

# Electric Power Daily

Thursday, June 24, 2010

## AEP under pressure to cut executive salaries in W.Va.

The majority leader of the West Virginia Senate has asked regulators to inform American Electric Power that no rate increases will be approved until executive salaries and benefits are brought into line.

Appalachian Power, AEP's subsidiary in the state, in May requested a 17% base rate increase. The Public Service Commission also has a settlement agreement pending before it regarding fuel costs, purchase power charges and environmental expenses that would raise rates 7.4%. "If you approve both requested rate hikes, residential electric bills will have increased 70% in the last four years," Majority Leader Truman Chafin, a Democrat, said in a letter sent earlier this month to the PSC.

Chafin obtained the salaries and benefits paid to top AEP executives through a Freedom of Information Act request. The total was \$104 million paid during the past 60 months, including \$54.7 million paid in salary and benefits to Michael  
*(continued on page 7)*

## Nevada PUC weighs revealing NV Energy PPA pricing details

The Nevada Public Utilities Commission later this month will consider a request to reveal the pricing details of seven renewable energy power purchase agreements.

NV Energy and renewable developers contend that releasing the details of the contracts violates trade secret laws and would stifle renewable development in Nevada

Earlier this month the Las Vegas *Review-Journal* asked the PUC to release the details of the contracts, totaling almost 422 MW, including the cost per kWh. "We believe that the press and ratepayers have a need to see this information now," Thomas Mitchell, *Review-Journal* editor, said in a PUC filing released Tuesday. "Release of this information will serve a vital public interest and allow the public to become engaged with the PUCN on the question of how much they will have to pay because of the purchase of renewable energy by [NV Energy]."  
*(continued on page 7)*

## Utilities surprised by Maryland PSC ruling on BGE meters

Utilities across the US were surprised by the Maryland Public Service Commission order earlier this week denying Baltimore Gas and Electric's plan to deploy advanced meters across its system as part of its smart grid proposal, according to Michael Morris, chairman, president and CEO of American Electric Power

The ruling from the PSC, which rejected BGE's \$835 million plan after concluding that the financial risk to ratepayers outweighed savings that the commission said were "largely indirect, highly contingent and a long way off," will have implications in other states as regulators examine utility smart grid plans, Morris said at a Washington conference Wednesday. BGE's effort, which included advanced meters and dynamic pricing plans for consumers, was yielding solid data on smart grid benefits, Morris said following a panel of speakers at the Demand Response Town Meeting, sponsored by the Demand Response Coordinating Committee.

In Ohio, regulators scaled back AEP's smart grid plan, and utilities need to be

## Anti-decoupling forces go on offense in Connecticut

The ailing economy has left energy efficiency under attack in Connecticut, as anti-decoupling forces argue against continuing the rate mechanism and state government siphons off utility efficiency funds to close its budget gap.

The state attorney general, industrials, Walmart and other are trying to persuade state regulators to refrain from taking the next step in decoupling rates for the state's largest utility, saying it is likely to lead to higher rates at a time when customers already are beleaguered.

The attack on decoupling — a rate mechanism meant to remove disincentives for utilities to pursue energy efficiency — comes at a "particularly damaging" time for efficiency programs, said Joyce Kung, an attorney with Environment Northeast. The General Assembly last month voted to sweep \$28.7 million collected annually from ratepayers for efficiency into its general fund to help offset the budget deficit.  
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## Environmentalists cast wary eye at biomass as carbon neutral

New biomass-fired generating capacity still is expected to play a big part in utilities' efforts to comply with renewable portfolio standards.

But an increasing number of environmental groups are pressing for assurances that the biomass to be used as a power plant fuel is procured in a sustainable way, and some are saying the biomass should not come from whole trees felled and chipped for burning.

Biomass-fired generation has always had mixed support among environmentalists. Some question whether burning it is truly "carbon-neutral," as biomass developers and other advocates assert, and warn that overdependence on biomass — particularly in regions without abundant forests and forestry operations — could result in wanton destruction of woodlands.

Most recently, a study prepared by the Manomet Center for Conservation Sciences for the Massachusetts Department of Energy  
*(continued on page 8)*

cognizant that regulators are “very sensitive” to anything that will increase costs to consumers, Morris said.

Tom King, president of National Grid, offered similar comments, adding that the PSC rejection shows a lack of national energy policy informing state regulators. The National Action Plan on demand response, which was released by the Federal Energy Regulatory Commission, should help in that regard, said Dan Delurey, executive director of the Demand Response and Smart Grid Coalition.

The rejection of the plan, which was one of 100 smart grid projects around the country to receive federal stimulus funding from the Department of Energy and one of the few picked to receive the maximum amount of \$200 million, may reflect the challenge utilities face in presenting the full benefits of smart grid projects, said Paul DeMartini, vice president and chief technology officer for smart grid at Cisco.

