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Global Power Report

March 13, 2008

With plenty of wind generation planned in US, the focus turns to plans for grid integration

If the answer to the country's thirst for renewable energy resources is blowing in the wind, the utility industry is trying to make sure it is asking all the right questions before putting the power grid at risk because of the variable nature of wind generation.

Industry groups are looking at measures like making greater use of wind forecasting tools, managing interconnection queues better and planning transmission to handle the remote location of wind resources. The need for planning is evident when projections for growth in wind generation are considered; up to 60,000 MW could be installed in the United States by 2015.

In Alberta, where wind generation makes up about 4% of generation in the province, "we are learning as we go," and other regions need to share best practices on how to best integrate wind resources in the US and Canada, said Warren Frost, vice president of operations and reliability at the Alberta Electric System Operator.

Frost is heading a new task force created by the North American Electric Reliability Corp. to deal with integrating variable generation resources, such as wind, solar and tidal

(continued on page 2)

Project finance finds a new niche, aggregating small, photovoltaic solar power installations

Project finance has found a new niche, solar power. Not the large thermal solar plants that lend themselves to utility scale installations, but photovoltaic solar power.

PV solar power is essentially distributed generation, meaning it is hard to string together discrete installations. So, even though it is an expensive form of generation, the individual installations do not have sufficient scale to attract bankers, who thrive on economies of scale.

That has meant that people who wanted to put solar panels on their roof had to finance the installations themselves, and between the high cost of solar PV panels and the long pay-back period, that has put a damper on the industry. But that is changing. More and more solar systems are being installed using some form of financial engineering.

One widely used mechanism is the PPA model. Instead of paying the high cost of installing a solar system, a customer contracts with a solar power company, a solar integrator, that installs the system on a customer's roof. The solar power company owns the system and sells the customer power under a fixed price contract.

Analysts at Greentech Media forecast that the PPA model

(continued on page 4)

Enel of Italy takes stake of almost 60% in Russian generator OGK-5 for $4 billion

Italian power company Enel has secured a 59.8% stake in Russian power generator OGK-5 for a total of Eur2.61 billion ($4 billion), according to final results of the mandatory public tender offer, Enel said last week.

The shares tendered in the public offer, which Enel launched in November 2007, amounted to 22.65% of OGK-5's share capital, according to the checks by relevant Russian authorities, Enel said.

These shares, added to the 37.15% shareholding in OGK-5 already owned by Enel ahead of the launch of the public offer brought the company's total ownership of OGK's shares to 59.8%.

In the public offer on the entire share capital of OGK-5, Enel had offered Rb4.4275/share for a total of approximately Rb35.474 billion ($1.48 billion).

Together with the acquisitions of OGK-5 shares in June and October 2006, Enel has paid a total of Eur2.608 billion to secure its current stake in the Russian generator.

"We are the first foreign operator to complete a public tender offer on a Russian company in the key energy sector, with full transparency, respect for the interests of all

(continued on page 2)

INSIDE THIS ISSUE

Enel of Italy takes stake of almost 60% in Russian generator for $4 bill ... from page 1

shareholders and compliance with market rules," Enel CEO Fulvio Conti said in a statement.

Enel has repeatedly indicated its interest in securing control of OGK-5 and last year received approval from the Russian antitrust regulator to increase its stake in the company up to 100%.

OGK-5 is one of six wholesale generation companies in Russia undergoing privatization. It was set up in 2004 as part of a reform of the electricity industry in Russia.

OGK-5's four main assets are the 2,400-MW gas-fired Konakovskaya GRES power plant in the Tver region (Central Russia), the 1,290-MW gas-fired Nevinnomysskaya GRES plant in the Stavropol region (Southern Russia), the 3,800-MW coal-fired Reftinskaya GRES plant in the Sverdlovsk region (Urals), and the 1,182-MW gas-fired Sredneuralskaya GRES plant in the Sverdlovsk region (Urals). — *Anna Shiryaevskaya*

With plenty of wind generation planned, focus turns to grid integration ... from page 1

power. The task force, which has 30 participants from many industry sectors, will examine a broad array of issues facing variable generation, such as the operational challenges and new tools that can "level out" the ramp-ups and ramp-downs of wind resources, said Mark Lauby, manager of reliability assessments at NERC.

"Bulk power system reliability must be maintained regardless of the generation mix," and grid operators need to understand the challenges associated with bringing more renewable generation into the picture, Lauby said last week during a web-based conference on integrating wind resources.

It has become clear that the integration requires special considerations in planning, design and operations of the bulk power system, particularly, he said, since "we find ourselves operating the system closer to the edge than ever before." The reliability aspect came into focus February 26, when the Electric Reliability Council of Texas had to call on interruptible service customers to shed load quickly to avoid the possibility of widespread outages. Late in the day, a sudden drop in wind output, coupled with strong weather-related demand and the loss of other generation resources, led to a frequency decline on the grid and problems with balancing generation and load.

ERCOT moved directly to step two of its emergency curtailment plan, calling on demand response resources and interrupting large users on interruptible service.

ERCOT intends to move up plans to integrate wind forecasting in its operating plan, spokeswoman Dottie Roark said last week.

The amount of wind capacity installed in ERCOT is about 4% of total generating capacity in the region. ERCOT has been working on a wind generation forecasting tool that it plans to use as part of its switch to a nodal market design in December, Roark said. The February 26 event made the use of the tools a higher priority, she said.

The wind power industry "supports and applauds that conclusion as it will enable continued diversification of power supplies while maintaining the robustness and reliability of the grid," said the American Wind Energy Association.

At the time of the incident, the amount of wind capacity on ERCOT's system fell to 300 MW from more than 1,500 MW. ERCOT relies on the resource plans and data provided by

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qualified scheduling entities to get a picture of upcoming load and generation needs and analyze adequacy. On February 26, "the resource plans reflected more generation capacity that was actually available, primarily accounted for by inaccurate wind energy expectations," ERCOT said in its operations report on the event, which was released last week.

Other generation resources also were unavailable at the time, though they had been planned in a day-ahead forecast. ERCOT did not identify plant owners or types of generation, but over a 30-minute period on February 26, non-wind generators dropped from falling 50 MW below their scheduled output to falling more than 600 MW below their scheduled output, a point that was picked up on by AWEA.

Wind forecasting tools, which were not used by ERCOT but will be at some point, "did predict the wind output with good fidelity," ERCOT said in its report.

Unlike the wind resources that declined steadily over a three-hour period that day, fossil-fuel and nuclear power plants "can and frequently do trip off-line instantaneously," as the power outage in Florida demonstrated, AWEA said.

Equipment failure at a Florida Power & Light substation in western Miami-Dade County caused several transmission lines and power plants to trip offline on February 26, cutting off electric service to 475,000 FP&L and more than 200,000 customers of other utilities in the state.

Another factor in the ERCOT event was an increase in electricity usage that was 950 MW more than expected, from 6 pm to 7 pm central time. An increase of 2,550 MW in usage coincided with a drop in responsive reserves, straining the grid, ERCOT said.

The grid operator tracks changes in resource plans using a tool called the market analyst interface, which runs an hour-ahead study every hour to determine if there is enough capacity to meet demand. "The study did not indicate an approaching problem because the resources plans indicated approximately 1,000 MW of capacity available that was subsequently unavailable," the operations report said.

With earlier detection of approaching generation deficits, more capacity can be procured from spinning reserves, ancillary services or other resources to be available when needed, ERCOT's report concluded.

Texas Public Utility Commission staff and ERCOT's independent market monitor are gathering data on the event. The market monitor and PUC staff plan to present a report to the commission by the March 27 meeting, PUC spokesman Terry Hadley said.

The ERCOT event provides "one more example of why we need good wind forecasting" and the need to include such forecasting in control area operations, said Rob Gramlich, policy director at AWEA. Wind forecasting is "not yet an exact science. There are a lot of studies being done" and independent system operators and utilities are developing new tools and operating strategies to incorporate forecasting, Lauby said. Grid operators in Europe are much more familiar with wind forecasting and are using such tools to help manage grid conditions, AWEA and others have pointed out.

A group on the front lines of these issues in the US, the Utility Wind Integration Group, has been advocating the use of wind forecasting for years, Gramlich said.

In fact, UWIG Executive Director Charles Smith has said that as wind generation numbers increase, the industry needs to change its way of thinking about such resources – not so much as generation but as "negative load" that can vary based on different conditions.

New control technologies on wind turbines can provide governing functions to even out ramp-up or ramp-down events. But "instead of talking about 'firming up' the wind to make it look like something that it is not, accept it for what it is, and deal with the net load accordingly," Smith said in a statement posted on the UWIG web site.

"The fact of the matter is that a wind plant is generally an energy resource, not a capacity resource. We live in a capacity world, and we have to think about a wind plant differently," he said.

"You can integrate wind reliably," but there often needs to be other load-following reserves added to account for variability, Gramlich said. Compressed air energy storage is one such technology, in which air is stored underground, released and used to drive generators to match demand needs.

In Alberta, wind generation is growing and the province's ISO is starting to use wind forecasting tools and projecting how wind generation forecasts correlate with load forecasts, Frost said, suggesting that "wind needs a dance partner," such as additional generation, storage technologies or other energy management tools to accommodate swings in production from wind facilities.

"We've been studying wind integration since about 2003" in Alberta, which has 523 MW of wind resources in operation and about 9,000 MW in the interconnection queue, he added.

Capacity factors for wind plants have increased with technology gains over the years, and the average capacity factor in Alberta was 35% in 2007, Frost said.

For planning purposes, however, ERCOT uses only 8.7% of nameplate capacity from wind plants to be used to meet peak demand requirements, Lauby pointed out. Similar percentages are used in other parts of the country.

For reliability reasons and to accommodate the move to cleaner generating sources, "we need to develop a clean energy superhighway" that will add transmission to move power where it is needed, Lauby advised. In Alberta, that will require $750 million in transmission additions, to integrate 3,300 MW of wind, Frost said.

Interconnection queue management, with more than 10,000 MW of wind planned to be connected in some regions of the

Quote of the Week...

"The fact of the matter is that a wind plant is generally an energy resource, not a capacity resource. We live in a capacity world, and we have to think about a wind plant differently." — Charles Smith, executive director of the Utility Wind Integration Group, speaking about issues raised by a disruption of electric power service in Texas caused by a sharp drop in wind resources (see story, page 1).

continent, along with transmission planning, are some of the issues to be tackled by the NERC task force, Lauby said.

The US could have 60,000 MW of installed wind capacity by 2015, up almost four-fold from today, according to Antonio Martins da Costa, chairman and CEO of Horizon Wind Energy. Speaking at an energy summit organized by the Greater Houston Partnership, Martins da Costa said he believes the US will see roughly 44,000 MW of wind capacity built out over the next seven years.

Horizon, which was acquired in 2006 by Energias de Portugal for $2.7 billion and has invested $1.3 billion over the past year, has about 1,500 MW of installed wind capacity in the US, and 2,000 MW of wind capacity in Europe. — *Tom Tiernan*

Project finance's new niche, aggregating small solar projects... from page 1

will drive 75% of commercial and industrial solar sales in 2008 and 2009.

Several companies claim to have pioneered the PPA model for PV solar power. Julie Blunden, vice president of public policy and communications at SunPower, says PowerLight did the first solar PPA deal in 1999.

PowerLight installed a 100-kW PV array on the roof of its manufacturing facility in Berkeley, California. GPU Solar owned the system, and Green Mountain Energy agreed to purchase the electricity from the solar plant on behalf of its California customers. SunPower bought PowerLight in January.

SunEdison claims that the Beltsville, Maryland company's founder and chief strategy officer, Jigar Shah, pioneered the solar PPA model or solar power service agreement, as they call it.

SunEdison's first application of that model was the installation of a 125-kW system on the roof of a Whole Foods Market store in Edgewater, New Jersey, in March 2004. With backing from Goldman Sachs & Co., SunEdison bought solar panels and installed them on the store's roof. Goldman owns the system, except for a small stake retained by SunEdison. Whole Foods signed a contract for solar energy from the system with a 2% escalator over the roughly 10-year term of the contract.

There are differences between the SunEdison and SunPower deals, but they have two common features: the customer does not own the solar system or pay for its installation and the customer enters into a power purchase agreement with the solar integrator for the solar power produced.

"The PPA model tears down the Berlin Wall of capital cost barriers and opens up a flood gate of installations," said Blunden. "If a company is looking at putting a system on more than one roof, they don't have to worry about installation costs or the expiration of tax incentives, all they have to look at is the energy cost." The PPA model reduces the decision to a single question, she says, "Is it at or below your existing cost of energy?"

Since its first deal, SunEdison says it has installed 93 solar systems based on the PPA model with an aggregate capacity of 26.4 MW. The majority of those installations are comprised of multiple locations for large retailers such as Kohl's, Staples, Suresave Stores, Wal-Mart and Whole Foods.

SunPower also targets retailers. In January the San Jose, California, company struck a deal with GE Energy Financial Services worth about $50 million that calls for the General Electric unit to provide financing for five California solar power projects totaling about 8 MW (*GPR*, 17 Jan, 17). The solar projects are at a Toyota parts center, HP research and development center, a parking lot for Agilent Technologies and ground systems for a correctional facility and a the water district. In another deal, in November, SunPower secured $190 million in financing from Morgan Stanley that will be applied to solar power projects.

Blunden said those deals represent two ways to do the same thing. In the GE deal, "we have the projects and then find the money," in the Morgan Stanley deal, "we get the money, then find the projects."

The aim, however, is the same. SunPower is looking for economies of scale "throughout the value chain," from manufacturing to delivery to financing, with the goal of cutting the price of solar power by 50% by 2012.

And "the lesson," said Thomas Werner, SunPower's chief executive officer, "is there is a very competitive market for financing systems in the United States with lots of high quality investors looking to participate in solar power."

In addition to Morgan Stanley, GE, and Goldman Sachs, Wells Fargo has also been funding solar power deals, as has MMA Renewable Ventures, a unit of Municipal Mortgage & Equity LLC (MuniMae). MMA Renewable says it has arranged financing for $300 million worth of solar energy projects. And Wells Fargo says it has committed $120 million to solar PV installations over the past six months.

"The PPA model is becoming the dominant model," said Edward Levin, vice president of global capital markets with Morgan Stanley. "It is no longer a plausible business model for a solar developer to sell panels to a property owner or corporation. A developer, or third party, needs to sell power and to line up financial institutions or other investors that can take the tax credits."

Unlike the residential market, the commercial market is not just being driven by a desire to be green. Solar power is exploding because of "pure economics," said Barry Neal, head of environmental finance at Wells Fargo.

According to the Solar Energy Industries Association, in 2006 the US PV solar market grew by 43% in terms of installed megawatts, and it is on track to grow by 60% in 2007.

Companies like Wal-Mart and Kohl's are turning to solar power because "they can actually reduce their electricity costs, particularly in states like California and New Jersey" where rates are high and rising, said Neal.

High electricity rates are key because they enable the solar power company to offer to reduce a customer's electricity costs. New Jersey has some of the highest rates in the country, and in California peak rates can be as high as 34 cents/kWh. That is one reason those two states account for about 85% of solar installations; the other is that they both offer generous incentives.

California's Million Solar Roofs Program aims to create 3,000 MW of solar power by 2017, and includes incentives that start at

$2.50/watt. That translates into an $8,000 payment for a typical home solar system. New Jersey's solar incentive program has been so popular — the state went from six solar installations in 2001 to 2,712 as of year-end 2007 – that it has run out of money. The budget allocations for 2008 have already been spoken for, so the state is moving from cash-based rebates to rebates paid in renewable energy certificates (*GPR*, 28 Feb, 21).

