBCS filed for bankruptcy October 3, several weeks after its parent Lehman Brothers Holdings filed for Chapter 11 protection.

In the ISO, a default may take two forms: failure to pay an invoice or failure to meet creditworthiness requirements.

"We are not expecting to have bad losses at this time," NYISO CFO Mary McGarvey said at NYISO's Business Issues Committee regular meeting.

McGarvey said LBCS' charges are currently just under $2.5 million and are expected to increase about $4 million by the end of the next billing period. NYISO holds about $10 million in cash collateral from LBCS, but the money was frozen by the bankruptcy court, she said. NYISO has retained counsel and believes the court will allow it to use the cash collateral to satisfy LBCS' charges.

Committee members, however, said they are worried the court may order the $10 million fund to be used to satisfy other claims that are senior to NYISO's claim. McGarvey said only that that issue has been addressed by ISO attorneys.

She told the committee that NYISO is now using working capital to pay suppliers. Assuming the court releases the LBCS collateral, that money will then be used to cover all charges.

Pro-Energy, a Buffalo, New York-based competitive retail supplier, is expected to resolve its default, McGarvey said.

The possible losses from the Quark Power default are estimated at less than $50,000, she said. In a notice to market participants October 24, NYISO said it does not consider Quark to be a material source of default exposure and continues to evaluate legal strategies to collect this default. *— Milena Yordanova-Kline*

ERCOT to increase its backup of wind power with more supplies from conventional sources

The Electric Reliability Council of Texas, which in February was forced to cut power to some large industrial and commercial customers after a sudden drop in wind generation, plans to increase the amount of conventional generation used to back up wind capacity.

ERCOT's board last week approved changes to the grid operator's methodology for determining how much reserve generation is necessary to serve load and maintain system frequency.

"We're coming into a wind-challenging time of year," said ERCOT spokeswoman Dottie Roark. "We already have more wind generation than we've ever had, and we're expecting much more to come online before the end of the year."

Beginning November 1, ERCOT will begin buying reserves based on wind and load forecasts rather than on a flat procurement, which traditionally has been equal to 1,354 MW, or the size of the largest power plant in ERCOT.

In addition, procurements of reserve generation will no longer be limited to peak load hours.

The increase in installed wind capacity also will be taken into account when determining reserve requirements for upcoming months, the board said.

ERCOT currently has roughly 6,000 MW of installed wind capacity. That number is expected to grow to more than 8,000 MW by the end of 2008 and to 8,500 MW in 2009.

But because of its intermittent nature, wind power has to be backed up by more conventional generation.

In February, ERCOT narrowly avoided a widespread outage by cutting power to some large customers after a sudden drop in system frequency resulting from loss of wind capacity, increased heating demand and lower-than-expected output from other generators.

Roark said, however, that the current methodology changes have more to do with substantial wind-capacity growth than February's events.

"Even if the events in February had not happened, we would still be seeing these changes," Roark said. "As we head into the fall and winter, wind is going to make up a larger portion of the generation picture, so it makes sense to have these changes in place ahead of time." *— Leticia Vasquez*

Texas PUC, ERCOT select Charles River Assoc. for nodal market plan cost-benefit analysis

The Public Utility Commission of Texas and the Electric Reliability Council of Texas signed a contract October 24 with consulting firm Charles River Associates to undertake a revised cost-benefit analysis for the transition to a nodal market structure in Texas, according to a PUC representative.

The new study, expected to be presented to the Texas PUC and ERCOT on December 17, will be supervised by Jess Totten, competitive markets director at the PUC. Totten said ERCOT is responsible for funding the study at an undisclosed cost.

Previously, PUC Chairman Barry Smitherman had recommended a second nodal cost-benefit study in September be conducted to familiarize the two new PUC commissioners, Kenneth Anderson and Donna Nelson, who were appointed in August by Texas Governor Rick Perry.

An initial cost-benefit analysis study, completed in 2004, was conducted by consulting firm Tabors Caramanis, which was subsequently acquired by Charles River Associates the same year.

According to the previous study's project co-leader, Ellen Wolfe, the market landscape in ERCOT has changed quite a bit since the original study was completed, in particular, the abundance of wind generation having come online in western Texas, which has created transmission and congestion challenges for the grid operator and its stakeholders.

Wolfe and previous study co-leader Alex Galiunas will conduct the new study on behalf of Charles River Associates, combining some of the modeling efforts from the 2004 study with updated analysis.

A rescheduled timetable and "go-live" date for the nodal market transition, originally scheduled for December 1, has been not yet been announced. *— Chris Knudson*

ERCOT reports zonal congestion declined significantly since June protocols revisions

Zonal congestion in the Electric Reliability Council of Texas has declined significantly since the operator implemented changes to its protocols earlier this year, according to the latest grid operations report released on October 22.

The protocol changes, implemented by ERCOT in June, were aimed at taming the congestion occurring in the region, which sent prices in the balancing energy market to more than $4,000/MWh at times.

According to ERCOT's latest operations report, congestion occurred on six days in August. On three days in August, congestion occurred when moving power from the North zone to the South zone. Moving power from the West zone to the North zone caused congestion on two days in August, while moving power from North to Houston and from North to West occurred one day in August.

By comparison, congestion occurrences were in the double digits in May for moving power from the North zone to the South zone and from the West zone to the North zone. Moving power North to South caused congestion 28 days in May, while moving power West to North caused congestion 20 days in May.

When congestion exists on a power line between two zones, ERCOT reduces the line loading by issuing instructions to increase the generation in the zone importing the power and to decrease generation in the zone exporting the power.

The instructions are based upon the generators' bids available in the balancing energy market. The resulting overall higher costs are directly assigned on a pro-rata basis to those market participants scheduling energy over the line.