Many benefits of smart grid plans, such as reduced greenhouse gas emissions from consumers shifting their load to off-peak periods, are societal benefits that are difficult to quantify, he said. The utility regulatory framework needs to take that into account, said DeMartini, who recently moved to Cisco from Southern California Edison, where he oversaw that utility’s advanced metering project.

BGE thought it had a “textbook case” that included pilot programs that showed good results and consumer enthusiasm for the smart grid proposal, and was mystified, surprised and disappointed by the PSC rejection, officials said Tuesday. The utility is looking at its next step, but thus far does not see a clear path forward, said Mark Case, senior vice president of strategy and regulatory affairs.

Matt Rogers, senior advisor to Energy Secretary Steven Chu, said DOE was disappointed in the PSC’s ruling because smart grid programs hold the potential to give customers more choice, reduce utility operating costs and increase reliability. If the Maryland PSC decision prevents BGE from meeting its cost sharing requirements and implementing the project on time and on budget, “we will have no choice but to explore” moving the

stimulus funds to other projects that have the backing of state regulators, Rogers said in an interview.

—Thomas Tiernan

## House bill on energy usage data to be revised

In response to concerns expressed by utilities, a bill in the House of Representatives to improve consumers’ access to energy usage data is being revised and a new version is expected to be released in a few weeks, a key staffer for the House Energy and Commerce Committee said Wednesday.

The House bill (H.R. 4860) was introduced by Representative Edward Markey, a Massachusetts Democrat, earlier this year, and similar legislation has been introduced in the Senate by Mark Udall, a Democrat from Colorado. The measures are designed to clarify who owns energy usage data, utilities or consumers, and would be used to take utility advanced meter and smart grid plans beyond utility efforts and provide access to usage data to consumers and third-party providers, speakers said at a Washington conference Wednesday.

Markey’s legislation calls on the Federal Energy Regulatory Commission to consult with state authorities and federal agencies and issue guidelines setting minimum national standards on consumers’ rights to access retail energy information. The Edison Electric Institute has concerns about the cost of providing real-time usage data to third parties and the value of doing so, said Rick Tempchin, director of retail distribution policy at EEL. “What’s the value to customers?” he asked at the Demand Response Town Meeting, sponsored by the Demand Response Coordinating Committee.

All the benefits of having utilities provide such data is not yet known, and they could vary in different utility business models and wholesale and retail market designs, said Nick Sinai, energy and environment director at the Federal Communications Commission. If consumers are going to be paying for smart grid plans and shifting load to different peri-

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ods of the day, it's important that they be able to access their usage data promptly to see the impact of their actions, added Paul Centolella, commissioner at the Ohio Public Utilities Commission.

Few states have taken action on access to energy usage data or privacy concerns expressed by some groups, but Ohio regulators expect to open a case on the subject soon, said Centolella. "I expect we'll have an open docket in the next few weeks" on the issue, he said after speaking on a panel at the meeting.

At the House Energy and Commerce Committee, lawmakers understand the concerns of EEI and are revising the bill, said John Jimison, senior counsel on the committee. "We're not interested in enacting something that won't work," but there is not a unanimous view among utilities that if utilities have installed advanced meters or other measures that increasing access to usage data presents a big cost burden for utilities, Jimison said.

The legislation is evolving in response to input from the power sector and others, and a revised measure is likely to be released in a few weeks, he said. Besides utility concerns about costs and benefits of increased access to data, privacy is an important element that may be taken into account in the revised House bill, Jimison said.

—Thomas Tiernan

## FERC using light touch on cost allocation

By not seeking to impose a uniform cost allocation method or one particular regional planning process through its proposed rulemaking, the Federal Energy Regulatory Commission is trying to employ a light touch toward resolving these issues, FERC General Counsel Tom Sheets said Wednesday.

"The preference would be not to force feed these things to any group," Sheets said. "The preference is to build consensus" because that approach leads to the right things getting done and people seeing the "goodness in it," he explained.

FERC on June 17 proposed rules to encourage interregional planning and to resolve cost allocation issues. The commission would have transmission planning take place on a regional and inter-regional basis and would tie cost allocation to those planning processes.

The notice of proposed rulemaking did not seek to dictate the solutions. Rather, it would leave it up to jurisdictional entities to propose the answers for their particular situations.

"The commission employed a certain pragmatism, too, in the way they went forward with this," Sheets said. "The notion is at the end of the day you'd like to have these community interests agree that transmission is the key to bringing renewables into the marketplace and you'd like to have some sense of agreement on cost issues if you can get it."

"It's kind of a natural evolution of things, considering what they've done before," Sheets suggested.

FERC issued Order 890 several years ago "and that improved the planning processes," added FERC Principal Deputy General

Counsel Michael Bardee. "Still, there are concerns about whether enough transmission is getting built."