In addition to state incentives, there is also a federal investment tax credit worth up to 30 cents on the dollar. For the bankers, the incentives and tax credits are key. "The ITC allows for a lower cash portion on the return," said Mark McLanahan, vice president of marketing and strategy at MMA Renewable Ventures, and that lowers the price firms like MMA can charge for electricity under the power purchase contracts.

Another reason these deals are attractive to bankers is the credit quality of the counter parties, said Neal. That is one of the reasons that firms like MMA Renewable and SunEdison focus on the commercial and industrial markets. The credit quality of the offtakers allows bankers to aggregate deals.

Credit quality issues make the residential market harder to crack, even though some homeowners have a desire to "go green" regardless of the economics.

SunPower is tapping the residential market through partnerships with homebuilders to install solar panels on new homes and is working with the New Resource Bank to offer second mortgages to finance solar installations on existing homes. But before the residential market can take off, the credit quality issues will have to be addressed.

There are several possible solutions. One being closely watched is a program the city of Berkeley, California, began working on last fall that would allow homeowners to install solar systems and pay for them through a 20-year assessment on their property tax bill (*see story, page 25*). The details have yet to be worked out, but bankers are looking carefully at that and other ways of aggregating financing for residential solar installations. Levin at Morgan Stanley said a solution could come in the next three to six months.

"A lot of people are trying to aggregate in the residential market," said Neal at Wells Fargo, but "the jury is still out."

But, as the subprime mortgage crisis has demonstrated, risk cannot be banished by repackaging it. Under the solar power purchase model, the customer — the retail store, the homeowner — takes the risk.

"Individual customers may save money [on a solar installation], but they are making a big bet that prices stay high," said Severin Borenstein, director of the University of California Energy Institute. Photovoltaic solar power is "incredibly expensive", he said. "It isn't economic, and you can't make it economic through financial engineering."

In fact, Borenstein warns that California is under "huge pressure" to revise its electricity tariff structure that was enacted into law after the state's 2000-2001 energy crisis, and he said that he has had exploratory discussions with the Public Utilities Commission on repealing or revisiting the law.

Phone requests for comment to the PUC were not returned by press time. *— Peter Maloney*

COMPANY NEWS

Endesa predicts strong growth in Europe under updated business plan to 2012

Endesa of Spain has outlined a fairly optimistic growth scenario for Endesa Europe and the domestic holdings that are to be acquired by Germany's E.ON, including a rise in EBITDA to Eur2.216 billion ($3.406 billion) in 2012 from Eur1.274 billion in 2007.

More specifically, in a March 11 filing to Spanish stock market regulator CNMV, the power producer projected EBITDA would increase in Italy to Eur1.488 billion from Eur1.038 billion, in France to Eur504 million from Eur232 million, in Poland to Eur23 million from Eur14 million, in Turkey to Eur9 million from Eur6 million and to Eur192 million from Eur97 million for the Spanish assets.

Endesa said it issued the report, essentially an updated business plan, in the interest of full transparency and given that negotiations are under way between company owners Enel of Italy and Acciona of Spain and E.ON to determine the fair market value of the properties that are to change hands.

Besides the projected rise in earnings, the Spanish generator estimated that capital expenditures in France would total Eur2.232 billion over the 2008-2012 period, Eur2.034 billion in Italy and Eur373.3 million in Spain.

In France, the specific target is to increase installed capacity in France to 6,132 MW from 2,817 MW, through the addition of 3,010 MW of CCGTs and 284 MW of wind energy installations.

In Italy, capacity is forecast to grow to 8,229 MW from 7,156 MW mostly via the addition of 1,220 MW of CCGTs, repowering projects entailing an 800-MW CCGT unit, 228 MW of gas turbines, a 410-MW supercritical coal plant, and 100 MW of wind generation, offset by a steep reduction in oil-fired capacity.

Endesa Europe also owns 69.35% of a 330-MW coal-fired plant in Poland and controls 50% of Altek, with 120 MW in operation and 80 MW under construction.

Spanish holdings scheduled to be taken over by E.ON include three existing plants totalling 1,476 MW and the 800-MW Foix CCGT near Barcelona in development.

Endesa went on to note that several post-2012 projects are also under review, namely, four CCGTs totaling 1,800 MW, a 700-MW super-critical coal plant and a 700-MW clean coal plant, all in France. In Italy it is developing five CCGTs totalling 2,160 MW and 150 MW of wind units. *— Henry Cybulski*

FINANCE

International Power's North American earnings rise by 35% in 2007 on gains in New England market

London-based merchant generator International Power last week said earnings at its North American operations rose to £136 million (US$273 million) in 2007 from £101 million in

2006, largely because of the start of the forward capacity market in New England and a full-year of ownership of the 632-MW Coleto Creek power plant in Texas.

IP acquired the plant from Sempra and Riverstone Holdings in July 2006 for $1.14 billion.

The generator said a mild summer in Texas last year cut demand for power from 2006, resulting in a flat spark spread at its Midlothian plant of $14/MWh and a reduced load factor of 55%. The spark spread at the company's Hays plant fell from $14/MWh in 2006 to $10/MWh last year and the load factor also dropped to 45% from 55% a year earlier because of forced outages related to defective welds on high-pressure steam pipes. IP said all four of the Hays units are now in operation.

The company said spark spreads at its New England plants rose to $16/MWh in 2007 from $12/MWh a year earlier at a constant load factor of 60%.

In addition, IP said its assets in the region benefited from the introduction of the forward capacity market. In February 2008, IP said ISO New England conducted the first auction for additional capacity for June 2010 through May 2011. IP said the auction attracted a "significant response" from both generation and demand side management projects, resulting in a capacity income of $4.25/kW-month from our New England plants for the period.

IP also said that in January it and the South Texas Electric Cooperative began the process to obtain permits to build a 650-MW coal-fired plant at its Coleto Creek site. — *Jeff Barber*

Energias de Portugal sees net profit down 3.6%, despite increased capacity, successful hedging

Energias de Portugal registered a net profit of Eur907.3 million ($1.396 billion) for 2007, down 3.6% year-on-year, the Portuguese power and gas utility announced March 6.

EBIT rose 24.5% to Eur1.560 billion, EBITDA 14% to Eur2.628 billion and revenues 6.4% to Eur11.011 billion. Net financial debt at December was Eur11.692 billion, up 26% from 12 months previous, while capital expenditures totalled Eur2.7 billion, up 85.4% year-on-year.

Factors affecting the results include a successful hedging strategy in the liberalized Iberian Peninsula electricity and gas markets, increased renewables capacity, the acquisition of Horizon Wind Energy of the US, the strong performance of its Brazilian holdings, a negative tariff deviation of Eur58 million and an ongoing program to control operating costs.

Also on March 6, EdP subsidiary HC Energia of Spain reported a net profit of Eur200 million ($308 million) for 2007, up 25% from the year previous.

EBITDA rose 26.3% to Eur541 million and revenues 1.2% to Eur2.132 billion, while net financial debt at December 31 totalled Eur1.491 billion, up 10% from 12 months previous.

HC Energia said the results were affected by increased power production, lower pool prices, synergies achieved with parent company EdP, an ongoing cost-cutting program, a growth in renewables capacity and increased electricity and gas sales in the liberated market.

The company's net power output rose 2.6% year on year to 13,936 GWh, while the amount of electricity distributed increased 1% to 9,622 GWh and sales in the liberated market by 29% to 10,731 GWh. — *Henry Cybulski*

Morris Energy Group closes refinancing of $100 mil facility for five plants, 630 MW

Morris Energy Group LLC on March 6 said it completed a $100 million refinancing in which the Morristown, New Jersey company consolidated five of its seven power plants under MEG Generating Co. LLC, the issuer of the $100 million credit facility.

Morris Energy said the proceeds of the financing were used to pay down debt and to provide funds for plant expansion projects and working capital.

The five gas- and oil-fired combined-cycle generating facilities, with a combined output of 630 MW, are in Bayonne, Camden, Pedricktown and Newark, New Jersey; and Dartmouth, Massachusetts. Morris Energy's York and Lowell facilities are held by a separate subsidiary, MEG Development Co. LLC, and have a combined output of 57 MW.

Morgan Stanley was lead arranger and book runner for the refinancing. GE Energy Financial Services was collateral and administrative agent. GE Energy Financial Services closed on the entire loan amount, subsequently syndicating a portion to Prudential Insurance Corp. of America.

"This major refinancing is an important step in the expansion of our company. This capital positions Morris Energy to participate in the growth of the Northeastern market," said Dennis Clarke, a principal and founding member of Morris Energy.

Morris Energy was formed in 2002 to acquire and manage distressed power generating assets in the US. The company acquired the Newark Bay, Bayonne, and Camden plants in 2004, followed by the Pedricktown and Dartmouth plants in 2005. The York and Lowell plants were acquired in June 2007 and January 2008, respectively. — *Peter Maloney*

Shear Wind secures $1.75 mil of funds to build two wind farms in Nova Scotia

Shear Wind of Halifax, Nova Scotia, has secured C$1.75 million (US$1.76 million) in debentures that it plans to use for the continued build out of its 230-MW Glen Dhu project and 100-MW Glen Ridge project, as well as general working capital requirements.

The debenture matures September 1. A portion, C$750,000, is convertible into units of the corporation at 80 cents/unit. Each unit would consist of one common share and one-half common share purchase warrant. Each whole warrant will entitle the holder to purchase on additional common share for 90 cents/share within 12 months of the conversion date. The debenture will bear interest at 5% a year.

Founded in 2005, Shear Wind has a pipeline of wind farms totaling 1,400 MW in Alberta and Nova Scotia and other Canadian provinces. Construction on most projects is scheduled to start later this year. — *Harriet King*

Standard & Poor's revises its rating on NRG to B+, its outlook to positive

Standard & Poor's on March 11 revised its outlook on NRG Energy's B+ corporate credit rating to positive from stable.

The ratings company cited the merchant generator's "strong cash flows over the past couple of years, improved prospects for the next few years, and ... expectations that ratings could be upgraded as the company continues to sweep debt and strengthen its financial profile" for the revision.

S&P, which, like Platts, is a unit of The McGraw-Hill Companies, said the B+ corporate credit rating reflects NRG's leveraged financial profile, risks associated with the merchant power business and significant growth plans.

These factors, however, are "mitigated by significant near-term cash flow stability created by the company's substantial hedging program, albeit one that creates operational risks; significant fleet diversity in terms geography, fuel, and dispatch position; as well as the current favorable market conditions for merchant power companies," S&P credit analyst Swami Venkataraman said.

"High gas prices and tightening reserve margins across the US, accentuated by a growing difficulty in building new baseload generation, are expected to result in strong cash flows over the next few years," he added. — *Staff Report*

ASIA/PACIFIC RIM

India's B.C. Jindal Group to spend $6.41 bil to develop 6,000 MW over the next five years

India's B.C. Jindal Group, in its first foray into the power business, plans to spend $6.41 billion to develop four power projects totaling 6,000 MW over the next five years.

The company plans to develop three coal-fired projects totaling 5,000 MW in the states of Orissa, Madhya Pradesh and Chhattisgarh. An official associated with the power business said the company has already signed the agreements with the governments of the three states to set up the projects, however, details on the mining rights, land rights and power purchase agreements have yet to be worked out. The official did not mention the specific target online dates for each of the plants.

The three projects together are likely to cost $4.93 billion. The Orissa project would have a capacity of 1,200 MW, the Madhya Pradesh project would be of 2,000 MW, while the Chhattisgarh project would have a capacity of 1,800 MW.

In addition to the three coal-fired projects, the company is also planning to set up a 1,000-MW hydropower project in North India at a cost of $1.48 billion. The company did not mention the exact location of the project or the time schedule.

All the projects are being funded with a debt-to-equity ratio of 80:20. The group has appointed SBI Capital Markets to arrange the project loans.

The B.C. Jindal Group has interests in the polyester, photographic goods and steel businesses. — *S. Anuradha*

Indian hydropower company postpones IPO to mid-2008, citing stock market weakness

State-owned National Hydropower Corp. has postponed its 1.67 billion share initial public offering until mid-2008 from the previously planned launch in the first quarter of the year because of the current weakness in the local and international stock markets.

An official associated with the issue said the IPO is likely to take place in July or August, but did not provide details on the pricing of the issue.

NHPC has been considering an IPO for the last two years, but has not been able to finalize its plans.

NHPC is raising the funds to add 5,322 MW to its existing capacity of 4,700 MW by 2012.

An analyst at an Indian investment bank said the poor performance of Reliance Power's shares after its much-publicized IPO has made investors skeptical about power sector IPOs. This, in turn, is forcing other issuers to delay their IPOs. "Companies are hoping the investors would have forgotten about Reliance Power by the time their IPOs hit the market," said the analyst.

In January, Reliance Power sold $3 billion of shares at $11.38 each in its IPO, but when the shares started trading in the secondary market in February they fell to $9.41. The sharp drop subsequently prompted Anil Ambani, the company's chairman and largest shareholder, to issue free shares to investors (*GPR*, 28 Feb, 6). — *S. Anuradha*

Nepal government awards 402-MW Arun-III hydroelectric project to Indian developer

Nepal has awarded the 402-MW Arun-III hydropower project to India's state-owned Satluj Jal Vidyut Nigam Ltd.

Nepal said Satluj's bid was the lowest among the nine other bidders, which included the GMR group, Jindal Steel and Power Ltd., Reliance Energy Ltd., and JP Associates.

Under the terms of the agreement, Satluj has to supply around 21.9% of the total capacity free of charge to the state-owned Nepal Electricity Authority. The remaining power would be exported to India, but Satluj did not provide any details on the transmission linkage.

The project is likely to cost $1.08 billion and is being developed on a build-own-operate basis.

The company had also bid for the 300-MW Upper Karnali project in Nepal, but the project was awarded to GMR Infrastructure Ltd. (*GPR*, 21 Feb, 7).

Indian companies have been looking to develop projects in the water-rich Himalayan countries of Bhutan and Nepal and to export the power to India.

Satluj's current capacity is 1,500 MW. The Indian federal government owns 75% stake in Satluj. The remaining shares are owned by the state government of Himachal Pradesh.
— *S. Anuradha*

Thailand's Ratchaburi, Italian-Thai, EGCO to invest in 3,660-MW Cambodian project

Thailand's Ratchaburi Electricity Generating Holding Co. has signed an agreement with Electricity Generating PLC and Italian-Thai Power Ltd. to invest in the 3,660-MW, $6.32 billion coal Koh Kong project in Cambodia, according to a Ratchaburi news release.

Ratchaburi and EGCO would together own 70% of the project. The remaining 30% would be owned by Italian-Thai. A Ratchaburi official said negotiations were under way on the size of the stakes that Ratchaburi and EGCO would each own in the project. The official said a local Cambodian partner might also take a stake in the project at a later stage.

All the electric output would be sold in Thailand. Ratchaburi said it was negotiating the power purchase agreement with Electricity Generating Authority of Thailand. The coal for the project is likely to be imported from Indonesia.

Ratchaburi said the project was its first investment in Cambodia. *— S. Anuradha*

Philippines' privatization agency changes auction schedule to quicken sale pace

Philippines' Power Sector Assets & Liabilities Management Corp. has proposed changes in the auction schedule to quicken the pace of the privatization program.

The 192.5-MW Palinpinon geothermal plant would be auctioned as a single asset in August instead of the previous plan of selling it with the 146.5-MW Panay diesel-fired plant, PSALM said in a news release. Under the revised auction plan, the Panay plant would be sold with the 22-MW Bohol diesel plant in July.