Local, or intrazonal, congestion is remedied by running higher cost, less-efficient generation to the local area to reduce transmission flows and to improve the voltage profiles in the area. To resolve local congestion, ERCOT uses out-of-merit energy, out-of-merit capacity or reliability-must-run services to deploy specific generating units. The costs associated with providing these services are uplifted to all load-serving entities within the ERCOT region. *— Leticia Vasquez*

ISO New England sees jump in day-head market; market manipulation does not seem to be in play

ISO New England has experienced a worrisome increase in excessive day-ahead net commitment period compensation payments for external transactions, though market manipulation does not appear to be in play.

The compensation payments are made to generators upon export when the price is reduced to below their offer prices when imports are used to reduce congestion on the external interfaces.

Although the ISO-NE market monitor has not detected market manipulation related to this issue, the ISO is working to resolve the issue quickly, spokeswoman Erin O'Brien said.

The payments, socialized as uplift charges to all market participants, have totaled $4.8 million since June despite action earlier this year to bar possible market abuses by individual market participants or their affiliates. An "apples to apples" comparison of the cost to this time last year was not possible because of the differing market conditions, as well as rules changes for external transactions since last fall, O'Brien said.

The net commitment period compensation, or NCPC, is a "make whole" payment to an eligible resource that did not recover its offer price from the energy market, day-ahead or real-time. The price is determined by comparing the supplier's offer price with the actual revenue from the market. If the revenue is less than the offer, the NCPC payment plus the energy price provides complete cost recovery for the generator.

ISO-NE market monitor David LaPlante gave a presentation to the grid operator's market committee last week, recommending changes to the congestion pricing rules to address the issue involving unaffiliated transactions. The proposal would incorporate congestion pricing at external interfaces in the day-ahead market. Congestion pricing already exists for nodes within New England, but not for external nodes.

By adding congestion pricing to the external nodes in the day-ahead market, which does not always reflect real-time system conditions, locational marginal prices will reflect the cost of the highest import offer cleared, eliminating the difference between the LMP and the offer, which creates excessive uplift costs. The change should reduce or eliminate the excessive uplift charges ISO-NE has been experiencing on external transactions, LaPlante said at the presentation.

Under the proposed rule, generators would not be able to earn revenue above their costs from NCPC payments.

In October 2007, ISO-NE changed its rules to eliminate the ability of individual market participants or their affiliates to receive the compensation payments when their external transactions were causing the congestion that needed to be relieved.

According to LaPlante, unaffiliated transactions were not believed to be a problem when ISO-NE last dealt with the problem of excessive day-ahead NCPC payments.

ISO-NE's market committee will discuss the change during it next two meetings and vote on it in early December.
— Lisa Lawson

Cal-ISO's market redesign launch date is still a challenge, California IOUs say

California's three largest investor-owned utilities have warned the California Independent System Operator that the planned February 1 launch date for its Market Redesign and Technology Upgrade may not be feasible. The launch date has already been pushed back several times.

While the February 1 date might still be feasible, "it presents significant challenges and will become infeasible unless [Cal-ISO] is able to successfully address several remaining key issues and demonstrate it can meet certain market participant needs prior to filing the 60-day certification" with the Federal Energy Regulatory Commission, Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric said in an October 27 letter to the Cal-ISO board.

Cal-ISO must demonstrate, among other things, that market prices are reasonable and that market monitoring will be effective for a February 1 launch date to be feasible, the IOUs said.

The IOUs raised the red flag after Steve Berberich, Cal-ISO vice president of corporate services, said in an interview that Cal-ISO is prepared for the launch and is "doing all it can to get all of our participants ready and will continue to provide them with access to our subject matter experts and others," to ensure that problems are addressed. *— Lisa Weinzimer*

Price range widens in latest auction of FTRs in PJM Interconnection area

An auction of financial transmission rights in the PJM Interconnection held earlier this month saw a wider price range than did a similar auction held a month ago, results show.

The most recent auction saw prices between positive $36,667/MW and negative $52,279/MW. The September auction saw contracts cleared between positive $42,207/MW and negative $41,997/MW.

October's auction offered monthly FTRs for November, December and January and for products for the last two quarters of the regional transmission organization's planning year, which began June 1 and ends May 31, 2009.

Most cleared deals were for obligation rights, but PJM also offers option FTRs for selected transmission paths.

An obligation right entitles the holder to revenue when day-ahead congestion occurs in the direction of the FTR and obligates that a payment be made when day-ahead congestion occurs in the opposite direction. An option right entitles the holder to collect revenue, but shields the holder from financial liability. As a result, option rights usually trade at a premium to obligation rights.

November on-peak FTRs moving power from the Eastern Hub to the Western Hub of PJM cleared at negative $1,864/MW for obligations and $658.25/MW for options. November on-peak FTRs moving power from PJM's Western Hub to its Northern Illinois Hub cleared at negative $3,163.50/MW for obligations and $836.80/MW for options.

Negative prices indicate negative transmission rights, the holders of which receive a payment from PJM if there is no congestion in the direction of the path but are liable for payments if congestion occurs.

January on-peak FTRs moving power from PJM's Northern Illinois Hub to its AEP-Dayton Hub cleared at $182/MW for obligations and $391/MW for options. November on-peak FTRs moving power from those same hubs cleared at $398/MW for obligations and $621.25/MW for options. — *Nushin Huq*

FTR volume in ISO New England auction rose 7% to 1,502 MW of cleared deals

The volume of cleared deals for peak financial transmission rights in the most recent ISO New England auction rose compared with its auction a month earlier, according to the grid operator.

The auction of peak November FTRs into the Massachusetts Internal Hub saw a total of 1,502 MW clear, compared with 1,402 MW for the October auction, a 7.1% increase. The price range was also wider than in the previous month. November's range was negative $2,316/MW to $2,314/MW, compared with the October range of negative $750.10/MW to $2,576/MW.

The highest positive peak FTR for a major hub for the month of November was valued at $1,383.20/MW for flow from Massachusetts Internal Hub to the Connecticut load zone, $946.80/MW less than FTRs for the month of October for the same path. A total of 334 MW cleared there. Constellation had about 161 MW of that total of winning bids.

The highest negative peak FTR for a major hub was valued at negative $254.43 for flows from the Massachusetts Internal Hub to the Maine load zone. The winning bid went to FPL Energy Power Marketing at 3 MW.