The NOPR "is one possible way to see if we can overcome some of the problems," Bardee said.

Last fall, FERC staff held a number of conferences around the country to review whether the Order 890 rules needed tweaking. The proposed rule is partly the result of what the commission heard during those events, the commission said when it issued the proposed rule.

—Esther Whieldon

## MISO unveils final cost allocation proposal

The Midwest Independent Transmission System Operator unveiled its final transmission cost allocation proposal Tuesday, and it does not include charges to generators, as previously proposed.

Under the latest and what it says is its final proposal, the total cost of regional transmission projects approved on or after July 16 would be charged to load and exports. The cost borne by load will be socialized regionally.

The breakdown on how much load pays and how much exports pay will vary and will be proportional to the energy flow, explained Jennifer Currin, MISO executive director of transmission infrastructure strategy.

The grid operator has been working with stakeholders on a long-term proposal for cost allocation that is due to be presented to the Federal Energy Regulatory Commission July 15. In October, FERC conditionally approved MISO's interim plan that shifts virtually all network upgrade costs to interconnection customers.

MISO staff has been working with stakeholders through the MISO regional expansion criteria board (RECB) task force. MISO staff also has been in contact with the Organization of MISO States. The OMS cost allocation regional planning group (CARP) has also been working on the cost allocation issue.

In CARP's proposal, parts of which MISO used in previous plans, generators would have been charged 20% of the cost for regional generation projects, while transmission would have been charged 80%.

"It's true that there's a logical inconsistency between the two proposals," said Brian Rybarik, executive assistant to Lauren Azar, commissioner at the Public Service Commission of Wisconsin. Azar chaired both CARP and the RECB. Rybarik said that whether or not each of the state commissions or the OMS will support the new proposal has yet to be determined. The groups will have to examine whether the new proposal will have the desired outcome.

CARP had its final meeting on Monday, therefore any comments from individual state commissions or the OMS will be done through comments in the FERC proceeding, Rybarik said.

In its presentation to RECB on Tuesday, MISO said it weighed the pros and cons of including generator charges. By allocating a percentage of costs to generators, those costs are

more precisely allocated to the “right load.”

On the other hand, it would introduce discontinuity across the seams and would be inconsistent with cost methodologies in adjacent markets/seams. There was also a chance that generators would be double-charged, paying a fixed portion of costs plus an export fee.

In the end, MISO said the introduction of a generation charge not borne by generators outside of MISO causes additional inefficiencies at the seam and the risks of impacts around the seams exceed the “incremental value from targeting of costs.”

The idea of allocating a portion of new transmission costs to generators has been controversial. During a May RECB meeting, task force members overwhelmingly voted against MISO’s last proposal, which included a 20% charge to generators. And though MISO is not obligated to follow the directive of the task force, the grid operator has a lot at stake.

At a January 19 informational forum, MISO CEO John Bear said that six utilities had filed withdrawal notices with MISO. Bear said the notices serve as a placeholder to give the utilities the option to leave if and when they decide to do so. All six utilities said they will base their decisions on how the cost allocation issue is decided.

In place of the cost to generators, MISO will be proposing an export charge on transactions that are exports from sources within MISO into the PJM Interconnection, or transactions from sources that are from outside MISO but use MISO transmission into PJM. Some market participants worry that this might exacerbate issues along the MISO-PJM seam or give MISO generators an economic disadvantage in the PJM market.

One MISO market participant said there probably is not a perfect solution, and this was a better approach than MISO’s previous proposal. Another market participant said that while it is possible an export charge to recover the costs of new transmission might put a MISO generator at a disadvantage, as long as the export fee was not larger than the basis, or price difference, between the two markets, it would not be a real barrier.

—Nushin Huq

## FERC affiliate restrictions plan questioned

A Federal Energy Regulatory Commission proposal under which utility affiliates would not be able to share employees who determine the timing of outages, make economic dispatches, engage in fuel procurement or resource planning, is being questioned by utilities that are concerned about costs tied to the plan.

Filing in opposition to the commission’s notice of proposed rulemaking, certain utilities on Monday said the blanket prohibitions would be out of line with FERC precedent established in individual orders, waivers, no-action letters and notices to companies. They said the requirements would require utilities to make significant organizational changes and rack up substantial

costs with little to no benefit.

“These added costs would have to be passed on to consumers,” said Ameren. “Such a result would be entirely unwarranted an inappropriate given that there has been no showing or even allegation of any harm whatsoever, let alone systematic or widespread harm that merits the imposition of the restrictions proposed in the NOPR.”

FERC in April proposed to revise its affiliate regulations to clarify that four particular restrictions apply to the use of shared employees in the market-based rate context. Companies could seek a FERC waiver of the new restrictions.