A PSALM official said the changes in the auction schedule had been made because the steam supply agreements for some of the geothermal plants have not yet been worked out. As a result, PSALM has decided to proceed with the sale of the diesel-fired plants separately.

PSALM said it has sought the Joint Congressional Power Commission's approval for the proposed changes.

When the Palinpinon-Panay complex was first put up for sale in 2007, five investor groups were interested in bidding for it, but the auction could not take place because the steam sale agreement had not been finalized. The auction was postponed to February 2008 and then to July.

PSALM said it was confident it could achieve the targeted 70% privatization level in 2008. Under government rules, PSALM has to privatize 70% of the 4,336 MW of capacity owned by the National Power Corp. in the provinces of Luzon and Visayas. PSALM has so far sold assets totaling 1,856 MW.

PSALM said that under the schedule for 2008, it would auction the 225-MW Bataan thermal plant in May, the 289-MW Tiwi and the 458.53-MW Makban geothermal plants in June, the 0.8-MW Amlan hydroelectric plant in June, the 620-MW Limay diesel-fired plant in July, the 112.5-MW Tongonan geothermal plant in September, the 114-MW Iligan diesel-fired plant in October, the 150-MW Bacman geothermal plant in October, and the 116-MW Subic diesel-fired plant in November. The108-MW Aplaya and the 22.3-MW General Santos decommissioned plants would be auctioned in December. *–S. Anuradha*

HK Electric posts 8.9% rise in 2007 profits to $957 million; revenue up 3% to $1.6 billion

Hong Kong-based power generator and supplier HK Electric Co. earned a net profit of $957 million in 2007, up 8.9% from $878 million in 2006. HK Electric's revenues rose 3.2% to $1.61 billion from $1.56 billion.

The company said higher contributions from the Hong Kong and Australian businesses boosted earnings. Profit from the Hong Kong operations rose 9% on the year to $864 million while profit from the international operations rose 7.8% to $93 million.

Operating costs rose to $126 million from $103 million mainly because of the rising prices of coal. HK Electric said coal prices would continue to rise in 2008, but did not provide further details.

Unit sales of electricity grew by 1.1% in 2007 compared with 0.2% in 2006. The company did not mention the specific unit sales.

Commenting on the expansion plans, the company said it was planning to invest in the overseas power sector to reduce the excessive dependence on the Hong Kong market. Currently, HK Electric owns stakes in power plants in Thailand and Canada with a total capacity of 2,210 MW.

HK Electric owns a 25% stake in Ratchaburi Power Co., which is developing the 1,400-MW Hin Krut project. The first 700-MW unit is scheduled to begin operations mid-March, with the second unit online in June.

In Hong Kong, HK Electric has a power generation capacity of 3,420 MW and supplies electricity to around 500,000 customers. *— S. Anuradha*

Asian briefs

■ India's **Bharat Heavy Electricals** has won a $220 million engineering contract from **Reliance Industries** for its 345-MW captive power plant. The oil and gas-fired combined-cycle plant would be built at Nagothane in the western Indian state of Maharashtra.

The scope of work includes the design, engineering, manufacture, supply, erection and commissioning of the Frame 9FA gas turbine generator set, a steam turbine generator set and a heat recovery steam generator.

The plant has to be built in the next 26 months.

■ **Electricity of Vietnam** and the **Ha Thanh Securities** Co. are planning to build a 2,400-MW thermal plant in the central Quang Binh Province at a likely cost of $2.4 billion. The coal for the plant would be imported.

EVN did not mention the target online date for the plant.

■ A consortium of India's **KEC International** and Saudi Arabia's **Al-Sharif** group has won a $119 million contract from **Saudi Electric Co.** to build a 380-kV transmission line.

KEC did not mention the time frame within which the transmission line had to be built. The transmission line runs over 268 kilometers.

KEC's CEO Ramesh Chandak said the contract underscores the company's expertise in the transmission engineering sector.

EUROPE/MIDDLE EAST

Ireland sees 2.2 GW of new wind developments seeking grid access; total could increase to 8 GW

A growing number of wind farm developers want access to Ireland's electricity grid, with new applications for about 2,200 MW of projects submitted since the start of 2008, the Commission for Energy Regulation said this week.

The recent flurry of applications means there are now 8,000 MW of potential wind farm projects seeking grid connections and several of the requests are for offshore wind farms, CER commissioner Michael Tutty told a parliamentary committee on energy.

The news is promising, given that the government aims to generate 15%, or 1,500 MW of the country's electricity from renewable sources by 2010 and 33%, or 4,600 MW by the end of 2020.

There is currently 803 MW of wind power installed on the national grid, with a further 231 MW of hydro already installed. There is an additional 451 MW of wind power due by the end of 2010, which would ensure Ireland's meets its 2010 target.

To meet the 2020 target the CER is currently issuing connection dates to 1,300 MW worth of wind farm projects, which it expects to complete shortly. These projects have already secured grid connection offers from national grid operator EirGrid and most, if not all, applicants are expected to take up their offers. This would increase the amount of renewables on the grid to 2,800 MW.

The CER is now in the process of finalizing details of how to deal with the 8,000 MW of unsigned applicants or applicants without a firm grid connection commitment. It expects to issue proposals within the next two months on how to proceed with these applications, some of which have been waiting for a considerable period.

The recently published all-island grid study conducted jointly by the Department of Energy and Northern Ireland Counterpoint showed that it is technically possible to generate up to 42% of electricity from renewable sources. *— Kieran Moran*

Israeli government calls tender for construction of two thermal plants of up to 250 MW in Negev

The Israeli government has issued a pre-qualifying tender for a build-operate-transfer project that calls for the construction of two 80-MW to 125-MW solar thermal plants at Ashalim in Israel's Negev Desert.

In addition the tender issued by the National Infrastructure and Finance ministries calls for a separate tender at the same site for a third solar plant to produce 15 MW using photovoltaic technology. There is also an option for doubling the size of the photovoltaic facility. The cost of the projects is estimated at $77 million to $800 million.

The tender requires those taking part to have previous experience in the construction, operation and maintenance of solar power plants, in addition to financial capabilities. Those that meet the preliminary prerequisites by a government committee will be invited to submit offers for the projects. The pre-qualifying process runs through July 1, and the government hopes to complete the selection process by year end or by early 2009. The solar power plants are expected to be fully operational in 2011.

"The solar tender at Ashalim is a cornerstone of our renewable energy policy," said National Infrastructure Minister Benjamin Ben-Eliezer. The ministry has set a target of 10% of all of Israel's electricity production to come from renewable energy sources by 2020, which would translate to about 2,000 MW. *— Neal Sandler*

European briefs

■ **Iberdrola Renovables** has acquired a 44.2-MW wind farm project in Spain's northeast Aragón region from affíliate Gamesa Corp., the Spanish generator said March 10.

The installation, designated La Torrecilla and formerly owned by Gamesa subsidiary Sistemas Energeticos La Torrecilla, has 16.15 MW currently operational, while the remaining 28.05 MW are in development.

With the purchase, Iberdrola Renovables said it has strengthened its presence in Aragon, where the company has seven operational wind farms totalling 261 MW and a 1-MW hydro station.

The transaction is part of a larger deal struck earlier covering Iberdrola's acquisition of up to 700 MW of wind farms that Gamesa is developing in Spain and Italy.

■ Also relating to **Gamesa**, Iberdrola reported March 7 that it has acquired another 4.625% of the Spanish renewables company, raising its direct ownership to 23.953%.

The stake purchase, from Iberdrola affiliate IBV Corp., entailed 11.3 million shares and cost Eur321 million ($494 million).

Iberdrola has been steadily turning its indirect interest in Gamesa, a leading Spanish turbine manufacturer and wind farm developer, into direct ownership since December 2004, when it bought 6%.

LATIN AMERICA

Brazilian state of Sao Paulo scheduled to auction 7,500-MW generator CESP

On March 26, the state government of Sao Paulo, Brazil, is scheduled to auction a 40% stake in power generator CESP, which controls around 7.5% of Brazil's generation system.

The auction has generated considerable interest. CESP serves Sao Paulo, Brazil's richest state, and has six hydroelectric plants totaling 7,500 MW.

On March 11, Sao Paulo state government announced that CPFL, Neonergia (owned by Iberdrola), Energias do Brasil Portugal (owned by Energias de Portugal), Tractebel (owned by Suez Energy), and Alcoa had pre-qualified to take part in the sale. If they confirm their interest and participate in the auction, they could bid individually or form partnerships to make an offer.

Alcoa said in a note to the press that its pre-qualification "reveals its intention to continue in the process, but it does not represent a firm commitment to take part in the auction." The company said it would only make a decision to participate in a more "advanced phase of the auction." The aluminum producer indicated that it if it decides to join the process it will form a partnership.

The minimum bid price is set at $29.2/share, which is considered high by investors. At the minimum price the winner would have to pay $4 billion and assume $3 billion in debt.

"It is a sale that can involve more than $6 billion," said Adriano Pires, who runs Brazilian Infra Structure Center, an energy consulting company.

"Everyone who wants to have an important presence in Brazil will be on the sale and it can draw attention to new players as the size is considerable. In one move a group can reach 7,500 MW in capacity, a figure no other private group has," said the president of major energy group in Brazil, who did not want to be identified.

Around 80% of Brazil's generation system is owned by state-run companies, most of which are owned by Eletrobras, and there are no indications that the government plans to sell its power sector holdings, so CESP is seen as a prize asset.
— Roberto Rockmann

Energias de Portugal's Brazilian subsidiary unveils program to invest up to $2 billion

Energias de Portugal's Brazilian subsidiary, Energias do Brasil, last week unveiled a strategy that entails investments of more than $2 billion to increase its generation capacity in Brazil to 2,500 MW from 1,000 MW over the next several years.

Energias do Brasil said it has set up two partnerships with Brazilian companies to undertake feasibility studies for hydroelectric projects and wind farms in Brazil. Energias do Brasil and its partners — state-run utility Cemig and private construction firms Andrade Gutierrez and Concremat — plan to study projects that involve 1,500 MW.

With Cemig, EDB plans to carry out wind power projects that could add around 500 MW and hydroelectric projects that could add more than 360 MW. With Andrade Gutierrez and Concremat, EDB plans to carry out hydroelectric feasibility studies for projects that could add 675 MW to its generation capacity.

"These partnerships are very important to our strategy", said Energias do Brasil's CEO Antonio Pita de Abreu, who did not disclose any more information on the partnerships.

Market sources said that if the projects are viable, the company could invest more than $2 billion to build them.

The strategy would reinforce Energias do Brasil's presence in Brazil just as energy consumption and prices are rising. In 2007, energy consumption was 5.5% higher than in 2006. In January prices hit $335/MWh, a record and three times higher than prices in January 2006. "Brazil is growing fast, and the estimates indicate a very strong year in 2008. So investments in the generation sector are likely to grow," said Fabio Silveira, a Brazilian economist who runs RC Consultores.

Last year Energias do Brasil posted $260 million in profits, a 12% increase over the previous year's results. *— Roberto Rockmann*

Ministers agree Chile could get more gas, but would have to pay a higher price for it

Chile could soon begin to receive more natural gas from Argentina, but at a higher price, Chile's national energy commission said March 11.

During talks between energy ministers from both countries, the government said that Argentina had agreed to inject additional volumes into pipelines supplying the north, center and south of the country until May when winter begins. The imports would resume when winter ends, the ministry said.

The gas would be in addition to volumes guaranteed for residential use and swaps negotiated between consumers in both countries, allowing generators in Chile to receive gas in exchange for supplying Argentinean power plants with alternate fuels. In the only deal currently functioning, Chile's Colbun supplies Argentina's Central Puerto with fuel oil in exchange for natural gas. The imports are to be effected through swaps to ensure the Argentinean government will allow the increase in gas exports.

Chile has contracts to receive 21 million cubic meters/day of gas but has been receiving less than 10% of this amount since the middle of the last year as Argentina prioritizes internal demand.

But Chile could end up paying more for the gas because Argentinean President Cristina Fernandez has announced that the government is increasing taxes by an unspecified amount on gas exports to offset the impact of higher prices for gas imported from Bolivia.

"What we pay to import gas [from Bolivia] will be financed with what we receive by exporting [to Chile]," Argentina's planning minister, Julio de Vido, said.

Chile's Energy Minister Marcelo Tokman said that the taxes had been discussed, but that it was "an internal decision for Argentina and as such is of exclusive concern to the government of that country." *— Tom Azzopardi*

Chilean government sends bill to congress aimed creating fuel tax remedy for generators

The Chilean government on March 10 said that it would send legislation to congress this week allowing power companies to reclaim taxes charged on diesel fuel consumed in their operations, which would allow a large number of emergency turbines to begin profitable operations and help relieve the country's tight energy situation.

Use of diesel in the country's electrical sector has skyrocketed since early last year when the Argentinean government severely reduced gas exports to its neighbors, forcing gas-fired plants to use liquid fuel.

But although the Chilean government allows industrial diesel users to credit the tax on the fuel against other tax liabilities, the large volumes of diesel fuel needed and the weak financial results of the power sector has prevented them from doing so because the fuel credits often exceed their other tax liabilities.

The new bill would establish a mechanism that would allow companies either to receive the amount paid in fuel tax back or to receive the difference between the fuel tax credit and their tax liabilities.

"Given the tight energy situation we are living through, it does not make sense that turbines and other projects that increase the supply and capacity of the electric system do not start up due to the current mechanism for recovering the fuel tax does not allow them to recover the taxes they have paid," said Energy Minister Marcelo Tokman.

The proposed change, which would run until March 2010, would allow around 800 MW of new capacity to be added to central Chile's SIC grid, the minister said. *— Tom Azzopardi*

NORTH AMERICA

PROJECTS

Sierra Pacific Resources' 1,500-MW coal project faces two year delay on account of federal review

Sierra Pacific Resources' proposed 1,500-MW coal-fired Ely Energy Center is being delayed by roughly two years because of a longer than expected federal review process for the project.

Reno, Nevada-based SPR originally expected to receive a final environmental impact statement from the Bureau of Land Management by mid-2008, said Mark Severts, a company spokesman. Construction cannot start until the final EIS is completed, he said.

BLM, however, does not expect to issue a final EIS until September 2009, said JoLynn Worley, a BLM spokeswoman. A draft EIS is being developed, and BLM expects to take public comment on the draft document in November. BLM had planned on taking comment on the draft in April, but SPR made changes to its Ely proposal, causing the comment period to be pushed back, she said.

SPR expects the Nevada Division of Environmental Protection to issue a final air permit for the power plant near Ely, Nevada, within a few months, Severts said.

In 2006, the Nevada Public Utilities Commission approved initial development for the project, but required the utility company to return to the commission for final project approval, a step that SPR thought would happen this year. A PUC staff member told the commission at a February 27 meeting that SPR would not ask for final project approval until late 2009 or 2010. The estimate is roughly correct, Severts said.

SPR has said the Ely project is being delayed, but has not offered details. The company plans to update the PUC on the project later this month, Severts said. When SPR proposed its project in early 2006, it expected the plant's initial 750-MW unit to be in operation in 2011, with the second unit online by 2014. The company now expects operations to start no earlier than 2013, according to SPR's annual report, filed February 27 with the Securities and Exchange Commission. The plant and a related 345-kV power line were originally expected to cost about $3 billion. If construction started today, the company believes the project would cost $5 billion, the filing said. *— Ethan Howland*

Panda Energy says it plans to build a 500-MW gas-fired plant in Texas

Panda Energy on March 11 said it plans to build a 500-MW gas-fired combined-cycle plant in Sherman, Texas. The power would be sold via Oncor Energy Delivery into the wholesale market, spokesman Bill Pentak said.

