

# Electric Power Daily

Monday, October 10, 2011

## Duke offers 'virtual divestiture', to sell power in day-ahead market

Duke Energy will propose a "virtual divestiture" plan to the Federal Energy Regulatory Commission this week to address market power concerns FERC expressed about Duke's planned acquisition of Progress Energy, Duke said in a Friday filing to the North Carolina Utilities Commission. Specifically, Duke said it and Progress will offer "to sell generation into the [day-ahead] market to address market power concerns."

But an attorney for the North Carolina municipal utility that raised concerns about the market power implicit in a Duke/Progress combination said that Duke's mitigation plan appears to fall far short.

"It looks like they are still in denial," John Coyle, the Washington attorney for the city of New Bern and its muni, said after reading Duke's NCUC filing.

In its conditional approval of the Duke/Progress merger on September 30, FERC said the \$26 billion deal would have "an adverse impact on competition" and

*(continued on page 6)*

## FERC November conference to examine effect of EPA regulations

Although members of the Federal Energy Regulatory Commission have said that regional planning authorities are the best forum to examine the impact of federal environmental rules on reliability, the commission scheduled a two-day technical conference in November to discuss policy issues on the topic.

FERC in a Friday notice announced the November 29 and November 30 technical conference on the impact of Environmental Protection Agency rules on reliability, to be held at FERC headquarters in Washington.

FERC said the conference will "discuss emerging issues, including processes used by planning authorities and other entities to identify reliability concerns that may arise in the course of compliance with Environmental Protection Agency regulations, and the tools and processes (including tariffs and market rules) available to address any identified reliability concerns." The agenda for the conference has not yet been posted.

Alaska Senator Lisa Murkowski, senior Republican on the Senate Energy and

*(continued on page 6)*

## Last-minute suits filed on Cross-State Air Pollution Rule

Friday, the final day to file suit over the Environmental Protection Agency's rule to tackle interstate air pollution from coal-fired generation, saw more litigation from utilities, state regulators, municipalities and union workers.

The latest litigants included the Municipal Electric Authority of Georgia, the South Mississippi Electric Power Association, City of Ames, Iowa, Northern States Power, Southwestern Public Service, the Kansas City Board of Public Utilities, Kansas Gas and Electric, Sunflower Electric Power and Westar Energy.

Also filing suit before the deadline closed were the United Mine Workers of America and the Environmental Committee of the Florida Electric Power Coordinating Group.

The suits follow those of several other energy companies and states that contend they will have a difficult time meeting EPA's pollution reduction targets and want the federal court to stay the Cross-State Air Pollution Rule while the litigation

## Ontario election results may force action on electricity prices

Ontario's electricity markets face an uncertain future following last week's re-election of the Liberal Party — but this time lacking a legislative majority — a situation not seen in almost three decades.

"We have a lot of questions, and I don't think a lot of answers," said David Butters, president and CEO of the Association of Power Producers of Ontario. "Folks are going to have to figure out how to run the government without stepping on mines and getting blown up."

Premier Dalton McGuinty was re-elected Thursday with the Liberal Party capturing 53 electoral district. But the Progressive Conservatives won 37 votes and the New Democrat Party 17 votes, leaving the Liberals in charge but without a majority in the Legislative Assembly.

The shift in power follows heated debate over renewable energy, electricity prices and power plant siting in the province. Conservatives attacked Liberal backing of

*(continued on page 7)*

## Credit reform implementation smooth: ISOs

Although the new minimum capitalization rules pushed some smaller companies out of markets, grid operators said that the implementation of the first set of Federal Energy Regulatory Commission-mandated credit reforms generally went smoothly.

Many of the changes required by FERC's credit reform ruling — including shifting to weekly settlement schedules, new minimum capitalization requirements and reductions in unsecured credit allowances — came into effect October 1.

While the specific changes varied among independent system operators, none of the ISOs reported any technical or logistical problems in implementing the requirements.