The NOPR suggested that franchised public utilities with captive customers and the utility’s power sales affiliates must not share employees who determine the timing of scheduled outages or handle economic dispatch, fuel procurement or resource planning (Docket No. RM10-20).

In a concurrent order, the commission issued an order on a request for clarification (Docket No. RM04-7) setting out these same restrictions. The request had come from a coalition of 27 energy companies that call themselves the Compliance Working Group.

The Edison Electric Institute subsequently asked the commission to stay its clarification order in the Compliance Working Group case pending a final rulemaking. FERC has not acted on EEI’s request.

The concurrent order “suggests that the commission has predetermined the outcome of this rulemaking,” EEI suggested in Monday rulemaking comments.

It went on to suggest the commission’s current affiliate restrictions “provide a solid and sufficient framework to protect captive customers without the need for the proposed changes.”

Existing regulations and past FERC orders, notices, waivers and no-action letters “have provided helpful guidance on which companies have relied, leading to settled expectations that the commission should avoid upsetting unless necessary, as demonstrated by record evidence of problems needing to be addressed,” EEI said.

Moreover, the proposed rules are “likely to end up ‘out of sync’ with commission action in this proceeding, creating confusion and potential conflict.”

Should FERC pass such restrictions, EEI requested the commission provide companies the opportunity to seek a waiver. If a waiver is not granted, companies should be given enough time to make the organizational and operational changes. Ameren suggests companies would need at least 180 days to hire new employees and train existing workers on the new requirements.

At a minimum, a generic exemption should be made for nuclear fuel procurement by the nuclear fleet, Entergy Services said.

EEI, the Nuclear Energy Institute and Entergy each suggested the rule would negatively affect the ability of nuclear power utilities to procure fuel.

It is unrealistic to think that an entity would allocate one

year's worth of fuel buys to an affiliate and another year of purchases to its regulated utilities because the "timing of fuel purchases is entirely based on when each unit, typically running at full output, would otherwise run out of fuel," Entergy said. Refueling outages are planned well in advance and those schedules are not altered based on fluctuations in fuel prices, it said.

Therefore, having two nuclear fuel divisions independently buy fuel and compete for the best prices would likely cause each division to pay "significantly more for the needed services."

Meanwhile, an informal association of transmission-dependent utilities was the only entity to voice support for the NOPR. "The proposed regulations are well grounded in the commission's experience and prior orders in policing abuses of market manipulation and affiliate abuse," said the Transmission Access Policy Study Group.

—*Esther Whieldon*

## SPP OKs building \$1.1 billion in new lines

The Southwest Power Pool's board and Members Committee on Wednesday approved construction of \$1.1 billion-worth of high-voltage transmission projects designed to move power from remote wind farms to load centers in the eastern part of the regional transmission organization.

The SPP's decision to approve construction comes after the Federal Energy Regulatory Commission last week approved the RTO's "highway-byway" cost allocation tariff.

The action allows work to begin on six "priority projects": a 345-kV line from Spearville in southwest Kansas through Comanche County, Kansas, on the Oklahoma state line, to Wichita in southeastern Kansas; a 345-kV line from Comanche County south to Woodward, Oklahoma; a 345-kV line from Woodward to Hitchland in the Texas Panhandle; a 345-kV line from southeastern Nebraska to the Kansas City, Missouri, area; a 345-kV line from southeastern Oklahoma to Texarkana on the Arkansas-Texas state line and an upgraded substation in Tulsa, Oklahoma.

The "highway-byway" cost allocation tariff requires the region to pay all of construction costs for grid projects of 300 kV or higher. For projects between 100 kV and 300 kV, two-thirds of the construction costs would be allocated region-wide, with one-third allocated locally. For projects below 100 kV, local zones would be responsible for paying all construction costs.

SPP staff estimate the project will take three to five years to complete.

Each transmission owner in the relevant area has 90 days to decide whether to build the projects itself or let SPP select another company to build the facilities.

State regulators must also approve the projects within their jurisdictions. An SPP staff member at Wednesday's meeting said some transmission owners have done "pre-emptive work" to

jump-start construction, but other projects have yet to be submitted to regulators.

SPP studies project benefits to total at least \$3.7 billion over 40 years, including reduced congestion costs, lower power losses, reduced fuel costs, enhanced reliability, jobs, tax revenue and expanded wind power revenue.

—*Markham Watson*

## CPUC details expected IOU renewables mix

California's investor-owned utilities are expected to derive 18% of their power from renewable sources this year and 21% next year, based on contracts that have been signed to date, the California Public Utilities Commission said Tuesday in a quarterly report.

The state's renewable portfolio standard requires IOUs to derive 20% of their electricity from renewable resources by the end of 2010, with exceptions if transmission barriers or other obstacles arise.