The plant will be on a 200-acre site at the Progress Industrial Park in Sherman. Construction will take approximately 24 months and is dependent upon financing, regulatory approvals and other conditions, a statement by Panda said. A tentative in-service date is early 2012, Pentak said.

Panda Energy previously announced that it has filed for an air permit to build a 1,000-MW combined-cycle plant in Temple, Texas.

Dallas-based Panda, founded in 1982, has built more than 9,000 MW of capacity in Texas, Arkansas, Arizona, Maryland, Oklahoma, North Carolina, China and Nepal. *— Staff Report*

American Electric Power receives permit to build 629-MW IGCC plant in West Virginia

American Electric Power last week said it has received authority from the West Virginia Public Service Commission to build a 629-MW integrated gasification combined-cycle plant in West Virginia.

Approvals still are needed from the West Virginia Department of Environmental Protection and the Virginia State Corporation Commission, since AEP subsidiary Appalachian Power operates in Virginia and is seeking to recover some costs from the planned $2.23 billion plant.

The SCC is expected to rule on the IGCC plant in April, AEP said.

Construction of the plant, which would be next to the company's existing Mountaineer power plant near New Haven, West Virginia, is expected to take four or five years.

"It is critical for our nation and the world that we move forward with advanced, cleaner technologies that allow us to continue to use coal for electricity generation," AEP Chairman, President and CEO Michael Morris said in a statement.

In an IGCC plant, coal is converted into a synthetic gas that moves through pollutant-removal equipment before the gas is burned in a combined-cycle gas turbine.

With peak demand records set twice within the last year, Appalachian Power has a clear need for additional generation capacity, added Dana Waldo, Appalachian Power's president and chief operating officer. "We recently added 175 MW of renewable wind generation to serve our customers, but it is critical that we also have baseload generation that is ready and able to serve our customers 24 hours, every day."

AEP also has proposed to build a similar 629-MW IGCC unit in Ohio, which is pending regulatory approvals in that state. *— Tom Tiernan*

FutureGen developers deny project is dead, but renew calls for DOE support, funding

Construction of the FutureGen plant cannot occur without the support of the Department of Energy, said Paul Thompson, chairman of the FutureGen Alliance, but the group backing the demonstration project is not giving up on the proposed advanced coal-fired plant.

"FutureGen is in distress," Thompson said during the American Coal Council Spring Coal Forum in Miami this week. "We continue to work to advance our relationship with the DOE" that will extend the federal government's participation in the program.

Without federal funds, Thompson said the alliance would have a difficult time fulfilling its mission of building the world's first near-zero emissions plant with carbon dioxide capture and storage technology.

Moving forward, Thompson said there is not much the alliance can do without DOE's public decision on supporting a specific site for the plant. He said the federal agency could "significantly delay" the development of the CCS technology, if it continues to drag its feet on the proposed plant.

But, if the government renews its commitment to FutureGen, Thompson said it is still possible that the plant could be completed as originally planned by 2030.

The current arrangement with DOE allows for funding FutureGen activities through about the middle of this year, according to Thompson.

FutureGen has become a "political problem," he said. In addition to gaining DOE funding, the alliance must persuade DOE to issue a record of decision on the proposed integrated gasification combined-cycle plant. Without the ROD, the official declaration of the agency's intention, the project cannot move forward.

Thompson said the agency would not issue the ROD until it receives a "detailed site characterization" of the proposed project, but he said the alliance believes a detailed study of proposed site has been completed.

Escalating costs have marred the project's future, but he said it is not alone in facing cost challenges as the prices of labor, steel and other components have skyrocketed in recent months. The project was originally estimated to cost $950 million, but the alliance has revised the figure upward several times with the latest estimates reaching $1.8 billion.

In December, the alliance selected Mattoon, Illinois, as the site for the proposed 275-MW plant, but DOE never supported the action. Worried about rising costs, the federal agency opted to support several smaller carbon capture and storage projects on different plants to test if the technology would perform as expected. *— Marcin Skomial*

Iowa authorities reject construction permit for LS Power's 750-MW coal project in Waterloo

The Iowa Department of Natural Resources has dealt a blow to independent power producer LS Power's plans for a 750-MW coal-fired plant in the Waterloo area by rejecting a construction permit application for the approximately $2 billion project.

In a March 6 order, the state agency said the request submitted by Elk Run Energy Associates, an LS Power subsidiary, failed to meet an administrative requirement.

The agency pointed out that an appeal is still ongoing at the City Development Board, also a state agency, which last year rejected a Waterloo rezoning ordinance for the proposed plant site.

Catharine Fitzsimmons, air quality bureau chief for the DNR, said Elk Run/LS Power can submit another application to the agency "after revisions are made to meet the issues specified in the construction denial."

LS Power spokeswoman Alyssa Becthold said the company plans to ask the DNR to reconsider its ruling.

The baseload coal project has drawn considerable opposition from environmentalists and others in the Waterloo area, but is largely supported by local officials. *— Bob Matyi*

Dominion Virginia Power reaches agreement on rates to move 585-MW coal plant forward

Dominion Virginia Power said that an agreement reached with state officials provides the incentives it needs to move forward with the construction of a 585-MW coal-fired plant in the southwestern part of the state.

The "stipulation and recommendation," which was made public on March 7, is an agreement among the utility, the attorney general's consumer counsel and the staff of the State Corporation Commission. The three said the agreement resolves all the issues in dispute among them and recommended that the commission approve the certificate of public convenience for the plant.

The agreement would allow Dominion to earn a 12.12% rate of return on the plant, which is 1% higher than the rate of return on common equity that it would normally receive for a generation asset. The company would collect the additional rate of return for 12 years. Dominion Virginia had asked for a 13.75% rate of return. The higher rate reflects the importance of the plant in meeting the energy needs in the state, the agreement said. It also reflects the risk associated with its development, it said.

Dominion Virginia originally claimed that the plant would be a carbon capture compatible, clean coal power electric generator. The agreement concedes that the plant would qualify as a clean-coal plant, but it said whether it should be considered a technology that would be compatible with carbon capture has not yet been determined.

If at a later time the plant is found to be "compatible" with carbon capture technology then the plant would be entitled to an additional 1% increase in its rate of return for 12 years.

The commission is expected to take comments on the agreement before making a final decision.

Separately, Dominion last week asked the State Corporation Commission to let it build a 580-MW gas-fired plant in

Buckingham County, about 60 miles from Richmond.

Dominion said it closed on the acquisition of the rights to build the plant from merchant generator Tenaska on March 4. At the time the deal was announced in December, Dominion said that Tenaska had already secured air and water permits for the project.

The proposed plant would be built on part of a site near New Canton, across the James River from Dominion's existing Bremo Bluff coal plant.

In its filing with the SCC, Dominion asked that the regulator approve the $619 million project in time for it to begin operating by summer 2011. *— Mary Powers*

Illinois EPA issues draft construction permit to revive 55-MW Robbins biomass project

The Illinois Environmental Protection Agency has issued a draft construction permit to Robbins Community Power for a 55-MW biomass plant in the Chicago suburb of Robbins.

IEPA has scheduled an April 8 public hearing at Keller Junior High in Robbins to receive comments and answer questions about the proposed permit.

The existing plant burned solid waste several years ago but was shut down. Robbins Community Power is repowering two existing boilers to burn wood to generate up to 55 MW for sale to the grid. The agency says emissions from the boilers would be controlled by selective non-catalytic reduction, an oxidation catalyst, a spray dryer absorber and a baghouse. *— Bob Matyi*

Orion Energy brings online 150-MW wind farm in Illinois; plans to start Ind. project in May

Orion Energy Group LLC's 150-MW Camp Grove Wind Farm in central Illinois is in commercial operation, while its 130-MW Benton County Wind Farm in northwestern Indiana is scheduled to go online in May.

Turner Hunt, project manager for Vision Energy, a Cincinnati-based co-developer with Orion, said in mid-March that Camp Grove's output is being sold on a merchant basis into the PJM Interconnection wholesale market.

Benton County, however, is marketed differently. Duke Energy Indiana, a subsidiary of Duke Energy, has agreed to purchase 100 MW from Benton County for 20 years while Vectren will buy the remaining 30 MW over the same period.

Hunt said there are plans to add a second, 100-MW phase at Benton County, "but nothing specific yet as to the start of construction."

Although Benton County is Indiana's first commercial wind farm, others may not be far behind. Several major wind energy developers, including Horizon Wind Energy, FPL Energy and Gamesa, a Spanish company, have been talking to Indiana farmers about securing easements for possible wind farms. *— Bob Matyi*

FERC approves settlement, clears path for 180-MW wind project in the Dakotas

The Federal Energy Regulatory Commission last week approved a settlement that clears the way for a 180-MW wind project spanning parts of North and South Dakota.

The settlement resolves all of the issues raised by Dakota Wind Harvest's March 2007 complaint relating to its need for a balancing authority to begin operations. Under FERC interconnection rules, a balancing authority is needed by the wind project to comply with reliability standards and regulations.

Dakota Wind complained to FERC that Montana-Dakota Utilities and the Western Area Power Administration refused to act as balancing agents for the project. The planned project will interconnect with MDU via a 230-kV power line, and WAPA is the designated balancing agent for the area, according to Dakota Wind.

Under the settlement, Northern States Power, an Xcel Energy subsidiary, will act as the balancing authority on behalf of the wind project on an interim basis. The agreement will end when the Midwest Independent Transmission System Operator can provide balancing authority services, or December 31, 2009, whichever occurs first.

Dakota Wind plans to sell power into the MISO real-time market, according to its complaint with FERC. Dakota Wind, now called Tantanka Wind, is owned by Global Winds Harvest, a developer based in Schenectady, New York, that has projects in New York and Pennsylvania. *— Ethan Howland*

Maine regulators promote 132-MW wind project, but generators highlight state grid constraints

Maine regulators and key stakeholders are moving to expand the state's wind capacity, but at least one developer is warning that transmission remains a major hurdle in adding wind farms in the state.

Last week, Maine regulators approved zoning changes to allow a 132-MW wind farm to be built by TransCanada to move forward. Catherine Carroll, director of the Maine Land Use Regulatory Commission, expects TransCanada to file a final project plan this spring for its Kibby Wind project.

TransCanada, based in Calgary, Canada, plans to sell 30 MW from the Kibby project to Massachusetts utility NStar. The deal, however, requires approval by Massachusetts regulators and it faces opposition. The state Department of Public Utilities must review the contract because it runs counter to restructuring rules, which do not allow utilities to sign long-term supply deals. NStar argues that the deals are necessary to help renewable energy suppliers get project financing. Retail suppliers, however, oppose such utility deals.

TransCanada expects to start building its $270 million wind project this summer and bring it online by 2010.

LURC March 5 also voted to deny a second attempt for approval by another wind farm, the 54-MW Maine Mountain Power, proposed by Edison Mission Group and Endless Energy of Maine.

Maine has 42 MW of wind capacity, but has the potential for 6,400 MW, according to the American Wind Energy Association.

A task force appointed by Maine Governor John Baldacci, a Democrat, in mid-February recommended that the state adopt a goal of having at least 2,000 MW of installed wind capacity by 2015, and at least 3,000 MW by 2020. The task force believes that at least 300 MW of the 2020 goal could be achieved with off-shore projects. The task force estimated that Maine had 5,320 MW of potential onshore wind capacity while the rest of New England has 4,097 MW of potential. Offshore wind potential including 1,200 MW for Maine, 430 MW for Rhode Island, and 6,500 MW for Massachusetts.

To reach the goal, the task force recommended that the Maine Legislature establish expedited permitting areas covering about two-thirds of the state. A bill is being drafted to reflect the report's recommendations, LURC's Carroll said.

UPC Wind, which owns the 42-MW Mars Hill project in northern Maine and is building the 57-MW Stetson project in eastern Maine, supports the governor's task force report, said Matt Kearns, UPC development director. However, the "fundamental restriction [to wind development] is access to transmission," Kearns said March 10. New England has strong policy support for wind through renewable portfolio standards and the Regional Greenhouse Gas initiative, but poor transmission. "We see a demand, but simply cannot meet it do to transmission constraints in the region," he said. "New England is not a liquid market."

UPC Wind expects to finish the Stetson project by the end of 2008, Kearns said. The company is in the process of marketing power from the project to both in-state and out-of state customers, he said. LURC's Carroll said she expected UPC Wind to seek to expand the Stetson project, but Kearns declined to comment. "These are somewhat uncertain times for wind developers in New England," he said. *— Ethan Howland*

MMS extends public comment period for 468-MW Cape Wind project in Mass.

The Minerals Management Service has extended by an additional 30 days, to April 21, the public comment period on a draft environmental impact statement for the controversial 468 MW offshore Cape Wind project, the agency said last week.

The extension, which MMS published March 10 in the *Federal Register*, responds to public requests for more time to review the document, the agency said. It released the draft EIS for public review on January 11. MMS plans to hold four public hearings in the state on the draft EIS starting March 10.

The proposed wind farm would comprise 130 turbines that could generate an average of about 180 MW. It would be located offshore of Nantucket Sound off the Massachusetts coast.

In the draft EIS, MMS said that while the wind farm could have a "moderate" impact on a single bird species, the roseate tern, overall it would have little impact on wildlife and fisheries in the area.

The report listed the environmental impact of the construction and operation of the project, and rated it on an increasing scale of harm: negligible, minor, moderate and major. If the project went forward as proposed in the statement, none of the categories considered would be affected in a way that would be classified as "major," the report found.

The impact on land and marine wildlife, as well as geology, water quality, air quality, fishing, cultural and recreational resources, noise, and navigation all were considered to be affected in a negligible or minor way, except for scenic quality and the roseate tern.

Community groups and Senator Edward Kennedy, a Massachusetts Democrat, have widely criticized the project, especially for its impact on the scenic quality of the Nantucket sound.

This view was echoed in the MMS draft, which concluded the turbines would produce a "moderate, long-term impact on scenic quality," but also found that impact to be "highly subjective." *— Keiron Greenhalgh*

N.D. PSC waives one-year holding period for Basin Electric's 115-MW wind project

The North Dakota Public Service Commission last week waived a one-year waiting period to expedite Basin Electric's plan to file an application in September for the $240 million, 115.5-MW PrairieWinds wind project it proposes to build in North Dakota.

PrairieWinds is one of a half dozen new generation projects that the Bismarck, North Dakota-based Basin Electric needs to provide 1,500 MW in the next decade to 120 member rural utilities in nine states.

The rapid pace of power demand is the result of increased industrial and mineral resources growth, energy industry development such as biofuel and ethanol and rural residential growth.

The company must gain regulatory approval for the projects and construction is expected to begin in April 2009. PrairieWinds would go online in January 2010.

Basin Electric said the project would include 77 wind turbine generators and a connecting 115-kV transmission line. The Western Area Power Administration would move the power for Basin Electric. *— Harriet King*

Progress Florida outlines need for capacity and proposes two greenfield nuclear units

Progress Energy Florida filed a plan with state regulators that outlines its need for electricity and proposes to meet that need by building two new nuclear units at a greenfield site in Levy County, the company said March 11.

The filing is one step in a lengthy process to see that nuclear power remains a viable option to meet growing demand for electricity, along with other resources and significant energy efficiency and demand response programs, the utility said.

