

2001 Restructuring Activities by State

Updated: 11/26/01

Alabama

Alabama Power and public utilities in Alabama, citing low power costs in the state, have urged the Public Service Commission to take no immediate action to restructure the state's electric industry.

According to filings Alabama Power made with the PSC, it was premature to determine whether retail competition would be in the public interest and the state commission should take the next two to five years to review the issue before making a decision that could hurt local customers.

At the same time, a coalition of Alabama industrial users has proposed that the state initiates retail choice by January 1, 2001 and completes a transition period by December 31, 2004.

According to the Alabama Industrial Energy Consumers (AIEC) even with the current low energy prices, customers in the state would benefit from retail choice.

At the same time, it said as high-priced states restructure Alabama would cease to have the current rate advantage and instead its refusal to provide retail choice would turn into a disadvantage in competing with other states.

The industrials noted that some Southern states, including Mississippi and Arkansas, have found restructuring to be in the public interest and also low-cost states such as Montana and Oklahoma had recognized the benefits of retail choice.

In their findings to the PSC the utilities said the problems with restructuring in other states, especially California, was another reason for Alabama to wait and learn from mistakes elsewhere (Docket No. 26427).

The industrial users, however, said that Alabama could already draw key lessons from California, including the need to avoid high stranded-cost charges and also to avoid a power exchange approach.

On stranded costs, both Alabama Power and public power groups called for full recovery of costs if restructuring was ordered in the state.

The AIEC, however, said that an initial review showed that Alabama Power's existing plants with low book values would be competitive in a deregulated market and the company would normally have no stranded costs to recover. If any costs were shown, the AIEC said, the burden should be split between ratepayers and stockholders.

While cooperatives and municipal power groups sided with Alabama Power in saying the state should go slow on restructuring, they sided with industrial consumers on the issue of curbing Alabama Power's market power once restructuring occurred.

The public power groups presented a study by Oregon-based consultant Gordon Taylor that asserted that Southern Company, including Alabama Power, would have a 70% share of generation in the Southern Company service territory in a deregulated market.

The study said that this market position would discourage new competition in the region and give Southern Company the ability to manipulate prices.

The public power groups, including Alabama Rural Electric Association, Alabama Electric Cooperative and the Alabama Municipal Electric Authority, said that to mitigate this power the state should create an independent system operator and also consider forcing divestiture of some Alabama Power generation assets.

The AIEC took similar position, saying the state should support creation of a regional ISO to run the transmission grid and should also force Alabama Power to either unbundle its generation business from other operations or divest generation assets.

Alabama Power opposed use of an ISO and also divestiture of assets and said a code of conduct and some restructuring of its business operations could handle any market power issues.

The PSC, which opened the restructuring inquiry in June 1998, will receive reply comments in mid-February. It will use the comments to develop a policy statement on retail competition issues during 1999, but it is not expected to issue an actual restructuring plan at that time.

Alaska

On April 5, 1999 a report on electric utility restructuring in Alaska was presented to the Alaska Public Utilities Commission and the Alaska State Legislature. The report, prepared by the combined efforts of CH2M Hill and Econergy International Corporation, made the following recommendations:

- ?? Continue and expand efforts to improve rural system efficiencies through aggregation of administrative, fuel-purchasing, operations, logistical and other appropriate functions among geographically separate but proximate villages.
- ?? In order to build experience in the use and deployment of distributed energy systems which offer potential long-term cost savings, consider the creation of a pilot program based on technology demonstration and deployment, conducted in coordination with government and non-government organizations.
- ?? Initiate a specific set of market-friendly regulatory reforms today in order to bring the real competitive opportunity into focus.
- ?? Complete a regulator agenda that –
 - ?? calculates and allocates component costs for Railbelt utilities in a rational and uniform manner (unbundling and cost allocation);
 - ?? rationalizes access to, and governance of, the transmission system to create a non-discriminatory open access network while ensuring reliability;
 - ?? rationalizes oversight of generation siting and construction to minimize stranded cost exposure and to foster the emergence of a competitive wholesale market with new merchant generators; and
 - ?? Implements central dispatch/power pooling recommendation of the October 1998 Black & Veatch study in the Railbelt to harvest near-term savings and to facilitate emergence of a competitive wholesale market over the longer term.
- ?? Maximize potential for market success –
 - ?? Mitigate regulatory and structural inefficiencies to produce near-term savings and encourage efficient market behavior.
 - ?? Design pilot and retail competition to encourage technology-based competition and to realize the potential for technological innovation to reduce costs.
 - ?? Design efficient commodity markets to enable value-added service innovation.
 - ?? Exploit Alaska's small electricity systems to lead the industry trend toward new, modular distributed systems.
 - ?? Harmonize restructuring agendas in telecommunications, natural gas, and electricity to realize convergence benefits.
- ?? Any market, regardless of size and scope, must carry its own administrative and oversight costs.
- ?? To increase market liquidity, consider a BTU Exchange, e.g., create a market exchange where both gas and electricity are traded as BTU contracts.
- ?? Consider retail market simulation modeling as part of the decision to move to full retail competition pilot or retail competition.
- ?? Modeling and simulation must precede full retail market opening in any case.

Arizona

Arizona Public Service is asking state regulators to overturn rules that would compel the utility to obtain all of its power from the competitive market by 2004, saying the market is too immature to support such a move. Instead, APS is proposing that it meet its power needs through 2015 from its parent, Pinnacle West Capital Corp., which would acquire power from its unregulated generating subsidiary. By 2008, the utility would buy 25% of its power needs from competitive suppliers.

APS believes the plan will protect customers from price spikes and provide greater reliability. "Our customers don't want to see anything happening here like what happened in California," APS President Jack Davis told investors in an October 19 conference call.

In the plan filed October 18, APS asked the Arizona Corporation Commission to make a ruling by year end. The company said it would make a related filing soon with the Federal Energy Regulatory Commission.

Under current rules, APS would have to purchase 50% of its power needs, or about 3,000 MW, through a competitive bidding process in 2004. Various developers have 21 projects, totaling 18,300 MW, under construction or in development in Arizona, but Pinnacle West said that the projects are being delayed for various reasons and that the competitive market will not be able to supply 3,000 MW by 2004.

Under the proposed plan, Pinnacle West Energy would be guaranteed an 11.25% return on equity on the power it would provide APS and would be subject to regulation by the ACC. Pinnacle West Energy owns the

operating 120-MW West Phoenix plant that came on-line this summer and has two merchant plants under development: a 500-MW, \$220-million expansion at West Phoenix it is building with Calpine Corp. and the \$1-billion, 2,120-MW Red Hawk facility. And APS is scheduled to transfer eight plants totaling nearly 4,000 MW to Pinnacle West Energy by December 2002.

Under the proposal, Pinnacle West Energy would act as the wholesale provider of last resort to APS, ensuring complete reliability of generation service.

In addition, APS said it would source some of its power needs through the competitive market. If the ACC approves the plan, Pinnacle West, acting as an agent for APS, would tender for 270 MW through a competitive bidding process in 2003. This bid obligation would increase 270 MW each year through 2008, when it would reach 1,620 MW or nearly 25% of APS' needs, a level APS officials believe the market can supply. APS supports retail competition and is not seeking to change a 1999 regulatory agreement that guarantees retail price cuts through 2003. Pinnacle West officials said the plan strengthens the competitive market by making it more liquid.

Arkansas

The staff of the Arkansas Public Service Commission, in a September 4, 2001 filing to the PSC, said that the state should consider delaying start up of retail competition in the state beyond the October, 2005 dead line under current state law.

Based on a report by Boston-based consultants Las Capra Associates, staff said that because of low utility generation costs in the state and new delays in creating a regional transmission organization, it was unlikely that most customers in the state, especially smaller users, will benefit from retail choice over the next ten years.

Under currently law, retail deregulation in the state must start between October, 2003 and October 2005. The PSC can decide when to start choice at twelve month intervals in that period.

Staff said that it was clear that the wholesale energy market in the state would not be ready to support deregulation by October, 2003. Therefore, as a first step, the PSC should exercise its right to delay choice at least 12 months to October, 2004.

At the same time, staff said, since market conditions were likely to remain adverse past October, 2005, the commission should recommend that the state legislature either push back the October 2005 deadline or simply repeal the original 1999 deregulation law and take a "wait and see" attitude about retail choice for the coming years.

It said the repeal option was better because it would eliminate the cost of further year-to-year decisions on the issue. The staff also said the PSC should act at once to suspend all activity in the electricity deregulation dockets until after 2003.

The commission opened a proceeding in July to get comments from the public and staff and decide when to start retail choice inside the two-year window. It must make progress report to the legislature by the end of 2001.

In its September 4, 2001 filing the staff noted particularly that the new Federal Energy Regulatory Commission order on the structure of regional transmission organizations was likely to slow development of an RTO for the area including Arkansas. It said there was no assurance an RTO could be formed by 2003 and that a "fully working" RTO might not be ready for up to five years.

While there has been new power plant development in the state in recent years, staff noted there had not been a corresponding development of transmission capacity. In any case, staff found that large coal and nuclear capacity of existing utilities would tend to keep cost of power in Arkansas under the regulated system low for the foreseeable future.

While prices would also remain low in the near term in a deregulated market, staff said there would be more uncertainty in the longer term. In any case, deregulated prices would not be lower than regulated prices through 2012. Therefore deregulation would offer no benefit to small users and could lead to cost increases later in the decade, it said.

California - New

NOTE: There is a great deal of turmoil going on in the California electric markets. The following items provide highlights of the latest events but are not intended to provide a comprehensive report.

Southern California Edison has submitted a new draft agreement to its qualifying facility suppliers outlining how the utility plans to pay for their power, but QFs said the utility still has some way to go before it comes up with an acceptable offer. While SoCal Ed has avoided bankruptcy court so far, QFs said that if the utility does not honor a payment settlement signed in June, it will likely be pushed into court as soon as January.

During a conference call Monday, Ted Craver, chief financial officer of SoCal Ed's parent Edison International, said the new QF agreements revise the original June settlement that the utility claims is invalid under its \$3.5-billion debt repayment plan approved by a federal court last month. SoCal Ed began paying QFs in March, but still owes money for power they supplied between October 2000 and March.

Craver said that the draft settlement with renewable energy QFs would maintain the 5.37 cents/kWh fixed rate for power contained in the June settlement. Still unresolved is when that rate would take effect — SoCal Ed is insisting on June, but QFs want it to begin earlier. QFs also have been unable to win the utility's agreement to set a date certain by which it would pay back past debt, Craver said. The company hopes to submit the new agreements with the California Public Utilities Commission by the end of this month, Craver said.

Craver's statements come after one QF — CalEnergy Operating — filed a lawsuit against the utility seeking

to recover more than \$100-million it is owed for power. In addition to demanding back payment, the suit calls on SoCal Ed to begin paying the fixed 5.37 cents/kWh price immediately. QFs said that they are anxiously awaiting the outcome of the suit to determine if they can file similar claims.

In the meantime, QFs continue to threaten to push SoCal Ed into bankruptcy if their debts are not paid and the June settlement is not honored. Under the June settlement, the producers agreed to forebear on any action on bankruptcy until Dec. 31.

Kelly Lloyd, chief financial officer for QF Enxco, confirmed that SoCal Ed and the producers are working on a draft but said there is no assurance that all producers will agree on a single version that could be submitted to the PUC. "We are owed money from Nov. 1, 2000, to March 26, 2001. We want that money," he said. "If Edison doesn't come to the plate with meaningful material, there will be a lot more CalEnergy-type lawsuits... The tide is shifting toward bankruptcy. After December 31, there will be no more time for discussions and we'll leave it up to the federal government" in bankruptcy court.

Brian O'Sullivan, chief executive officer for Coram Energy, said that while SoCal Ed has avoided bankruptcy court, producers are facing their own filings. "We need to get paid the [5.37-cents] rate. Every month we don't get that rate, we lose money," he said. "They're railroading us. In a bankruptcy court, someone will tell them how to behave."

While it struggles with QF issues, Edison International will fall short of meeting analyst earnings expectations this year and the next. According to Craver on Monday, Edison International in 2001 and 2002 will earn \$1.27-\$1.30 and \$1.50-\$1.60 a share, respectively. Analysts polled by First-Call were expecting \$1.63 and \$1.84.

Craver said that the company is still pushing to pay off its creditors under the debt repayment plan by late February or early March. The settlement is presently being appealed by consumer group The Utility Reform Network. The utility Tuesday plans to file a motion with the U.S. Court of Appeals for the Ninth Circuit opposing TURN's request for a stay of the settlement. TURN took its request to the appeals court after a U.S. District Court in Los Angeles refused to grant a stay.

Federal regulators ordered the California Independent System Operator to end its preferential treatment of the state Dept. of Water Resources and consider DWR a scheduling coordinator.

The decision by the Federal Energy Regulatory Commission directed DWR to follow the same tariff conditions as all other market participants and restricted commercial information the ISO was making available only to the state agency.

"Everyone has got to follow the tariff," Commissioner William Massey said at the open meeting.

FERC's rule came after generators and lawmakers alleged the ISO gave DWR access to commercially sensitive market information, and bought more expensive power bilaterally out-of-market instead of purchasing cheaper generation from inside the state.

Reliant and Mirant, specifically, filed the complaints, claiming that the ISO was purchasing more expensive out-of-market power when cheaper generation was available from within the ISO.

Additionally, California Rep. Doug Ose sent the commission a series of letters echoing these concerns, and

forwarded a confidential memorandum from an independent consultant to an ISO board member that appeared to outline the alleged improprieties between the grid operator and DWR.

“The...memorandum clearly illustrates the perils of a lack of independence at the CAISO. CDWR’s heavy-handed involvement in the energy markets has resulted in higher prices for consumers and threatened blackouts,” the congressman charged.

The April 13 memo, written by Eric Woychik, of the 27-member ISO stakeholder board that was disbanded in January, to Mike Florio, one of four current ISO board members, charged that DWR practices are causing “very large additional costs for purchases” for customers and that they “also compromises reliability.” Woychik claimed that DWR required the ISO to buy power for \$400/MWh, forcing it to turn down \$60/MWh electricity from the coal-fired Mojave plant in Nevada.

Further, Woychik’s memo accused DWR of “over scheduling” cheap power from southern California, while underscheduling power in the north, an action that “caused the ISO to violate Path 15 transmission constraints for an extended period.” The practice, the memo said, forced the ISO to “back down everything it could control at the time in order to avoid burning down high voltage transmission lines in the middle of the state.

“This situation is worse than alarming, it’s a potential bombshell of negative publicity waiting to go off. Further, what does this suggest for the governor’s plan to have the state take a larger role...? If the press, Legislature, or FERC get wind of this, I think we are toast.”

DWR is the state’s primary buyer of electricity and started purchasing energy on behalf of beleaguered utilities Southern California Edison and Pacific Gas and Electric earlier this year. DWR also serves as the ISO’s only creditworthy backer, and both state agencies have said this arrangement makes it necessary for DWR to receive certain non-public information.

“It’ll always be an unusual relationship because DWR is the ISO’s credit backstop,” ISO board member Mike Florio said. “Nobody else backs the ISO’s transactions.”

But FERC said this type of information sharing gives DWR a competitive advantage. “The commission rejected this assertion,” FERC said in a press release. The order was not available at press time.

DWR is not entitled to private information such as forecasts of participants’ shortfalls unless all market participants receive that information, the commission said. “It is important to hold everyone accountable as we try to get California back on its feet,” FERC Chairman Pat Wood said. Wood also said the commission was in the midst of reassessing the ISO’s entire operating system and hinted that further changes — including the make-up of the grid operator’s governing board —are likely. “We’re not done with them,” Wood told reporters.

Spokesman for both the ISO and DWR said they fully intend to comply with the order.

California Public Utilities Commission staff began meeting with Gov. Gray Davis’ staff to discuss renegotiation of suppliers’ \$43-billion in long-term power contracts with the state Dept. of Water Resources. While generators had yet to be contacted by Davis’ office, his staff continued to assemble information to form a strategy for future talks.

After the PUC’s biweekly meeting, President Loretta Lynch confirmed that she had met with Davis’ staff, although she would not detail what was discussed. She did, however, say that they did not discuss the contracts in the context of a so-called “rate agreement” for the DWR. The PUC, led by Lynch, earlier this month refused to pass a rate agreement because the commissioners feared it would lock the state into long-term contracts now seen as more expensive than necessary given the drop in wholesale power prices.

“We talked about the long-term contracts only,” Lynch said when asked if there had been discussion of compromising on a pared-down rate agreement if some contracts are renegotiated. Davis has been at odds with Lynch over the rate agreement issue because he fears lack of an agreement would jeopardize a \$12.5-billion bond issuance to pay for DWR power spending.