While the IOUs are on track to fall short of the 2010 requirement in terms of delivered renewable energy, so-called flexible compliance provisions allow for more time to reach the targets, depending on circumstances.

In 2009, 15.4% of the electricity that California's IOUs delivered came from renewable resources, up from 13% in 2008, the PUC report said. The regulator cited newly installed renewable capacity, small hydroelectric facilities generating more power, additional contracts with existing facilities and decreased demand in 2009 as reasons for the increase in renewable generation to 2009 from 2008.

Southern California Edison topped the list, with 17.4% renewables delivered, followed by Pacific Gas & Electric's 14.4% and San Diego Gas & Electric's 10.5%.

The report points out that utilities have signed contracts for 36 projects through a feed-in tariff program established by a 2006 feed-in tariff law. At the same time, however, utilities are asking federal regulators to preempt the state's feed-in tariff for combined heat and power facilities up to 20-MW.

The 2006 law requires utilities to purchase excess renewable energy produced by renewables facilities up to 1 MW that are owned by wastewater agencies. The law caps these sales at 250 MW statewide.

Designed to spur renewables development, feed-in tariffs require utilities to purchase a certain amount of renewable resources at a set price through long-term contracts.

Under A.B. 1613, which passed the Legislature in 2009, the PUC requires IOUs to purchase excess electricity produced by combined heat and power facilities at prices set by state regulators.

In a May 11 filing with the Federal Energy Regulatory Commission, SoCal Ed, PG&E and SDG&E assert that since the PUC lacks authority to establish wholesale prices for electricity;

the state's CHP feed-in tariff should be preempted.

Acceptance of the PUC's argument that setting a wholesale purchase price is not a regulation of wholesale power sales, "would create a loophole in the [Federal Power Act] so large that states would effectively take over the role of FERC as to wholesale power prices," warned the utilities.

Jim Metropoulos, senior advocate with the Sierra Club, was critical of the IOUs' challenge of feed-in tariffs.

The IOUs are "asking the state to give them credit toward the RPS by signing feed-in tariff contracts, [but] are at the same time going to FERC" saying those contracts are illegal, he said.

—Lisa Weinzimer

## S&P upgrades Xcel and three units to A-

Standard & Poor's Ratings on Wednesday upgraded the corporate credit ratings of Xcel Energy and three utility units from BBB+ to A-, citing management's credit-supportive strategy of investing in regulated utilities and obtaining cost recovery for its sizable construction program.

S&P upgraded utilities Northern States Power Minnesota, Public Service of Colorado and Southwestern Public Service. Northern States Power Wisconsin was affirmed at A-.

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"During its large construction program, operating cash flow has continued to expand through numerous rate riders that help provide timely cost recovery of projects, and rate case filings to place recently completed projects in rate base," said Associate Director Gerrit Jepsen and Director Barbara Eiseman. "Throughout the recession and the large construction program, management maintained ample liquidity through cash on hand and significant unused capacity in credit facilities."

This is S&P's first action on Xcel since the October 16, 2007 upgrade from BBB to BBB+.

Cash flow should rise as capital spending falls, allowing Xcel to fund 90% to 100% of capex internally, S&P continued. The company has enough liquidity to handle collateral calls under a "stressed scenario" of both a negative credit event and adverse movement in commodity prices, S&P added.

The outlook was moved from positive to stable, reflecting S&P's expectations that management will continue to focus on regulated utilities, and cash flow will improve.

The outlook could be moved to negative if construction projects are not completed on time and on budget, rate recovery is less than expected or financial measures do not remain at expected levels.

But it could be revised to positive if financial measures exceed S&P's forecast, such as the ratio of funds from operations to debt exceeding 20%, and, debt falling to less than four times earnings before interest, taxes, depreciation, and amortization, as well as less than 55% of total capital, S&P continued.

—PAUL CARLSEN

## S&P downgrades 2 NextEra wind financing

Standard & Poor's Ratings on Wednesday downgraded the senior secured debt of two NextEra Energy wind financing units, citing higher operation and maintenance costs and a lower wind resource at two units that directly own wind projects.

Those negative developments have slashed cash distributions to the financing units, reducing their ratio of cash flow to debt service obligations, added Associate Grace Drinker and Director Terry Pratt.

S&P downgraded the financing units, FPL Energy Wind Funding and FPL Energy National Wind Portfolio, from BB- to B+ (S&P's fourth-highest speculative grade), and kept their outlooks negative.

Debt service coverage ratios, now only about one-to-one, could decline further if O&M costs for the wind projects keep rising faster than inflation, and the wind resource keeps weakening, S&P said.

"O&M costs for many US wind projects have risen substantially during the past few years due to the simple result of demand exceeding supply [i.e.] a shortage of skilled labor, cranes and materials. Costs are forecast to trend down ... but is it unclear if or when. If prices remain at current elevated levels long term, coverage would be consistently weak," S&P continued.