Negative prices indicate negative transmission rights. Holders of negative rights receive a payment from ISO New England if there is no congestion in that direction but are liable for payments if congestion occurs on the path.

The biggest player in the November FTR auction was Saracen Energy, with 2,039 MW of peak trades. None of the volume was for FTRs between major hubs or load zones and was instead between network nodes.

For the FTRs between hubs and load zones, Constellation had the large volume, at 358 MW. — *Lisa Lawson*

TRANSMISSION

Arizona stakeholders craft plan to build power lines to reach renewable zones

Arizona stakeholders have mapped out a plan to build a series of power lines to reach six renewable energy zones that have a total capacity potential of about 7,750 MW.

The plan developed by the Arizona Renewable Transmission Task Force calls for adding 445 miles of 500-kV line and 247 miles of 230-kV line at a cost of about $1.6 billion, Peter Krzykos, task force chairman and transmission supervisor for Arizona Public Service, said during an October 23 Arizona Corporation Commission meeting.

The plan would allow the state to tap its entire renewable potential. Arizona has the potential for 4,650 MW of solar, with the vast majority of the solar resource coming in the southwestern part of the state. It also has four zones with the potential for about 3,100 MW of power, mostly from wind resources.

The ACC called for the plan two years ago as part of the state's transmission planning process. Other states in the West are in the early stages of mapping out potential transmission routes to link up with renewable zones, and in concert with that Arizona is conducting its efforts in coordination with Southwest Area Transmission planning group. The SWAT footprint includes Arizona, New Mexico, southern Nevada and part of California.

Since the task force gathered data for its report, there has been even more interest in solar power with developers submitting plans for solar projects totaling up to 9,000 MW, said Peter Krzykos, task force chairman and transmission supervisor for Arizona Public Service.

Since then, the number has jumped even higher, with filings for 1,120 MW added to APS' queue since the beginning of September. That has also raised the total expected price tag of adding renewable resources to the grid to about $2 billion.

On the issue of paying for power lines, ACC Commissioner Kristin Mayes said she is open to establishing a policy that would allow utilities to recover the costs of building the lines as they are being built, instead of waiting until a rate case if filed. She would also consider pre-approving lines, which could make them easier to finance.

Various Western states have established governmental agencies with the authority to issue bonds to pay for power lines. Mayes said she was skeptical of those efforts, noting that they have so far produced few results.

Some of the issues surrounding transmission and renewable energy may be taken up as part of the commission's review of the ACC's Biennial Transmission Assessment. — *Ethan Howland*

Arizona water district plans an open season for 2,000-MW power transmission line project

The Central Arizona Water Conservation District early next month will hold an open season on a transmission project that could offer up to 2,000 MW of capacity for generators west of Phoenix.

The Harcuvar transmission project was first floated about seven years ago, Ken Bagley, manager for Genesee Consulting Group, said October 28. Genesee Consulting, based in Phoenix, is managing the project for the conservation district.

The project was revived after the Arizona Corporation Commission in May 2007 rejected Southern California Edison's 500-kV Devers-to-Palo Verde II line, which would have run from the Harquahala switchyard to the Devers substation in Riverside County, California. The ACC told SoCal Ed that the commission would be willing to consider a Devers line that offered more benefits for Arizona, such as allowing renewable generators to interconnect with the line.

About a year ago, CAWCD, which oversees a system that delivers water to the Phoenix and Tucson areas, started talking with SoCal Ed to see if the Harcuvar project could mesh with the Devers line, potentially allaying some of the concerns raised by the ACC, Bagley said.

The Harcuvar project has two main components, including a 100-mile, 230-kV double-circuit transmission loop west of the Palo Verde hub. The southern end of the loop would interconnect with the proposed Devers line. The northern end would interconnect to the Western Area Power Administration's existing Harcuvar 230-kV substation.

The second component of the Harcuvar project entails joint ownership rights in the Devers II line, from the point of interconnection east to the Palo Verde hub. CAWCD is in talks with SoCal Ed about taking a stake in the Devers project, Bagley said.

The Harcuvar transmission project would give generation projects a means of interconnecting to the regional transmission grid as well as simultaneous access to the Palo Verde hub, the California grid and WAPA's Parker-Davis transmission system. The loop is in a prime area for both solar and thermal generation projects.

CAWCD is holding an open season meeting November 7 on the Harcuvar project. Statements of interest, including the amount of desired capacity, are due November 12. Once the scope of interest in the project is clear, the conservation district will start the interconnection process with SoCal Ed and WAPA, Bagley said. Bagley expects that final participation agreements could be completed in the first quarter.

If the permitting goes smoothly, the roughly $300 million project could be in service by 2013, Bagley said. Nearly all of the project would be inside a Bureau of Land Management utility corridor, he noted.

CAWCD is interested in the project because it needs about 200 MW for its pumping stations, Bagley said. Because its needs are relatively small, it could never build the project alone, he said.

ACC commissioners are eager to see a revamped Devers project. "We expect SoCal Ed to refile the power line," ACC Commissioner Kristin Mayes said in an interview. Mayes would like the utility to withdraw its request for the Federal Energy Regulatory Commission to overrule the ACC's decision on the Devers line. "I would like to address the issue in Arizona," she said. "It's the appropriate thing to do. The FERC backstop authority is such a disincentive for utilities to work with states." *— Ethan Howland*

Allegheny and AEP reconfigure path of power line from W.Va. to Maryland

Allegheny Energy and American Electric Power have reconfigured a proposed high-voltage transmission line that would transport power across West Virginia to Fredrick, Maryland.

The line was determined by the PJM Interconnection last year to be necessary to relieve expected overloads in 2012 on 13 existing lines in Maryland, Virginia, Pennsylvania and West Virginia.

The joint venture of the two energy companies had expected to apply for a certificate of need by December 1, but the reconfiguration will delay the application until March, the companies said last week in a filing with the West Virginia Public Service Commission.