In the meantime, other PUC commissioners support holding out on a rate agreement to work on the contracts. “The state should try to get better contracts for consumers,” Commissioner Carl Wood said Wednesday. “Generators held a lot of the cards (back when the deals were signed earlier this year)... The issue of fairness is in question.” He said that a rate agreement is not “off the table,” however, and is one of many options the PUC is considering.

Wood said he expected generators to negotiate their contracts because the deals could be overturned by courts or the Federal Energy Regulatory Commission. Wood said he still had faith that FERC would consider the fairness of the contracts despite its decision Wednesday not to review a 10-year DWR contract with PacifiCorp

Power Marketing at the PUC's request. The PUC had argued that prices charged under the agreement were neither just nor reasonable.

FERC let the marketer withdraw the pact from commission review because, it said, it had submitted it only because it was unsure whether it had to do so. It determined later that it did not have to, and asked to withdraw it. FERC agreed review was not appropriate, but it said the PUC could challenge the pact in a different way, using Section 206 of the Federal Power Act.

The contract talks last week followed letters from the PUC and state attorney general's office over the legality of Senate Bill 18xx, a plan the PUC supports as an alternative to the rate agreement. In an Oct. 9 advice letter, Chief Deputy Attorney General Peter Siggins told Barry Goode, Davis' legal affairs secretary, that the bill would provide a good deal of risk to the bond sale and to a \$4.3-billion interim loan coming due Oct. 31. Because it allows PUC review of DWR's costs, the bill could constitute an event of default by the lending banks because DWR would no longer be the only party to determine the size of its revenue stream required for debt service, he said.

Siggins also backed Davis' claims that the bill would encourage breach of contract claims by generators. Generators could claim that the bill decreases their security interest, diverts funds to pay for their contracts and alters the payment priority under the deals, he said. He added that generators could sue the state for monetary damages for injuries from the breaches, money that would be taken from the state's power fund or its general fund. Davis plans to veto the bill when it comes to him from the Senate, said spokesman Steve Maviglio.

PUC General Counsel Gary Cohen in an Oct. 12 letter to Siggins rebutted many of the Davis official's claims. He argued that SB 18xx is a "superior financing mechanism" for bond repayment that would improve the lender's credit position. He said that there is no case law to support legal action against the state for damages.

As the PUC works on the rate agreement and contract issues, it is also working on DWR's "revenue requirement," another order critical to the bond issuance. Lead commissioner on the issue, Geoffrey Brown, said Thursday that a final order is likely in December. He expected PUC hearings in November to take testimony on DWR's revenue needs, which the agency revised downward about \$4-billion to \$17.2-billion on Oct. 19. DWR consultant Ron Nichols said the agency's expected costs fell because it is planning to buy less on the spot market.

"We want to wrap it up in December," Brown said of the PUC's revenue requirement vote. He said the PUC may have to hold a special meeting in December to vote on the revenue requirement since it is scheduled to meet only once, on Dec. 11, in that month.

The California Board of Equalization voted to allow the state to assess property taxes on power plants based on the full market value of the plants. The board—which administers state tax programs—voted 3-1 with one abstention to allow the rule to take effective Jan. 1, 2003, for plants over 50 MW, according to a board spokeswoman.

She said the plan must be reviewed by the Office of Administrative Law before it can go into effect. The board Nov. 28 will take up objections to the decision. Created by board chair and state Controller Kathleen Connell, who has criticized generators for overcharging for power, the decision paves the way for higher taxes on the plants. The board in 1999 had transferred its tax assessment of power plants to California counties, who under Proposition 13 have to limit their assessments based on land value at purchase and a 2% annual increase.

In what has become an interagency battle, the DWR claims a surge of large industrial customers switched to alternative power suppliers this summer after the PUC raised rates and postponed several times its vote on suspending direct access. Delaying the suspension allowed customers to switch, leaving fewer utility customers to pay off the state's huge debt from its wholesale power purchases over the next 10 years.

DWR claims 13% of the customers of the state's three largest utilities now buy their power from alternative suppliers, up from just 2% on July 1. The PUC counters the number is actually 8%, and argues that the customers' departure will lower DWR's costs in 2002 since the agency will need to buy less on the spot market.

The controversy erupted when DWR announced its revised revenue requirement, projecting total costs from Jan. 17, 2001, through Dec. 31, 2002, have been adjusted from \$21.45-billion to \$17.2-billion. DWR charges the projections would have dropped significantly more had the PUC suspended direct access on July 12 as originally scheduled instead of Sept. 20.

For its part, the PUC countered that a July 2 memo from the director of DWR, a deputy state treasurer and the Dept. of Finance established a new schedule for legislative action on direct access that required a postponement

of the scheduled July 12 vote to after Aug. 14. The Legislature adjourned Sept. 14 without taking any action so the PUC suspended direct access Sept. 20.

From a statewide survey of small and medium-sized business customers in California, Xenergy is preparing a report that finds higher energy prices, and not the threat of blackouts, motivated conservation efforts among 75% of those polled, while 34% reported taking conservation measures out of civic duty.

Pacific Gas & Electric oversaw the study on behalf of the PUC for the state's four investor-owned utilities. PG&E contracted Xenergy to complete the survey, which was funded from the public benefits fees paid by all utility customers, according to the utility.

The Xenergy report is still being prepared, but officials gave a briefing on the findings to the California Energy Commission last week.

The study suggests that much of the reduction in demand the state saw this summer that was attributed to energy conservation will disappear if customers perceive that the state's energy crisis is over. But because higher energy prices were the key motivation for most customers, what they do in response to increased utility bills will be critical in maintaining long-term conservation, said Julie Blunden, a Xenergy vice president. Blunden said utilities now need to reinforce the idea that customers could sustain lower bills by investing in energy efficiency.

Edison International is talking with generators about a plan to let subsidiary Southern California Edison pay what it owes for past power deliveries.

"They understand our view that we want to resolve our problems and to have certainty [as] to our cash flows as soon as we can," CFO Ted Craver said in a conference call with bondholders Oct. 19. "People seem to be approaching it in that spirit."

Craver said the results of PUC votes on DWR's revenue requirement and rates for the generation California's utilities were allowed to keep after restructuring took place—utilities' retained generation (URG)—will affect the settlement reached in early October between Edison and the PUC. The agreement, aimed at saving the company from bankruptcy, allows it to use revenue from customer bills to pay \$3.3-billion in power purchase debt. The company plans to pay off all defaults by the first quarter of 2002, Craver said.

It was unclear whether the settlement would be stymied by court challenges. The Utility Reform Network, a consumer organization, has appealed the package but had not decided whether to seek a stay. Los Angeles County, one of SoCal Ed's largest customers, was considering joining TURN in the appeal.

On the matter of utilities' "retained generation," the PUC Thursday decided it could set the rates in future proceedings without performing a market valuation of the generation. The PUC is charged with determining the value of PG&E's generation before Dec. 31, 2001, under the state's retail deregulation law passed in 1996. Paul Clanon, PUC Energy Division Director, said after the meeting that he expected draft decisions on the URG valuations for PG&E, Southern California Edison and San Diego Gas & Electric sometime this week.

Colorado

In their final vote, following 18 months of study and debate, the 29-member Colorado Electric Advisory Panel voted against recommending deregulation of the state's electricity industry to the Colorado Legislature, the body that created the panel.

Panel members claimed deregulation of the state's electricity industry would mean higher prices for consumers. The findings will be contained in a formal report to the Legislature. Opponents of deregulation in the Legislature are expected to use the document to quash any move in the coming session to open the state's power sector. Deregulation is strongly favored by the state's largest electric utility, Public Service Colorado, but opposed by most rural cooperatives across the state.

In response to the final vote of the panel, Public Service Officials suggested the panel members, and perhaps the Legislature, is out-of-step with the rest of the country.

The panel's report almost certainly means there will be not deregulation in Colorado for at least another year. Still, introduction of deregulation measures is expected in the state Legislature when it convenes in January. Previously introduced bills have died in three consecutive sessions.

Although it favors deregulation, it is Public Service's huge market share that frightened panel members away from recommending changes. The utility holds a 70% market share in the state, which enjoys relatively low

electricity rates. Without the existing controls on electricity prices, the utility would be free in a competitive environment to increase those prices, the panel said.

Previously, the panel concluded prices in the state would initially go up as retail competition to Public Service was introduced.

Many of the panel's conclusions were based on a controversial analysis by engineering firm Stone & Webster, which also suggested the significant market share of Public Service would thwart competitors. Colorado power rates are already low when compared to other Western states and low rates dull profit opportunities for other suppliers, Stone & Webster said.

Connecticut

The Connecticut Department of Public Utility Control issued a final order November 8, 2000, authorizing Northeast Utilities to issue rate reduction bonds to securitize up to \$1.55 billion in stranded costs for its Connecticut Light & Power subsidiary (Docket No. 00-05-01).

Under the order, the bonds can be issued for 10 years starting January 1, 2001, and will be supported by a 0.915 cents/kWh charge on all CL&P customers approved by the DPUC. This charge may vary in the future.

NU officials said that, based on the order, they now hoped to issue the bonds during January 2001, and are currently holding talks with rating agencies. NU hopes to receive the same 'AAA' rating that has been granted securitization bonds issued by other utilities.

Under the DPUC order, NU will establish a number of special purpose entities to issue the bonds. These entities will be rated separately from CL&P itself. The DPUC said that the bonds would reduce CP&L's carrying charges on stranded costs from 10.58% to 7.91% - saving customers about \$180 million over a 10-year period.

Connecticut began restructuring earlier this year under a 1999 law which permitted securitization of certain CL&P stranded costs under DPUC supervision. CL&P customers are already paying a competitive transition assessment charge (CTA) to cover stranded costs and the charge related to the bonds will become part of the overall CTA charge.

The stranded costs covered by securitization will include \$1.03 billion for buying down power purchase contracts and about \$500 million in costs for other regulatory assets.

NU officials said that CL&P started with a total of about \$3.6 billion in stranded costs claims approved by the commission but, due to successful sales of fossil, hydro and nuclear generation assets, total stranded costs have shrunk to about \$2.2 billion, of which \$1.5 billion will now be securitized.

Connecticut lawmakers specifically forbid NU to securitize any costs for its nuclear plants but, since then, NU has been able to sell its Millstone units at a premium price, eliminating any stranded cost concern.

While the legislature also extended the securitization option to United Illuminating, the utility has not yet petitioned to securitize stranded costs.

Delaware

Conectiv has filed shopping credits that are being reviewed by the Delaware Public Service Commission. The company will open retail competition for customers over 1 MW in October, then users with at least 300 kW in February 2000 and to all others in August 2000. The PSC expects to rule on the shopping credits by the end of August 1999.

Delaware Gov. Thomas Carper signed HB-10 that will begin retail competition on October 1, 1999 and phase-in the change by early 2001. The measure was backed by utilities, industrial users and consumer advocates.

The Delaware House of Representatives has passed legislation (HB10) that would open retail competition to industrials on October 1, 1999 and extend the change to all customers by early 2001.

The legislature recessed at the end of January and will not reconvene until mid-March, when the Senate will take up the bill. During that time, the Senate will hold public hearings on the issue.

HB 10 calls for retail competition to open on October 1, 1999, for Conectiv customers with loads of at least 1 MW. Conectiv users of at least 200 kW would be able to shop for supplies starting February 1, 2000, while smaller consumers would gain access to the market on August 1, 2000. The schedule would run six months' later

for Delaware Electric Cooperative (DEC). The bill does not cover municipal utilities, though they could introduce competition at their own timetables.

Conectiv, which includes the former Delmarva Power and serves most customers in the state, has not incurred high stranded costs in Delaware because it has limited nuclear investments and no major independent power contracts, explained Bruce Burcat, executive director of the PSC. Therefore the company would only recover \$18-million in restructuring costs, and these would be collected only from large commercial and industrial customers – another concession to small consumers.

The bill would also cut rates 7.5% for Conectiv residential customers, starting October 1, 1999, and would freeze those rates for four years. Larger users would only receive a rate freeze, running three years. In DEC territory, all customers would be covered by a five-year rate freeze, but would receive no rate cuts, since the co-op recently enacted a 5% reduction.

At the end of the four-year transition period, the PSC could open bidding to replace Conectiv as the default generation supplier for customers that do not select outside marketers. If it does not open such bidding, it will require the utility to provide generation at market prices, explained Burcat of the PSC.

A number of consumer benefits are included in the bill as well, including licensing of power suppliers by the PSC, consumer education on electricity choice, \$800,000 in annual funding for low-income customers, \$800,000 annually for energy conservation and environmental incentive programs and PSC authority to curb market power.

District of Columbia

The District of Columbia opened retail competition on January 1, 2001, though the Public Service Commission is still reviewing licenses from retail marketers, a process that it expects to complete by the end of the month. The PSC is also focusing on consumer protection, with regulations to prevent “slamming” – or unauthorized switching of customers.

Potomac Electric Power is the only electric utility in the district, supplying about 195,000 residential customers and 26,000 commercial users. It also has 480,000 customers in Maryland, which opened access in July, but where there is very little activity.

D.C. PSC Chairman Angel Cartagena thinks the district will see more participation, partly because the customers are concentrated in a small area, making it easier for marketers to reach them. He added, “Over the next year, we’ll monitor how things pan out, and make adjustments to the regulations, if necessary.”

To prevent slamming, the PSC will require third-party verification of customer sign-ups by marketers. These third parties must be independent companies and must be subsidized by the retail marketers. In addition, the PSC will punish marketers that slam, Cartagena said.

Six companies have applied for retail marketing licenses, and the PSC has so far approved one, for Washington Gas Energy Services, an affiliate of the local gas utility. By the end of the month, Cartagene expects to finish reviewing applications from the five other companies: Pepco Energy Services, and unregulated affiliate of the electric utility; Washington Energy Consortium; SmartEnergy.com; Allegheny Energy Services; and FirstEnergy Services. Allegheny has successfully marketed to aggregated residential customers in Pennsylvania and the D.C. PSC is encouraging aggregation. Further, the D.C. Office of Energy will aggregate low-income customers.

At this point, the PSC has established only “shopping credits,” or “prices to compare” for Pepco, since the company recently sold most of its power plants. In that divestiture, Pepco sold about 4,400 MW to Southern Energy Inc. for \$2.75 billion. Over the next two to three months, the commission will adjust the credits based on the sale, which was lucrative for Pepco, and eliminate stranded costs.

The interim credits are: residential, 5.18 cents/kWh; residential low-income, 4.5 cents; small commercial, 4.68 cents; and large commercial, ranging from 4.43 to 3.68 cents. Those figures include generation and transmission.

In the power plant deal, Southern Energy agreed to sell Pepco power from the plants for up to four years, at prices below its current costs, assuring that the utility has supplies for native load customers that do not shop.

Florida - New

The Florida Public Service Commission told investor-owned utilities to go back to work and submit a plan for an independent system operator rather than the GridFlorida regional transmission organization because it was not convinced of the benefits of forming the RTO.

Bob Trapp, who works in the PSC's policy section said the primary difference between the RTO and the ISO is that the utilities would keep their transmission assets, but would still need some type of organization to operate the ISO. Trapp said the PSC approved most of a recommendation on GridFlorida, but did not rule on legal matters, because it decided that was not necessary at this time.

Staff said participation in the GridFlorida RTO was voluntary under the Federal Energy Regulatory Commission's Order 2000. While the RTO might enhance the effectiveness of the wholesale generating market, "it is not a prerequisite for competition, since open access transmission is currently available." It also noted, however, that wholesale generating competition is currently restrained, because the state's Power Plant Siting Act prohibits merchant plants.

Trapp said the ISO would meet the requirements of FERC Order 2000, because it would still ease the transmission restraints FERC sought to eliminate.

"We hope FERC reacts favorably," Trapp said. Florida regulators and FERC have been at odds over jurisdictional questions concerning the RTO. "We hope we're entering into a new cooperation with FERC." The companies involved in GridFlorida – Florida Power & Light, Florida Power and Tampa Electric – had been unable to quantify the potential savings to themselves or any other market participants.

Staff added that, although formation of the RTO had not been demonstrated to be financially prudent, the IOUs were prudent in being proactive in responding to Order 2000, and should be allowed to recover \$9 million of the funds spent in that effort. The estimated total cost of forming the RTO would have about \$200 million.

Staff said an RTO for the Southeast that would include the Florida IOUs would not be a better alternative than GridFlorida, and would not be advantageous for the IOUs' ratepayers, but the utilities "should continue to participate in discussions regarding the creation of a Southeast RTO in anticipation that the FERC may one day mandate all FERC-regulated utilities to join a regional transmission organization."

Georgia

July 23, 1998: The Georgia Public Service Commission has ordered two Southern Company affiliates - Georgia Power and Savannah Electric & Power - to analyze how industry restructuring will impact their 10-year integrated resource plans and future investment decisions. (Docket No. 98-8708-U, 98-8709-U)

The PSC also asked Georgia Power to submit a report within 90 days on how the state transmission system will handle new power flows created by deregulation and said both companies should delay implementing cuts in reserve margins until the commission completes a restructuring-related study of reliability issues.