The enactment of the PJM Interconnection's new minimum capitalization requirements — the strictest proposed by any ISO — prompted 17 of its 738 members to reduce their market participation, according to Suzanne Daugherty, PJM's vice president, CFO and treasurer.

Although some companies had urged

*(continued on page 7)*

goes forward. The case is before the US Court of Appeals for District of Columbia Circuit.

The cross-state rule covers 27 mostly eastern states and aims to reduce emissions of sulfur dioxide by 73% and nitrogen oxides by 54% below 2005 levels by 2014.

The rule was developed to replace the Bush Administration's Clean Air Interstate Rule, which was remanded to EPA in 2008 following lawsuits concerning its emissions allowance market construct. The new rule, like its predecessor, includes an emissions market but tighter budgets and deadlines for states.

The final cross-state rule is significantly stricter than what EPA drafted in 2010. For example, the final rule set the trading limits two years earlier — 2012 instead of 2014 — and requires those that fail to comply to surrender two emission allowances for each ton emitted.

The final rule, published in the *Federal Register* August 8, included tighter emission budgets than initially proposed and called for Texas to reduce its annual emissions of NOx and SO2 emissions rather just its ozone-season NOx emissions as in the proposed rule.

Entergy, which filed suit last week, said EPA's modeling upon which it based states' emissions budgets, failed to take into account nearly 10,000 MW generated by the utility and so that the allowances permitted were insufficient to its cover normal operations.

According to Murray Energy Vice President Rob Murray, the cross-state rule would target 81,500 MW of coal-fired generation for closure. The rule is "not about improving the environment, but rather a deliberate attempt to eliminate the use of coal," he said. The coal company also filed suit with several others.

On Thursday, EPA proposed to revise the cross-state rule in two areas — increasing the emission budgets for 10 states and postponing penalties for the first two years — as a means to "ease limits on the market-based compliance options."

EPA's proposed revisions would increase the ozone-season NOx budgets for Florida, Louisiana and Mississippi; increase the annual NOx budgets for Michigan and Nebraska, and increase the annual SO2, NOx and ozone-season NOx budgets for New

Jersey, New York, Texas and Wisconsin.

Enough allowances to cover existing emissions is key to utilities that face emission reduction deadlines but have not installed pollution control technologies on their coal-fired units, a process that can involve significant investments and time for construction and permitting.

EPA proposed to delay until 2014 assurance penalty provisions to take into account future years when more fossil-fuel generation is online than the baseline year. Under the current final rule, these penalties start in 2012.

These proposed changes are subject to a 30-day public comment period that includes a public hearing at EPA on October 28.

Many companies and states are still reviewing the impact of these proposed changes. But analysts and lawyers at this time say it is doubtful these revisions would result in any dropped lawsuits. They expect companies to favor a delay in the rule's implementation if not a complete remand of the rule over the proposed revisions.

"Just because the EPA is proposing to resolve some obvious data failures, it doesn't mean that the petitions lodged have lost their merit, in our view," R.W. Baird senior analyst Christine Tezak said in an analysis of the EPA draft rule changes.

— Cathy Cash

## Program may not speed line construction

A federal initiative designed to help get transmission lines built will likely help keep those lines on schedule, but they may not expedite construction, according to two utilities with transmission projects in the new Obama Administration initiative, the Rapid Response Team for Transmission.

"Idaho Power has learned through experience that the process of permitting major transmission projects is very challenging and extremely time-consuming," said Lynette Berriochoa, a transmission specialist with Idaho Power. Two transmission lines Idaho Power is developing are pilot projects for the Rapid

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

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Response Team for Transmission. The federal team will coordinate the efforts of nine federal agencies involved in siting and permitting of transmission lines.

Although the Obama administration says the effort will accelerate construction of lines, Idaho Power is keeping on schedule, she said.

Construction of Gateway West, a 1,150-mile line between Glenrock, Wyoming, and Hemingway, Idaho, is expected to be built in segments beginning in 2014. Idaho Power is developing that line with Rocky Mountain Power. Construction of Idaho Power's 300-mile, 500-kV line between Boardman, Oregon, to Hemingway is expected to begin in 2016.