The later filing is expected to delay the in-service date of the project, but it is too early to know the length of the delay, said Jeri Matheney, an AEP spokeswoman. The project originally was to be online in June 2012. The PSC has 400 days to render a decision.

The line originally was approved by the PJM Interconnection as a 765-kV line from St. Albans, West Virginia, just west of Charleston, to the Bedington substation near Martinsburg, West Virginia. Twin-circuit 500-kV lines would have run from Bedington to a proposed substation southeast of Fredrick.

But after siting studies and protests, including inquiries from Senator Robert Byrd, the new configuration will eliminate the Bedington substation and the twin-circuit 500-kV lines to the planned Kemptown substation near Fredrick. Instead, a single 765-kV line will run from the Amos substation near St. Albans to the Kemptown substation. A new midpoint substation will be built, but the location has not been identified. The costs of the two configurations are estimated to be similar, about $1.8 billion.

PJM has determined that the benefits of the newly configured line would be the same as the original.

The new configuration is essentially equivalent in its ability to carry power, but it will provides a solution that will take less right of way, said Tom Holliday, an AEP spokesman. *— Mary Powers*

Idaho Power, PGE sign MOU to integrate 500-kV transmission-line projects in region

Idaho Power and Portland General Electric on October 23 said they signed a memorandum of understanding to possibly build transmission lines originating near the city of Boardman in eastern Oregon.

Idaho Power has applied for permits to construct a proposed 300-mile, 500-kV line connecting the Boardman power plant with the planned Hemingway station near Melba, Idaho. PGE is still evaluating plans for its proposed Southern Crossing 500-kV project. The MOU lets the utilities integrate a portion of the proposed lines if both projects move forward.

No major interregional transmission lines have been built in the Pacific Northwest in more than a decade, the companies said. Existing transmission lines in the region are often at or near capacity, creating significant bottlenecks in the system as demand increases in population centers served by generation in eastern Oregon and eastern Washington.

The utilities will explore interconnecting their projects with existing facilities in the Boardman area, which could contribute to development of an interconnected transmission hub in the area, they said.

The two projects are among a number of proposed transmission projects in eastern Oregon that are being coordinated by the Transmission Coordination Work Group. Idaho Power and PGE are both participants in the group.

"Transmission is a key factor in meeting today's growing electric demand," said Dan Minor, Idaho Power senior vice president for delivery. "Our regionally integrated approach with this project enables the proposed transmission line to benefit the Northwest region's electric grid."

PGE serves more than 813,000 residential, commercial and industrial customers. Idaho Power serves 485,000 residential, business and agricultural customers. — *Rod Kuckro*

US-Canadian power line is approved by Montana environmental regulators

The Montana Department of Environmental Quality has issued a decision that will allow construction of the Montana portion of a broader transmission project that will interconnect the electricity markets of Alberta and the US through a 300-MW transmission line.

When completed, the 214-mile line will run from Lethbridge, Alberta, to Great Falls, Montana.

Canada-based Tonbridge Power, the 100% controlling shareholder of the Montana Alberta Tie Ltd., or MATL, transmission line project said October 22 that the Montana DEQ issued a record of decision authorizing the construction of MATL's 230-kV merchant transmission line in Montana.

The specific authorization granted in the decision is a certificate of compliance as required under the Montana Major Facilities Siting Act and is the state permit required to proceed with the project.

The DEQ decision was issued 20 days after the DEQ and the Department of Energy jointly issued an environmental impact statement for the MATL line on October 1.

Tonbridge Power noted that the certificate of compliance authorizes the construction of a transmission line along the preferred alternative that was selected by the DEQ and the DOE and described in the final EIS.

The only outstanding permit required before construction can begin is a presidential permit to be issued by the US Department of Energy. The permit will allow Tonbridge Power to construct, operate, maintain and connect the MATL line across the US-Canadian border.

DOE must wait at least 30 days post issuance of the EIS before its record of decision and presidential permit can be issued, which would be in early November.

MATL received all the Canadian permits required to build the line earlier this year. — *Staff Report*

FORECASTS

New Jersey issues energy master plan; calls for $33 billion of investment by 2020

New Jersey issued an energy master plan last week that calls for a $33 billion investment in the state's energy infrastructure by 2020.

The master plan set a goal of increasing the state's 22.5% renewable portfolio standard to 30% by 2020 and to an even greater, unspecified, amount through 2025.

The renewable energy supply would come from 900 MW of biomass capacity, at least 3,000 MW of offshore wind capacity, 200 MW of onshore wind capacity and 1,800 MW of solar energy production.

The plan calls for the creation of an offshore wind planning group to drive the development of the 3,000 MW. The 900 MW of biomass and biofuel generation would not involve incineration. The plan also includes a 50-MW carve-out for new and emerging technologies.

The master plan would also encourage the development of 1,500 MW of new cogeneration capacity by 2020 through a series of actions, including rebates and sales and use tax exemptions.

But energy efficiency measures, renewable energy development and new cogeneration capacity would still leave 45,000 GWh of demand to be met with traditional generation. That demand must be satisfied with options that are consistent with the state's 2020 and 2050 greenhouse gas targets.

"Importing additional conventional coal-based electricity or developing more high-emitting power plants within New Jersey will undermine our efforts to fight global warming," the master plan said. To help reach that goal the state will work with electric and gas utilities to develop master plans that include implementing smart grid technologies and modernizing the electric grid to 21st century technologies. It also will include consideration of nuclear energy if additional baseload supply is needed.

The master plan also sets a goal to reduce energy consumption by at least 20% by 2020. Peak demand must be reduced by 5,700 MW by 2020 under the plan. But the plan noted that the demand response initiatives are experimental and largely untested, but the state will continually assess the results of the programs.

The master plan also calls for the reduction of energy costs by 22% for residential customers, 37% for commercial customers and 29% for industrial customers.