The two nuclear units are estimated to cost about $14 billion, which includes prices for land, plant components, financing costs, construction, labor, regulatory fees and reactor fuel. The utility also estimates spending $3 billion for the needed transmission facilities to integrate the project with its existing transmission system.

If the two units are approved by federal and state regulators and built, they are expected to begin operating in 2016 and 2017, respectively, and they would be among the first nuclear plants on a greenfield site in more than 30 years, Progress Energy Florida said. The Levy County site's proximity to the utility's existing Crystal River nuclear plant would provide opportunities for efficiencies in shared support functions at both facilities, the company said.

Other steps in the company's plan, besides the filing for a determination of need with the Florida Public Service Commission, include other state approvals and a combined operating license application with the Nuclear Regulatory Commission, which are expected to be filed later this year.

The company has selected the Westinghouse AP-1000 design for the proposed nuclear units, which would have a capacity of 1,100 MW each.

Progress Energy Carolinas also has selected the Westinghouse design for two new units it may build at its Harris nuclear plant near New Hill, North Carolina, the company said late last month. — *Tom Tiernan*

CONTRACTS

NRG signs deal with SoCal Ed to supply 550 MW from El Segundo gas-fired plant

NRG Energy has signed a deal to sell 550 MW of new generating capacity at its El Segundo gas-fired plant to Southern California Edison for 10 years under a new power purchase agreement, the Princeton, New Jersey-based company said last week.

The new capacity at the plant in El Segundo, California, is expected online by June 1, 2011, in time to support the expected summer peak on the SoCal Ed and California Independent System Operator systems, NRG said.

The El Segundo facility currently provides up to 670 MW of power. By replacing units 1 and 2, which were retired in January 2003, the facility will be repowered using combined-cycle units that can be online in 10 minutes, providing back-up support for wind and other renewable power, NRG said.

In light of California's growing energy demands and continued tight reserve margins in Southern California, the California Public Utilities Commission authorized SoCal Ed to obtain up to 2,000 MW of new generation capacity. NRG's contract at El Segundo is subject to CPUC approval. — *Staff Report*

San Antonio, Texas, municipal utility signs 15-year PPA with PPM Energy wind farm

CPS Energy, the San Antonio, Texas municipal utility, on March 10 said that it has signed a 15-year agreement with PPM Energy to purchase 76 MW of output from a coastal wind farm now under construction.

PPM Energy, Portland, Oregon, is building 84 wind turbines capable of producing 201.6 MW in the first phase of a wind farm on a private ranch along the Gulf Coast south of Corpus Christi, Texas. The agreement with PPM entitles the utility to the output from 32 of the turbines. The project is now under construction and is expected online in 2008, the company said.

CPS's goal is to purchase 15% of its peak electrical demand from renewable sources by 2020. The addition of the coastal wind power will put the utility's renewable energy use slightly above 12% of its projected 2009 peak demand, Aurora Geis, chairman of the utility's board, said. — *Mary Powers*

SECONDARY MARKETS

Kelson deal to sell 1,230-MW plant in Oklahoma to OGE unit receives federal antitrust approval

Kelson Holdings' sale of its 1,230-MW Redbud plant near Luther, Oklahoma, to OGE Energy subsidiary Oklahoma Gas & Electric for $852 million this week received federal antitrust approval.

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

When announcing the deal January 22, Kelson said OG&E also has agreed to sell partial stakes in the Redbud plant to the Grand River Dam Authority and the Oklahoma Power Municipal Authority.

"The sale of our Redbud power plant to OG&E reflects Kelson's strategy of acquiring assets at a discount — improving their operating and financial performance and then divesting when we can realize a full and fair price," Neal Cody, Kelson Holdings president, said January 22.

"We believe that new-build costs for power plants in the regions in which we operate have increased dramatically over the past several years and the $693/kW purchase price for Redbud reflects a discount to actual replacement costs," he said.

Kelson is a subsidiary of Harbinger Capital Partners Funds. It owns or leases four combined-cycle gas-fired facilities in the Southwest Power Pool and the Southeast Electric Reliability Council with a combined capacity of 4,002 MW. — *Staff Report*

SOLICITATIONS

Connecticut DPUC receives 11 proposals in solicitation for 500 MW of peaking power

The Connecticut Department of Public Utility Control said it received 11 proposals in response to its solicitation for additional peaking power in the state.

The state agency sought 500 MW of peaking power to implement a 2007 state law, which required the additional power to meet federal requirements and to promote energy independence, Beryl Lyons, a DPUC spokeswoman, said.

The General Assembly mandated the solicitation in an effort to decrease the state's high congestion charges, Lyons said. The charges are contributing to the state's position as one of the highest-priced electricity markets in the nation.

The solicitation allows utilities to re-enter the generation business for the first time since the state passed its restructuring law in 1998. The law allows states to own peaking plants, but not baseload plants. Connecticut Light and Power and United Illuminating, Connecticut's two investor-owned utilities, were required to bid, but other companies were allowed to bid, the

DPUC said.

The solicitation implemented an approach meant to create a level playing field between utilities and competitive generators. Non-utility companies that are selected from the solicitation will be allowed utility-style cost recovery and rate of return on the peakers.

United Illuminating, together with NRG Energy, submitted three proposals to provide gas-fired peaking power, including 194 MW in Devon, 194 MW in Middletown and 97 MW in Montville.

Maxim Power submitted two proposals for 96 MW in Bridgeport and one for 170 MW in New Haven. All are gas-fired.

Bridgeport Peaking Power proposed 200 MW in Bridgeport, and Bridgeport Energy proposed 350 MW in Bridgeport. Both proposals are for gas-fired power.

PSEG Power proposed 134 MW of gas-fired peaking generation in New Haven harbor. FirstLight Power proposed 100 MW of gas-fired power in Southbury.

CL&P proposed 200 MW of diesel-fired peaking generation in Lebanon and 65 MW of gas-fired peaking power in Waterbury.

Some of the proposals are for new plants, others are for repowered units, Lyons said. The agency did not release details from the proposals, including the size of and the number of units bid or whether or not they were for new construction.

Regulators may accept or reject any or all of the proposals.

The DPUC expects to make a decision by July 1.

— Mary Powers

To improve reliability, Central Maine Power to ask generators for offers to relieve load

In an effort to improve grid reliability, Central Maine Power plans to ask generators to make offers for new power plants to meet the needs of constrained load pockets.

CMP, a subsidiary of Portland, Maine-based Energy East, is also planning on building a 200-mile, 345-kV line from Orrington, Maine, to Newington, New Hampshire, which could provide Maine generators with increased access to markets in southern New England.

Besides building the power line along existing transmission paths, CMP is planning to build or upgrade roughly 200 miles of smaller lines, John Carroll, utility spokesman, said March 10.

In a move that is unusual for a utility that is in the transmission and distribution business, CMP will ask power plant developers and companies that specialize in demand-side management and conservation to offer bids to deal with various load pockets in the state, Carroll said. If constraints can be dealt with less expensively by adding new generation or conservation, CMP would proceed in that direction, he said. "If technically sound and the right choice, the [non-transmission project] would be rolled into the proposal for the [Public Utilities Commission]," Carroll said.

CMP expects to file an application for its proposal by June with the Maine PUC. The utility has already been meeting with landowners and municipalities that might be affected by the proposal. If approved, construction could begin by 2010 and the line could be operating by 2012.

The line could also help wind developers in Maine, according to Matt Kearns, a project manager for UPC Wind, which is building a 57-MW project in northeastern Maine. "Reliability and access to markets are one and the same," he said. UPC Wind is based in Newton, Massachusetts, and has built and is developing wind projects in the Northeast and West.

Meanwhile, Bangor Hydro Electric in December finished a 345-kV line between New Brunswick and Orrington, Maine, where the planned CMP line would interconnect. The Northeast Reliability Interconnect is expected to spur market opportunities between Maine and Canada's Maritime provinces. *— Ethan Howland*

NRG drops appeal against rejection of its bid into a 2006 Connecticut RFP

NRG Energy last week said it is dropping its plan to appeal a Connecticut Superior Court decision that rejected the company's claim that its bid under a 2006 solicitation for power was not properly evaluated by regulators.

The company said its intention when appealing the decision was to ensure that the people of Connecticut received the most reliable and cost effective generation. "However, it now appears that our pursuit of this appeal is not likely to serve that purpose, and for that reason, and in light of the Department of Public Utility Control's concerns, we are fully withdrawing it," John Ragan, president of NRG's northeast region, said.

William Palomba, DPUC's executive director, said after NRG filed the appeal March 4 that it was a "slap in the face to Connecticut ratepayers and a blow to Connecticut's effort in achieving tangible milestones and completing projects that would have directly lowered ratepayer bills."

NRG prefers to work with Connecticut regulators in a positive way, Ragan said.

Representatives of other merchant power producers said they were not surprised to see NRG drop its appeal. "Ultimately as a seller of power their contracts have to be approved by the regulators," an industry observer said. Challenging the regulators is not a good way to build a positive relationship, he said.

"Once a company has challenged regulators, it is really dicey to push it further," another industry player said. "NRG's decision makes good business sense. NRG is in the business of selling power, not fighting battles," he said.

NRG has proposals before the DPUC to add additional generation by 2010 in partnership with United Illuminating. "NRG continues to look for solutions that will lower costs for Connecticut ratepayers," Ragan said.

NRG's appeal was centered on clarifying the process by which competitive bids are selected, ultimately leading to the best solution for the state both economically and in terms of electric reliability, the company said. "With the withdrawal of our notice of appeal, we hope to eliminate the DPUC's concerns and continue to work together towards our common goal of ensuring the supply of affordable, clean and reliable power to the citizens of Connecticut now and in the future," Ragan said.

— Mary Powers

San Diego Gas & Electric issues request seeking offers for renewable energy supplies

San Diego Gas & Electric issued a request for offers seeking renewable energy supply. SDG&E is seeking a variety of offer types, including power purchase agreements, PPAs with a buyout option and turnkey projects.

Deliveries must start in 2009, 2010, 2011 or 2012.

Suppliers can propose a 10-, 15- or 20-year PPA for capacity and/or energy from an eligible renewable resource. Proposed short-term agreements of from one to five years will also be accepted. Offers for any other contract duration may be considered, the utility said in the March 10 RFO. All resources must ultimately be delivered to any point within California.

Respondents can also propose a PPA with a buyout option. Respondents offering new renewable resources can provide an option price for SDG&E to acquire a facility along with all environmental attributes, land rights, permits and other licenses, thus enabling SDG&E to own and operate the facility at the end of the PPA term. Resources must be located in the San Diego County or Imperial Valley areas.

Under a third alternative, respondents can propose to develop, permit and construct a new renewable generating facility to be acquired by SDG&E. Resources must be located in the San Diego County or Imperial Valley areas.

SDG&E noted that its goal is to achieve an overall resource portfolio comprised of 20% renewable energy resources by 2010. Resources offered must meet the California renewable portfolio standard eligibility criteria set forth by the California Energy Commission.

A pre-bidders conference is scheduled for March 27, and responses to the RFO are due April 30.

Questions related to the RFO can be e-mailed to renewablerfo@semprautilities.com.

For additional information and to download the necessary documents, go to www.sdge.com/renewablerfo2008.

Another California utility, Pacific Gas and Electric, recently issued a formal solicitation for new renewable energy. Offers in response to PG&E's RFO are due May 12. *— Paul Ciampoli*

Ontario government invites four parties to participate in solicitation for new reactors

The Ontario government has invited four vendors to participate in its request for proposal process for new reactors.

Ontario's 20-year energy plan includes replacing aging reactors to maintain its current nuclear capacity of 14,000 MW, according to the province's Ministry of Energy.

Ontario Minister of Energy Gerry Phillips announced a two-phase competitive RFP last week.

In the first phase, Ontario has invited the following vendors and their respective designs — Areva's 1,600-MW US-EPR, Atomic Energy of Canada's 1,100-MW ACR-1000, General Electric-Hitachi Nuclear Energy's 1,600-MW to 1,700-MW ESBWR, and Westinghouse Electric's 1,100-MW AP1000 — to offer tenders. Responses are due in May.

The second phase, involving the choice of the vendor and subsequent negotiations, will begin at the end of June, said George Nutter, a spokesman in the energy ministry's office. He said it was unclear when that phase would end.

Ontario has 16 operating power reactors, all of Candu design by crown corporation AECL. *— Staff Report*

MARKETS & GRIDS

Cal ISO offers alternatives to pricing rules under market redesign, technology upgrade

The California Independent System Operator has issued "straw proposals" that, if approved, would call off implementation of two pricing rules called for under the ISO's pending Market Redesign and Technology Upgrade.

But even if the proposals are approved, the grid operator would retain the option of going back to review whether the pricing rules are needed once the MRTU begins. The launch date for the MRTU remains in limbo.

Cal-ISO was ordered by the Federal Energy Regulatory Commission to allow constrained output generation, or COG, units to set the market price when they are needed and to consider a decremental energy bid activity rule that would stop the "DEC game" that was played when decremental energy was bid into the system during the California electricity crisis of 2000-2001.

Both proposals are only suggestions and must be vetted through a conference call with stakeholders on March 17, as well as stakeholders' written comments that must be submitted by March 24. The proposals would then be voted on by the Cal-ISO Board of Governors at its May meeting. If they clear all of these hurdles, the proposals would then be submitted to FERC for final approval.

"Back when we filed the MRTU tariff in February 2006, we included a DEC rule, which stated that generators cannot lower their decremental energy bids from the day-ahead market into the real time market," said Greg Cook, Cal-ISO's manager of market design.

What happened often during the crisis is that generators, for instance, would schedule 500 MW to flow down a line they knew could handle only 100 MW, and then get paid by the ISO to not produce power, Cook said.

"So they would not have the cost of burning fuel or running their generators, yet they would get paid," Cook said. Cal-ISO came out with a rule to stop that practice, but one that they say should end on its own anyway under the nodal price point element of the MRTU market structure.

"What we are suggesting we do instead is monitor the market to see if the DEC game is being played once the MRTU is imposed and is up and running for a few months to a year," Cook said.

"With DEC rules, we recognized there could be a problem, and proposed a solution, but upon further consideration, we realized that MRTU's structure solves the DEC issue pretty well without special rules," said Cal-ISO spokesman Gregg Fishman.

And rather than revamp its MRTU software to create a special designation for COG units, Cal-ISO has suggested it be allowed to simply consider COGs as flexible generating units, and allow them to set the market price when their power is needed. During peak energy times, such as summer heat waves, the last unit dispatched by Cal-ISO sets the market price for that interval. FERC wants that last unit to be a COG unit and to allow it to set the price, Cook said.

COGs are usually smaller electric generators that either must run full out or be switched off and cannot be scaled back while operating. For example, if a COG produces 10 MW, it must produce all 10 MW or be shut off.

A study by an independent energy consulting firm cautioned that Cal-ISO should consider creating a special category for COGs based on a problem with the units that had been experienced by the New York ISO. "But New York City and Long Island are loaded with COG units. We found out we had about 10 in the entire state of California, producing a total of about 230 MW," Cook said.

Rewriting the MRTU software this late in the process to accommodate such a limited number is neither cost-effective nor productive, the ISO decided. So, like with the proposed DEC rule, it now suggests nothing be implemented unless a problem is witnessed once the MRTU is up and running for several months.

"We really doubt 10 units are enough to affect much at all," Cook said.