Portland General Electric just hopes it can keep on schedule for its Cascade Crossing line.

"We are hoping that [the initiative] provides more certainty to our schedule," said John Sullivan, project director for Cascade Crossing. "Optimistically we are hoping it might shorten the schedule."

The utility is expecting to receive a final federal record of decision on Cascade Crossing in 2014, at which point construction on the 500-kV line from Boardman, Oregon, to Salem, Oregon, would begin.

Until now, a utility has had no way to anticipate how long an environmental impact statement might take, and a federal agency might not have any trained or dedicated staff to manage the EIS, Sullivan said.

Citing an example of how things can go wrong, he said Gateway West received its draft environmental impact statement in July — two years behind schedule.

"There was no specified time line when they are going to kick out the result," Sullivan said. "I don't think there's been a top down approach to that," and the process lacked accountability, he said. The initiative will provide dedicated staff and training to oversee the transmission projects. Training for all of project managers for the agency has been scheduled for November, he said.

During a conference call announcing the initiative, Interior Secretary Ken Salazar talked about the "limbo" that can wreak havoc on transmission time lines.

Salazar said the 145-mile, 500-kV Susquehanna to Roseland line in Pennsylvania and New Jersey, one of the seven selected for the pilot project, has been delayed because of disagreement over mitigation measures for the line. The line is being developed by PPL Electric Utilities and Public Service Electric and Gas Company. Salazar said that as part of the initiative, he directed the National Park Service to work with the utility to develop an acceptable mitigation plan, "instead of having Susquehanna to Roseland line to stay in regulatory limbo for years or decades."

— Pam Radtke Russell

## Dominion solar charge draws lawmaker's ire

A proposal by Dominion Virginia Power to impose a charge on net-metering residential customers would discourage the installation of new systems or the expansion of exist-

ing systems, a Virginia lawmaker said in a letter to the State Corporation Commission.

The solar energy industries association that represents developers in Virginia, Maryland and the District of Columbia said the charge would inhibit growth in solar generation in the Virginia residential market and asked the SCC to hold a hearing on the proposal.

The Legislature this year increased the allowable amount of customer generation from a maximum of 10 kW to 20 kW. The law allows for a standby charge for operations that exceed 10 kW. Dominion in July proposed a charge and method for determining that charge for residential customer-generators who have a system that exceeds 10 kW.

The law limits the standby charge to an amount that allows utilities to recover only the portion of its infrastructure costs "that are properly associated with serving such eligible customer generators."

Dominion proposed to calculate the standby charge by using the highest average kW demand from customer-generator during any 30-minute interval during a month. It proposed such a methodology because of the intermittent nature of renewable installations, the company said. "By calculating the standby charge based on the individual demand imposed by each eligible customer-generator, as opposed to a flat charge or a charge based on the installed capacity of the generating facility, the standby charge will relate more precisely to the customer-generator's demand on the company's system," Dominion said.

The proposed standby charge would result in more appropriate apportionment of cost among residential customers and reduce the cross-subsidization of net-metered customers by non-net-metered customers, the company said.

The proposed charge is divided into three components, \$2.79/kW for distribution costs, \$1.40/kW for transmission-related costs and an amount yet to be determined for generation-related costs.

The MD DC VA Solar Energy Industries Association in its request for a hearing by the SCC said the methodology proposed by Dominion does not account for the benefits associated with distributed solar generation when determining the fees. "These outcomes will significantly impact the businesses of [our] members," the association's filing said.

Dominion does not support its claim that the charge would not "unduly discourage" installation of net-metered systems with a capacity between 10 kW and 20 kW. "MDV-SEIA is prepared to provide evidence to the commission to the contrary," the association said.

State Delegate David Toscano, a Democrat, said in a letter made public by the SCC last week that it is premature for the SCC to assess the standby charge. Dominion's proposal would be a disincentive for customers to expand existing system beyond 10 kW and it would be a disincentive for the development of new systems, even those smaller than 10 kW or smaller, Toscano said. That was not the intention of the Legislature, he said.