The plan established a state energy council that includes members from 12 state agencies that are charged with implementing the plan. The group will monitor the progress quarterly and issue annual assessments. It will be chaired either by Governor Jon Corzine or his designee. The plan designates the agencies with the legal authority to implement portions of the plan and it specifies legislation that is needed in some cases. — *Mary Powers*

NERC finds most capacity margins improving, though desert Southwest, western Canada lag

Capacity margins in North America are improving over last year, mostly because of new supply and demand responses, but the desert Southwest and western Canada face reliability issues unless more resources are brought online by 2010, the nation's electric reliability watchdog said October 22.

The North American Electric Reliability Corp. in its 2008 Long-Term Reliability Assessment said New England, California, the Rocky Mountain region, Texas and the Midwest all showed improvements in capacity margins because of new resources or the establishment of forward capacity markets.

A forward capacity market — under which generators are paid incentives to increase existing capacity or bring new generation online — was introduced in New England earlier this year and has boosted resource adequacy in that region, the report says.

Long-term capacity margins are still inadequate, although there was a 4.2% improvement over last year's assessment and new demand response is projected to reduce peak demand in the US and Canada by 1% as of 2016. Projected transmission mileage increased by 14% over last year, NERC said. Summer peak load is projected to increase 16.6% for the 2008 to 2017 time frame, compared with last year's 17.7% forecast.

Projected capacity additions are significant, although NERC acknowledged during a conference call that its figure of 145,000 MW of new wind capacity due to come online by 2017 includes many proposed projects sitting in interconnection queues around the country that might not be built.

NERC listed other new supply of 25,000 MW of proposed coal plants and 9,000 MW of new nuclear by 2017. Consistent methods are needed to determine wind on-peak capacity to ensure accurate measurement of its contribution to capacity margins, according to the report.

Climate change initiatives such as greenhouse gas reductions, state renewable portfolio standards, clean water rules and other legislation will be one of the main factors affecting reliability, NERC said.

"Burning natural gas instead of coal at electricity-generating units to reduce greenhouse gas emissions involves important tradeoffs related to economic, environmental, infrastructure, and fuel supply considerations," NERC said in the report. "Converting existing capacity to natural gas poses substantial challenges due to fuel supply constraints, changes to infrastructure, and economic considerations."

Another major issue is a critical need for new transmission that will be needed to manage intermittent and remote wind sources due to come online, NERC said.

The Environmental Protection Agency is considering new standards for power plant cooling systems, and some units might be required to build "closed loop" self-contained systems. The added costs could cause some units to retire sooner, and the load requirement for the cooling equipment itself will result in a de-rating of some unit's output capability, NERC said. This could also affect capacity margins, NERC said.

NERC said that over half the 29 "disturbance events" occurring in 2006 were due to "misoperation" of system protection devices. NERC drew the analogy of a house fuse tripping off to describe such systems, which NERC President and CEO Richard Sergel said "are not operating as we would like. They are occasionally becoming part of the problem."

NERC said its 2008 long-term reliability assessment does not include the possible effects of the global financial crisis, but NERC is monitoring that impact and will reflect on it in future assessments.

NERC said the key findings outlined in the report are based on observations and analyses of supply and demand projections submitted by separate NERC regions in their long-term reliability assessments, assessment of the results by NERC staff as well as industry trends and comments. NERC said it is also monitoring another emerging challenge to the electric system reliability, an aging work force that is a "growing challenge." *— Jason Fordney*

Wind power's record growth over past two years unlikely to be repeated, says director of AWEA

The record growth of wind power seen in the past two years is unlikely to be repeated in 2009 because of the global economic crisis squeezing the credit markets, an American Wind Energy Association official said last week.

AWEA Executive Director Randall Swisher said during a Washington news conference that "given all the uncertainty" in the financial markets, he would not forecast what kind of growth wind power will experience next year. He said, however, that it was "not realistic to expect another 45% jump" in projects such as what was seen in 2007 and predicted by the end of 2008.

Swisher said it was also impossible to forecast the price of wind power, labeling it a "mixed bag" for utilities seeking to enter contracts to buy wind power next year.

The credit crunch and a less liquid capital market will play a role, as well as the decline in the price of oil, which would reduce the shipping cost of wind turbines, he said. "How that plays out over the next year, there's no way to tell," Swisher said.

Meanwhile, AWEA will work next year to get the federal production tax credit extended at least five years and encourage the Congress to impose a federal renewable portfolio standard. The credit expires by the end of 2009.

The electric power industry, along with AWEA and other renewable energy groups, also will push next year for getting more electric transmission sited to ensure wind power and capacity from other sources can get on the grid and to load centers, said Swisher. This could involve stronger federal siting authority for building large regional power lines, he said.

There needs to be a "fundamental change in the way transmission is built in this country," said Swisher. "You're going to see a lot of discussion and outreach to get this done." *— Cathy Cash*

RENEWABLE ENERGY

Duke Energy scales back its solar plans in North Carolina, halving them to $50 mil

Duke Energy Carolinas on October 23 said it has decided to cut in half the magnitude of its proposal to install, own and operate solar photovoltaic panels at hundreds of customer sites in North Carolina and feed the panels' output to Duke's grid.

However, Duke also said it would not revise its "Save-A-Watt" decoupling plan, under which the utility would dramatically expand its energy-efficiency offerings in North Carolina and implement a rider on customer bills to recoup 90% of the costs avoided by reducing customers' electricity demand.

Duke's revised solar PV plan, which is currently being reviewed by the North Carolina Utilities Commission, calls for the utility to invest $50 million and install PV panels at 425 customer sites. Duke originally had proposed investing $100 million and installing panels at 850 sites.

Duke spokeswoman Paige Sheehan said the utility changed the plan in response to concerns expressed by the Public Staff, solar energy advocates and other intervenors such as Walmart about the program's size and its potential impact on efforts by the private sector to install solar panels of their own. The Public Staff is an independent state agency that represents consumers.

North Carolina's year-old "renewable energy and energy efficiency portfolio standard" requires Duke and other utilities in North Carolina to secure increasing amounts of their electricity needs from renewable energy and energy efficiency. Beginning in 2010, 0.02% of the electricity sold to customers in the state must be produced by solar sources. That requirement grows to 0.2% in 2018.