Under Georgia law, the two utilities must submit updated integrated resource plans every three years and seek approval by the PSC. In return, they have the right to ask for PSC pre-approval for spending on new resource acquisitions.

The two companies submitted proposed IRPs in February 1998, but the PSC staff complained that the ten-year plans ignored the fact that the Georgia energy market was likely to be deregulated within that time frame, resulting in a major impact on the need for new resources.

So far the debates on restructuring in Georgia, the Southern Company affiliates have called for delay saying the state already has low prices and does not need retail competition. The PSC is just beginning a formal investigation of the issue and the state legislature is not expected to consider a restructuring bill until 2000 at the earliest.

In the filings to the PSC, company representatives said that the issue of restructuring was irrelevant to the planning effort and that they did not want to submit internal company data on the possible affects of decontrol.

The PSC decided against a staff proposal to bar the companies from collecting stranded costs on new investments if they failed to carry out the studies. PSC members said they were not sure they had legal authority for such a step.

On the reserve margin issue, staff complained that the two companies planned to reduce margins by 1.5% to 12.6% despite a June spike in Georgia power demand which almost forced the company to start cutting back supply. They said such a low level would also be out of line with neighboring utilities.

Hawaii

In April 1999, both houses of the state legislature approved a resolution asking the Public Service Commission to report on the status of its restructuring investigation. In November 1998, a collaborative of 12 stakeholder groups reported to the Public Service Commission that they failed to reach a consensus on basic aspects of comprehensive industry restructuring.

As the 1999 legislative session adjourned, both houses of the state legislature passed a resolution requesting a report from the PSC on the status of its restructuring investigation. The report is due by January 2000, when the next session begins. There has been no action on the investigation since November 1998, when the collaborative group studying restructuring reported that it could not reach a consensus.

The collaborative report, filed in 12 separate position papers by participating stakeholders, noted general agreement with the idea that Hawaii's unique situation as a state comprised of islands precludes the kind of restructuring underway in the mainland states. The report also noted that some parties favor increased competition in customer services, management of electricity demand/conservation and generating unit operations and maintenance services. The utilities tended to recommend competitive bidding for new generation, performance-based ratemaking and innovative pricing mechanisms.

Idaho

Idaho Governor Dirk Kempthorne signed a bill that blocks one effort at retail competition in the state, and others that might have risen, by closing a loophole in a 30-year-old law that industry observers said could have led to deregulation without express approval by the state.

The bill, HB 142, was passed by the Legislature. Drafted by a group of investor-owned utilities and rural cooperatives, the legislation puts into permanent law an emergency measure passed in December and set to expire on March 1, 2001. The measure "preserved our [Public Utilities Commission] authority so we didn't become deregulated," said sponsor Representative Bert Stevenson.

The bill was drafted in response to a decision last October by the 9th Circuit Court of Appeals, which ruled that Idaho's Electric Supplier Stabilization Act of 1970 illegally allows utilities to give up customers, acquire new customers and swap territories without approval by state regulators to ensure that such transactions are in the public interest. "The statute simply allows private parties to decide under what circumstances competition will be allowed," the court said, advising the legislature to repair the deficiency.

The purpose of the 1970 law was to promote cooperation among utilities in Idaho by prohibiting "pirating" of another supplier's customers, discouraging duplication of generation capacity and stabilizing service territories. Toward the end, the Legislature expressly restricted competition for existing utility customers.

The appeals court ruling came in an antitrust lawsuit by the Snake River Valley Electric Assn., which said PacifiCorp and its subsidiary, Utah Power & Light, were violating federal antitrust law by refusing to let the cooperative supply power to its members and to PacifiCorp customers through PacifiCorp's transmission lines.

A lower court ruled in PacifiCorp's favor and said the utility was shielded from antitrust suits by virtue of the 1970 law.

In October, the Appeals Court reversed in part: It agreed that PacifiCorp was within its rights to bar access to its customers, but said the utility's actions were not shielded from antitrust charges under state-action immunity doctrine because the 1970 law did not provide the required regulatory supervision over agreements among electricity suppliers. The three-judge panel remanded the case to the lower court and in late January denied a petition by PacifiCorp and the state for a hearing before the full Appeals Court.

As part of the negotiations, Idaho's municipal utilities and rural cooperatives agreed to limited PUC oversight. The PUC will review and approve any contracts allocating service territory. The PUC, rather than the courts, will settle disputes about which utility is closest to new customers and whether a consumer is entitled to retail wheeling. Utilities will still be able to refuse retail-service access to their transmission lines by competitors, but consumers will have the right to take their case before the PUC.

Illinois

The outlook for residential customer choice in Illinois is bleak. Under the state's Electric Service Customer Choice and Rate Relief Law of 1997, residential customers become eligible for choice on May 1, 2002. But because lawmakers granted residential customers in Commonwealth Edison's service territory a 20% discount on their bundled electric service, these customers are not likely to discern any tangible benefit to customer choice when it goes into effect next year.

“The decision to provide automatic, up-front savings for residential customers...necessarily reduces the potential for further savings through participation in the open access system,” ComEd’s Vice President of Regulatory and Strategic Service Arlene Juracek told the Illinois Commerce Commission in the company’s June 1 petition for approval of residential delivery service charges. She said the ICC should be prepared for the possibility that alternative energy suppliers will find it less attractive to compete for the business of residential customers when these customers are already seeing discounted rates for bundled service.

Residential customers were given a 15% rate cut in August 1998 and will receive an additional 5% reduction in October 2001. The action was intended to offer savings to bundled residential customers while non-residential customers were offered customer choice.

The ComEd petition seeks approval of an average delivery service rate of 2.05 cents/kWh for all customer classes. This translates to delivery service charges for the five classes of residential customers of 2.55 to 4.66 cents/kWh. ComEd said these figures are comparable to charges imposed by other companies in open retail markets.

Last year, ICC Chairman Richard Mathias reported that prospects for retail activity in Illinois had declined over the last half of 2000. A roundtable with 23 representatives of electric utilities, alternative suppliers, and others, concluded that a vibrant, competitive wholesale market combined with an increase in the amount and availability of power and energy was needed before these could be effective retail competition.

At least one component works in favor of choice. Illinois continues to be the preferred Midwestern state for the development of new gas-fired power plants, with 59 plants representing 27,881 MW now permitted, under regulatory review or placed in operation since late 1999.

A buyer’s coalition made up of the City of Chicago and 48 suburban governments has selected Enron to supply the municipalities with electricity, thereby saving more than \$4 million annually over the rate charged by current provider Commonwealth Edison.

The deal, which still must be ratified by the various city councils, will unplug ComEd for 60% of the group’s municipal electricity supply.

The city itself expects to save \$3 million annually. Also included in the deal is power for the Chicago Transit Authority, Chicago Park District and city colleges.

“We used our purchasing power as local governments to get the best price we could and at the same time promote competition in Illinois,” said Chicago Mayor Richard Daley. Overall, members of the Local Government Power Alliance represent a load of more than 400 MW. Chicago is the largest user at 200 MW, with the CTA next with about 100 MW.

In a related development, the coalition selected ComEd to supply 80 MW of renewable energy within five years. This represents 20% of the overall 400 MW load and gives back to ComEd some load it lost to Enron. ComEd retains 20% of the historical load of coalition members in Northern Illinois.

Last July, the Alliance issued a request for services (RFS) to the 13 alternative retail energy suppliers (ARES) then certified by the Illinois Commerce Commission. According to Steve Walter, head of City of Chicago’s energy division, only three responses were received: one from Enron, one from ComEd and one from a Chicago-based minority firm CEI that was considering teaming up with a certified ARES.

A ComEd spokeswoman said the company has always been a strong supporter of restructuring and customer choice in Illinois. The company will take the 240 MW freed up by the coalition’s selection of Enron and offer it for sale on the wholesale market.

Indiana

Indiana lawmakers have California and merchant power plants on their minds as they debate newly introduced legislation that would create an Energy Policy Commission to craft a comprehensive energy plan for the state.

Senate Bill 233, sponsored by State Senator Beverly Gard, was inspired by California’s electricity crisis and continuing controversy in Indiana over the development of merchant power plants.

Gard and other members of the General Assembly point out that the state lacks a true energy policy that could serve as a blueprint to address future electric load growth.

“Merchant power plants have been a divisive issue in the past year and a half,” Gard said. “There are many people who feel if the state has a comprehensive energy policy, it might be better able to deal with this issue. And we also have to pay attention to what’s happened in California.”

More than two-dozen merchant plant projects have been proposed for Indiana, with seven receiving approval so far from the Indiana Utility Regulatory Commission. Gard said she’s not convinced merchant plants “will be the long-term answer” to the state’s energy needs. Indiana, she believes, need new baseload generation to replace its aging fleet of mainly coal-fired power plants.

Gard’s bill would set up a temporary commission with members appointed by Governor Frank O’Bannon, representing various stakeholder groups, including state government, industry, labor and environmental. The commission would begin work in October and present a final report to the governor 14 months later, in December 2002.

Although electric deregulation would not be a prime focus of the commission, the “specter of deregulation” would have to be examined in some fashion, she said.

SB 233 has been sent to the Senate Rules and Legislative Procedures Committee. Gard predicts it will pass the Senate, although chances in the house of Representatives are less certain.

Iowa

The state Senate adjourned in May without mustering enough votes to approve House File 577, a legislative package that would foster development of new generating capacity.

The bill would have allowed the Iowa Utilities Board to irrevocably approve power purchase agreements between electric utilities and unregulated power suppliers, including affiliates. Specifically, under HF 577, and Iowa utility that signed a PPA for electricity that equaled or exceeded 5% of the utility’s retail load and that drew power from a new plant in Iowa would have been given irreversible contract approval by the IUB within 90 days, provided the agency found the contract “reasonable and prudent.” If the utility itself sought to build a new plant, the proposed legislation would have required the IUB to specify in advance the ratemaking principles it would use in allowing the recovery of and return on the company’s investment.

Republicans and private and public utilities supported the proposed legislation. Democrats, backed by labor and the senior citizen lobby, opposed it. Senate Minority Leader Michael Gronstal said the special ratemaking provisions granted to utilities were inappropriate without corresponding requirements that new generation in Iowa serve Iowa customers.

Kansas

Saying “immediate action” is needed “to prevent irreparable harm to the public interest and safety,” the Kansas Corporation Commission ordered Western Resources to halt its planned corporate restructuring.

The KCC said the plan could burden Western’s regulated utilities with the debts of unregulated operations. The asset allocation agreement between Western and its unregulated Westar Industries unit is of no legal effect because it has not been approved by the KCC as required by state law, it added (Docket No. 01-WSRE-949GIE).

Also the Financial Accounting Standards Board told its staff to draft final versions of a new rule on goodwill and intangible assets that would have a material negative impact on Protection One, Western’s money-losing 85% owned monitored security unit.

The asset allocation agreement is an integral part of the restructuring plans and rights offering, which would split Western’s regulated utilities (KPL and KGE) from unregulated operations. The plan was filed with the Securities and Exchange Commission (S-1 Registration Statement No. 333-47424).

Western’s filing for expedited approval by the SEC shows the company’s “intent to proceed with the proposed rights offering without regard to the outcome of the Commission’s investigation and review process established in this docket, and without regard to the possible practical difficulties of restoring Western Resources financial condition, particularly its capital structure, to its pre-restructuring state should the Commission ultimately determine that Western Resource’s actions in the restructuring transactions are inconsistent with its public service duties and obligations to ratepayers,” the KCC said.

The order also required Western not to take any action that would boost debt in its capital structure. The KCC set a hearing for June 14 on issues covered in the new order, which came two weeks after the KCC began investigating Western's restructuring plan and the effect on the utilities of the unregulated holdings.

The new order noted, "The Commission hereby finds that there is a distinct possibility that Western Resources electric business' capital structure is inconsistent with the public's safety and convenience, and adversely affects its ability to provide efficient and sufficient service at just and reasonable rates."

A major problem facing Western is Protection, which in the years 1997-2000 lost a combined \$198 million on revenue of \$1.6 billion. "We do not expect to have earnings in the foreseeable future," it noted in the Form 10-Q for the first quarter, during which it had a net loss of \$8.5 million, down from year-before net income of \$3 million, on revenue of \$87.8 million, down 24.4%. The after-tax operating loss was down 9% to \$26.8 million. Extraordinary gains on debt repurchases (after tax) fell 42.5% to \$18.3 million.

Western has taken the position that problems at Protection have no bearing on its regulated utility operations. In comments published May 22 in The Topeka Capital Journal, Western executive vice president and chief administrative officer Carl Koupal was quoted as saying that if the KCC wanted the restructuring delayed until the KCC investigation is completed in October, it should have explicitly said so. "It didn't say that in the order," he added. Hours later, it did.

A spokeswoman said Western was reviewing the order "to determine our options." Hearings are underway in Western's rate case, which the two utilities want a net \$151 million hike. The KCC staff has urged a net \$92 million decrease.

On May 24, Western stock gained 62 cents to \$21.26, down 3.4% in a week, but up 38.3% from a year before. Protection closed up 3 cents at \$1.48, up 3% from May 24, 2000.

Kentucky

A special Kentucky Electricity Restructuring Task Force recommended that lawmakers wait until the 2002 General Assembly to consider opening the state's electric industry to competition.

"There is no compelling reason at this time for Kentucky to move quickly to restructure," the 20-member task force concluded in its report. The task force was established during the 1998 legislative session after a deregulation bill died in committee.

A final report will be presented to Kentucky Governor Paul Patton before the legislature convenes in January 2000. The General Assembly meets every two years in regular session in Kentucky.

The task force said in the report that Kentucky, which relies heavily on coal-fired generation, "is in a unique position because of its existing low electricity rates, which currently are the lowest east of the Rocky Mountains."

Despite the possibility of congressional legislation to mandate restructuring and actions taken by 23 states to restructure, there are "obvious advantages for Kentucky adopting a wait-and-see approach to electricity restructuring," the task force said.

Such a position allows Kentucky to monitor the progress of restructuring in other states and to develop options that protect Kentucky's low rates for electricity, the task force added.

The task force also found:

- ?? Restructuring can be expected to have multiple effects on Kentucky's electricity prices. If the state's electric rates are deregulated, price fluctuations probably would be larger in magnitude than fluctuations under cost-of-service regulation.
- ?? Three utilities that operate in Kentucky – Cinergy, Big Rivers and the Tennessee Valley Authority – collectively have potential stranded costs that range from \$295 million to more than \$1 billion. The state's remaining utilities are in a "negative stranded cost" position, meaning the market value of their generating assets and purchase power contracts is higher than the book value for these assets in a regulated market.
- ?? Restructuring is not expected to reduce the importance of natural gas in new generating capacity in Kentucky. During the past 10 years, all new capacity in Kentucky has been gas-fired. The last coal-fired unit, Louisville Gas & Electric's 495 MW Trimble County plant came on-line during the early 1990s. "As the cost advantage for gas-fired generation continues to increase and the demand for electricity continues to grow during summer peaking months, the expectation is that new capacity will be gas-fired combustion turbines."

?? The task force report disappointed Cinergy, perhaps the leading advocate of restructuring in Kentucky. Cinergy is the parent company of Union Light, Heat & power, which serves about 120,000 electric customers in northern Kentucky. It also is the parent company of Cincinnati Gas & Electric and PSI Energy.

Louisiana - New

The Louisiana Public Service Commission adopted a resolution November 7, 2001, calling for a new round of studies of deregulation issues, but takes no action to begin retail choice in the near future.

The five-member panel has been reviewing a staff proposal for the last six months allowing large customers to begin retail competition in 2003. But the commission has backed away from the partial deregulation approach, apparently because several members were concerned about approving any moves toward deregulation in the wake of the California problems.

The resolution, which was supported by all five members, instructs staff to organize a series of collaborative with wide public participation to explore remaining open issues connected with electricity deregulation, allowing the state to act more quickly in the future should deregulation become advisable.

The commission also told its staff that if any of Louisiana's three neighboring jurisdictions – non-ERCOT-Texas, Arkansas or Mississippi – start retail competition, staff should study the results after the first year of operations and make recommendations within three months to insure Louisiana does not lose edge to other states in attracting industry.

Currently, Mississippi is showing no signs of deregulating and Arkansas is expected to delay retail competition until at least 2005. The situation in Texas is less clear, with state regulators still undecided on the timing of deregulation outside the core ERCOT areas.

Staff will also report to the PSC on any action by Congress or the Federal Energy Regulatory Commission which could have adverse consequences for the state. The PSC will then “take whatever steps are necessary to protect Louisiana ratepayers and preserve the Commission options.”