"It is clear that the Legislature wishes to encourage a more robust renewable energy sector. There is a belief that over the

long term, bringing more of these renewable resources online will create more competition in the marketplace, exert a downward pressure on rates and provide greater generation capacity," Toscano said.

Toscano also noted that the General Assembly established a working group to discuss the methodology to be used for developing the standby charge and the SCC should defer consideration of Dominion's proposal until after the working group completes its job.

Republican Delegate Terry Kilgore, Chairman of the House of Delegates Commerce and Labor Committee, said in a letter to the SCC that utilities consistently take the position that other customers are subsidizing customer-generators for the difference between wholesale and retail rates.

Proponents argue that the subsidy is relatively low "if it exists at all" because of the value net-metered systems add by putting off infrastructure upgrades and the construction of new generation, Kilgore said.

The Commerce and Labor committee asked the working group to consider the extent to which the value of payments and credits to customer generators exceed the value received by the utility from the customer's power.

— *Mary Powers*

## More retail suppliers offering demand response

With large commercial and industrial customers looking to save money any way possible, retail marketers are increasingly offering demand response services beyond traditional power supply contracts with customers, the head of the Retail Energy Supply Association said Friday.

In competitive retail markets, "a growing number of suppliers are offering demand response products and services" to keep up with their competitors, said David Fein, president of RESA and vice president of energy policy and director of retail energy at Constellation Energy. "We are all in the business of meeting customers' needs," and as consumers become more sophisticated in trying to manage their energy costs, retail marketers will go beyond commodity sales and help customers shift or trim their usage in response to price signals, Fein said in an interview.

Retail marketers have been branching into the demand response sector for some time, with companies such as Direct Energy, Constellation and Hess having the size and resources to provide such services on their own. Other marketers, such as TransCanada Power Marketing and PPL EnergyPlus, partner with Comverge or other demand response firms to provide hardware or software to consumers in order to offer demand response products.

"I think you'll continue to see a mixture of both approaches," with larger firms entering the demand response field on their own and smaller companies seeking partners, said Fein. Smaller firms may not have the internal capabilities to manage portfolios and focus on demand response efforts, so they could seek joint ventures with demand response firms, enabling

them to concentrate on commodity sales and meeting customer needs, he said.

The latest entrant in the partnership group is ConEdison Solutions, a subsidiary of Consolidated Edison, which last week formed a partnership with Viridity Energy enabling customers to curtail or shift their usage and receive compensation from independent system operators.

The "energy optimization" offering comes from the companies installing energy management software and controls at customer facilities, enabling the customers to change usage habits based on prices or demand response events called by ISOs. The equipment is installed at no cost to customers, explained Cara Olmsted, director of new business development at ConEdison Solutions. Customers will have the option of making the usage changes themselves or empowering ConEdison Solutions to do so, Olmsted said in an interview.

"My sense is most customers will want us to do that" as they become familiar with the service and realize that rather minor usage adjustments at large facilities can produce savings, she said.

ConEdison Solutions will offer the service to current customers and as a marketing tool to attract new customers, Olmsted said. The company is offering the service in New England, New York, PJM Interconnection and the Electric Reliability Council of Texas. With the price swings and supply concerns experienced in ERCOT this year, customers there may see real value with the service, she said.

With the demand response effort, ConEdison Solutions customers "can turn their energy management programs into revenue generating sources" by buying power at fixed prices and selling it when market prices exceed a certain threshold, said Jorge Lopez, president and CEO of the marketer. "This offering brings in dollars for customers by turning users into suppliers," Lopez said in a statement.

— *Tom Tiernan*

## Maryland utilities seeking gas-fired supplies

Maryland's utilities are seeking generation under a long-term contract that could result in as much as 1,500 MW of natural gas-fired generation built in the eastern part of the state under requests for proposals issued Friday.

Baltimore Gas & Electric, Delmarva Power, Potomac Edison and Pepco issued the RFPs.

The PSC has been considering for two years whether they should require utilities to build generation since the PJM Interconnection's reliability pricing model has been "unsuccessful in attracting appreciable new generation."