Sheehan said that Duke's expectation is that it will comply with the REPS' solar requirement through a mix of utility-owned solar capacity, power purchase agreements with solar capacity developers, renewable energy credits and other means.

Duke also said it is standing by its Save-A-Watt plan despite the criticism it is facing. North Carolina's Office of the Attorney General said the program would enable Duke to earn excessive profits. The NCUC has not indicated when it will issue its rulings on Duke's solar and Save-A-Watt proposals.

Duke is still awaiting a ruling from the South Carolina Public Service Commission on its Save-A-Watt proposal there.

Duke has said that it will need 3,400 MW of incremental capacity in its North Carolina/South Carolina service territory by 2012, and that the Save-A-Watt plan has the potential to meet 1,860 MW, or just over half, of that total. The utility also is planning to build an 800-MW coal plant and two 620-MW gas-fired, combined-cycle plants, and may build one or more new nuclear units as well. *— Housley Carr*

Massachusetts seems poised for solar build-up in the wake of solar target in renewables law

Massachusetts appears poised for a solar energy buildup that is attracting large players drawn by substantial incentives and the state's goal to develop 250 MW of new solar energy by 2017.

The Massachusetts market is so strong that one large California solar contractor, Borrego Solar, has set up an office in the state, which it says recently drew more sales leads than its California office.

Solar advocates say the state has the right fundamentals for a strong rooftop photovoltaic market, that is, many roofs with southern exposure, high electricity rates, skilled labor, and a population with an environmental awareness.

A new state energy law opens the door for more solar by increasing renewable portfolio standards and allowing utility ownership of solar projects of up to 50 MW. In addition, a new eight-year extension of the federal tax credit for solar energy is expected to advance the solar market nationwide.

The new law lets utilities own solar facilities for the first time since the state restructured more than a decade ago.

National Grid already has announced plans to spend about $38 million on four solar projects, totaling about 5 MW. The utility plans to issue a solicitation for the projects, and says it will announce more solar projects in the coming months. NStar is in the process of identifying sites for large-scale solar projects. Northeast Utilities also has plans to develop a solar energy program and expects to have details available in about a month.

Solar companies and environmental groups are pushing for state regulators to strengthen the Massachusetts market further by creating a solar "set-aside" or "carve-out" in the state's renewable portfolio standard. Solar advocates are making the pitch in a proceeding before the state Division of Energy Resources, which is creating compliance rules for the state energy law, signed by Governor Deval Patrick in July.

Massachusetts utilities and retail suppliers used solar energy less than 1% of the time to meet the state RPS in 2006, according to the DOER. Landfill gas projects accounted for 48%, and biomass projects, 42%.

Without a solar set-aside, utilities and suppliers "gravitate to the lowest-cost option," solar developer SunEdison said. Solar's ability to act as a fuel hedge, diminish peak load and avoid transmission costs needs to be factored into the cost analysis, the company said.

Meanwhile, solar companies and utilities are at odds over how to handle penalty or "alternative compliance payments" that utilities and suppliers must make to the state if they do not accrue enough renewable energy to make the RPS requirement.

The Solar Energy Business Association of New England says it is necessary to create a penalty payment that is higher for onsite solar energy because it is typically more expensive than other forms of renewable energy. If the penalty payment is too low, utilities and suppliers will pay it instead of paying the premium associated with solar energy. *— Lisa Wood*

Dynegy reaches agreement with N.Y. AG regarding disclosing GHG risk exposure

New York Attorney General Andrew Cuomo last week announced an agreement that will require Dynegy to disclose climate change-related risk related to its power plant portfolio in a move to provide investors with more clarity about a company's financial future in a carbon constrained future.

In August, Cuomo's office reached its first such settlement, with Xcel Energy, and the state official expected that other companies will follow their lead (*GPR*, 4 Sept, 1).

Under the recent agreement, Dynegy has agreed to provide disclosure of material risks associated with climate change in its 10-K filings to the Securities and Exchange Commission, including an analysis of material financial risks from those related to climate change to present and probable future climate change regulation and legislation, climate change-related litigation, and physical impacts of climate change.

The independent power producer also committed to a broad array of climate change disclosures, including current carbon emissions, projected increases in carbon emissions from planned coal-fired power plants, and company strategies for reducing, offsetting, limiting, or otherwise managing its emissions.

Dynegy said the company had used its SEC filings in the past to identify climate or other material risks, and the New York attorney general "did not find any weakness or impropriety in our past disclosures."

"We're going to continue to provide appropriate information to our investors about climate change risks," said Dynegy spokesman David Byford. "We'll do this through SEC disclosures. In the event that we identify a material risk, we're going to disclose them."

Dynegy's power generation portfolio consists of more than 18,000 MW of plants fueled by a mix of natural gas, coal and fuel oil. Some of its assets are in states involved in the Regional Greenhouse Gas Initiative, a carbon cap-and-trade program set to go live January 1. New York is involved in RGGI as the largest CO2-emitting state in the program.

With RGGI and other regional and federal cap-and-trade efforts under way, Cuomo in September 2007 subpoenaed the executives of several major energy companies for information on whether disclosures to investors in filings with the SEC adequately described the companies' financial risks related to their emissions.

In addition to Dynegy and Xcel, the companies that received subpoenas were AES Corp., Dominion Resources, and Peabody Energy. The inquiry regarding these remaining companies is ongoing, Cuomo's office said.

Dominion and AES have generating assets in the RGGI region. RGGI recently held its first carbon allowance auction, with demand seen from generators as well as the financial sector. The allowance clearing price was $3.07. A second auction is scheduled for December. *— Christine Cordner*

Department of Interior to make 197 million acres available in West for geothermal power leases

The Department of Interior will make 197 million acres of federal land in the West available for geothermal energy leasing under a final development plan issued October 22.

The plan would open 118 million acres of Bureau of Land Management-administered land and 79 million acres of National Forest System land to geothermal leasing. It also would bar geothermal leasing on National Park Service land, according to Interior Secretary Dirk Kempthorne. BLM and NPS are part of Interior. The Forest Service is part of the Agriculture Department.