The problem is that a COG can create a "stuck market price" by setting the market price even after its power is no longer needed. "For instance, if we needed a COG switched on for the first increment of an hour, 10 minutes, but didn't need it the rest of the hour, the COG could continue setting the price for the rest of the hour even though we don't need its power," Cook said. *— Daniel Guido*

Three generators complain to FERC about Cal-ISO's interim capacity plan

In a filing with the Federal Energy Regulatory Commission, a trio of generators contends that payments under the California Independent System Operator's controversial proposed Interim Capacity Procurement Mechanism would be "unjust and unreasonable" and must be higher to offset generation costs.

Cal-ISO's proposal is before FERC for approval. Stakeholders had until February 29 to submit their comments to the agency. While FERC typically decides such issues within 60 days, Anthony Ivancovich, Cal-ISO's assistant general counsel for regulatory matters, said this time FERC might take longer to reach a decision.

"Because the ICPM goes into effect whenever the Market Redesign and Technology Upgrade does, and the MRTU's launch date has not as yet been decided, FERC has some time," Ivancovich said.

Basically, the filings indicate that generators oppose the ICPM while load servers support it. The primary objection raised by generators in their filings is to the price of $41 per kilowatt year that the ISO proposes it pay for capacity.

"There is a major dispute on pricing," Ivancovich acknowledged. While he would not comment on the arguments put forth in the generator's filings opposing the ICPM, he said Cal-ISO needs to implement the plan because it "would allow us to fill a gap in deficiency in [resource adequacy] procurement. The ICPM provides the backstop for the period of the deficiency."

The filing by the three generators contends the ICPM price should be "no less than $117/kW-year, with monthly payments shaped to reflect the higher reliability needs of summer months." The generators — Dynegy, El Segundo Power and Reliant — also argue that there should be no fixed sunset date for the ICPM, currently set to expire in 2010.

The ICPM would serve as a temporary successor to the ISO's reliability capacity services tariff, which was set to expire at the end of 2007. Under Type-1 procurement schedules, the ISO would call on generation when a load serving entity fails to obtain adequate resources in advance of its compliance year, or if an LSE would not meet specific ISO locational needs. Under Type-2 procurement schedules, the ISO would call on a resource if something happened that caused a shortfall in an LSE's resource adequacy during the compliance year.

Under the ICPM, Cal-ISO would pay for the option to dispatch part or all of the capacity of a generation resource.

In another filing opposing the ICPM, Independent Energy Producers contends that the "core of the problem is that much of the demand response resources counted on as resource adequacy cannot be called upon until the ISO is in a stage two emergency …. Simply put, the planned demand response is not available as expected."

Calling the ICPM pricing "unduly discriminatory," the IEP argues the "most appropriate mechanism" for creating a capacity price is to establish a market-based rate or determine a proxy price level based on expected market outcomes. Because older plants often have higher fixed costs, "capacity prices should be defined by market-based going forward costs, and not the going forward costs of a brand new merchant peaker," the IEP contends.

The ideal solution, the IEP stated, would be for FERC to require Cal-ISO to update its existing Reliability Capacity Services Tariff "rather than implement a new tariff."

But after nine months of stakeholder review, Cal-ISO contends the ICPM should be approved by FERC without major changes. "Both sides are polarized on this, despite all the input," Ivancovich said. "We need to get this resolved and move on." *— Daniel Guido*

FERC OKs NYC capacity market restructuring to protect against buy-side market manipulation

The Federal Energy Regulatory Commission last week approved a restructuring of the New York City capacity market that will involve some short-term pain for generators , but long-term protection against buy-side market manipulation.

FERC's Office of Enforcement also issued a report concluding that the claims of market manipulation made against capacity suppliers were invalid. Those claims especially targeted the KeySpan-Ravenswood limited liability company, the largest power and capacity supplier in the city.

The plan to revamp the market was proposed in October by the New York Independent System Operator after buyers and sellers of power could not agree on reforms. The issue boiled up in late 2006 after the entry of new capacity into the market failed to depress prices, giving rise to the push for reform and the accusations of "economic withholding" to artificially support prices.

NYISO's reform proposal, with provisions to limit price manipulation by both buyers and sellers, contained much that drew objections from both sides in the bitter dispute. FERC rejected the larger protests and conditioned its approval on relatively minor tweaking of the plan.

Under the new system, the in-city capacity market will lose its price cap but gain a reference price to limit offers and a must-offer obligation to limit the potential for market manipulation by any supplier with at least 500 MW of capacity. Although offer prices will be constrained by the reference price, the market's clearing price may rise higher. If the price clears at a level above the reference level, all suppliers will be paid the clearing price.

NRG Energy has said the reform would lower capacity revenue by more than 60% on an annualized basis. But in response to objections that the capacity payments will be below the cost of new entry, FERC said that is the appropriate outcome during years when supply exceeds demand, as in the current situation.

An offer floor for new projects will be established to prevent buyers from arranging for "uneconomic entry," or the offer of capacity at low or zero prices to manipulate clearing prices downward. Consolidated Edison of New York and the New York Power Authority, the two dominant buyers, have been accused of doing exactly that through their control of capacity that was first offered into the market in 2006.

Con Ed and NYPA both objected to the idea of measures to prevent market manipulation by buyers, but FERC approved those measures and noted that it had approved similar measures for the forward capacity markets in the PJM Interconnection and ISO New England.

Suppliers had wanted the floor price to be applied not only to new generation but to the two units that first began offering their capacity in 2006, because those units have the potential to depress prices for another year or two until demand growth absorbs the capacity surplus. FERC would not agree. The purpose of the floor is to deter uneconomic new entry, the commission said, noting that it is too late to deter plants that have already entered the market.

One of those two units is a 500-MW generator owned by NYPA. The other is a 500-MW generator called the Astoria Energy project, built by developer SCS Energy with help from investment fund money and under a long-term contract to Con Ed.

Also exempt from the floor price are demand response providers. The floor price might create a barrier to entry for demand response providers, FERC said.

The new reference price designed to serve as an offer cap will be the higher of two possibilities: either a price based on an estimate of what would occur if all qualified capacity cleared the market; or a price based on covering the net "going-forward costs" of the marginal unit, that is, the costs the unit could avoid by being mothballed.

The new floor price will be 75% of the estimated cost of new entry after subtracting revenues from sales of energy and ancillary services (Docket No. EL07-39).

Con Ed and NYPA, with support from some city and state officials, demanded refunds for what they claimed were excessive prices charged by KeySpan-Ravenswood, Astoria Generating (US Power Generating) and NRG, the owners of divested Con Ed generators in the city. But FERC would not agree with that, either. The conclusion of FERC's Office of Enforcement investigation reinforced the commission's position that no illicit manipulation had occurred.

The commission gave NYISO 60 days to file tariff revisions reflecting the new rules for the in-city market. — *Alan Kovski*

PJM plans to increase forward prices sparks ire with market participants

The PJM Interconnection recently proposed a sharp increase in basic reference prices for its forward capacity market, and capacity buyers including utilities, state officials and industrial companies, let it be known last week that they are far from ready to accept the price increases.

"PJM has ignored the will of its stakeholders and circumvented the requirements of its own tariff in order to make a change that will have significant adverse impacts on consumers and distort any price signal," a coalition calling itself the RPM Buyers said in a protest filed at the Federal Energy Regulatory Commission.

PJM has admitted that it was unable to win the support of the PJM Members Committee to proceed with the plan, which would raise the estimates for cost of new entry in the market. The new reference prices would be 41% to 48% higher than current estimates, depending on the region.

A Members Committee vote on January 24 "essentially split between supply and load interests," PJM acknowledged when it filed the proposal. The PJM Board of Managers met January 26 and decided that a revision of the reference prices was necessary. Those prices are used in the PJM-administered "demand curves" that establish the price patterns in the capacity market.

The proposal was submitted to FERC January 30. Expressions of support from owners of generating plants appeared in February. Then came the wave of buyer opposition.

Capacity revenues are intended to supplement energy and ancillary services revenues, but the PJM proposal upsets a careful balance between those cash streams by overweighting the capacity payments, the RPM Buyers coalition said. The coalition's 20 members include the PJM Industrial Customer Coalition, several other industrial groups, the public utility commissions of Maryland and Pennsylvania, several state consumer counsels and several municipal and cooperative utilities. Its name comes from the abbreviation for "reliability pricing model," PJM's name for its capacity market.

The group asked that FERC either reject the proposal outright or at least suspend it for five months and set it for evidentiary hearings (Docket No. ER08-516).

The American Public Power Association and the New Jersey Board of Public Utilities were among the interests that also weighed in with support for the RPM Buyers position.

Large amounts of money are riding on the capacity markets. The New Jersey BPU estimated that the results of the first four RPM auctions would add about $5.94 billion to the cost of electricity in the state over the first four years of the market's implementation.

Under PJM's proposed change, the estimated cost of new entry, or CONE, would be raised for the next capacity auction, scheduled for May to commit capacity for the year starting June 1, 2011. "Power plant construction costs have increased substantially in the last two years, and the CONE values developed during 2004-05 have become outdated," PJM explained in its filing.

The grid organization used an analysis by consulting company Pasteris Energy, which was assisted by energy services firm The Wood Group. Pasteris and Wood similarly provided the 2005 analysis that was used to set the initial CONE pricing point for the PJM capacity market. The "2008 Update of Cost of New Entry Combustion Turbine Power Plant Revenue Requirements," like the earlier study, based its estimates on a two-unit plant using GE Frame 7FA combustion turbines.

The CONE estimates are subdivided for three regions. The current estimates are $72,207/MW-year for New Jersey, $74,117/MW-year for Maryland and $73,866/MW-year for Illinois. The revised estimates are $106,904/MW-year for New Jersey, $105,414/MW-year for Maryland and $104,260/MW-year for Illinois. — *Alan Kovski*

Wholesale power prices in PJM Interconnection driven higher in '07 by demand, grid congestion

Wholesale power prices in the PJM Interconnection were driven up by growing demand and transmission congestion during 2007, while fuel prices declined slightly, the grid operator's market monitor said March 11.

Releasing PJM's "2007 State of the Market Report," market monitor Joseph Bowring said the markets for energy, reserves and capacity within the regional transmission organization remained competitive, with the possible exception of regulation reserves. The competitiveness in regulation service, involving real-time adjustments in supply to maintain the balance with demand, could not be adequately determined, the report said.

In terms of a load-weighted average, real-time locational marginal prices in 2007 averaged $61.66/MWh and day-ahead prices averaged $57.88, according to the report. Those real-time prices were 15.6% above the year-earlier level, while the day-ahead prices were up12.8%.

"It's primarily tighter conditions throughout the system," Bowring said.

That occurred despite the peak demand in 2007 falling short of 2006's peak. It was growing demand and congestion throughout the year that pushed the prices up, the report indicated.

As grid congestion increased, an administrative change also added to the higher locational marginal prices. On June 1, line losses were removed from estimates of load and included in locational prices, pushing locational prices somewhat higher.

The growth of demand doubled the number of hours in a year that were rated as high-load hours, meaning that demand reached at least 90% of available supply. In 2007 there were 157 high-load hours, up from 70 in 2006, the report said.

Fuel prices were a relatively less important factor. Coal prices declined slightly, while natural gas and oil prices increased. Overall that resulted in a slight decline in fuel costs, which "helped to moderate the increase in LMP," Bowring said.

The marginal units setting the spot prices mostly were coal-burning units. Coal-burning units were on the margin 70% of the time, while gas-fired units were on the margin 24% of the time and petroleum-burning units were on the margin 5% of the time, the report said.

Bowring said his independent market monitoring unit continues to recommend the introduction of mitigation in the regulation market through what is called the "three pivotal supplier test," which now is used to gauge market power in the other PJM markets. But so far that proposal has not been accepted by the PJM membership.

The proposal now is before PJM's Three Pivotal Supplier Task Force, and Bowring said he remains hopeful that PJM will end up accepting the proposal.

The market monitor also is recommending that scarcity pricing in PJM be improved through the development of better tools to measure available capacity. Under scarcity pricing, offers of power can exceed the market's $1,000/MWh offer cap.

Another recommendation from the market monitor is that all exemptions from rules governing local market power be eliminated. Those exemptions apply to 56 generating units and four internal interfaces in PJM.

The market monitor also is recommending modification of the rules governing demand-side programs to ensure legitimate payments and adequate measurement and verification.

"It's possible to do nothing, literally, and get paid," Bowring said of companies signed up for demand-side programs.

Asked about the unhappiness in New Jersey over proposals to export more power to New York, Bowring said the proposals need to be the subjects of "very elaborate studies" to minimize their consequences for PJM. "There are a lot of impacts on the system," he said.

Offering an example, Bowring said the Neptune line, completed last year to move power from New Jersey to Long Island, New York, caused unexpected problems for spinning reserves after it began moving about 600 MW on a regular basis. — *Alan Kovski*

Centrica, Macquarie and Suez applaud PJM move to relax credit policies for foreign participants

Foreign companies participating in the PJM Interconnection market and that have been subject to harsh credit requirements support the grid operator's proposal to relax its credit policy for foreign entities.

Direct Energy Services and Energy America, subsidiaries of the UK-based Centrica; Macquarie Cook Power, owned by the Australian corporation Macquarie Group Ltd.; and Suez Energy North America filed on March 7 with the Federal Energy Regulatory Commission in support of the recent PJM proposal to loosen credit policies for companies based outside the US and Canada.

PJM's proposal would allow companies incorporated outside the US but also operating in the PJM market to establish unsecured credit with PJM based on the financial strength of the parent foreign guarantor. Through its unsecured credit provisions, PJM allows companies in good financial standing and with high credit scores to trade up to a certain volume without posting collateral.

Currently, PJM only accepts financial guarantees from US and Canadian companies but not from foreign parent companies, a practice that has put foreign entities at a disadvantage, the joint filing by DES, Energy America and Suez said. Macquarie Cook Power made comments on the PJM proposal in a separate filing.

"Allowing additional sources for credit guarantees reduces collateral requirements and promotes a higher level of unsecured trading in the PJM markets, which benefits … members without imposing unreasonable risk to others," PJM's proposal filed with FERC February 15 said.

Under the proposed change, to qualify for unsecured credit, foreign companies would have to meet two credit-rating requirements: that of their guarantors, most likely their parent companies, and that of the country where the main company is incorporated.

Canadian companies would continue to be treated more favorably than other foreign entities, although some new requirements would be put in place for them. Currently, Canadian and Domestic companies receive the same treatment under PJM rules.

Among other things, both Canadian and foreign companies guaranteeing for their affiliates in PJM would have to show credit ratings, provide financial statements in accordance with US accounting principles and satisfy all the provisions of the PJM credit policy applicable to domestic companies. Once a Canadian entity meets the above mentioned criteria, it would be treated as a domestic company.

Further, companies incorporated outside the US would have to show a minimum credit rating of BBB/Baa2 from all agencies that rate the entity, be domiciled in a country with a minimum rating of AA+/Aa1 and demonstrate financial commitment to its activity in the US. Guarantors with ratings of BBB- will not be eligible for unsecured credit. This rule would not apply to Canadian companies, which would continue to receive more favorable treatment because of the "unique relationship that Canada has with the United States," the filing said.

According to the PJM filing, about 20 countries meet the rating criteria required by PJM, including France, Germany, Ireland, Norway, UK, Sweden and Switzerland. However, if a foreign company meets all proposed criteria, it would still qualify for a lesser amount of unsecured credit than a domestic counterpart, according to the PJM filing.

The Midwestern ISO also plans to relax its credit policy for foreign entities, but the members agreed to wait for FERC to approve the PJM proposal first. At this point, MISO's proposal mirrors the PJM's filing.