The PSC had been considering deregulation for several years and, in January 2001, the staff concluded that retail choice would probably not benefit smaller users, but might help larger customers. During the year, major utilities led by Entergy worked out a partial deregulation plan with industrials whereby customers would get an initial six months window to switch to the competitive market, with further opportunities to switch in later years. That plan now appears to be suspended for the foreseeable future.

Maine

In a new sign that energy markets in New England are moderating, the Maine Public Utilities Commission has secured contracts to supply standard offer energy in the 5 cents/kWh range to Central Maine Power and Bangor Hydro Electric residential and small business users for three years starting March 1, 2002.

The deals, announced Sept. 19, are good news for about 100,000 Bangor Hydro residential and small business customers, who now pay 7.3 cents/kWh under a contract negotiated late last year when market prices were significantly higher. Rates will be cut 46% to 5 cents/kWh next March and the “all in” rate—including distribution charges— will drop 14% to 14.4 cents/kWh for residential and 14.5% to 13.6 cents/kWh for small business users.

The news is less good for CMP's 500,000 small users who are now getting energy at 4.1 cents/kWh under a two year contract negotiated in 1999 when the market was still low. Under the new deal, energy costs will increase 21% to 4.95 cents/kWh next March and the “all-in” standard offer rate for CMP users will go up about 7% to 12.9 cents/kWh for residential and 13.2 cents/kWh for small business users.

CMP officials, however, noted that the increase will be moderate compared to what it might have been if New England energy costs had stayed at previous levels.

The PUC, which has the primary responsibility to arranged standard offer contracts for the utilities, issued RFPs July 23, saying it hoped to take advantage of falling market conditions and gain benefits for the small users in the state, most of whom still now take the standard offer instead of competitive supplies.

The PUC said Sept. 19 that it had received “numerous and very competitive bids” for both territories. It decided to take the three year deals to give retail users relief from annual energy price fluctuations and provide a “stable target” for competitive suppliers to make offers against over the period.

PUC Chairman Tom Welch believes New England prices were still falling and that when the new standard offer rates took affect next March, competitive sellers might still offer better deals. The PUC said it would not reveal the identities of the sellers for two weeks to give them time to cover their supply positions.

Welch also revealed that the PUC had waited a week to set the new rates to be sure the Sept. 11 terrorist attacks did not drive up the market. But in the end there was little affect, he said, and, if anything, additional worries about the economy seemed to be depressing rates.

The PUC already acted in August to reject a proposal by Bangor Hydro under which the utility itself wanted to procure standard offer energy for its small and medium users at 5.5 cents/kWh for four years. At the time, commission believed it could get a better deal, which, in fact, it has now done.

The PUC must still issue RFPs to procure standard offer energy starting next March for Bangor Hydro and CMP medium and large users who are currently paying rates in the 7.5 cents/kWh range for supplies.

Maryland

Baltimore Gas & Electric has chosen Constellation Power Source and Allegheny Energy Supply to provide power for its "standard offer service" (SOS) customers – those that do not shop in the open market.

The utility needs supplies because after Maryland deregulated in 2000, parent Constellation Energy Group (CEG) shifted all of its power plants to Constellation Power Source and Constellation Nuclear, both unregulated entities. Constellation Power Source is now supplying BGE, but that contract expires in mid-2003, before the utility reaches the end of the competition "transition" period, when rates are frozen for customers.

In May, BGE issued a solicitation, and received bids from six companies, according to a spokesman. On August 24, 2001, the company announced that it had chosen affiliate Constellation Power Source to supply 90% of the utility's load and Allegheny to supply the remaining 10%. The spokesman explained that bidders proposed supplies in blocks representing 10% of the BGE load.

Constellation and Allegheny will supply up to 5,300 MW for all BGE's SOS customers through mid-2004. At that time, the "transition" period will end for commercial and industrial users, and their rates will be unfrozen. From mid-2004 through mid-2006, the suppliers will provide up to 2,900 MW for residential customers.

The utility did not provide prices, but said they are no greater than the retail SOS rates, which are frozen. The contracts will lock-in prices that will allow it to provide the frozen rates "without any adverse financial impact on the utility," BGE stated.

Constellation Power Source controls about 4,500 MW of fossil plants that belonged to BGE, plus other plants it has developed or acquired, and independent power projects originally owned by other affiliates. It also runs a wholesale marketing operation. Constellation Nuclear operates the 1,700 MW Calvert Cliffs station as a merchant plant. By the end of the year, CEG plans to spin off all of these generating and marketing operations as a separate, publicly-traded company.

Allegheny Energy Supply is the unregulated generating and marketing unit of Allegheny Energy, which also plans to spin off the company.

Massachusetts

Joining a growing list of New England utilities slashing retail energy rates to reflect declining wholesale power prices, NSTAR, Massachusetts' largest electric and gas utility, plans to lower its default service rates.

The parent of Boston Edison, Cambridge Electric and Commonwealth Electric asked regulators to approve a 27% decrease in residential default service (DS) rates beginning January 1, 2002. Commercial and industrial DS customers will see similar decline. The rates are effective through June 30, 2002. Even lower DS rates are scheduled for the second half of 2002.

Neighboring utilities Massachusetts Electric and Unitil/Fitchburg Gas & Electric also announced rate cuts, as have utilities in Maine and Rhode Island.

NSTAR also plans to announce a drop in its standard offer (SO) rates. Customers who have been with the utility since deregulation began in March 1998 take SO service, while those who have joined the utility after deregulation take default service. The SO rate is based on long-term contract prices that the utility has negotiated with suppliers, while DS power is purchased under short-term agreements.

If approved by the state Dept. of Telecommunications and Energy, DS rates for Boston Edison residential customers will drop in January from 8.743 cents/kWh to 6.393 cents/kWh. Small C&I rates will drop from 9.035 cents/kWh to 6.574 and large C&I rates from 8.664 to 6.549 cents/kWh.

For sister company Cambridge Electric, rates will drop from 8.333 cents/kWh to 6.060 cents/kWh for residential customers; from 8.622 cents to 6.232 cents for small C&I and from 8.23 cents to 6.175 cents/kWh for large C&I. Commonwealth Electric will decrease rates from 8.651 cents to 6.289 cents for residential customers; from 8.956 cents to 6.468 cents for small C&I; and from 8.511 cents to 6.410 cents for large C&I.

For July through December 2002 Boston Edison proposed rates of 5.638 cents/kWh for residential customers; 5.671 cents/kWh for small C&I and 5.922 cents/kWh for large C&I. Cambridge Electric plans to charge 5.351 cents/kWh for residential; 5.380 cents for small C&I and 5.613 cents for large C&I; and Commonwealth 5.520 cents for residential; 5.552 cents for small C&I and 5.792 cents for large C&I. In comparison, rates were 8.2 cents/kWh to 9 cents/kWh during the same period in 2001.

The new DS rates reflect the result of the utility's recent competitive solicitation for DS power.

The Massachusetts Division of Energy Resources has proposed that utilities buy a percentage of their standard offer and default service power from renewable sources beginning in 2003. The state legislature mandated that the DOER create the regulations as part of the state's restructuring law.

Under the proposal, both utilities and retail suppliers would buy one percent of their power from renewables beginning in 2003, increasing to four percent by 2009. After 2009, the standard would continue to rise by one percent a year until the state decides to suspend the annual increase.

The power must come from "new" renewables, meaning those that begun commercial operation after December 31, 1997. A wide-range of resources qualify, including solar, wind ocean thermal, wave and tidal energy, landfill methane, fuel cells and certain biomass projects. The power can be imported from outside Massachusetts.

As an alternative to buying power, utilities can make a payment to the Massachusetts Technology Park Corporation, which provides seed money and financing for renewables development. The DOER says it offered this choice to help avoid market abuses by generators and to protect customers should renewable power prices spike. The payment rate is \$50/MWh in 2003 and will be adjusted annually based on the Consumer Price Index.

The DOER expects the new regulations to have only a small impact on consumer rates. Typical bills will increase about 0.2 percent in 2003 and 0.8 percent in 2009.

Written comments are due to the DOER by November 2, 2001. The regulations are available at www.state.ma.us/doer/rps.

Fitchburg Gas & Electric, a Massachusetts utility owned by Unitil Corp., announced that it has proposed a 45% drop in its default service rates. The announcement comes after other utilities in the area have lowered their rates but none so drastically.

The new rate reflects declining wholesale prices, specifically the low bid the utility received in its recent solicitation for DS power. Several multi-national energy suppliers responded to the solicitation, many with bids well below current rates, according to the utility.

FG&E issued the solicitation through the web-based Energy Exchange of Enermetrix. The utility did not release the name of the winning bidder.

If approved by the Massachusetts Dept. of Telecommunications and Energy, rates will drop for residential DS customers to 4.996 cents/kWh from 9.128 cents/kWh; small commercial to 5.005 cents/kWh from 9.113 cents/kWh and large industrial to 4.679 cents/kWh from 8.787 cents/kWh. The bill of a typical residential DS customer using 500 kWh/month will drop to \$65.40 from the current level of \$86.06, a reduction of \$20.66 or 24% on the total bill.

DS rates, which reflect only the generation portion of the bill, are watched closely by retail suppliers because they typically must beat the rate to lure customers from utilities. DS customers are those who lost or left their competitive supplier, or who joined the utility's service territory after deregulation began.

The new rates will be effective December 1, 2002 to May 31, 2002, pending regulatory approval. Since utilities directly pass their DS contract price to consumers, the review is typically straightforward, with approval usually coming within a week.

Massachusetts Electric, a subsidiary of National Grid USA, asked state regulators to approve a more than 2 cents/kWh reduction in default service rates. Default service is Massachusetts' version of back-up service for those who have lost or left their supplier. It is also for anyone who moves into a new service territory since deregulation has begun.

Rates for fixed-price residential default service will drop from 9.213 cents/kWh to 6.917 cents/kWh, pending approval by the state Dept. of Telecommunications and Energy. Commercial rates would drop from 9.556 cents to 7.045 cents/kWh and industrial rates from 9.054 cents to 6.787 cents. The new rates reflect the utility's wholesale power costs from November through April. Mass Electric declined to name the supplier. About 25% of Mass Electric customers – or 300,000 – take default service.

A municipal aggregation has asked Massachusetts regulators for permission to become a retail default service (DS) provider, a role so far held only by utilities in the state.

The Cape Light Compact, an aggregation of 21 municipalities, wants to supply DS service to 42,000 customers now served by NSTAR's Commonwealth Electric. Default service is a safety net for customers who have lost or left a competitive supplier, or who are new to a utility service territory.

If the 15-month pilot project wins approval from the Dept. of Telecommunications and Energy, the compact will be the first non-utility in Massachusetts to provide default service to retail customers.

Under the plan, all DS customers in the 21 municipalities would automatically be switched out of utility service, unless they specifically opt out of the compact program. Those who do opt-out could buy power from a competitive supplier or continue to take default service from the utility. Anyone new to default service also would be placed in the compact program.

NSTAR, which makes no profit on default service, but passes costs directly on to customers, said the pilot program is in keeping with plans by the state to transition customers out of default service and into the competitive market. At the same time, however, the utility expressed concern about various scheduling and customer transition aspects of the plan. The utility emphasized that it will need adequate time to make system changes in customer enrollment and supplier transactions.

The compact said that this is a good time to initiate the pilot project because utility default service prices have reached a "cross over" point with market prices, creating savings opportunities for customers.

Commonwealth Electric's fixed DS prices for September are: 7.421 cents/kWh for residential customers; 7.671 commercial; and 7.267 industrial. The utility buys the power under short-term contracts secured through competitive solicitations.

The compact did not specify how much savings it will attempt to achieve, and the state Attorney General's office criticized the plan for not making clear if the aggregation will solicit supply through a request for proposals that seeks power priced below utility DS rates.

The pilot won support from the state Division of Energy Resources, which described it as a "worthy opportunity" for non-utilities to learn the daily logistics of an alternative supply program. Low-income advocates also have praised it, saying it will provide badly needed rate relief.

Critics, however, say the plan could make retail suppliers shy away from Massachusetts out of fear that they may suddenly lose their customers to a municipal aggregation's "opt out" program. "Such an opt-out systems operates essentially as a form of slamming by the municipality," Dominion Retail said in comments recently filed with the DTE.

Michigan - New

Alternative energy suppliers with no regulated business operations in Michigan are essentially excluded from a modified code of conduct adopted by the Michigan Public Service Commission. The PSC initially adopted the code on December 4, 2000, to promote fair competition in the state's deregulating electric utility industry by establishing measures to prevent cross-subsidization, information sharing and preferential treatment between a Michigan utility's regulated and unregulated services or between an alternative electric supplier offering regulated services in Michigan and its affiliates.

Several companies, primarily alternative energy suppliers, subsequently requested a rehearing in hopes of making changes in the code. The commission's final order "clarified the applicability to alternative energy suppliers by stating that the code only applies to those alternative electric suppliers that have regulated operations

in Michigan,” explained Mick Hiser, director of the PSC’s Licensing and Enforcement Division. “Previously, the code of conduct would have applied to any and all alternative electric suppliers.”

Hiser supports the change, pointing out the general premise of a code of conduct is “to prevent unfair competitive advantages of operating regulated and unregulated enterprises within a given market.” The PSC order also permits electric utilities and alternative electric suppliers to request waivers from one or more provisions of the code after demonstrating the waiver would not inhibit the development of a competitive market.

Minnesota

A comprehensive energy bill that provides for the streamlining of power plant siting and transmission line routing but does not deregulate the electric industry in Minnesota is on its way to Governor Jesse Ventura, who is expected to sign the legislation.

According to the Minnesota Dept. of Commerce, 3,000 MW to 5,000 MW of new generating capacity will be needed in the state between 2006 and the end of the decade.

Senate File 722 continues the authority of the Minnesota Public Utilities Commission to determine project need and of the Environmental Quality Board to rule on siting and environmental issues. It exempts from any need determination projects that upgrade existing large energy facilities unless the modification increase output by more than 100 MW or 10% of the existing capacity, whichever is greater.

The final bill offers two fast-track review alternatives for specific projects, including new generating plants less than 80 MW, those fueled by natural gas, transmission lines between 100 kV and 200 kV, and T-lines greater than 200 kV but less than 10 miles long. Projects in this class no longer have to prepare a full environmental impact statement, but are subject only to an environmental assessment worksheet, a lower level of environmental review. In a second alternative, project developers who fall into this class can opt for local rather than state review.

Debate among conference committee members focused primarily on renewable energy, said Bill Grant, executive director of the Izzak Walton League. The Senate version required a renewable portfolio standard of 10% of retail electricity sold coming from renewables by 2015. The House version, however, contained a less stringent green pricing approach, he said. The conference compromise retains the 10% level by 2015 but makes it a goal rather than a requirement.

The Department of Commerce must report to the legislature by January 15, 2002, how the goals will be implemented.

Mississippi

The Mississippi Public Service Commission has ruled that it is not in the public interest to begin retail competition in the state at this time. May 2, 2000, PSC Chairman Nielsen Cochran said the commission had determined that because Mississippi was a low-cost state, deregulation would cut costs for some large users, but probably not for all users and that there was evidence some users might face higher total costs because of retail competition.

Also, because of the strong position of local utilities, Cochran questioned whether competing sellers would enter the state once the market was opened. If they didn’t, he noted, small users would not have meaningful choices of suppliers.

He said the PSC believed it was unlikely the federal government would force states to deregulate their electric markets, but feared federal guidelines in areas such as transmission would be forced by the Federal Energy Regulatory Commission on those states which chose to deregulate, hiking costs for users.

He said that the PSC might be able to limit adverse impacts on users from deregulation through complex transition regulations. But it was unclear from experiences in other states whether true competition could actually be achieved after the transition period. It made sense for Mississippi to wait to see how things played out in those states before acting.

The PSC, therefore, found deregulation of the state’s electric market would be premature at this time. Instead, the commission will monitor national developments and review the issue again if there is new evidence deregulation would be in the interest of all the customers.

The ruling effectively cancels a PSC staff plan issued in late 1997 to start retail choice in the state in January 2001. It also appears to insure that the state legislature will take no action on the issue in the foreseeable future.

A plan had been floated in the legislature to set up a committee to review electricity deregulation later this year. But lawmakers said they now wanted to review the PSC findings before making any decisions.

The PSC ruling should also give ammunition to anti-deregulation groups in nearby states such as Alabama, Georgia and possibly Louisiana, where state commissions are also deciding whether to deregulate.

Earlier this year, Entergy had supported going ahead with deregulation in Mississippi, saying it was inevitable. In a statement May 2, however, Entergy said it supported the PSC action to shift the initiative on the issue to the legislature but did not endorse the findings. Entergy stressed that the PSC order left the door open for restructuring at a future date.

In practical terms, the PSC action means that for the foreseeable future Entergy's utility system will be divided into a deregulated side in Texas, Arkansas and probably Louisiana and a regulated side in Mississippi.