Maryland is the second state that has taken action based on the inability of the reliability pricing model to attract new generation. The New Jersey Legislature in January required regulators in that state to subsidize the construction of 2,000 MW of generation.

The state continues to face the threat of insufficient new capacity, the PSC said in the order issued September 30. PJM in 2008 showed shortfalls of up to 1,500 MW, but no new gen-

eration has been built in the region “despite the fact that the RPM has imposed prices [in the eastern Maryland area] that are approximately double that of the rest of the PJM region.”

The RFP is for capacity and energy that will be located inside PJM’s Southwest Mid-Atlantic Area Council, which includes BGE’s and Pepco’s territory, Ray Dotter, a PJM spokesman, said. The PSC is considering issuing a separate RFP for the state’s Eastern Shore. It also is considering issuing a separate RFP for renewable resources.

Respondents can offer products in any quantity but are not to exceed a total of 1,500 MW. “The commission may award one or more contracts to one or more suppliers,” the RFP said. The PSC reserves the right to acquire more than 1,500 MW or to reject all submissions, the RFP said. The PSC has made a preliminary determination of need and will hold a hearing on January 31 to make a final determination. “The commission is solely responsible for determining contract awards under this RFP and may authorize one or more of the Maryland [utilities] to enter into a long-term contract as a buyer,” the RFP said.

The RFP is for gas-fired units only because Maryland is in a unique position to benefit from low gas prices projected from shale deposits, the order said. It also will allow the responses to be more “accurately and objectively” evaluated, the PSC said. The projects proposed must not have cleared any prior PJM base residual auction for capacity. The winning bidder must offer the capacity into the base residual auction according to rules as they exist throughout the term of the contract. Bidders will not be paid for any year in which the capacity does not clear the auction, the order said.

Bidders must submit proposals to commit generation for an initial term of up to 20 years beginning as early as June 1, 2015 but no later than June 1, 2017.

Proposals are due November 11. The PSC will hold a hearing January 31 and will select winning offers on February 23.

All questions regarding the RFP should be directed to Dolline Serra at dserra@psc.state.md.us.

Information on the RFP is on the PSC’s website at [www.psc.state.md.us](http://www.psc.state.md.us) under case number 9214.

— *Mary Powers*

## Stalled California CHP settlement progresses

Modifications to a sweeping settlement meant to bolster California’s combined heat and power industry were approved by regulators last week, following close to a year of disputes over CHP-related costs that should be borne by customers leaving investor-owned utility service.

Adopted by the California Public Utilities Commission in December 2010, the settlement establishes a new competitive procurement process that requires investor-owned utilities to run competitive request for offers for a total of 3,000 MW of CHP resources. Parties to the settlement include investor-owned utilities and CHP trade groups.

The 3,000 MW roughly equals the CHP that is either operat-

ing under one-year contracts or will expire before January 2015.

Essentially, the “commitment was made to retain the existing amount of CHP capacity until the next PUC long-term procurement proceeding is concluded in 2015 or 2016, where it is expected a decision will be made as to what amounts of additional CHP capacity, above and beyond the 3,000 MW, will need to be contracted by the IOUs,” said Steven Kelly, policy director for the Independent Energy Producers Association, in an email.

Additionally, the settlement resolves the many claims regarding power purchase contracts between CHP owners and utilities. The settlement will also relieve IOUs of the must-buy obligation under the Public Utility Regulatory Policies Act for qualifying facilities larger than 20 MW. But the settlement as been in limbo, as publicly-owned utilities, energy service provider trade groups and representatives of community choice aggregators petitioned the PUC to modify rules related to the settlement’s requirement that costs of CHP capacity procured by IOUs be spread to all ratepayers in the state, including those entities who leave IOU service.

Those charges apply to, for instance, a customer who switches to the Sacramento Municipal Utilities District from Pacific Gas & Electric service.

The decision adopted Thursday on a 3-2 vote removes from a July decision language that settlement parties and California Municipal Utility Association said was not needed. Overall, the July decision clarified the extent to which IOU customers switching to munis would be responsible for any non-bypassable charges associated with the settlement.