In its joint filing, DES, Energy America and Suez stated that in the past they had to post "cash deposit or letter of credit in an amount and form determined by and acceptable to PJM." Using its discretion, PJM did not accept corporate guarantees of foreign entities, thus requiring foreign affiliates to post mainly cash. "Thus, the extent of a foreign subsidiary's participation in [the] PJM market had to be weighed against the lost investment opportunity associated with the increase in cash deposits," the filing said.

Further, the companies point out that PJM's proposal will remove a "potential form of discrimination … that has occurred in practice."

Macquarie Cook Power commented that in recent years, several overseas companies entered the PJM market through their trading affiliates, and the new proposal will ultimately increase liquidity. — *Milena Yordanova-Kline*

PJM files complaint with FERC against Tower, charging manipulation of FTR, energy markets

The PJM Interconnection last week filed a complaint at the Federal Energy Regulatory Commission against all seven of Tower Research Capital's companies, saying they manipulated PJM's financial transmission rights and energy markets.

PJM is also asking FERC to prohibit the Tower companies from participating in the PJM market and impose civil penalties.

The grid operator's filing provides more information about the manipulation charges that PJM leveled in a March 3 filing.

Tower Research Capital operates seven affiliated companies in PJM: Power Edge, BJ Energy, Accord Energy, Franklin Power, GLE Trading, Ocean Power, and Pillar Fund.

According to PJM's complaint, "Tower Companies have knowingly and recklessly used a device, scheme or artifice to defraud, and engaged in acts, practices, or courses of business that operate as a fraud or deceit in connection with the purchase or sale of electric energy or transmission of electric energy." Also, the complaint said that the companies engaged in fraudulent trading to benefit the financial position of the affiliates by creating congestion.

PJM alleges that the Tower companies' conduct falls into two categories of manipulation. First, collusion among affiliates to purchase FTR offsetting positions for the gain of one or more affiliates and secondly, virtual bidding intended to boost congestion in order to increase the value of FTRs while at the same time increasing the obligation taken by Power Edge, which ultimately defaulted.

PJM urged the commission to direct BJ Energy to disgorge at a minimum $10.4 million of unjust profits, order a public hearing to investigate the companies and assess civil penalties. PJM also asked FERC to issue an order prohibiting the companies from future participation in the PJM market.

Prior to PJM's late filing, Tower Research Capital said last week that the March 3 allegations by PJM that the fund engaged in market manipulation could seriously damage its reputation and called "inexcusable" PJM's decision to make the allegations public without offering any evidence.

PJM's March 3 filing alleged that the Tower companies traded in the virtual trading market to impact transmission congestion to benefit positions in the FTR market. According to PJM, Tower affiliates took at least 354 MW of FTRs opposite to the 13,000-MW FTR positions held by the company in default, Power Edge, in an attempt to increase revenue for the company holding the positive right. Also, PJM said that one of the affiliates, BJ Energy, submitted virtual bids in the day-ahead market that aim to create congestion and increase the value of its FTR positions.

PJM also alleged that while making that attempt to increase its profits, Tower isolated all its risky positions in one affiliate, Power Edge.

When those risky FTR positions caused losses, Power Edge defaulted and failed beginning in December to make congestion payments it owed to the PJM FTR market.

PJM's unusual public disclosure of its allegations of alleged market manipulation by Tower came in a proceeding at FERC in which PJM is seeking FERC approval to go after the Tower affiliates to get the money that Power Edge owes.

Tower blasted PJM for its handling of the manipulation allegations. "Market manipulation should not be alleged lightly and indiscriminately, as PJM does, especially without thorough legal analysis and a presentation of the factual basis for the charge," it said in the filing.

"The accusation of 'manipulation' can seriously damage a commercial entity's reputation," it continued. "But PJM has now chosen *twice* to tag the Tower Companies with the manipulation label without even once offering *any* evidence to support such serious allegations. Alleging manipulation and then stating that it expects to provide more details later in another proceeding is inexcusable behavior for the operator of the nation's largest electricity market. It is particularly inexcusable when PJM claims that it knows that the independent PJM Market Monitor is conducting an investigation, which, if that is the case, clearly has not run its course."

According to PJM members, the standard PJM procedure is for the market monitor, if it sees behavior it considers constituting manipulation, to privately notify FERC. FERC would then investigate the allegations privately, and in some cases even the companies being investigated themselves are not aware of investigations. FERC has discretion to make the investigations public or keep them private.

Asked if it is allowed to publicly air allegations of market manipulation prior to when they are investigated by FERC, PJM spokeswoman Paula DuPont-Kidd said: "Parties, such as PJM, can always file a complaint with FERC. That is an independent right from FERC's enforcement rights and from the MMU's [PJM's Market Monitoring Unit] investigation and referral rights. If we feel a party has violated" the Federal Power Act, "we can file a complaint and name that party in the complaint."

PJM's public disclosure of the alleged manipulation also raises questions about how quickly it detected the manipulation and when and if its market monitor intended to turn the allegations over to FERC for investigation.

PJM said in its March 3 filing to FERC filing the alleged manipulation occurred over a period of several months. PJM declined to comment further when asked when the manipulation began and how long it continued.

David Patton of Potomac Economics, which monitors markets in the Midwest, California and the Northeast, said in a recent interview that the type of manipulation alleged by PJM is possible but very difficult to carry out because it can be easily detected. Patton said he was speaking generally and not about the PJM allegations concerning Tower.

Tower did not explicitly deny any of the PJM allegations, but said that the affiliates "did not hold such offsetting positions and that… such offsetting positions would be a risk-free bet only if the losing position was expected to exceed the losing entity's collateral, an assumption that did not apply to Power Edge."

Further, Tower's filing said that PJM's rationale for the allegations could only mean that "affiliates should be liable for the default of another affiliate whenever that affiliate holds a net short FTR position."

Finally, Tower said that it will fully cooperate with FERC and PJM's market monitor in any investigation and has confidence of the independence of the investigating staff. "The Tower companies are at a loss to understand why PJM would take that action when it could be seen to be an effort by PJM management to influence the outcome of any investigation by prejudging the result and creating public pressure on these investigating bodies to ratify PJM's announced conclusion," the filing said. *— Milena Yordanova-Kline*

FORECASTS & PLANNING

Climate change laws could prompt 20% rise in gas consumption in 10 years: trade groups

Natural gas consumption could jump by as much as 20% over the next 10 years if climate change legislation under consideration in Congress becomes law, several gas trade groups said this week.

"We want members of Congress to understand that their actions will have serious consequences for America's natural gas customers," Dave Parker, president and CEO of the American Gas Association and a member of the Natural Gas Council, said in a statement. "Meeting the nation's clean air goals requires natural gas and lots of it. While the natural gas industry whole heartedly supports increased energy efficiency, conservation, and use of renewable fuels, US energy demands cannot be met by these measures alone."

The council's findings, sent in a letter to members of Congress, contradict an earlier analysis by the Energy Information Administration, which indicated that gas use would fall if a CO2 emissions reduction bill (S. 280) sponsored by Senators Joe Lieberman, Independent Democrat-Connecticut, and John McCain, Republican-Arizona, becomes law.

According to the NGC letter, the legislation would lead to an increase of roughly 20% in gas consumption over the next decade.

EIA estimated that the US would need to add 145 new nuclear reactor units in the next 22 years, while the NGC's review — citing political opposition driven by environmental and safety concerns — puts the number of new reactors at closer to 25.

"Because of the rules under which EIA operates, that agency didn't factor in the political and societal realities industry and policymakers will need to face when complying with a possible climate change law," said NGC member Barry Russell, president and CEO of the Independent Petroleum Association of America. "When such realities are considered, the same analysis reveals a very different and striking impact on energy markets."

"As a country we need nuclear power, solar, wind and coal too. But electric utilities are switching to natural gas because it provides on-demand power and clean air objectives quickly," added Skip Horvath, president and CEO of the Natural Gas Supply Association.

According to Don Santa, the president of the Interstate Natural Gas Association of America, such a switch to natural gas must be accompanied by increased access to new natural gas supplies.

"There is currently an estimated 250 TCF of natural gas — more than 10 years of supply at the country's current rate of consumption — that is off limits to US consumers," Santa said. "If we had access to those areas, we could help the US economically achieve its goals to reduce greenhouse gas emissions and keep downward pressure on prices." — *Chris Newkumet*

Interstate grid connection could end lower rates for Maine as capacity is sold elsewhere: report

Maine could see a hike in power costs as new transmission allows generators to sell outside of the state, according to a recent draft report from London Economics International.

Commissioned by the state Public Utilities Commission, the report attempts to guide the commission in resource planning as it prepares to seek long-term capacity contracts.

Called "A Resource Adequacy Plan for Maine: Consideration of Electricity Sector Investment Strategies," the report found that Maine ratepayers benefit from the state's transmission isolation. Maine's transmission congestion prevents generators from selling their capacity surplus to other states. As a result, the state has ample supply, which lowers power prices.

Maine has a 1,250-MW capacity surplus, and forecasts demand growth of only 370 MW over the next decade.

"Unlike sub-regions like southwest Connecticut and Boston, Maine has much more generation capacity than necessary to meet its current and future internal electrical load. The existence of transmission constraints has actually provided a natural hedge against escalating peak prices in other parts of New England," said Julia Frayer, LEI managing director, who announced the release of the report this week.

Maine's grid isolation offers price benefits for consumers. However, it creates a competitive disadvantage for existing generators in Maine. They end up producing less power than they would otherwise because of the grid congestion that prevents them from selling to other states.

However, Maine's grid isolation is likely to end soon because several transmission projects are now in planning that could allow greater flow of power from Maine to load centers further south.

Central Maine Power recently announced plans to build 200 miles of transmission from Orrington, Maine, south to Newington, New Hampshire (*see story, page 16*). And Northeast Utilities is working on bringing together New England stakeholders to agree upon transmission projects from northern New Hampshire southward.

The report recommends that Maine increase demand response programs and develop more low-cost renewables. This would better position Maine in the regional forward capacity market and keep prices in check when the transmission grid is reconfigured.

The key is for Maine to encourage the kinds of generation that result in the lowest possible capacity clearing prices in the forward capacity auctions and in the hourly energy markets, according to the report.

Maine ratepayers are expected to be hit with a large bill because of the region's new forward capacity market. In fact, state regulators and lawmakers are so concerned about the costs, they have threatened to have the state's utilities leave ISO New England to form their own transmission operator or join up with New Brunswick. Maine's portion of the FCM cost is likely to be $142.5 million in 2010, rising to $187.5 million by 2016. "These are not insignificant market costs for Maine ratepayers," the report said.

After the commission finalizes the resource plan, it will solicit capacity contracts with assistance from LEI. The Maine Legislature mandated that utilities sign the long-term deals as part of an energy law passed in 2006.

The Maine PUC is seeking comment on the draft report by March 21.

The draft report is available at http://mpuc.informe.org/easyfile/easyweb.php?func=easyweb_hitlist. — *Lisa Wood*

Northwestern planning council considers geothermal power to meet region's power needs

An influential Northwest power planning council this week was set to discuss the potential for geothermal power to be included in its emerging plan for shaping the region's power supply.

"Geothermal is one of the more attractive renewable energy choices available. It provides a more consistent source of power than wind, in which most renewable development to date has been focused," said Terry Morlan, director of power planning for the Northwest Power and Conservation Council.

The matter is becoming pressing because utilities such as Idaho Power are soliciting for geothermal as well. "We are focusing on geothermal at our meeting in Idaho," said Jeff King, the council's power generation manager. "The costs of wind and thermal-fired plants have gone up substantially but the sense is that costs for geothermal have not gone up that much. We also have renewable standards to consider in northwest states and geothermal could help meet mandates."

The council has asked Doug Glaspey, chief operating officer of US Geothermal of Boise, Idaho, to brief the company's operations in Idaho and Oregon, which include US Geothermal's Raft River project in Idaho and the 26-MW Neah Hot Springs project in Oregon.

The Renewable Northwest Project, which tracks renewables in the region, said several geothermal developers are active in the region. Ormat is involved in geothermal in Idaho. Developer Idatherm has proposed both a 100-MW geothermal project near Idaho Falls and a 100-MW project near Soda Springs in Idaho. Calpine has been developing a 55-MW project proposed for Glass Mountain at Four Mile Hill in northern California as well as the 48-MW Telephone Flat area at Glass Mountain.

The Geothermal Energy Association said geothermal sources now generate nearly 3,000 MW a year across the country, equal to about 0.4% of the nation's total energy use. The group notes that the US Geological Service contends there are 20,000 to 26,000 MW of known geothermal sites throughout the country. The Western Governor's Association recently estimated that 3,000 MW of identified resources are expected to be developable within the next five to 20 years. — *Harriet King*

RENEWABLE ENERGY

Bush defends US' role in tackling climate change, citing developments in new 'clean' technologies

President Bush said last week that the nation is taking a leading role in confronting climate change, forcefully responding to critics in a speech to the Washington International Renewable Energy Conference.

"Stereotypes are hard to defeat," he said, but "America is in the lead when it comes to energy independence. We're in the lead when it comes to new technologies. We're in the lead when it comes to confronting climate change, and we'll stay that way."

Bush's comments come as many around the world are questioning the US commitment to reducing greenhouse gas emissions through a binding international treaty. The White House has remained opposed to emissions caps ever since Bush pulled the US out of the Kyoto Protocol in 2001.

Critics contest White House arguments that the so-called major economies climate discussions, begun in September, are a distraction to central United Nations climate negotiations.

Bush went after that assertion, saying that the major economies discussions are "not in lieu of the UN process" and will "enable the UN process."

He said that the major economies discussions, which include large developing nations like China and India, are needed because of high emissions growth in the developing world.

"Those agreements must include commitments, solid commitments, from every major economy and no country should get a free ride," he said.

Bush also positioned himself as a champion of poor developing nations. He said that their economic growth must be central to a new climate treaty. "It's hard to commit money if you don't have any," he said, adding that each country should have its own national plans. "An effective agreement is one that recognizes economies have got to grow," he added.

He then issued a challenge to delegates to embrace free trade and nuclear power. He said that if people are serious about climate change, they should back nuclear energy and also back a proposal from the US and European Union to eliminate clean energy trade barriers. "There's too many impediments. There's too much protectionism," he said. — *Alexander Duncan*

California regulators voice support for moves to regulate greenhouse gas emissions in West

California regulators are reacting favorably to a Western Climate Initiative proposal focused on regulating greenhouse gas emissions from fossil fueled fired-plants in the West, saying it is consistent with a California climate plan for the electricity sector.

The WCI favors a cap-and-trade market to cover California, Arizona, New Mexico, Oregon, Utah, as well as the Canadian provinces of British Columbia and Manitoba.

California's 2006 climate law commits the state to reducing its greenhouse gas emissions by about 25% by 2020. The California Air Resources Board is the lead agency for the climate law, but the California Public Utilities Commission and California Energy Commission are developing recommendations for CARB on the energy sector's compliance with the law.

WCI officials are proposing to make the point of GHG emission regulation the first entity that the WCI partner has jurisdiction over and delivers power on the WCI grid.

Similarly, a joint proposal by the PUC and the CEC calls for CARB to designate the first sellers or deliverers of electricity to the power grid as the "point of regulation."

Stanley Young, spokesman for CARB, said the WCI proposal dovetails with California's plans. Representatives from CARB, CEC and PUC helped craft the plan and the "WCI direction is consistent with our views," Young said.

Young said the WCI proposal does address "leakage" issues. The preferred solution is to have all states in the Western Electricity Coordinating Council participate in WCI. Leakage refers to the potential for GHG emissions to increase in states bordering the WCI region.