Southern Company affiliate, Mississippi Power, which has opposed deregulation in the state, welcomed the ruling which it said was correct based on the data and testimony presented in PSC hearings. The company said the PSC should continue its "realistic" approach to the issue and act cautiously until there was clear evidence deregulation would be worthwhile.

Industry representatives in the state, who have lobbied since 1997 for immediate deregulation, opposed the decision and said it would keep electric bills higher than necessary.

Missouri

The PSC approved the reorganization of Kansas City Power & Light (KCPL). KCPL will form a holding company, Great Plains Energy, Inc., with three subsidiaries: KCPL which engages in the generation, transmission, distribution and sale of electricity to approximately 467,000 customers located in western Missouri and eastern Kansas., Great Plains Power, Inc. which develops competitive generation for the wholesale market, and KLT, an unregulated subsidiary with investments in energy-related businesses. Conditions of the reorganization are designed to protect KCPL customers. Also, purchase supply agreements between KCPL and Great Plains Power or its affiliates will require PSC approval and must be cost-based.

Montana

Montana regulators want to postpone for two years, until July 1, 2004, moving to customer choice for residential and small power users until they can be sure the market will provide firm supplies at an affordable price.

Most affected would be Montana Power's 285,000 customers since 23 of the state's 25 rural electric cooperatives have opted not to restructure or offer retail choice, an option provided by the state's electricity industry restructuring legislation.

Customer choice was scheduled to begin July 1, 2002, but customers could voluntarily seek other suppliers before then, if they chose to do so. So far, less than 0.5% of Montana Power customers have opted to switch. Only one alternative supplier – Great Falls-based Energy Northwest – is active now but has announced that it will pull out of the state because the Public Service Commission has imposed a rate hike moratorium on Montana Power customers through July 1, 2002, and marketers cannot beat the utility's rate.

Energy Northwest customer will be returned to Montana Power service. The regulators said Montana Power would be responsible for purchasing power from the market to provide default supply service to its non-choice customers until July 2004. But the utility would be able to fully recover their power supply costs in rates, said the PSC.

On October 2, Montana Power announced plan to sell its electric and gas distribution businesses to NorthWestern Corp. of Sioux Falls, S.D. for \$1 billion. NorthWestern will keep the Montana Power name and will supply power through July 1, 2004.

"We were not surprised by this development," said Pat Corcoran, Montana Power vice president of regulatory affairs. Senate Bill 390, the basis for the state's deregulation legislation, allows for a delay to occur, he said.

The utility's main concern is that the PSC give the company the latitude to enter into longer term power purchase contracts and save money over short term market prices. But Corcoran said the company should be allowed to be fully reimbursed for these long-term contracts, even if market prices were to unexpectedly drop.

The PSC was spurred to act partly because several state legislators in October said they would draft legislation to lessen the impact of deregulation, or even repeal legislation that enabled restructuring. The state legislature meets again in January. But regulators are not sure "if the genie can be put back into the bottle." Montana Power has either signed agreements to sell, or has sold, all of its generation and its electric and gas distribution businesses. The company plans to refocus on its Touch American telecommunications business.

Nebraska

This unusual state with a unicameral legislature and 100% public power has begun a three-year legislative study of the state's electric power industry. The goal is to examine moves towards competition in the industry nationwide and develop alternatives to enhance the ability of Nebraska's public power industry to thrive in a competitive environment. Phase I of the study, to be completed by the end of 1997, will be an examination of the structure of the power industry in the state and issues facing the state's electric utilities. Phase II will be an in-depth analysis of issues related to competition and of possible policy changes to strengthen public power's position in the future. This phase will begin July 1, 1997 and be completed by the end of 1999.

Nevada

Daylight savings time has apparently saved a Nevada bill allowing large customers to shop for power starting next spring. Assembly Bill 661 passed the legislature shortly after midnight on the morning of June 5, 2001, minutes after the legislative session had ended, but the state's legislative counsel declined to send the bill to Governor Kenny Guinn, saying time had run out on the session. Reno-based Sierra Pacific Resources, however, joined state mining and casino trade groups in a suit, arguing that, with daylight savings time in effect, the Legislature has an extra hour to act on bills.

The Nevada Supreme Court agreed with SPR. "The question presented by these writ petitions is whether the legislative action was constitutional," the ruling states. "We conclude that it was, because midnight Pacific Standard Time; is equivalent to 1:00 am Pacific Daylight Saving Time; thus the Legislature's final action on the bills was taken before the constitutional deadline and the bills must be enrolled and delivered to the Governor." Governor Guinn signed the bill shortly after the ruling.

The bill allows commercial and industrial customers and governmental agencies that use more than 1 MW on average annually to shop for power. Customers that elect to shop for power in southern Nevada will be required to buy an additional 10% of their total requirements and then re-sell that 10% to Nevada Power at cost. The bill reasons that, by getting some less expensive power from deals cut by the large customers with alternative suppliers, Nevada Power's residential customers may see some benefits.

Competitive shopping begins April 1, 2002, in northern Nevada and June 1, 2002, in southern Nevada. In response to California's energy crisis, Nevada had halted its move to deregulate its electrical markets earlier this spring, but large energy users and SPR succeeded in convincing state lawmakers that limited retail access would lower power costs for the entire state.

SPR supported A.B. 661 in part because it should free up energy supplies for customers that remain with the utilities. SPR's utilities buy about half their power need on the wholesale market. Under the bill, the Nevada Public Utilities Commission must approve contracts between customers and competitive providers, but details of the deals will remain confidential.

New Hampshire

Public Service of New Hampshire says it does not expect to begin full retail choice for its 430,000 customers until at least May 1, 2001 instead of the previous April 1, 2001 target date.

PSNH said that rating agencies needed more time to complete reviews and assign ratings to \$500 million in securitization bonds which will be issued at the time of deregulation to finance part of PSNH stranded costs.

PSNH officials said they were confident the bonds would win high "AAA" ratings, but they said the review process had been slow since legal agencies had to resolve questions about lingering legal challenges to the PSNH restructuring plan. A local ratepayer group, which lost a state supreme court challenge to the PSNH

restructuring, is now expected to file a new appeal of the case to the U.S Supreme Court. PSNH officials say they believe there is little chance that the court will take up the issue.

Under state law, PSNH – a subsidiary of Northeast Utilities – had lowered its rates 5% in October, 2000 in anticipation of deregulation and it was supposed to lower them another 11% at the time of deregulation.

But authority under state law for the initial 5% decrease will end April 1, meaning ratepayers will normally face a 5% rate hike in April and then get a full 16% rate decrease at the time of decontrol in May.

But PSNH officials, at the urging of New Hampshire Governor Jeanne Shaheen, say they are trying to work out a way to avoid such up and down fluctuation and keep rates stable until decontrol starts. But it would cost the company about \$3 million/month to simply leave the 5% October rate cut in place.

While waiting for deregulation to start, state legislators are considering several bills to insure PSNH can cover standard offer energy needs for its 430,000 users when choice begins. Under a law adopted in May 2000, users will receive energy from PSNH at 4.4 cents/kWh during the initial transition stage.

Lawmakers are concerned PSNH will not find supplies at the low rate, and are considering actions to either delay sales of some PSNH power plants or require new plant owners to sell back power to PSNH for standard offer use.

PSNH and NU officials say they could accept some delay in selling PSNH's 1,200 MW of fossil fuel and hydro assets beyond 2001, but they did not want to delay sale of Seabrook nuclear plant because of the hot market in the region for nuclear assets at this time.

New Jersey

The latest of scheduled rate reductions under NJ's law that restructured the electric power industry took effect for customers of PSE&G and GPU Energy. With the original reduction of 5% in August 1999, these reductions bring the total reductions to 9% for PSE&G customers and 8% for GPU customers. By 2003, rate reductions totaling 15% are scheduled for all NJ customers.

New Mexico

Amid rising concerns about volatility in the Western Wholesale market, New Mexico's legislature approved a bill to delay deregulation until 2007. The move follows similar action by Nevada which announced that it was delaying competition indefinitely because adequate consumer protections were not in place.

New Mexico Governor Gary Johnson, a strong proponent of deregulation, preferred to hold off competition for less than five years but signed the bill on March 8, 2001.

Some legislators discussed holding off retail competition for only three years, but decided that a five-year delay was better in light of California's experiences with open access.

The Senate passed S.B. 266, sponsored by Senator Michael Sanchez, after it was amended with the backing of Public Service Company of New Mexico. PNM, based in Albuquerque, threw its support behind the bill once it was changed to allow PNM to set up a holding company and build unregulated power plants to sell power into the wholesale markets before deregulation begins.

Over the next five years, PNM expects to invest between \$400 million and \$800 million to add up to 1,500 MW to its generating portfolio, said a company spokesman.

The additions could be in the form of new power plants, joint partnerships with other power producers or shares of existing plants, said Hagan.

PNM's revenues from wholesale power sales jumped to about \$750 million in 2000, up from \$81 million in 1995. PNM's wholesale operation mainly buys power for resale, but owning more generating capacity would help the wholesale unit reduce its risks, Hagan said. PNM has about 1,520 MW in generating capacity.

PNM's goal to expand its generating capacity could be affected by another bill, S.B. 452, sponsored by William Payne.

The bill aims to streamline the approval process for building new plants by directing state regulators to review applications in less than six months. The bill has been assigned to two committees and has not been heard yet. New Mexico's legislature is set to adjourn March 17, 2001.

Electric deregulation in New Mexico may be on hold for up to five years, with the state Senate unanimously passing a bill that would delay retail competition until 2007. Two original opponents of postponing deregulation, Governor Gary Johnson and Public Service New Mexico signaled support for the bill.

New Mexico had been set to open its retail market in 2002, but the energy crisis in California has given many in New Mexico second thoughts, including the sponsor of the 199 deregulation legislation, Senator Michael Sanchez.

Sanchez introduced S.B. 266, which would push back deregulation until 2007 for residential customers and small businesses and until 2008 for all other users. New Mexico's large energy users and the state's attorney general supported Sanchez's bill.

However, Governor Johnson and Public Service New Mexico opposed the original bill, saying deregulation should go ahead as planned. But Johnson endorsed the bill after meeting with bill's sponsor.

Public Service New Mexico endorsed the bill once it was amended to resolve some of the utility's key concerns, said Bob Hagan, a PNM spokesman. The amendments will allow PNM to build unregulated power plants to sell power into the wholesale markets before deregulation begins, Hagan said, noting that power trading was a growing part of PNM's business.

PNM's revenues from wholesale power sales increased to \$748.2 million in 2000, up from \$365.4 million in 1999.

Under the amendment, in New Mexico needs power, the state's utilities would be required to tap any new unregulated power stations to serve the local market at "cost of service." Another amendment to S.B. 266 will allow PNM to establish a holding company so it can proceed with plans to buy Western Resources Electric Operations, based in Topeka KS, as well as enter into other business ventures, Hagan said.

"The amendments give PNM elbow room with which to proceed with our strategic plan and planning for new generation that New Mexico will need in coming years," Hagan said.

During the debate on delaying deregulation, the Senate rejected an amendment that would have slowed open access by only three years. Governor Johnson and some House members support a delay of less than five years, the governor's aide said.

PNM will not likely press for a shorter delay, Hagan said.

The bill moves to the House and maybe voted on as early as the week of February 19, 2001.

Spooked by skyrocketing power prices in the West, key proponents of deregulation in New Mexico want to push back open access until 2007, leaving only that state's utilities and the governor as advocates for moving ahead as planned.

State Senator Michael Sanchez, who helped shepherd the original 1999 deregulation legislation through the legislature, is now pushing a bill he drafted to delay open access. Deregulation has been set to start in 2002. The bill, S.B. 266, would push back deregulation until 2007 for residential and small businesses and until 2008 for all other users. It passed a Senate committee on February 2 with support of many of the state's large energy users and the attorney general's office.

S.B. 266 was approved by the Senate Corporations & Transportation Committee and sent to the Finance Committee for a hearing. If approved, it will then go to the full Senate and then to the House. The New Mexico Legislature wraps up business in about April.

But New Mexico's largest utilities and the governor oppose putting off deregulation. "We don't think delay, or repeal, is the right answer," a spokesman for Albuquerque-base Public Service Company of New Mexico said. "We think we should continue to move forward and learn from California's mistakes." In an effort to calm fears about deregulation, PNM has offered to cap its retail prices for five years and then have transition prices for another five years after that.

The uncertainty with deregulation makes it hard for the company to make long-term plans, he said. For example, currently, New Mexico has enough generating capacity to meet the state's needs, he said, but with rapid population growth the state must begin preparing for new power plants. But with the uncertainty, PNM cannot plan ahead.

Southwestern Public Service Co. based in Amarillo, Texas, also supports sticking to the original open access timetable. Governor Gary Johnson supports deregulation going ahead, but has said he might be open to a short delay.

However, New Mexico's Attorney General Patricia Madrid and many of the state's large energy users, who originally supported retail competition, believe the state should hold off on deregulation until the Western energy markets calm down.

New Mexico is part of the Western Power Grid and either electricity would be sold into the California market or prices would rise in New Mexico to match prices in the Golden State, said Steve Michel, an attorney representing the New Mexico Industrial Energy Consumers, a group of 10 companies that use about 10% of the state's power. NMIEC would like to see a shorter delay than that proposed in the Sanchez bill, but the group still supports the legislation, Michel said.

The New Mexico Rural Electric Cooperative Assn., the City of Albuquerque, the Municipal League and other groups also support delaying deregulation.

California's crisis has spilled over into New Mexico, forcing Phelps Dodge Corp. to prepare to close two copper mines in southern New Mexico due to high energy prices. The mines buy power on the spot market, which in the past had been a solid strategy, a company spokesman said.

New York

The New York Independent System Operator board of directors has proposed development of a "circuit breaker" type mechanism that would put the brake on prices when they climb unreasonably high.

Market players are being asked to come up with ideas on how the mechanism might work. The NYISO hopes to have it in place by the spring, so that it can protect consumers next summer. Meanwhile, the ISO board wants wholesale price caps to remain in place and directed staff to petition for an extension of a \$1,000 MWh bid cap imposed earlier this year by FERC. No date was established to end the cap, but the idea is that it will remain in place until the other consumer protections are established, a NYISO spokesman said.

"Efficiency in our electricity markets requires that we minimize interference with the market processes," said Richard Grossi, NYISO board chairman. "But at the same time fairness requires that we cushion consumers against temporary disturbances that result when an entire regulatory system transformed."

The board concluded that the market has malfunctioned because demand is rising, while supply remains stagnant. To resolve the supply shortage, the NYISO board called for its staff to help environmental groups, government agencies and market players find ways to speed up the power plant siting process.

In addition, the board called for the rapid restoration of generation plants that are being repaired and for identification of retired plants that can be brought back into service. The staff was also directed to develop a price responsive mechanism for next summer that will allow high volume customers, like industrials, to curtail load when prices are high.

Last summer's price spikes also spurred an investigation by the state Attorney General Eliot Spitzer, who subpoenaed the NYISO for information on any questionable activity the ISO witnessed on June 26, when day-ahead prices spiked to the highest point for the summer, then dropped suddenly the next day. The ISO was ordered to provide information to the AG on price changes, price setters and ISO data collection.

Spitzer also asked if the ISO routinely identifies the generator or other market source that sets the clearing price in the day-ahead market, real-time market or other markets. A similar inquiry is underway by the Public Service Commission, according to an NYISO spokesman.

North Carolina

North Carolina may still phase in retail competition by January 2006, but its state legislature should not enact a comprehensive restructuring law this year – or maybe even next. This appears to be the consensus among members of the Study Commission on the Future of Electric Service in North Carolina, a panel of legislators, utility leaders and other stakeholders that has been examining the issue.

Study Commission Co-chair and State Senator David Hoyle said the commission is standing by its May 2000 recommendation that customer choice be phased in between January 2005 and January 2006. He added, "We could decide later to delay [the phase in] for a year, or even two, if news out of California and other states is not good." Hoyle also said the Study Commission has directed consultant – the Research Triangle Institute – to study what could be done to enhance the state's wholesale electric market and to protect consumers from California-like price spikes under retail wheeling.

He added, finally, that the Study Commission asked the North Carolina Utilities Commission to look into changing its rules to allow merchant projects to receive NCUC approval even if they do not have power-sales agreements in hand.

The Study Commission will be on hiatus until the 2001 legislative session of the North Carolina General Assembly adjourns this summer.

North Dakota

Changes in the state's service territory law were defeated during the 1999 legislative session. A standing six-year legislative committee examining competition in the electricity industry is due to file a report during the legislature's next regularly scheduled session in 2001.