The decision clears the way to establish a settlement effective date if there are no appeals, said Beth Vaughan, executive director of the California Cogeneration Council.

Under the settlement, two conditions must be met before the settlement can be implemented. There must be a final non-appealable PUC decision, and a final, non-appealable Federal Energy Regulatory Commission approval of the IOUs’ application to terminate their PURPA purchase obligations.

Also at the meeting, the PUC approved a \$25 million ratepayer-funded program that will provide financial incentives to low-income ratepayers to install solar water heating systems. The solar water heating systems are meant to lower electricity bills by displacing use of natural-gas. The effort is part of the California Solar Initiative.

Additionally, the PUC opened a rulemaking focused on whether and how to extend the “public goods charge,” assessed on ratepayers that it said is critical for energy efficiency and renewables efforts.

The Legislature in September rejected bill that would have reauthorized the program, which is set to expire in January.

The public goods charge program provides energy efficiency funding each year totaling \$250 million for each IOUs and about \$150 million for various renewable-related research and development projects overseen by the California Energy Commission. The program is funded by a monthly charge on ratepayers’ bills.

— *Lisa Weinzimer*

## Duke offers 'virtual divestiture' ... from page 1

that Duke and Progress needed to propose possible mitigation measures such as joining a regional transmission organization, implementing an independent coordinator of transmission arrangement, actual or virtual divestiture of generation assets and/or transmission upgrades.

Duke and Progress' top executives said October 3 that they would submit a mitigation plan to FERC by October 17, but to do so the NCUC would need to exempt Duke from a requirement that the company notify the North Carolina commission 30 days in advance of making any significant filing to FERC.

In its Friday filing requesting that exemption — or, failing that, allowing Duke to provide only seven days' notice this time — Duke told the NCUC that it would like to file its proposed market power mitigation plan with FERC by October 17.

The proposed eight-year mitigation plan calls for Duke Energy Carolinas and Progress Energy Carolinas to offer to sell 300 MWh during each summer hour and 225 MWh during each winter hour into the DEC's balancing authority area, and for Progress Energy Carolinas to offer to sell 500 MWh during each summer hour into PEC's eastern balancing authority area.

Duke told the NCUC that the sales price for the energy would be the forecasted average incremental cost — after serving retail and wholesale native load and existing firm obligations — plus 10%. "The price will be established on a day-ahead basis based on the amount and hours of energy actually purchased during the offer process," Duke said in a term sheet it filed with the NCUC.

Duke said the energy would be offered on a day-ahead basis. DEC and PEC "would be obligated to commit generation units on the next day if necessary to satisfy requests" for energy, with the associated start-up costs included in the incremental costs to be recovered," it said.

Duke told the NCUC that its proposed mitigation plan "will in no way impact the \$650 million in guaranteed savings" that Duke and Progress committed to provide to their North Carolina and South Carolina customers as part of settlement agreements the companies reached in early September with the NCUC's independent Public Staff and the South Carolina Office of Regulatory Staff.

On Wednesday, the ORS asked the South Carolina Public Service Commission to delay the PSC's planned October 26 hearing on DEC and PEC's joint dispatch agreement until it became clear what Duke's mitigation plan consists of and whether the plan would be acceptable to FERC.

Coyle, the attorney for New Bern, said Friday that he and his colleagues continue to evaluate Duke's newly released mitigation plan. He added, however, that "given the low load levels at which FERC found the screening violations to occur, it would be very surprising if day-ahead energy sold at incremental system cost plus 10% after native load and firm obligations were met would make any difference" in Duke and Progress' market power.

Coyle noted in an earlier interview, "One interesting thing that people need to think about is that some of the biggest [market power] concentration problems occur at low load levels." Since utilities dispatch units based upon economic merit, "that

tends to suggest that the divestiture of some lower-cost units would be required" as part of any effective mitigation plan.

The NCUC will likely respond early this week to Duke's newly filed request for leniency on the 30-days-notice rule.