"If coverage ratios do not improve in the near term we could lower the ratings," S&P warned.

S&P also shifted its outlook on the two project-owning units from stable to negative and affirmed their senior secured debt at BBB- (S&P's lowest investment grade).

They are FPL Energy National Wind, which owns nine US wind projects totaling 534 MW, and FPL Energy American Wind, owner of seven projects totaling 697 MW.

—Paul Carlsen

## Utility output rises 6.2% on year in week

Utilities generated 84,553 GWh in the week ended June 19, which was 6.2% above the 79,591 GWh generated in the corresponding week of 2009, the Edison Electric Institute said Wednesday.

The weekly total was 3,936 GWh above the 80,617 GWh total posted for the week that ended June 12, EEI said.

Output rose in all of the nine regions EEI surveys, with the highest-percentage increase coming in the Mid-Atlantic, where generation rose 14.3% on the year to 9,056 GWh.

That was followed by the Central Industrial region, where output rose 12.8% from the same week of last year, to 14,316 GWh, EEI said.

Utility generation in the first 25 weeks of 2010 was 1.87 million GWh, or 3.1% above the 1.82 million GWh generated in the same period of 2009, EEI said.

The numbers are based on generation from investor-owned utilities, cooperatives and government-owned utilities.

—Jeff Barber

## AEP under pressure ... *from page 1*

Morris, president and CEO, Chafin said. The public does not understand why significant rate increases are required of them when “such salaries” are being paid to AEP’s upper management team, the letter said.

Chafin attached a letter written to him from a charity located in southern West Virginia that said it is in danger of running out of funds because of the amounts it has paid to Appalachian Power to help local citizens with their power bills.

Phil Moyer, a spokesman for Appalachian Power, said AEP’s executive salaries are not out of line with other companies of its size and that AEP must pay the salary necessary to attract the leadership it needs to run the company. “The difference is [Morris] leads a company that has historically been one of the largest users of West Virginia coal, one of the state’s largest employers and one of its largest taxpayers,” he said.

The executive salaries and the impact they have on Appalachian Power’s customers will be addressed during the proceedings for the base rate case filed in May, Moyer said. Appalachian Power’s president Dana Waldo took a voluntary severance earlier this year. The company’s new president, Charles Patton, came from AEP Texas last month, Moyer said. The FOIA request did not request the salaries for Appalachian Power executives, Kayla Brown, Chafin’s executive assistant, said in an interview.

Brown said Chafin also is concerned that the reliability in the southern part of the state is not what it should be. “If it rains the power goes out,” she said. It took Appalachian Power 14 days to get the power back on to some customers after a snowstorm in December, she said. “Why did that happen? And now they want to be paid for the extra help to repair the lines,” she said.

Byron Harris, director of the consumer advocate division at the PSC, said AEP’s most recent rate requests “will only add to a very disturbing trend.” With the 7.4% increase in the fuel and purchased power settlement agreement and the 17% base rate request, it would mean that residential customers’ rates between January 2006 and March 2011, will increase 70%. “That is many, many times the rate of inflation and income. It is real hardship for customers,” he said.

The \$155 million base rate request is just beginning its discovery phase, so Harris could not comment on whether the request is justified. It will be November before documents are filed, with the resulting rate increase taking effect next March, he said.

The average residential rate in West Virginia is 8.5 cents/kWh, Harris said. “It’s still relatively low cost power compared to surrounding states, but still, people are quite upset,” he said.

The spokeswoman for the PSC did not respond to a request for a comment by press time.

- According to the FOIA response, total compensation for Morris in 2004 through 2008 was \$54.7 million.
- Total compensation for CFO Susan Tomasky in 2004 through 2007 was \$10.1 million.

- Thomas Hagan, executive vice president received \$7.4 million from 2004 through 2007.

- Holly Koeppel, executive vice president, received \$8.7 million from 2004 through 2008.

- Robert Powers, executive vice president, received \$8.9 million between 2004 and 2008.

- Carl English, president of AEP utilities, received \$9.21 million between 2005 and 2008.

- CFO Brian Tierney received \$1.2 million in 2008; John Keana, senior vice president received \$1.7 million in 2006 and Henry Fayne, executive vice president received \$1.8 million in 2004.

—Mary Powers

## Nevada PUC weighs revealing ... *from page 1*

The projects related to the contracts include: the 150-MW Spring Valley wind farm proposed by Pattern Energy Group; a 100-MW solar project planned by SolarReserve; a 50-MW solar photovoltaic project to be built by NextLight Renewable Power; a 53.5-MW geothermal project planned by Ram Power; 25-MW and 40-MW geothermal projects proposed by Ormat Technologies; and, a 3.2-MW landfill energy project proposed by Waste Management.