The plan, which will govern geothermal development on federal lands in Alaska, Arizona, California, Colorado, Idaho, Montana, New Mexico, Nevada, Oregon, Utah, Washington and Wyoming, will go into effect in December.

Kempthorne estimated the plan could result in 5,540 MW of new geothermal electricity generation by 2015.

Revenue sharing called for in the plan would give the states 50% of the revenue associated with the leases, the counties where the lease is located 25%, and BLM 25%. BLM is required to use its share for a "geothermal royalty fund" that would support the development of geothermal resources.

In August, the BLM held a lease sale for lands in Nevada that brought in $28 million in bids, a record for geothermal leasing, for more than 100,000 acres. Another geothermal lease sale is scheduled for December that will offer parcels in Utah, Idaho and Oregon, according to BLM.

There are also currently 19 geothermal lease applications that have been pending since 2005, and a decision will be announced on those when the final plan is formally adopted.

Public lands hold the potential to supply 90% of the country's geothermal power, and there is currently about 1,250 MW of geothermal capacity from 29 plants on federal lands, accounting for half of the total.

Despite the promise of geothermal power, access to electricity transmission has emerged as a concern and potential limit on its development.

Interior and the Department of Energy plan to release in the next several weeks a final environmental impact statement that will lay out a plan for designating transmission corridors that could be used by geothermal projects, C. Steven Allred, Interior's assistant secretary for land and minerals management, told reporters.

"One of the major issues in developing alternative energy is access to transmission. That will be one of the issues dealt with in the final corridor EIS study," Allred said. — *Derek Sands*

REGULATION & LEGISLATION

EPA still working on NSR rule, despite warnings by Congress to stop efforts

The Environmental Protection Agency said October 27 it will continue to work on a revised rule for new source review requirements for electric power plants despite calls by Congress to withdraw efforts lawmakers believe will weaken current clean air regulations.

"Work continues on the rule," said EPA spokesman Jonathan Shradar. The EPA has set no time line for completion, he said.

But key senators are urging the agency to halt its plans to put out an NSR rule they believe will allow high-emitting fossil fuel plants to continue to operate without pollution controls. The chairman of the House of Representatives Oversight and Government Reform Committee, California Democrat Henry Waxman, also wrote EPA last week on its concerns about the pending NSR rules.

EPA first proposed new NSR rules in 2005 and 2007 that would apply hourly emissions tests to electric generating units rather than weigh their total annual output of harmful emissions in determining whether these facilities should install pollution control equipment.

The agency had said any additional emissions from these sources would be offset by emission reductions required under its Clean Air Interstate Rule. However, in July, a federal court threw out CAIR, which was challenged by electric utilities over its provisions for a regional emissions trading program. EPA has petitioned for an appeal.

The court's vacating of CAIR "throws into serious doubt the already questionable wisdom and legality of the [electric generating units] hourly test proposal," according to Senate Environment and Public Works Committee Chairman Barbara Boxer and Senator Tom Carper, chairman of the subcommittee on clean air and nuclear safety.

EPA's proposed NSR rule changes would allow power plants to boost their operations and annual emissions without pollution controls, the senators said.

"As EPA's proposal recognized, the electric power companies are almost certain to extend the life of these plants through renovations," Boxer a California Democrat, and Carper, a Delaware Democrat, wrote EPA Administrator Stephen Johnson.

"Once renovated, these plants can be expected to operate for longer periods of time without installing additional controls, which will result in their annual, actual emissions increasing significantly, degrading air quality to the detriment of human health and environment."

But the senators add that "given the weight of evidence against the rule, if the EPA does promulgate the rule, this committee may be compelled to undertake extensive investigation and oversight" of the agency's activities related to the NSR proposal. — *Cathy Cash*

Federal appeals court is seeking views of involved parties on rejection of CAIR

A federal appeals court is asking whether parties involved in lawsuits that led to its July order vacating the Clean Air Interstate Rule want the entire rule to be thrown out or to be kept in place until the Environmental Protection Agency revises it.

The US Court of Appeals for the District of Columbia Circuit on October 21 ordered petitioners, which include utilities Duke Energy and Entergy, to respond within 15 days to its inquiry.

It is a move CAIR supporters see as a hopeful sign. "We see it as a sign that [the court is] working through the reasoning of our position and, hopefully, will make the right decision" and keep CAIR in place, said EPA spokesman Jonathan Shradar. Asking the petitioners whether they want the entire rule thrown out or a stay of the court mandate indicates the DC Circuit is "taking our petition seriously," he added.

If the DC Circuit stays its mandate, CAIR could stay in place until EPA puts in place a revised rule.

EPA last month petitioned for rehearing by either a panel of judges or the entire appeals court of its July 11 decision vacating CAIR. A three-judge panel ruled then it had found "more than several fatal flaws in the rule" and vacated it in its entirety although petitioners had challenged specific parts of CAIR.

CAIR, issued in 2005, called for 28 Eastern states and the District of Columbia to reduce 61% of the region's nitrogen oxide emissions and 73% of its sulfur dioxide emissions below 2003 levels by 2015. NOx reductions were to start in 2009 and SO2 reductions in 2010; a second phase of reductions of both emissions was to begin in 2015.

CAIR provided for a regional emissions trading program to help fossil-fueled electric generation comply with the emission limits. Many electric utilities and environmental groups favored the rule as a way to cut air pollution. But Duke Energy and four other utilities complained about the rule's SO2 emission allocations, and Entergy sued over CAIR's NOx budgets. — *Cathy Cash*

FERC grants Vernon, California, settlement of $14.2 million from 2000-2001 energy crisis

The Federal Energy Regulatory Commission on October 23 granted a $14.2 million settlement between the city of Vernon, California, and several entities it traded with during the western energy crisis of 2000-2001.

The deal ends disputes that Vernon or any other market participant in the settlement illegally inflated prices for power, ancillary services or transmission congestion from January 1, 2000, to June, 20, 2001.