In a Friday interview before Duke made its filing, NCUC Chairman Edward Finley said, "We'll have to see some certainly from FERC" on approving market power mitigation plans to be proposed by Duke and Progress before the NCUC can determine whether it will need to re-open its hearing on the Duke/Progress combination. That hearing ran from September 20-22.

FERC's demand that Duke and Progress propose mitigation plans "may set things back a bit" in the NCUC's review, Finley said, adding that the NCUC is "under no deadline" to act on Duke's request to approve its planned acquisition of Progress.

— Housley Carr

## FERC November conference ... from page 1

Natural Resources Committee, has pressed FERC to do a formal study on the impact of EPA regulations on coal-fired generating capacity. Murkowski in letters to FERC earlier this year indicated her displeasure with FERC's activities on the issue.

Democrat Jon Wellinghoff, appointed to the commission in 2006 and named FERC chairman by President Barack Obama in March 2009, has indicated that the existing planning authorities provide the appropriate forums for addressing any potential impact of EPA regulations on electric reliability. Developing such a capability at FERC would not be an efficient use of government resources, Wellinghoff said in September 14 testimony to the House of Representatives Energy and Commerce Subcommittee on Energy and Power. He also noted that FERC does not have the authority to require the construction or retirement of generation facilities.

Wellinghoff in his testimony said that FERC "does not possess either the data or the models necessary to replace the industry's individual and collective planning processes in addressing the potential local and regional impacts of the EPA regulations on electric reliability."

But FERC member Philip Moeller, a Republican, has appeared to push for more of a FERC role in examining the issue, telling the Subcommittee on Energy and Power in September 14 testimony that "at a minimum" FERC should direct its staff to analyze the impact of EPA's rules on reliability and hold a technical conference on the topic. FERC staff has held discussions with EPA and done an informal staff study of EPA's regulations on coal-fired generation.

FERC spokeswoman Mary O'Driscoll on Friday said the decision to hold the technical conference does not mean FERC is considering a formal study of the effects of EPA regulations on reliability and is rather "part of our normal course of business." The EPA regulations are one issue that will be discussed, and "that's the issue that's on everybody's mind right now," she said. "I think everything that the chairman has said still stands," O'Driscoll added.

— Jason Fordney

## Ontario election results ... from page 1

green energy feed-in tariffs and smart meters, while the NDP pushed for more public and less private ownership of renewable energy projects.

With pressure from the right and left, the McGuinty government is going to have to engage in a lot of “brokerage,” Butters said. This will represent a shift in business-as-usual, since Ontario’s winning party usually has the votes to simply put its policies in place.

Some of the brokering is likely to center on energy prices, according to Butters. “There are cost pressures building up in the electricity sector. They will not want that fire to ignite. They will be looking at ways to manage costs.”

Ontario’s regulated electricity prices have risen about 6.3% annually since 2006, according to a report published last month by London Economics International. The report blamed integration of high-priced renewable energy, a lack of competitive procurement and market distortions. Ontario functions under what is known as a ‘hybrid market’ which has elements of central planning and competition.

LEI said that a lack of competitive procurement has created a “disproportionally large” supply of baseload and intermittent resources, such as nuclear, wind, solar, combined heat and power and certain hydroelectric facilities. Total supply is about 26,000 MW.

The government’s policies have led to a high reserve margin that will exceed 30% over the next three years, well above a target of 18-22%, LEI said. The McGuinty government has been pursuing a policy of phasing out coal-fired generation and encouraging renewable energy development through feed-in tariffs.

Regulated rates in the province run from about C6.8 cents/kWh to 7.9 cents/kWh with competitive retail prices running as low as 4.12 cents for variable rates plans. Retail suppliers would like to introduce new products to drive down prices, but have been hampered by market restrictions, according to Tanis Kozak, vice president and general manager of Direct Energy, Canada.

“In well-functioning markets people see prices fall when demand falls,” she said. “Ontario consumers are paying higher electricity costs even though demand is falling and the price input of fuel is falling.”