The developers support NV Energy’s position that the contract details should remain confidential. Releasing the information would hurt “the ability of project developers to secure competitive financing for future projects, potentially threatening the ability to build future projects,” Pattern Energy Group said in a filing. “If developers are forced to disclose information in Nevada that is not required to be disclosed in other jurisdictions, future development of renewable energy projects in Nevada will be threatened.”

In negotiating its PPA, Pattern Energy Group bargained for, or opted to forego, certain rights on issues like the wind farm’s construction schedule, liquidated damages and curtailment rights, the company said. “These are heavily negotiated provisions because they affect the economic position of each party,” Pattern Energy Group said. “Thus, disclosure of these terms in particular means that owners would be operating at a disadvantage in future PPA negotiations for Nevada wind projects because other parties would know what the owner had been willing to agree to in the PPA, and the market standard for such terms would be artificially impacted.”

Pattern Energy Group said that disclosing the pricing information could lead to higher costs down the road. “If renewable power generation project owners did enter into PPAs with Nevada utilities they may require higher pricing, in order to offset the negative impact of likely disclosure of sensitive commercial terms,” the company said.

Nevada Attorney General Catherine Cortez Masto and Consumer Advocate Eric Witkoski support the newspaper’s request to release the contract information. Masto and Witkoski argue that the contracts are subject to Nevada’s public records

laws once they are filed with the PUC. Also, the information in the contracts is not a trade secret because they contain “no economic value.” They contend that NV Energy’s status as a regulated monopoly weighs in favor of requiring transparency to benefit ratepayers.

PUC staff told the commission that it does not oppose keeping the information confidential, although staff noted that NV Energy offered no evidence that its request for proposal process would be hurt by releasing the contract details.

Commission staff noted that NV Energy often asks for information to be kept confidential for five to seven years, but that the utility provides pricing details to federal regulators when the utility begins receiving power under its PPAs.

The PUC is expected to consider the confidentiality issue at a June 30 meeting.

—Ethan Howland

## Anti-decoupling forces on offense ... *from page 1*

The money diverted into the general fund represents 35% of ratepayer collections meant for the Connecticut Energy Efficiency Fund. The large “fund raid” makes it even more important that Connecticut continue a move begun in 2007 to fully decouple rates, according to Kung.

The attack is being made in a state that is often described as having one of the nation’s leading energy efficiency programs. The American Council for an Energy Efficient Economy last year ranked Connecticut as having the third best efficiency effort in the nation, behind only California and Massachusetts.

So far, the state Department of Public Utility Control appears to be siding with the anti-decoupling forces. In a recent draft rate decision for Connecticut Light & Power, the DPUC turned down CL&P’s request to move from partial to full decoupling, saying it wants to first see the results of a two-year pilot program underway by another of the state’s utilities, United Illuminating. The DPUC intends to analyze the results from the pilot program in 2011.

Kung said in an interview Wednesday that there is little need for the delay. “Other states have been implementing decoupling with this mechanism for years. We’re not sure what we’re going to learn in two years from United Illuminating that we haven’t already learned from other states’ experiences.”

Meanwhile, Connecticut Attorney General Richard Blumenthal sent a letter to the DPUC Wednesday saying the state should do away with decoupling altogether once the two-year United Illuminating pilot ends. He argued that decoupling is not spurring more efficiency, but is a “tool to stabilize the company’s revenues.”

Similarly, Connecticut Industrial Energy Consumers said that decoupling puts upward pressure on rates at a time when the business climate is already poor. Walmart said that full decoupling will cause cross-subsidization among rate classes.

UI in a letter sent Wednesday to state regulators said that opponents do not understand the way full decoupling works. In

a year when a utility charges, rather than credits ratepayers, it is not earning extra revenue, but what it is supposed to receive based on the target set by regulators, UI said.

“The AG’s brief illustrates a deep misunderstanding of UI’s decoupling rider,” UI said.

CL&P has partially decoupled its rates, meaning that part of its distribution rate is fixed, or decoupled, while the remainder is based on kilowatt hour sales. The utility sought permission as part of its recent rate case to move into full decoupling, where regulators would set a target revenue rate annually and then true it up against the amount of revenue the utility actually collects. The utility would then earn a credit or charge, depending on whether it over or under-collected revenue compared to the target.

Proponents of decoupling say that without the rate mechanism utilities have an inherent incentive to forego energy efficiency, since they profit from the sale of energy, not its saving.

Both CL&P and UI argued before the DPUC that efficiency also helps legitimize their efficiency efforts in the eyes of customers, who might otherwise question utility motives for pushing energy savings.

ENE called for the DPUC to reverse its draft decision and support full decoupling for CL&P. The DPUC expects to issue a final decision July 7.

—Lisa Wood

## Environmentalists cast wary eye ... *from page 1*

Resources found that biomass plants that use whole trees for fuel create greater carbon dioxide emissions than coal-fired plants over a 40-year time frame.