Ohio

The Ohio PUC adopted rules for local government aggregation of electricity customers. Under Ohio's restructuring legislation passed in July 1999, local governments could serve as an aggregator for electricity customers. The new rules focus on three issues: Cooperation of the utilities in providing lists of the customers in the local government's jurisdiction, forming programs for customers to "opt-out" of the aggregation, and the requirements for providing customers with written notices of inclusion in the aggregation unless the customer specifically "opts-out."

Oklahoma - New

Independent power producers have planned far too much new capacity in Oklahoma over the next nine years and some of the projects are likely to be cancelled or deferred, according to a study released November 6, 2001 by the U.S. Department of Energy's Oak Ridge National Laboratory.

"Even with reduced plant construction, most new plants could lose money," the report adds, citing the very low costs of existing coal and hydro units. And if Oklahoma chooses to deregulate, rates to consumers could rise 5% to 26%, although this "will have only a modest effect on overall economic activity within the state."

The report says generating capacity will more than double by 2010 – from 12,170 MW to 25,690 MW – by the end of the decade. But domestic demand, plus maximum exports possible given existing transmission constraints, would require, at most, 20,390 MW, leaving a surplus of 5,300 MW.

This creates a reserve margin "of 26% in 2010 and even higher in earlier years. Such a high level of excess capacity cannot be sustained in a restructured market. In fact, there is a growing realization that the market may be set for a bust in the near future," the report says.

It notes that transmission lines are harder to site and build than new power plants, and adds that only one 345-kV addition is planned in Oklahoma during the study period.

The study says that if plants offer power at rates matching today's market – 7 cents/kWh for residential consumers, 6-7 cents/kWh for commercial and 4-5 cents/kWh for industrials – "most new plant lose money. If plants could raise prices by adding some of their fixed costs into their price, they become profitable but prices rise for all consumers." In fact, the report said, under one of the most likely pricing scenarios new combined cycle plants would provide a return on equity of negative 2% rather than the anticipated 14%.

The report was presented to the Oklahoma Corporation Commission and was to be presented to the Electric Restructuring Advisory Task Force during its regular meeting November 7, 2001. The OCC asked for the study after deregulation plans in the state faltered.

Developed in two phases, the first of which was issued in the spring of 2001, the study is designed to give lawmakers and other parties an objective base of information on which to make decisions on any future deregulation. The issue is now up in the air in Oklahoma – a 1997 law required deregulation in the state by July 2002, but implementation legislation failed in this year's legislative session, putting deregulation on indefinite hold while further studies are conducted.

The study speaks frankly about the use of market power to make new plants profitable. It examines a number of scenarios, from companies tacitly agreeing to raise their bids to provide wholesale power, to develop group bids, or to withhold capacity. It said, for example, that by adjusting output from its planned plants in Pocola and Lawton, Smith Cogeneration could boost its net income by \$2 million and its overall ROE on the projects from 12.7% to 13.2% even though gross revenues would fall by \$6 million. Oklahoma Gas & Electric could achieve

similar results by manipulating production of a major regulated coal plant to increase production of highly profitable and unregulated peaking plants, the study adds.

The study also said price elasticity is relatively ineffective if applied on a year around average, but very effective if applied during peak periods. Real-time pricing could reduce peak loads by as much as 9%, it said.

The study said the biggest impacts of anticipated higher prices under most deregulation scenarios would be reduced output of 0.595% for the explosives industry, 0.516% for the logging industry, 0.411% for the uranium and metal mining industries and 0.393% for the agricultural, forestry and fishery service industries. Various sectors of the electric industry would see output increases of 10.6% to 10.7%.

The report concludes that dealing with restructuring issues will not be easy: "The economic impact of restructuring the electric power industry could be relatively modest or could raise prices to consumers. A key difference will be how the restructuring takes place: what plants are included in the restructuring, how costs or prices are communicated to consumers, and whether capacity additions are in line with expected growth in demands.

"Any restructuring must take into account that many of the existing plants have costs well below market rates. The difference between cost and market prices are currently received by consumers since the plants' production is priced at cost plus a reasonable return. Policy makers will need to address how the future price and cost difference is shared between the state's consumers and the owners of the facilities.

"It appears that the announced new plants to be constructed in the state are well in excess of the internal needs of the state and more than the transmission system can effectively export. Delays or cancellations are likely in order to prevent a glut on the market. Customer response to real-time prices and competition in external markets could further reduce the need for new plants. Information such as this study, and evaluation of the market by developers and the OCC, should help to avoid the worst of any market volatility due to an imbalance between supply and demand.

Oregon

Legislation calling for a five-month delay in implementing Oregon's restructuring law has emerged as the most likely proposal to pass the Oregon Legislature. The Senate passed House Bill 3633 and the House expected to follow suit, said Leann Bleakney, a natural resources policy analyst for the Oregon Senate Majority Office.

HB 3633 is favored over a number of other restructuring bills, including two bills calling for 2-year delays, she said. Under Oregon's restructuring law, large commercial and industrial customers will choose between direct access and a market-based standard offer.

Smaller customers will remain with their utilities and choose from a portfolio of options. The law calls for restructuring to take effect October 1, 2002.

HB 3633 would guarantee large commercial and industrial customers regulated, cost-of-service rates until July 2003, Bleakney said. Under the bill, the Public Utility Commission would assess whether the cost-of-service rates would benefit customers for an even longer time period.

"The commission would decide after July 2003 whether large customers could go to the market," said a spokesman for the commission. "Of course, we would have to do a study to see if the market was agreeable."

A group of large commercial and small industrial customers had pushed for the cost-of-service rates, saying they worried that the direct access and market-based standard offer options would expose them to too much market volatility.

"This is the favored bill," said Bleakney. "I think of this as a compromise. One of the whole points of the restructuring law was to help encourage additional supplies of generation in Oregon, and delaying restructuring run counter to the idea," she said.

The 5-month delay will apply to all portions of the bill except the requirement that the larger customers choose between a standard offer and direct access.

In March, smaller customers would choose from a portfolio of options, including green power and a time-of-use rate.

Under the bill, the "public purpose" section of the restructuring law would be delayed until March. That section says utilities will collect an amount equal to 3% of revenues and invest it in conservation and renewable energy.

Originally, HB 3633 called for an 18-month delay, but restructuring supporters argued that a long delay could kill restructuring altogether in Oregon, which would stymie innovation and reduce customers choices.

Opponents of restructuring worry that restructuring will create the kind of problems California has experiences. Supporters, however, argue that Oregon's restructuring law is a "go-slow" approach that will spur innovation and power plant construction.

Pennsylvania

PPL Corp. has completed a solicitation to obtain long-term supplies for its utility unit, PPL Electric Utilities, and has chosen its marketing subsidiary PPL EnergyPlus to provide up to 6,000 MW. The company said PPL EnergyPlus had submitted the lowest bid among six competitors. It did not name the others, citing confidentiality clauses.

PPL EnergyPlus and PPL Electric Utilities have signed a supply contracts running from 2002 through 2009, which are to be submitted to the Pennsylvania Public Utility Commission and the Federal Energy Regulatory Commission. The utility plans to use the power to serve customers that do not shop for another supplier in the open market.

Last year, when Pennsylvania deregulated, PPL transferred about 8,000 MW of utility plants to an unregulated unit PPL Generation, and assigned PPL EnergyPlus to market the output. That unit has been supplying PPL Electric Utilities under a contract that expires at the end of 2001. In April, PPL solicited bids to supply the utility from 2002 through 2009, which is the end of PPL's "transition period" under its Pennsylvania restructuring settlement. After 2009, caps on consumer rates are to end.

Under the contract, PPL EnergyPlus is to supply power at "pre-established, capped prices," to fall within the rate caps. In addition, PPL EnergyPlus will receive a \$90 million payment by the start of 2002 "to offset differences between the revenues expected under the capped prices and projected market prices through the life of the supply agreement." The company is not disclosing the total value of the contract, a PPL spokesman said.

This long-term agreement will cut risk for the utility unit, PPL noted, since it will not rely on the fluctuating spot market to serve customers at capped rates – the combination that has ravaged California utilities. As a result, the utility can boost debt without adversely impacting credit ratings. Therefore, PPL Electric Utilities has asked the PUC to let it issue up to \$900 million in bonds in the third quarter.

According to the spokesman, the utility plans to use the proceeds to pay the \$90 million premium to PPL EnergyPlus, buy back stock to decrease the amount of high-cost equity; and to refinance higher-cost debt.

At the same time, PPL said this contract would balance the portfolio for PPL EnergyPlus between long-term agreements and short-term sales in the spot market. The marketing unit sells about 4,000 MW elsewhere, partly from former PPL Electric plants, and partly from other assets that PPL has acquired around the country, such as the plants it purchased from Montana Power. The company is developing another 4,600 MW around the country.

The Pennsylvania Public Utility Commission okayed a deal filed two days earlier allowing GPU's two Pennsylvania utilities to defer for future recovery power costs exceeding amounts recoverable in rates, retroactive to Jan. 1, 2001.

Under the accord—which came only five days after settlement talks were reported to have broken down—there will be no overall rate hike for customers of Metropolitan Edison and Pennsylvania Electric.

The deferrals, most related to their "provider of last resort" (POLR) obligation, would continue through the end of 2005, with carrying costs equal to the utilities' after-tax embedded cost of debt (currently 4.25%). They would be booked as a "regulatory asset" through Dec. 31, 2010, when unrecovered costs would have to be written off.

But the "competitive transition charge" would remain on bills through 2015, with the funds applied to pay down stranded costs.

The settlement was filed June 12 by the two holding companies, Met Ed and Penelec, and several intervenor groups. That day GPU stock traded as high as \$35.59 before closing up \$2.10 (6.3%) at \$35.35.

It fell 73 cents June 14 to \$35.15, up 23.1% from a year before. FirstEnergy gained 41 cents to \$31.01 June 12, and two days later dropped 73 cents to \$30.28, up 22.6% from June 14, 2000.

The settlement was signed by intervenors including the state Office of Consumer Advocate, industrial users, and the Small Business Advocate. It was approved 3-0 by the PUC with Chairman John McQuain abstained from voting since he will soon be leaving the PUC and it is not clear whether he will have a position in the private

sector that could be affected by the ruling, a source said. Nora Mead Brownell resigned from the PUC on June 11 in order to join the Federal Energy Regulatory Commission.

The PUC May 24 okayed FirstEnergy's acquisition of GPU. FirstEnergy testified before the PUC that it would "carefully review the PUC's action" regarding the POLR losses "to determine whether the consequences would have a 'material adverse effect' on GPU or the combined company," allowing FirstEnergy to walk away from the deal.

Without relief from the POLR costs, GPU warned in the first quarter Form 10-Q, it would face higher costs and more restrictive terms to renew credit facilities or otherwise access capital markets, forcing it to cut capital spending and possibly the dividend on common stock.

GPU sold all but 285 MW of its generation in 1999-2000, and must supply customers mainly via power pacts and the wholesale market to serve customers. Over the last year and a half, though, wholesale prices have soared and GPU has incurred big losses, since it must supply retail customers who did not choose other suppliers at capped rates, as provider of last resort.

Under the 1998 PUC restructuring orders, Met Ed and Penelec customers have been permitted to shop for power suppliers since Jan. 1, 1999.

The PUC approved a competitive bid process designed to assign POLR service to other suppliers, referred to as Competitive Default Service, for 20% of MetEd's and Penelec's retail customers on June 1, 2000, 40% on June 1, 2001, 60% on June 1, 2002 and 80% on June 1, 2003.

But the companies got no bids in the initial solicitation for other POLR providers in February 2000. They were forced to supply 550 MW (Met Ed 250 MW and Penelec 300 MW) they had not foreseen. Then customers requiring another 240 MW at Met Ed and 360 MW at Penelec returned from other suppliers in summer 2000, again boosting the utilities responsibilities as default POLR. Another solicitation for alternate POLR suppliers got no bids.

In the Form 10-Q, the utilities estimated that another 560 MW of Met Ed load and 540 MW of Penelec load would return by June 1, resulting in a loss for GPU's Pennsylvania supply business of about \$70-million at Met Ed and \$80-million at Penelec, based on their assessment of market prices. As wholesale prices have risen, retail marketers have found it difficult to provide savings, and have been sending customers back to their native utilities.

Earlier this year, GPU asked the PUC to let it defer its losses for later recovery from ratepayers. However, the OCA fought the plan, arguing that the rate caps were an integral part of the state's restructuring plan. Other critics said GPU could have avoided trouble if it had signed long-term pacts with suppliers.

The PUC rolled the rate issue into its consideration of the FirstEnergy deal. An administrative law judge recommended letting GPU raise rates by \$317-million to cover past losses and expected 2001 losses. In approving the merger, it postponed a ruling on the rate issue.

Under the settlement, there will be no rate hikes for customers. However, GPU will be allowed to defer all past losses and all future losses through 2005, and carry them on its books through 2010. If wholesale prices fall—as they have already started to do—GPU's expenses could drop below its cost to serve customers. In that case, it will use those profits to offset the losses.

The rate caps, which had been slated to expire at the end of 2007, will also stay in effect through 2010.

Although rates will not rise, there will be an increase in the "shopping credit" that retail marketers compete against, i.e. the utility's cost of power included in rates, or the "price to beat."

A higher shopping credit gives marketers a bigger target to aim at in trying to save money for customers, so this provision could spur more retail competition, the PUC said.

Those credits will rise from an average 4.357 cents/kWh to 4.606 cents/kWh for Met-Ed, for the period Jan. 1, 2002 (or the effective date of the FirstEnergy acquisition, whichever is later) to Dec. 31, 2005.

For Penelec, the credit rises from 4.404 cents to 4.643 cents for that period.

The total generation rate stays at 5.138 cents and 4.786 cents, respectively, by slashing the "competitive transition charge" (for collecting stranded costs) from 0.781 cents to 0.532 cents for Met Ed and from 0.382 cents to 0.143 cents for Penelec.

The shopping credits do not change for the following five years, ending Dec. 31, 2010, but the CTC jumps to 0.789 cents for Met Ed and 0.382 cents for Penelec. Shopping credits end at the end of 2010, but those CTCs remain in effect until the earlier of Dec. 31, 2015, or, recovery of all stranded costs. Any stranded costs remaining at the end of 2015 would be written off.

The settlement also commits FirstEnergy to contribute \$2.5-million to each Pennsylvania utility's "Sustainable Energy Fund," and to invest \$10-million in "cost effective renewable energy projects" in the service territories of GPU and FirstEnergy's Pennsylvania Power unit, over the next five years.

FirstEnergy is to spend that money "as evenly as possible recognizing the difficulties in implementing renewable energy projects with such level spending requirements," the settlement specified. It agreed to consult with intervenors Penn Future, the Clean Air Council, and Citizen Power (which opposed the settlement). But it is "not required to accept any such suggestions."

Of the \$10-million, FirstEnergy also agreed to "investigate and consider the possibility of spending up to \$3-million for wind generation. The other \$7-million, or the entire \$10-million if a cost-effective wind project cannot be developed, is to be spent on "such programs as wind generation incentives, wind block marketing programs, solar photovoltaic applications, renewable energy consumer education, conservation, and distributed generation."

Met Ed and Penelec agreed to "develop and implement a cost effective demand-side response program...to maximize the cost-effective reduction of peak load to reduce exposure to high POLR costs," with proposed plans to be filed at the PUC within 120 days of closing of the FirstEnergy deal.

And, the utilities are to form a "reliability committee" along with representatives of the OCA, PUC staff, and industrial customers.

The PUC agreed to "provide approval" for FirstEnergy to seek Securities and Exchange Commission approval to invest up to 500% of retained earnings in acquisitions. FirstEnergy, currently an "exempt" holding company under the Public Utility Holding Company Act of 1935, is not subject to such a limit. But it requires SEC approval as a "registered" holding company to complete the GPU deal.

The settlement approval is dependent on FirstEnergy completing the acquisition of GPU, which has been approved by the FERC. However, it is still being reviewed by the New Jersey Board of Public Utilities, whose staff opposes it on the grounds it could hinder competition. If the merger falls through, GPU can return to the PUC to seek rate relief, although losses from January through May 2001 would be written off. In that case, the PUC would have to issue a final order within 90 days.

Commissioner Robert Bloom said the settlement was in the public interest for several reasons, but mainly because it preserves the rate caps for GPU customers through 2010, giving them an additional three years of rate protection. He also mentioned the higher shopping credits and the contribution to renewable energy.

GPU Chairman Fred Hafer said "The ruling was the correct way to deal with a very difficult issue, and we recognize the PUC for its leadership in solving what was a real problem for GPU and for the Commonwealth of Pennsylvania." He added that the decision "will enable Met-Ed and Penelec to continue as economically viable providers of electricity to our customers."

A FirstEnergy spokesman said the companies are confident of offsetting the losses through lower wholesale prices because there are many merchant plants in development that should bring prices down.