Ontario is more restrictive about the kind of products retail suppliers can offer consumers than are places like Texas or Pennsylvania, she said.

“In Texas, we have pay-as-you-go with smart meters, in Pennsylvania we have free power Saturday,” she said “This kind of innovation is actively discouraged in market rules in Ontario.”

Meanwhile, renewable energy advocates say the election is likely to continue strong development of wind and solar in the province. The province now offers a generous feed-in tariff for renewable energy, which runs as high as 71.3 cents/kWh for solar projects no larger than 250 kW. The feed-in tariff for onshore wind is 13.5 cents/kWh.

But the future of renewable energy policy will depend on whether or not the Liberals and the NDP, both pro-green, will

come together in voting.

“I think there will be a convergence with the NDP and Liberals on green energy. When it comes down to it they are both supportive. We will have to wait and see,” said Cherise Burda, a policy director at the Pembina Institute, a renewable energy advocacy group.

— Lisa Wood

## Credit reform implementation ... from page 1

FERC to reject PJM’s minimum capitalization requirements on the grounds that they would reduce liquidity and competition, Daugherty said that the 17 members who had to reduce their participation accounted for just 0.1% of financial transmission rights auction bids and less than 0.2% of summer 2011 energy market transactions.

“It does not appear that there will be a negative impact on liquidity,” Daugherty said.

Igor Kliakhandler, president of Intergrid Mideast Group, said the requirements to remain in the PJM’s FTR market were at the “borderline” of what his company was capable. However, he said, other small players he knows were not able to meet the minimum capitalization criteria.

“For small companies, like me, who have to do it from scratch, it’s at the verge of what’s doable,” Kliakhandler said. “I’m able to make it, but I know a number of guys who are going out of the market because they’re unable to do it.”

Kliakhandler said the exit of some small companies from the FTR market — where PJM’s capitalization requirements are most stringent — could result in lower prices in the short-term.

“I basically expect FTR prices will slightly drop next month because some people will go out of the market,” Kliakhandler said.

“On the long term, it may not change much,” he added. “In some sense, competition will decrease. Can I say dramatically, maybe not. ... [But] smaller players will get out, and big players will be happy to purchase things at reduced prices.”

Other ISOs reported less of an impact due to their minimum capitalization rules. The Midwest Independent Transmission System Operator and Southwest Power Pool said all of their market participants met the requirements.

The California Independent System Operator said the changes might prompt some companies to leave the Cal-ISO market, but did not supply information about whether any of its market participants had already done so.

“The new order was designed to limit the participation of those entities that have sufficient financial backing and risk management sophistication to participate in the market,” Cal-ISO spokesman Steven Greenlee wrote in an email. “It is possible the ISO will see some market participants leave our market after making the business decision that best meets their needs.”

While all the ISOs enacted some new minimum capitalization criteria, only the New York Independent System Operator required its market participants to submit their officer certification forms by October 1. Because FERC gave the ISOs until

December 14 to propose systems for verifying the claims made by companies in their officer certification forms regarding risk management, training and staffing, the other ISOs held off on requiring market participants to submit their forms.

Ken Klapp, spokesman for the NYISO, declined to say whether any NYISO market participants failed to meet the new requirements or submit their officer certification form.

One market participant from a company active in multiple markets said they were able to deal with NYISO's certification form because it is much more general than forms proposed by other ISOs, especially PJM.

But while the minimum capitalization requirements hit small companies the hardest, he said larger companies could wind up have the biggest problems with the officer certification forms.

"I think it's actually easier for those little participants to meet that [officer certification requirement]," he said. "In big organizations where there are a lot of controls, you can't sign a form without knowing what it means. It's more likely that bigger and more responsible market participants would be at risk."

Furthermore, with the ISOs each developing or refining verification plans, he said, companies that participate in multiple markets could face a challenge in meeting the ISOs' differing requirements.

"If the burden comes so great in terms of having various levels of certification and submission and audited forms, then people ask the question, 'Is the cost of being in the market really worth it?'" he said.

— *Juliana Brint*

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