It also resolves issues regarding Vernon's transmission revenue requirement that, along with the TRRs of other participating transmission owners, is used to determine the California Independent System Operator's transmission access charge, the order said.

Under the proposed settlement, the California Power Exchange will release $5.5 million to Cal-ISO to resolve TRR amounts that Vernon owes Cal-ISO. As it applies to Vernon's TRR, the settlement is for the period between January 1, 2000, and April 30, 2008.

Cal-PX will release the remaining $8.7 million from an energy crisis escrow account to two escrow accounts established by the California parties, a group of market participants and governmental entities.

The California parties include Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, the state of California, California Public Utilities Commission, California Electricity Oversight Board and the California Department of Water Resources. — *Esther Whieldon*

Delaware Dept. of Natural Resources OKs proposed rules tied to RGGI participation

The Delaware Department of Natural Resources and Environmental Control on October 24 approved proposed rules for carbon allowance trading under the Regional Greenhouse Gas Initiative that will go into effect November 11.

DNREC Secretary John Hughes issued an order approving the rules, which will position the state to participate in the December 17 auction with the nine other RGGI states: Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont.

RGGI, which is set to go live January 1, is a carbon cap-and-trade program covering power generators with a CO_2 cap of 188 million short tons each year from 2009 through 2015. The cap will fall 10% by 2018.

The states offer their annual portion of the cap in auctions, the first of which was held September 25 and offered 12.5 million allowances from six states. Delaware's portion of annual allowances totals 7.5 million, a relatively small amount compared with New York, the largest CO_2-generating RGGI state, at 64.3 million.

Delaware will offer 755,979 allowances in the second auction, while New York will offer 12.4 million.

In recent details released on the second auction, RGGI administrators said that they expected Delaware to approve rules in time for participation in the December auction, which will offer 31.5 million allowances. RGGI said that it would issue a supplemental notice by November 13 confirming the final allowance quantity given Delaware's update.

The clearing price of RGGI allowances in the first auction was $3.07 per allowance, but prices have moved toward to the $4 range that was seen before that event and where market players have said fundamentals place allowance value. — *Christine Cordner*

Oregon governor introduces legislative package; includes participation in cap-and-trade program

Oregon Governor Ted Kulongoski on October 27 rolled out an extensive legislative package aimed at combating climate change, ranging from participation in a regional cap-and-trade program to the introduction of a solar feed-in tariff.

Kulongoski unveiled the series of bills in advance of the Legislature's biennial session, scheduled to begin in January. One element of the package is legislation that would allow the state to participate in the regional cap-and-trade program for carbon dioxide now being developed by the Western Climate Initiative.

Another measure would authorize the state's Public Utility Commission and Department of Energy to develop a new emissions standard that would require any new energy production sources to be at least as clean as natural gas and would "ensure that no new sources of high-emitting greenhouse gases (particularly conventional coal) are added to our existing electricity production," according to a document from the governor's office explaining the legislation.

Other portions of Kulongoski's plan include establishing a goal of net-zero emissions homes and buildings by 2030, giving local governments bonding authority to finance energy efficiency projects, offering a $5,000 tax credit for the purchase of plug-in electric and all-electric vehicles, and developing a pilot feed-in tariff for solar electricity that would pay for the electricity produced by a solar project, rather than for the capital investment.

In 2007 the state approved new laws to promote renewable energy production in Oregon and set a goal of reducing greenhouse gas levels to 10% less than 1990 levels by the year 2020. — *Pam Radtke Russell*

California's SCAQMD eyes legal fix to remedy court decision blocking emission credits account

California's South Coast Air Quality Management District is unlikely to appeal a recent court decision threatening more than 4,000 MW of power projects and is instead seeking a legislative fix, according to the air pollution control agency's general counsel.

On July 29, the Los Angeles Superior Court threw out two air district rules that would have allowed project developers to buy emission reduction credits from a special priority reserve account before they started construction of the plants.

The court's decision came in response to a complaint filed by the Natural Resources Defense Council and three other environmental groups in Los Angeles Superior Court in August 2007, claiming that the two air district rules violated

California's Environmental Qualities Act.

Edison Mission Energy's 500-MW Walnut Creek Energy Park project is among projects affected by the dispute.

SCAQMD "does not intend to obey," the court's requirement that it conduct an environmental review of each power project needing credits, Curt Wiese, general counsel for the air pollution agency said last week. The order is redundant, because the California Energy Commission is required to conduct environmental reviews, he added.

Weise also said the agency is discussing potential legislation that would exempt it from the environmental review requirement, but he declined to identify the lawmakers involved.

"It is unfortunate that the air district is seeking a ' legislative fix,'" said Tim Grabiel, attorney with NRDC. At the same time, he said, the "legislative process is a long and unwieldy one, with plenty of opportunities for public involvement, and we look forward to convincing the Legislature" that the agency should heed the court's decision.

The environmental analysis required by the court focuses on potential environmental impacts of the use of emission credits, while the CEC review does not, he added.

SCAQMD is the air pollution control agency for all of Orange County, California, and the urban portions of Los Angeles, Riverside and San Bernardino counties. On its web site, the agency says this is the second most populated urban area in the nation and one of the smoggiest.

Meanwhile, the air district is contending with a related legal challenge filed in August that alleges that the district's actions violate the Clean Air Act.

Filed by the NRDC, Communities for a Better Environment and others, this suit could also put at risk existing generation in Southern California as it alleges that power plants that received invalid credits are still operating.

Jan Smutny-Jones, the executive director of the Independent Energy Producers Association, recently said that California power projects face a "perfect storm" of regulations. He cited, among other things, the emission reduction credits' pending rules from the State Water Resources Control Board that he said threaten coastal plants that use once-through cooling methods.

— *Lisa Weinzimer*

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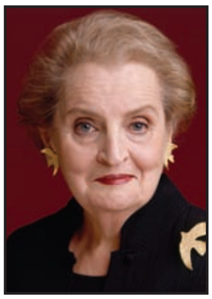

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