Moody's Investors Service June 14 affirmed Met Ed and Penelec senior secured debt at A2, because the agreement removed regulatory uncertainty as to recovery of the POLR costs, said senior vice president—corporate finance Mo Ying Seto.

But they, GPU (senior unsecured debt Baa1) and Jersey Central Power & Light (senior secured A2) remain on review for downgrade pending the acquisition by FirstEnergy, whose utility units all have lower ratings (Ohio Edison senior secured Baa1 and Cleveland Electric Illuminating and Toledo Edison Baa3).

With power costs jumping 109.4% to \$471-million, Met Ed last year saw net income fall 13.3% to \$81.9-million. In the first quarter net fell 39.5% to \$16-million, with power costs up 35.3% to \$125.3-million.

Penelec's power costs soared 95% last year to \$545-million, and net income plummeted 74% to \$39.2-million. It lost \$2.1-million in the first quarter, down from year-before net of \$26.9-million, as power costs rose 60.7% to \$169-million.

Both incurred first-quarter pre-tax charges of \$9-million for a voluntary enhanced retirement program which was accepted by 101 workers at Met Ed and 106 at Penelec. The latter also had an after-tax charge of \$2.1-million related to termination of a power pact with Allegheny Electric Cooperative.

Rhode Island

Rhode Island utilities are preparing to cut generation charges by as much as 2 to 3 cents/kWh as wholesale power contracts begin to reflect declining fuel costs.

The Rhode Island Public Utilities Commission approved the state's first decrease in Narragansett Electric's standard offer rates since the state deregulated four years ago. Beginning October 1, rates for standard offer, the service taken by most Rhode Island customers, will decrease from 6.3 cents/kWh to 5.5 cents/kWh.

The SO rate decrease, combined with a decline over the years in stranded cost charges, would bring the total customer electric charges to the lowest point since 1997. The rates had steadily climbed, particularly over the last 18 months, and were only 3.8 cents/kWh in January 2000.

Narragansett, the state's only major investor-owned utility, was able to cut rates because a clause in its long-term supply contract with PG&E National Energy Group allows for adjustments based on fuel prices.

"Last resort" service customers in Rhode Island will also see a rate decline for many on the next 12 months thanks to new short-term supply contracts Narragansett recently signed with Morgan Stanley Capital Group and Select Energy, an unregulated subsidiary of Northeast Utilities. Under the Morgan Stanley contract, LRS customers will pay a flat 5.674 cents/kWh from September 2001 through February 2002. Last year during the same period rates varied from 4.5 to 8.9 cents/kWh.

After the Morgan Stanley contract expires, Select Energy becomes the utility's wholesale supplier with rates that run as much as 3 cents/kWh lower than 2001. The specific rates are 5.128 cents/kWh in March 2001 compared to 8.5 in March 2001; 5.193 cents/kWh in April 2002 compared to 7.9 in April 2001; 5.164 in May 2002 compared to 5.9 in May 2001; 6.365 in June 2002 compared to 8.1 in June 2001; 7.481 in July 2002 compared to 10.4 in July 2001 and 7.496 in August 2002 compared to 10.0 in August 2001.

The amount of power supplied by the wholesalers will vary depending on how many retail customers buy last resort service. As of June 2001, 1,754 Narragansett customers were on the service, compared to 460,000 on SO rates.

South Carolina

South Carolina, like North Carolina, appears likely to spend 2001 and maybe 2002 considering electric industry restructuring but not acting on it.

South Carolina State Representative William Sandifer, chairman of the House Subcommittee on Public Utilities, said that he expects to introduce a "skeletal" restructuring bill that would enable legislators to continue debating the issues surrounding retail competition this year. He added, however, that he is "very confident" that the bill will not be enacted in 2001, and he declined to predict when a restructuring bill might get to a vote.

Sandifer cited a number of factors in the general reluctance of South Carolina legislators to act on restructuring now, including the state's low electric rates and public concern about deregulation raised by the ongoing California crisis. He added that the bill he may submit "will not have any meat on it" such as proposed schedule for phasing in competition.

Meanwhile, small and large electric customers are on opposite sides of the deregulation issue. The South Carolina Small Business Chamber of Commerce says it opposes retail competition because it would only result in lower rates for the biggest electricity users.

But the South Carolina Manufacturers Alliance, which represents nearly 100 of the state's largest employers, has said restructuring is one of its top legislative priorities. The state's largest utilities also are split, with Duke Power supporting retail competition and Carolina Power & Light and South Carolina Electric & Gas opposing it.

Restructuring also remains on the back burner in North Carolina. There, the consensus on the Study Commission on the Future of Electric Service is that for now the state should focus on tracking developments in other states and enhance its wholesale market.

South Dakota

In February 1996, South Dakota enacted two laws giving the state's Public Utilities Commission authority to use incentive rates and allow flexible and competitive ratemaking. As of August 1999, there were no new legislative or regulatory restructuring developments.

Tennessee

The General Accounting Office, in a new report, says the Tennessee Valley Authority has fallen behind in its debt reduction program and will have problems competing with investor-owned utilities if Congress decides to deregulate its market.

The GAO said the continued high cost of financing its \$26 billion debt and the overhang of about \$6.3 billion in deferred nuclear plant costs would limit TVA's abilities to sell power competitively in the future. The GAO also dismissed TVA claims that market costs for energy would rise in the Southeast more than expected, helping the competitive situation.

It also said the fact that residential energy costs in the TVA region were still below the national average was not relevant since it "does not provide a complete picture of TVA's costs, not its ability to operate in a competitive environment."

GAO issued a report in 1999 on TVA's debt problems but said that since then TVA has fallen behind in its debt reduction efforts and now is likely to still have \$19.6 billion in long term debt by 2007 instead of \$13.2 billion as previously planned. This means TVA will have an extra \$416 million/year in interest expenses at that time compared to its 1997 projections, hampering its ability to lower rates and compete if it is in a deregulated market by then.

The report was released March 8, 2001 by Senator Mitch McConnell, a longtime TVA critic, who said he will reintroduce legislation to bring TVA under federal rate regulation and protect ratepayers. He introduced a similar bill in the last Congress.

Other bills are also expected to be introduced in the near future in the Senate which would force TVA to give its 159 distributors more freedom to buy energy from other suppliers.

The GAO said that despite some progress on debt reduction, TVA still was paying much more in financing costs than competing investor owned utilities. While 28 cents of every dollar of TVA revenue went to interest costs in 1999, it said IOU's only paid 9 cents for every dollar of revenue in the same period. GAO also found that TVA had much higher levels of unrecovered costs than the private utilities. As a result, "TVA's financial flexibility to respond to financial or competitive challenges is less than that of its likely competitors," GAO said.

The report noted that TVA's special advantages as a federally-owned corporation may not exist in the future, further hurting its financial position and especially its bond ratings. Further, TVA's debts and deferred costs could lead to high TVA stranded costs if Congress ordered deregulation and prospects for recovering those stranded costs were poor.

The GAO noted, however, that the longer Congress waits to end TVA's monopoly status, the more time TVA will have to reduce debt and deferred costs and improve its competitive position.

TVA, in comments attached to the report, disputed several of the GAO findings saying higher energy prices would increase revenues and help pay down debt, and it also challenged the GAO's financial comparisons with IOUs. TVA said in late 2000 that it had been forced to revise its 1997 debt reduction plan because of the extra costs of building new generation plants and making environmental upgrades.

Texas - New

The Public Utility Commission of Texas has approved a settlement agreement that calls for delaying the start of full retail competition in Entergy Gulf States' service area in southeastern Texas by at least eight and a half months. The settlement agreement, which the Entergy Corp. unit had reached with the PUCT staff and other parties, said that full retail wheeling in the Entergy Gulf States area should begin no sooner than September 15, 2002.

The agreement grew out of widespread concern that the Entergy Gulf States area – the only part of Texas within the Southeastern Electric Reliability Council (SERC) region – would not be prepared for full retail wheeling on January 1, 2002. PUCT Chairman Max Yzaguirre said that "[a]ll the evidence shows" that more needs to be done to establish the conditions for customer choice to succeed in the SERC/Energy portion of Texas.

Among other things, the PUCT noted that the Federal Energy Regulatory Commission has yet to approve a regional transmission organization for SERC, and that there has been "no marketing by retail electric providers

in the Entergy area to date, resulting in no customer participation in the pilot project” that started during the summer 2001.

The newly approved settlement agreement includes a process for market participants to promote competition in the Entergy Gulf States area. Entergy has said it is optimistic its Texas service territory will be prepared for competition by September 15, and that no further delay will be needed.

Retail wheeling will begin on schedule on January 1, 2002 in most IOU service areas in Texas, including TXU Electric’s Reliant Energy/HL&P’s and Texas-New Mexico Power’s.

Texas still has problems to solve before it implements full retail competition on January 1, 2002, but most of the parties involved said they are optimistic that deregulation in the nation’s second most populous state remains on track.

Texas had planned to start a seven-month retail electric pilot on June 1, but because of computer and other delays the Electric Reliability Council of Texas did not process its first request to switch a pilot participant to its new “retail electric provider” (REP) until July 31. About 3,600 request have been switched, leaving 100,000 more pilot participants still to be switched.

Still, ERCOT’s top executives said their organization is making progress toward ramping up the daily pace of approving customers switching, and that pilot participants should receive power from their new REPs by sometime in October.

“We understand the frustration” of REPs who had promised their new customers they would benefit from lower electric rates this summer, only to see customer switching delayed, said ERCOT Chief Executive Officer Tom Noel. He acknowledged that “[t]he pilot has been more complicated and more problematic than we would have wanted, but people have to remember that [the transition to a competitive market] is not a sprint, it’s a marathon.”

ERCOT, however, has been speeding up the pace of processing switch requests. In a one-day test on Thursday, August 30, it processed 1,650 such requests and on September 6, it planned to process 7,000 requests. If, as expected, that test proves successful after a review, ERCOT is likely to ramp up to a 21,000 customer/day pace. The faster daily pace, a spokeswoman said, would allow ERCOT to meet its goal of processing switch requests for all of the pilot participants by mid-September.

In recently, several REPs participating in the pilot have told ERCOT and the Public Utility Commission of Texas that systems responsible for switching pilot participants to must be fixed quickly or consumer confidence in retail competition may be irreparably harmed. Vanus Priestley, vice president of AES NewEnergy said, in his view, ERCOT’s computer systems “are not performing up to par...There are customers that selected new suppliers in February, expecting to be switched in June” but still remain several weeks away from being switched.

The AES NewEnergy executive added that, while he is confident that ERCOT’s systems can be fixed over the next four months, it would be “devastating” if the implementation of full retail competition in Texas were delayed beyond January 1, 2002, ERCOT’s Noel and Jones insist that such a delay is not needed, and that full competition will be implemented on time.

Meanwhile, Noel and Jones said that ERCOT’s newly consolidated control area is working very well. On July 31, ERCOT consolidated its 10 utility control areas into one, largely to allow for a more fluid transfer of wholesale power between different parts of the ERCOT area. “Of course, when you implement a new control project you find a few things you can only find when you go ‘live,’” said Jones. “Those things have been fixed.”

Jones continued, “Early on, there was quite a bit of congestion on the system. We made the switch [from 10 control areas to one] in the peak of the summer, and a lot of new generation came on in the southern part of the state before the northern part,” causing some congestion on the main south-north transmission lines.

“We’re managing that congestion now,” he said, noting that occasional spikes in clearing prices for “balancing” power have had only a minimal impact on overall power costs.

Noel added that in one instance, ERCOT had to deal with the loss of “one nuclear plant, two gas plants and one coal plant within 90 minutes. The system worked” without any impact, he said, asserting that “not many states could lose that much power in so short a time” and end up with the same result.

Finally, the PUCT said in late August that will continue discussing the possibility of delaying the planned January 1, 2002, start of retail competition in the parts of the state served by units of Entergy Corp. and American Electric Power.

The commission staff recently recommended that retail wheeling in the Southeastern Electric Reliability Council area and the Southwest Power Pool be delayed until those regions have Federal Energy Regulatory

Commission-approved regional transmission organizations and signs of true competition among retail electric providers. The Texas investor-owned utilities within those areas are Entergy Gulf States and Southwestern Electric Power and West Texas Utilities units of AEP.

Entergy and AEP both opposed the staff's recommendation, and urged the PUCT to let them implement customer choice on schedule in about four months. A commission spokesman said that the commissioners' discussion at their August 23 meeting was "focused on steps they could take to help competition work" in the Entergy Gulf States, SWEPCO and WTU areas, not on whether the start date for competition there should be delayed.

Concerned about the readiness of several parts of Texas for full retail competition, legislators and regulators in the state have been paring down the investor-owned-utility service areas that will be offering customers choice on Jan. 1, 2002.

Retail wheeling is still almost certain to start on schedule in just over two months for all the customers of at least investor-owned utilities within the Electric Reliability Council of Texas, which oversees what is by far the state's largest power pool.

The IOUs poised to begin offering choice on Jan. 1 include TXU Electric, which distributes electricity to 2.7 million retail customers in the Dallas-Fort Worth metroplex and North Texas; Reliant Energy/HL&P, with 1.7 million customers in and around Houston; and Texas-New Mexico Power, with 200,000 customers in West Texas.

Consumer groups such as the Consumers Union and the American Association of Retired Persons in mid-October asked the Public Utility Commission of Texas to consider delaying the planned start of retail wheeling in all areas—including TXU's and Reliant's—citing concerns about the readiness of computer systems and about whether choice will reduce electric bills.

But the PUCT and ERCOT quickly dismissed the groups' concerns, and expressed confidence about implementing retail wheeling on schedule in the TXU, Reliant, and TNMP areas. The PUCT did decide, however, that competition should be delayed indefinitely in the small portion of the state within the Southwest Power Pool area, and it may decide as soon as this week to delay competition in the Entergy Gulf States area until Sept. 15, 2002.

The PUCT said in mid-October that the planned Jan. 1 start date for customer choice in the SPP area—including Southwestern Electric Power Co.'s entire service area, as well as in a small piece of West Texas Utilities' area—will be pushed back to a date to be determined later.

A total of about 162,000 SWEPCO customers and 7,000 WTU customers will be affected. Both SWEPCO and WTU are subsidiaries of American Electric Power.

The PUCT said that market conditions supporting true competition are not in place in the SPP. It noted that the Federal Energy Regulatory Commission has yet to establish a regional transmission organization including the SPP, and that during Texas's ongoing retail electric pilot there have been no offers by competitive retailers—therefore no customer participation in the pilot and no chance to test computer systems supporting customer choice.

A PUCT spokesman noted that retail competition will be implemented on schedule on Jan. 1 in the rest of WTU's area, which is located within ERCOT.

Meanwhile, the PUCT's staff in mid-October signed a memorandum of understanding with Entergy Gulf States—as well as Texas's Office of Public Counsel, the Texas Industrial Electric Consumers and CLECO Marketing and Trading—that calls for delaying the start of retail competition in Entergy's service area by eight and a half months, to Sept. 15. The proposed agreement will be considered by the PUCT itself at a planned hearing this Wednesday, Oct. 31.

Entergy Gulf States, which distributes electricity to about 300,000 customers in southeastern Texas, said that is "optimistic that Sept. 15 is a reasonable and realistic timeframe for retail open access to begin" in its area.

Finally, the start of retail competition will be delayed for a full five years—to Jan. 1, 2007—in the Southwestern Public Service area in the Texas Panhandle, where the electric grid is largely disconnected from the grid in the rest of the state.

Utah

PacifiCorp filed proposals with regulators in five states to create individual electric company subsidiaries in each state that would contract for power from a single generation company, a move PacifiCorp hopes will allow it to move toward deregulation in different paces in different states.

The company proposes to create a single generation company and a single service company with PacifiCorp's transmission controlled by RTO West, the nascent regional transmission organization, while all new companies would be PacifiCorp subsidiaries, said a PacifiCorp spokeswoman.

PacifiCorp – which operates in Utah, Oregon, Wyoming, Idaho, Washington and California – did not file the proposal in California because its territory in that state is being sold, said the spokeswoman. Of the remaining five states, Oregon is closest to deregulating, she noted, while the others are moving more slowly.

An Oregon law grants large commercial and industrial customers open access beginning October 1, 2001. State regulators had asked PacifiCorp to file by December 1 a plan identifying which of the company's resources would be dedicated to serving the small commercial and residential customers who will remain with the company.

The re-alignment and the use of state contracts are designed to help the company meet the Oregon requirement. "What the contracts will allow us to do is allocate the costs and benefits of resources to an individual state on a permanent basis," said Andrea Kelly, director of regulation for PacifiCorp. "As it stands now, the way costs and benefits are allocated is dynamic, based on what happens in an individual year," she said.

But an economist for the Utah Public Service Commission and an attorney for the Oregon Citizens Board were skeptical about the benefits of the proposal.