The Manomet report said that its assessment of biomass supply in Massachusetts “suggests that if demand increases due to the expansion of [biomass-fired] electric power plants, it will almost certainly be accompanied by increases in whole-tree harvesting due to the limited supply of other forest biomass and the cost advantages of whole-tree methods.” It added, “it appears that electric power plants [in Massachusetts] would need to obtain most of their wood from whole trees.”

Gudrun Thompson, an attorney at the Southern Environmental Law Center, said that biomass used for generating power must come from sustainable sources. She added that the issue of using chipped whole trees in biomass-fired plants is a significant one, particularly in the Southeast, where regulators and utilities generally view biomass as the most widely available renewable resource.

“The carbon implications of [firing plants with] wood waste are quite different from the carbon implications of burning [chips from] whole trees,” said Thompson, who earlier this week filed joint comments by the law center and the Environmental Defense Fund with the North Carolina Utilities Commission on Duke Energy Carolinas’ plan to use chips from whole trees to co-fire one or more of five older coal-fired units at its Buck and Lee stations.

SELN and EDF argued in their filing that North Carolina’s

S.B. 3, the state's three-year-old "renewable energy and energy efficiency portfolio standard," limits woody biomass to wood waste. "Whole tree biomass is not wood waste and is not a renewable resource under [S.B.] 3," the filing said. "In defining 'renewable energy resources,' the General Assembly chose to use the term 'wood waste' in the list of biomass resources — not 'wood' or 'wood chips' or even 'whole trees.'"

The law center and EDF noted that a consultant's study prepared for the General Assembly before enactment of S.B. 3 discussed only "wood residue" and "wood waste" as woody biomass resources; the study also cited the NC GreenPower program's determination that wood chips derived from processing whole trees within forested land "will not be allowed as qualifying wood waste" in its program.

NC GreenPower is a statewide program under which utility customers pay a price premium to support the development of small-scale renewables.

Further, SELC and EDF said that "[f]orests in North Carolina continue to be depleted." They urged the NCUC to follow the recommendation of the state's Environmental Management Commission that the General Assembly be asked to clarify its definition of woody biomass. The EMC also said that a broad definition of woody biomass that includes chipped whole trees "should be adopted only in conjunction with sustainable management requirements."

However, Duke's view that chipped whole trees are considered to be woody biomass under S.B. 3 was reinforced in newly filed testimony by Robert Slocum, executive vice president of the North Carolina Forestry Association.

Slocum said that "[w]ood is clearly a biomass resource and nothing in [S.B.] 3 limits the definition with respect to wood to strictly wood waste." He said that, in fact, North Carolina had more forestland in 2007 than it did in 2002, and that harvesting what he called "low-end marketable timber" for use in biomass-fired plants would have "a positive impact on timber inventories and overall forest productivity in North Carolina."

The NCUC plans to hold a July 14 evidentiary hearing on Duke's request that generation based on the burning of chipped whole trees qualify for renewable energy credits, and thereby

help the utility meet the requirements of S.B. 3. The commission is expected to rule on the matter later this year.

The proper sourcing of biomass also is an issue in Ohio, said Will Reisinger, a staff attorney at the Ohio Environmental Council, an environmental group. He said that the OEC is opposing FirstEnergy's plan to convert its 312-MW R.E. Burger coal plant in Shadyside to biomass firing because the utility has failed to provide with any specificity the kind of biomass the converted plant will burn.

Reisinger noted that Ohio law requires that biomass used to comply with the state's RPS must be "available on a renewable basis," but that all FirstEnergy has said is that biomass to fuel Burger will come from "the US and/or Canada." He added, "If and when FirstEnergy enters into contracts or learns anything else about the source [of its biomass], they are under a legal duty to supplement their answers. So we have to presume, at this point, that they know nothing about how they will procure their fuel."

Reisinger said that the OEC is "concerned" about the possibility that FirstEnergy may decide to burn chipped whole trees rather than wood waste. "If their plan is to cut down standing timber and chip it, that could result in the widespread destruction of forests and would not be sustainable."

The OEC is "certainly not opposed to the use of biomass" from sustainable sources to generate electricity, he said, noting that the group recently expressed its support for another, smaller biomass-fired project in Ohio whose developer provided details on the biomass that would be burned.

Kathleen Logan Smith, executive director of the Missouri Coalition for the Environment, said that Missouri's forestry industry already uses virtually all of the wood it harvests. "There's not a lot left to burn," she said, adding that she is concerned that any biomass plants that do come online in Missouri will need to turn to whole trees and other non-sustainable sources for their fuel.

"The more I learn about biomass-fired generation, the less I think it's a good idea," Smith said, particularly if the projects generate tens or even hundreds of MW each.

—Housley Carr