Jason Eisdorfer, attorney for CUB, a consumer group, said that while his organization understood that PacifiCorp is trying to find a way to meet the requirements of Oregon's restructuring law, CUB will not support the individual state utilities signing long-term contracts with a generation company. He said that CUB does not trust PacifiCorp's new owner – ScottishPower – and does not think negotiating long-term contracts with ScottishPower is a good idea. CUB's distrust is due, in part, to the fact that the group has had difficulty negotiating agreements with ScottishPower, Eisdorfer said.

Rich Collins, a utility economist for the Utah Public Service Commission, said he is worried about how the PacifiCorp proposal will affect prices for customers in other states. One of the main purposes of the re-alignment, he said, seemed to be to meet the requirements of Oregon's restructuring law, but the re-alignment didn't seem to offer benefits to other states, he said.

PacifiCorp's Kelly said that under the proposal, PacifiCorp envisions that the state electric companies would sign contracts for power that would be tied to the life of a given PacifiCorp generating resource. The electric companies might pay an initial price that would escalate with an index over time, she said.

Kelly said the contracts would allow each state electric company to acquire resources or make decisions without seeking approval from the regulators in other states in which PacifiCorp operates. "Once the contracts are established and the state electric companies are established, Washington could meet its load growth however it saw fit without seeking the opinion of other states," she said. "If power is needed, the state electric company would issue an RFP. PacifiCorp Generation could respond to it, and so could other suppliers," she said.

Vermont

Central Vermont Public Service and Green Mountain Power have proposed to the Vermont Public Service Board that retail choice begin in the state in September 2001, saying the almost two-year delay would give them time to renegotiate supply contracts with Hydro-Quebec and local independent power groups and reduce stranded costs.

In March 1999, the two utilities issued an outline for restructuring in Vermont which called for competition to start in early 2000, but since then they have been unable to buy down high cost contracts with Hydro-Quebec and local independent power producers.

In the case of Hydro-Quebec, Senator Jim Jeffords recently failed in an attempt to force a deal by threatening to void the power sales contracts and it is unclear when talks will move ahead.

For the local IPP contracts, the utilities are pursuing a separate case before the PSB to get costs reduced by administrative action. And in October, the Vermont utilities selected AmerGen to buy the Vermont Yankee nuclear plant – the largest generation asset in the state. But that deal will also not be completed until later in 2000.

In a new restructuring proposal, filed with the PSB November 23, 1999, the two utilities said they would voluntarily give up their generation supply obligations and become wires only companies with exclusive rights to provide service to their existing franchise areas.

They proposed that the PSB certify energy marketers in the state and subject them to several conditions including a renewables portfolio standard and air emissions limits. They also recommended that the PSB handle procurement of default and standard offer service.

At the same time they said the PSB should hold a series of workshops on key issues to work out detailed rules based on input from all parties.

CVPS attorney Morris Silver, said the plan was a “careful and prudent approach to customer choice” which would provide time to settle stranded cost issues well in advance of final PSB decisions on rates.

The utility proposal is designed to be implemented by the PSB alone without the need for legislative approval – a tactic aimed at circumventing objections to restructuring by key members of the Vermont House of Representatives who blocked earlier proposals. But utility officials also said they would also welcome legislative support for the plan.

Virginia

Even as some states are delaying the start of retail competition, Virginia’s Corporation Commission has ordered that the schedule for implementing full customer choice be accelerated for all but one of the state’s investor-owned utilities.

Virginia’s electric-industry restructuring law calls for choice to be phased in beginning on January 1, 2002, and be fully implemented by January 1, 2004. However, in December, the SCC staff recommended that Allegheny Power, American Electric Power and Delmarva Power & Light open their Virginia service areas to full competition all at once on January 1, 2002.

The staff also urged that Dominion Virginia Power phase in customer choice in three stages between January 1, 2002 and January 1, 2003, and that only electric cooperatives and the state’s smallest IOU – Kentucky Utilities – be given until January 1, 2004, to complete the phase-in.

Allegheny Power, AEP and Delmarva all supported the idea of an all-at-once “flash-cut” to full choice in their service areas next January. But Dominion Virginia Power had urged that the original plan for a two-year phase-in remain in place.

In its order, the SCC fully endorsed its staff’s phase-in recommendations, asserting that completing Dominion Virginia Power’s phase-in over a one-year period “is a critical goal that can and should be realized.” Noting that Dominion Virginia Power is the state’s largest IOU, the commission said that “[m]aking the Commonwealth’s largest electric market competitive as soon as possible is obviously a critical link in the success or failure of the development of a competitive market for retail generation in Virginia as a whole.” It also said that implementing customer choice more quickly will simplify the consumer-education process, and “is critical to encourage new market entrants and the development of a truly competitive market.”

The SCC-order plan calls for Dominion Virginia Power to implement full retail wheeling for about 600,000 customers in the northern Virginia portion of its service area and six million MWh of commercial and industrial load throughout its system on January 1, 2002.

A similar number of Dominion Virginia Power customers in central Virginia and another six million MWh of commercial/industrial load will be given choice on September 1, 2002; choice for its southeastern Virginia customers and the balance of its C&I load will come on January 1, 2003.

With the start of retail competition only 10 months away, Virginia’s State Corporation Commission and its staff are taking a number of preparatory steps. First, the SCC scheduled an October 10, 2001 hearing to consider Dominion Virginia Power’s plan to structurally separate its generation and transmission/distribution businesses in anticipation of electric-industry competition. Parties interested in commenting on the separation plan (Case No. PUE000584) must notify the SCC of their intent by March 15, and submit their comments by August 15.

Under the plan, Dominion Virginia Power proposed the state’s largest utility would transfer \$6.7 billion in generation assets – plus its right and obligation under its non-utility generation contracts – to Dominion Generation, another subsidiary of Dominion, the utility’s corporate parent.

Dominion Virginia Power's \$3.8 billion in long-term debt would remain with the utility, which would become only a transmission and distribution entity. Dominion Virginia Power and Dominion Generation would share responsibility for payments on that debt.

Dominion Virginia Power's proposal to transfer its more than 14,500 MW of generation assets and more than 3,400 MW of NUG contracts to its Dominion Generation affiliate goes beyond the requirements of Virginia's 1999 electric-industry restructuring law, which only calls for utilities to "functionally" separate their generation and wires businesses.

Under the utility's proposal, Dominion Virginia Power would purchase from Dominion Generation the electricity the utility needs to serve retail customers in its traditional service territory who do not switch suppliers.

Under the restructuring law, the rates Dominion Virginia Power charges those "default" customers will be capped at their current levels until July 1, 2007. After that, the utility's default rates will be based on the prevailing competitive regional electricity prices.

Dominion Virginia Power is already in the second phase of its retail competition pilot program, under which nearly 31,000 utility customers in the Richmond area and in northern Virginia have selected alternative suppliers.

Full customers choice in the utility's service territory is expected to be phased in beginning on January 1, 2002, and continuing for either one year or two, depending on whether the SCC decides to stand by its original two-year phase-in plan or to adopt a quicker one-year phase-in proposed by the commission's staff in December.

In another action, the SCC's staff revised its proposed schedule for phasing in retail competition to give the state's 13 electric cooperatives an additional year to implement customer choice.

In December, the SCC staff had proposed that the commission accelerate that start of full retail wheeling by having most of the state's investor-owned utilities implement customer choice all at once on January 1, 2002, rather than phasing in customer choice during calendar 2002 and 2003.

For Dominion Virginia Power, customer choice would be phased in by January 1, 2003, while the state's 13 co-op each would have the option of either all-at-once implementation of choice on January 1, 2002, or a one-year phase-in beginning on that date.

In a supplemental report, however, the SCC staff said that "a review of the work that will be involved to prepare all of the cooperatives for competition gives that staff concern that a January 1, 2003, directive may be difficult for all the cooperatives to accomplish."

The staff explained that, as the co-ops mentioned in their comments on the staff's December proposal, "we are already faced this year with five cooperative rate cases and thirteen cooperative functional separation cases.

Upon completion of those cases, the cooperatives and staff will need to turn their attention to setting 'prices to compare'" and preparing each co-op's computer systems for the customer choice era.

The staff noted that unlike Dominion Virginia Power and American Electric Power, that state's other big IOU, the coops do not have experience with competition.

A delay in the deadline for co-ops to implement customer choice to January 1, 2004, it said, "will not have a detrimental effect upon the success of our overall plan," in part because the mostly rural areas served by the co-ops "will probably be the last to be served" by competitive suppliers anyway.

"According to the National Rural Electric Cooperatives Association, 13 distribution cooperatives in Pennsylvania began offering retail choice to all their members as of January 1, 1999, and not one alternative supplier has registered to serve in any of those territories." The SCC staff said it also is recommending that the state's smallest IOU – Kentucky Utilities, which serves about 29,000 customers in extreme southwestern Virginia – also be given until January 1, 2004, to fully implement retail wheeling.

Among other things, the staff explained, Kentucky – where most of KU's customers are located – has no immediate plans for customer choice, and the IOU's Virginia service territory is not interconnected with any Virginia utilities "so access to its customers would involve a circuitous route through Kentucky." The SCC will consider its staff's overall customers choice phase-in proposal over the next few months.

Washington

In 1999, the legislature took no action on restructuring. An observer notes that next year restructuring legislation is very unlikely to be introduced. In December 1998, a legislatively mandated study, submitted to state lawmakers, concluded that the benefits of the federal power system are key to keeping power costs low.

West Virginia

While some West Virginia legislators are getting nervous about implementing retail competition in the state later this year, the Chairwoman of the state's Public Service Commission said there is no need for jitters.

The PSC last year approved a restructuring plan that called for customer choice to be implemented after the 2001 session of the state legislature makes related changes in state tax laws.

Among other things, the plan calls for freezing the retail rates of incumbent utilities for four years, then letting them rise very gradually over the following nine years. It also calls for levying a small charge on all electric bills and using the resulting funds to help hold down rates for residential customers when the 13-year rate-freeze-and-cap period ends.

PSC Chairwoman Charlotte Lane said that the ongoing crisis in California has some legislators "wondering if restructuring is a good idea and asking a lot of questions," Lane added that, while she understands their concern, she is confident that West Virginia's generation surplus and the PSC's plan to protect consumers make her state's situation vastly different from California's.

"We have plenty of power, we export 70% of what we produce and we can produce even more," she said, noting that the PSC in 2000 approved plans for three gas-fired merchant plants and a 70-MW-plus wind farm. Plans for the biggest merchant project yet – a 1,100 MW gas-fired plant proposed by Panda Energy International – will be considered by the commission this spring.

Key legislators suggested, however, that they should hire a consultant familiar with deregulation in other states to look not only at the tax implications of restructuring but at the wisdom of implementing retail wheeling in the state at this time.

State Senator Oshel Craig, chairman of the West Virginia senate's finance committee, said the PSC "make(s) a compelling argument for restructuring, but [legislators] may not be astute enough to ask the right questions." The consultant to be hired later this month, Craig said, should be able to provide that expertise, and presumably complete its review "in time for us to vote on [the needed tax-law changes] this session," which ends in mid-April.

Chairwoman Lane expressed concern about whether the consultant's work could be completed quickly enough, adding that while she still hopes the state can implement retail competition in the second half of this year, the start date for customer choice is "up in the air" for now.

Lane plans to continue meeting with stakeholders, legislative leaders – and the state's incoming governor, Bob Wise – to keep the restructuring plan on track. The implementation of customer choice is supported by the state's two primary utilities, American Electric Power and Allegheny Power.

Wisconsin

Citing customer identification with the electric shortages and high prices that plague California, Wisconsin Public Service Corp. announced it will withdraw its corporate restructuring plan filed with the Wisconsin Public Service Commission.

The plan, filed on November 30, 2000, included the transfer of approximately 1,200 MW of wholly-owned non-nuclear capacity into an unregulated generating company. The initiative was an attempt to jump-start competition in Wisconsin while allowing WPS to retain its generating units and become a market player in the state.

The company said the provision allowing transfer of its generating assets to an unregulated subsidiary was incorrectly linked with California's deregulation experience by many customers. Most of them "seem to accept the current system of utilities building and owning electric plants," said Larry Weyers, chairman, president and CEO of WPS Resources.

He said that over the past few summers, Wisconsin has come close to not having adequate supply. Discussions with large users in Wisconsin, including industrials and large commercial customers, revealed a concern with power reliability, especially if it became the responsibility of out-of-state providers.

Although the company has not yet decided if it will revise its proposal and refile it with the PSC, it is possible to do so without the unregulated subsidiary and with an eye still on developing competitive generation in Wisconsin, Weyer said. Independent power producers would be encouraged to enter the state by prohibiting any new rate-based construction of generating plants by regulated Wisconsin utilities.

Under WPS initial plan, utilities were required to purchase incremental power from third parties, although they could offer existing firm retail customers the chance to leave the system and obtain their power from non-

utility suppliers. Only if the PSC determined that competition had failed to develop, could a Wisconsin utility be allowed to construct a new generating facility, under the WPS plan.

“Customers in Wisconsin will be better served by competition than by regulation in the long run,” Weyer said. “We will continue to pursue the principles that will help create a competitive generation marketplace with many suppliers without the transfer of existing assets.”

Fearful that the power supply plan proposed by Wisconsin Energy and Wisconsin Public Service Corp. will result in a protracted legislative battle over the creation of unregulated generating companies, a coalition of public power utilities and environmentalists has crafted a plan that will provide incentives for utilities and independent power producers to build new generation in the state under current law.

“The real selling point for this plan is that it gives the PSC an option for spurring the construction of new power plants that would clearly be within its jurisdiction,” said Brian Rude, director of external relations at Dairyland Power Cooperative. “Our plan offers a way to get generation built quickly within the existing regulatory framework.” Dairyland Power is one of the members of Customers First! The coalition that proposed the plan filed with the Wisconsin Public Service Commission on January 11, 2001.

According to Customers First! Attorney Lee Cullen, Wisconsin’s load growth is 2% per year and with projected plant retirements, the state could be facing a 3,000 MW to 4,000 MW electricity shortfall over the next decade. No baseload plant has been built since 1985, he said.

The plan seeks to provide incentives for utilities to build new rate-based generating units and for entering into long-term purchase power contracts with independent power producers.

Rate recovery mechanisms for new plant construction should be defined by the PSC at the outset, and these should be contained in an order upon which the utility can rely, the plan states.

Specifically, companies could be given an increase in their rate on equity for new coal-fired plants said Roy Thilly, president and CEO of Wisconsin Public Power Inc. In addition, the PSC could change the depreciation schedule from the conventional 35-40 years to, say, 25 years. These changes would provide incentives to utilities to build new baseload plants by resolving uncertainty and improving cash flow – cash that could be used to construct the next plant, he said.

Moreover, the PSC is encouraged to be flexible in approving new financing mechanisms that would facilitate new construction. These could include third-party financing; construction and ownership by an affiliate lessor with a long-term operating lease back to the utility; or “synthetic leases” where the lessee [utility] secures accounting and tax benefits even though the owner is a utility affiliate, bank or pension fund.

The plan also envisions an arrangement under which utilities get operating-lease accounting benefits while savings from lower capital costs (due to a more leveraged capital structure) are shared between stockholders and ratepayers.

Regarding independent power plants, new baseload projects require anchor tenants who are willing to sign long-term contracts, Cullen notes. But a 15-20 year agreement transfers risks to the buyer; it is not unreasonable, therefore, that the utility be compensated for this, he says. Accordingly, the Customer First! plan encourages the PSC to approve a “modest” surcharge on long-term contracts. This gives the utility a margin on the power purchase transaction instead of simply passing these costs through to ratepayers. This incentive could be approved when a utility can demonstrate that the purchase power option is more beneficial to customers than building a new plant.

Late last year, Wisconsin Energy and Wisconsin Public Service Corp. filed their power supply plans with the commission; these include the creation of independent generating companies. The two proposals would fundamentally alter the existing regulatory compact by removing major generating assets from state jurisdiction and placing them under federal control, the coalition argues.

“Such a fundamental loss of regulatory authority at a time of generation scarcity would be a costly mistake,” the Customer First! plan states. Moreover, given the California experience, it is uncertain whether Wisconsin lawmakers would even adopt such changes, the plan notes.

“One of the lessons of California is that good old-fashion utilities should not be shut out of building business,” Cullen concluded.

Wyoming

As of August 1999, no new restructuring-related legislation or regulatory activity was reported among Wyoming policymakers. In 1998, the legislature adjourned its legislative session in early March, asking an interim committee to continue to study restructuring issues.

=====
Sources: This table has been compiled from a variety of sources including Electric Utility Week, Public Utilities Fortnightly and state commission and legislative Internet websites. This table was compiled by Laura Cvengros. Questions or comments can be directed to her at 317/ 233-5315 or email LCVENGROS@urc.state.in.us. If you would like to receive this table directly when it is updated please email Laura Cvengros to be placed on the routing list.