Young said, "Because that is not yet happening, however, the proposal recommends that the first jurisdictional deliverer approach be employed to address coverage and leakage issues during the transition to full WECC participation in the WCI."

Terrie Prosper, spokeswoman for the PUC, echoed CARB's views. Under the WCI concept, Prosper said, if the regional program expands to include all states in the WECC connected to the western grid, it would no longer be necessary to have anything other than an in-state generator-based program since all electricity in the Western system would be covered.

In the meantime, since all states are not part of the WCI agreement, the partners would work on a first jurisdictional-seller approach, which is consistent with the PUC/CEC proposal that faces a PUC vote on Thursday, Prosper said.

Steven Kelly, policy director for the Indepenendent Energy Producers, noted that WCI has much work to do to meet the August deadline to release its plan on cap-and-trade program design.

Kelly said that while he has not yet reviewed the WCI proposal, he believes it is a good sign if the regional plan dovetails with California's approach. — *Lisa Weinzimer*

Solar power development takes off in Northwest; Columbia Energy partners plans 2-GW project

Solar power is gaining ground in the Northwest, aided by new renewable standards in Washington and Oregon, and Columbia Energy Partners has unveiled the largest project to date, a $20 million, 2-MW development near Arlington, Oregon.

Until now, Puget Sound Energy was the solar leader with a $4 million, 450-kW demonstration solar project under way at its 229-MW Wild Horse Wind and Solar Facility in eastern Washington. The utility completed installing 2,408 solar panels in October 2007 and will add another 315 panels this spring.

Puget's goal is to test the viability of large-scale solar projects. Nearly 250 Puget customers also have solar panels and in total, Puget's system has 1,200 MW of solar capacity, said Christina Mills, Puget spokeswoman.

Seattle and Portland receive nearly 40 inches of rain annually and 16 hours of sunlight on June 21 that dwindles to

8.5 hours on December 21. But across the mountains in the semi-desert that flanks the Columbia River in eastern Oregon and Washington, where the solar projects are being located, the sunshine is equivalent to that in Houston, Puget contends.

In the new Oregon venture, Columbia Energy of Vancouver, Washington, plans to connect the project to PacifiCorp's grid. The project will use photovoltaic solar panels and is expected online by the fall, said Chris Crowley, president.

The project will be built as a qualifying facility under the Public Utility Regulatory Policies Act, and power would be sold to PacifiCorp, said John Norling, Columbia Energy's general counsel. The Germany-based bank HSH Nordbank will arrange construction financing.

The solar project has received pre-certification for eligibility from Oregon's business energy tax credit program and will be eligible for federal tax credits and accelerated depreciation provisions of the 2008 economic stimulus package passed recently by Congress.

Other utilities and companies are also exploring solar power in the region. Energy Northwest, a joint operating agency that owns the Columbia nuclear plant near Richland, Washington, built the 40-kW White Bluffs solar project that was developed jointly with the Bonneville Power Administration and the Bonneville Environmental Foundation. BPA is buying the power and green tags are for resale through the BEF.

The city of Ashland, Oregon, began operating a solar demonstration project in 2000 that generates 30 kW. It is a joint effort with BPA and the state of Oregon.

Spokane, Washington-based Avista said it has established a clean energy test site that developers can use. Two solar technology companies using the site. *— Harriet King*

Berkeley, Calif., expects to launch pilot program to fund household solar installations this summer

The city of Berkeley, California, plans to roll out the pilot bond financing this summer for a program that would help homeowners pay the upfront costs of installing solar power systems, a city official said in an interview.

"The goal [of the program] is to avoid out of pocket costs of the customer," said Cisco DeVries, who was chief of staff to the mayor of Berkeley and helped develop the program. DeVries is in the process of leaving his post in the mayor's office.

The size of the pilot financing has yet to be determined, but it will likely be a $500,000 to $1 million bond issue, he said, adding that the bonds to finance the program could eventually be in the $100 million range.

The city already has term sheets and is in the process of negotiating with several "major" banks, said DeVries.

It is a model that could spread to other cities, he said. "There is significant serious interest from cities all over the country."

The details of the program have yet to be worked out, but in general terms the city would provide the financing for homeowners who want to install a solar system on their house. The loan would be paid off through a 20-year property tax assessment or lien.

"We wanted to help people who want to go solar" but are put off by the out-of-pocket costs, said DeVries. "We identified the financial hurdle as a market failure."

"People want to pay for solar power like they pay their electricity bills and not be forced to pay for 20 years of electricity up front," said DeVries. The installation of a typical household solar system can cost $20,000 to $40,000.

The program grew out of a city-wide ballot initiative in Berkeley, Measure G, in the November 2006 elections that passed by 81%, said DeVries.

Measure G calls for an 80% reduction in the city's greenhouse gas emissions by 2050. "There is no penalty, except political, involved in the program," said DeVries, but the mayor said he would take responsibility for the success or failure of the program.

The Financing Initiative for Renewable and Solar Technology program, as it is called, is based on the city's underground utility district program, which DeVries implemented. In that program, neighborhoods can elect to bury their power lines and pay off the expense through a city administered tax assessment.

Like the undergrounding program the solar initiative bonds would not be fully tax deductible because the recipients, the homeowners, receive a personal benefit.

The tax lien also helps address another hurdle. Many homeowners who want to install solar panels are concerned that they will move before they can recoup their investment. If a homeowner did move after installing solar panels under the program, the solar tax lien would remain with the property and become the responsibility of the new owner.

In addition to giving homeowners more financial options to support a desire to use solar power, from the financing point of view the solar initiative program provides an enhancement to credit quality because tax payments take high priority with consumers and in foreclosures. And, if bankers are more comfortable with the credit risks, they are also more likely to aggregate many loans into a single bond issue, which brings down the costs of capital. The banks would also help administer the record keeping and billing required under the program, said DeVries.

DeVries said that if the schedule for the pilot financing does not slip and is rolled out this summer, the full fledged program could be ready to launch by year end. *— Peter Maloney*

REGULATION & LEGISLATION

House lawmaker Boucher predicts 50-50 chance of Bush signing cap-and-trade bill in 2008

A key House of Representatives lawmaker this week predicted the odds for enacting an economy-wide carbon cap and emissions trading bill this year are "better than 50-50" and anticipates utility industry support for a measure he foresees will retain coal generation in the mix with free credits and permissible offsets.

Speaking at Platts Energy Podium in Washington, House Energy and Air Quality Subcommittee Chairman Rick Boucher said that the odds were better than even that a GHG cap-and-trade bill to reduce industry emissions by 60% to 80% by 2050 could clear both the House and Senate and be signed by

President Bush. Such a bill also would have to have bipartisan as well as industry support and be written in a way not to disrupt the economy, he said.

"That is our goal and it will occur very soon," said Boucher, a Democrat from Virginia's coal-producing counties. "I would rate the chances of our passing a cap-and-trade bill and having it signed into law this Congress to be better than 50-50."

If federal climate change legislation is not enacted this year, Boucher said a cap-and-trade bill had an "80% or better" chance of enactment under the next Congress and next administration, noting that all three presidential contenders — Republican Senator John McCain of Arizona and Democratic Senators Hillary Clinton of New York and Barack Obama of Illinois — are expected to make addressing global warming a priority.

"You're not going to see the federal government fail to act [to cap carbon emissions] very much longer," Boucher said.

An aide to John Dingell, the Michigan Democrat who chairs the House Energy and Commerce Committee, has said the chairman hopes to have draft legislation ready by the end of April. But Boucher declined to specify when a climate bill would emerge.

"There are discussions under way internally about the dates upon which we will set as goal posts" for the process to pass legislation this year, Boucher said. "I'm not in a position today to give you firm time frames for the various steps that we intend to be taking. Our intention is to produce a bill in time for House passage, conferencing with the Senate and presentation to the president prior to the end of this session of Congress and we believe we can meet that schedule."

The House committee, in the meantime, continues to try to build consensus on the toughest issues, identified by Boucher, to capping industry GHG emissions: Setting a schedule for emission reductions, determining the allocations of emissions allowances and addressing the obligation of developing countries to reduce their emissions.

To that end, Boucher's subcommittee is drafting position papers on issues in an effort to build consensus for how to tackle these issues in legislation. But the chairman said he would look to the Clean Air Act's much-lauded sulfur dioxide cap-and-trade program for coal-fired utilities that gave away 97% of the emission allowances and auctioned only 3%.

Cap-and-trade to reduce coal-fired generation emissions has proven to be effective, said Boucher, but the "burden of proof rests on the shoulders of those who say we ought to auction allowances."

Still, Boucher said that coal-fired utilities would have to make "broad-based reductions" between the date the bill takes effect and 2025, when technologies to control carbon emissions from coal-fired power plants and a geologic carbon storage system are likely to be available. "They will not be given a pass," he said.

To that end coal generation, which provides half the country's electricity and more than a third of its carbon emissions, could look to offsets in the agriculture sector or in helping to prevent deforestation in the tropical rainforest, he said.

"It's particularly important that electric utilities not be forced to abandon coal prior to the time [low-carbon] technology is available, affordable and reliable," said Boucher. "We predict that time to be 2025." Otherwise, these utilities will default to natural gas, causing spikes in the home-heating fuel that would "wreck economic havoc" nationwide.

"Reductions will be required in the near term but [they can be] achieved by electric utilities using the existing fuel mix," said Boucher.

Podcasts of Boucher's remarks at the Platts Energy Podium are available at www.platts.com/energypodium. — *Cathy Cash*

Democratic representatives call for moratorium on coal-fired plants without carbon capture

Two prominent Democrats in the House of Representatives introduced legislation this week that would stop coal-fired power plants from being built unless they are equipped with technology to capture carbon dioxide and store it.

Representative Henry Waxman of California, chairman of the House Oversight and Government Reform Committee, joined with Representative Ed Markey of Massachusetts, who heads the House Select Committee on Energy Independence and Global Warming.

Before a greenhouse gas emission cap takes place, the bill would bar the Environmental Protection Agency or state regulators from granting operating licenses for coal-fired power plants unless they include CCS. Once a federal emissions cap is implemented, any plants without technology for permanent CCS could not get free or discounted emissions allowances under an economy wide cap-and-trade program.

"It's important for ratepayers and regulators to understand the financial risks if their power company wants to build a new uncontrolled coal-fired power plant," Waxman said in a statement. "Those plants will be a lot more expensive to operate when global warming pollution is regulated. Ratepayers need to make sure they won't be stuck with the bill."

The committee chairmen are vocal advocates of mandatory cuts to CO_2 emissions. They also are two of House Speaker Nancy Pelosi's most trusted lieutenants in Congress.
— *Alexander Duncan*

Uncertainty over greenhouse gas legislation is freezing energy investment, says Wyo. governor

The lack of a clear federal policy on greenhouse gas emissions has led to an atmosphere of uncertainty that is freezing investment in new energy developments, Wyoming Governor David Freudenthal said last week.

"Investments are frozen because we don't have a federal [GHG] policy. You need to attach a value to [carbon dioxide emissions], but until then the market will not move to invest," Freudenthal told a Canada Institute forum on carbon capture and sequestration in Washington. "We're not going to get financing for [power] plants until we are sure the question of CO_2 is answered."

In the past, a company would go to the state utility regulator and work out problems with permits and customer rates, he said, adding that the industry would know the risks involved with building a coal-fired power plant.

But under the current situation "we can't tell you what the risk is in terms of cost or the regulatory environment," he said.

To bolster investment in Wyoming, Freudenthal, a Democrat, last week signed into law a regulatory framework for geologic sequestration.

The law specifies that the state's Oil and Gas Conservation Commission should continue to regulate drilling activities, that surface owners control the underground pore spaces where carbon dioxide could be sequestered and it gives the state's Department of Environmental Quality the authority to regulate the long-term storage of carbon dioxide.

"At some point the heavy handed feds will come in with their plan, but in the meantime we needed a legal and regulatory framework so that investors know what they are getting," Freudenthal said.

Freudenthal also said if the US had offered clean coal generation the kind of tax incentives it did for wind and solar, there might be more advanced coal-fired plants operating.

"In the near term, we will make some headway with efficiency and conservation. But we are going to get hammered on energy costs if we keep canceling this project and that project," Freudenthal said.

He said he would continue to permit coal-fired power plants as long as CO2 remains an unregulated pollutant and utilities meet the environmental laws that are on the books.

"Natural gas can't meet all our needs and renewables will not be able to do it alone. All this canceling is going to come home to roost. America's low energy costs are coming to an end," he said. *— Regina Johnson*

DOE, EPRI pledge joint action to promote demand-response programs across the US

The Department of Energy said last week it had struck a deal with Palo Alto, California-based Electric Power Research Institute to promote the adoption of demand-response programs across the electricity grid.

Demand response gives households and businesses feedback on their power usage so they can curtail energy use during peak load periods. That reduces the load on the grid, as well as decreases the air pollution that power plants generate, experts say.

The memorandum of understanding that EPRI, the electric industry's research arm, signed with DOE says the two entities will coordinate activities on several fronts, including researching demand-response programs for buildings, industrial processes and household appliances.

"This MOU will help ensure America continues to lead the way in cutting-edge energy research, development and commercialization projects to enhance our national, energy and economic security," said Alexander Karsner, DOE's assistant secretary for energy efficiency and renewable energy.

Michael Howard, EPRI's senior vice president, called the MOU "a major step forward that will help the electric sector meet an ever-growing demand for electricity while addressing the environmental challenges associated with climate change." *— Brian Hansen*

EPA opens public comment period for greenhouse gas emissions report

The Environmental Protection Agency opened up the public comment period for its annual greenhouse gas emissions report, the agency said last week in a *Federal Register* notice. The February draft report said that in 2006, US emissions declined by 1.5% relative to 2005.

The comment period for the report, known as Draft Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2006, is open until April 6.

EPA said that this was just the third time since 1990 that emissions declined from one year to next. However, the data show an overall growth trend in emissions despite the drop from 2005 to 2006.

The report measures where GHGs come from within the economy and where they are displaced in sinks, such as forests. EPA showed that the US had 7,202 million metric tons of carbon dioxide equivalent, but a net of 6,319 million metric tons when sinks were accounted for.

One major factor, EPA said, was milder weather that decreased electricity demand for air conditioning in the summer and natural gas for heating in the winter.

The findings in the report mirror similar conclusions by the Energy Information Administration, the Department of Energy's independent statistical branch. *— Alexander Duncan*

NERC submits proposed standards for reliability on bulk power grid

The North American Electric Reliability Corp. has submitted for approval by the Federal Energy Regulatory Commission "violation severity levels" for NERC's 83 reliability standards for the bulk power grid.

NERC, the designated national electric reliability organization, said the violation severity levels define the degree to which compliance with a standard was not achieved and will be used to determine the possible base penalty range for a violation of a reliability standard. The violation severity levels have also been submitted to Canadian regulators, NERC said.

The rules rate as "severe" such things as a regional reliability organization failing to assign reliability coordinators. Another violation deemed severe would be a reliability coordinator failing to take action within 30 minutes of identifying a way to deal with a particular system emergency.

Under NERC rules, each regional reliability organization, subregion or interregional coordinating group must establish one or more reliability coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across other regions.

Another severe violation would be a generator or utility failing to notify a reliability coordinator that it cannot follow reliability directives because it would violate safety, equipment, statutory or regulatory requirements, while simply delaying compliance with such a directive would be considered a lower level of severity.

NERC also submitted its violation severity level for nuclear plant interface coordination even though FERC is still approving the reliability standards in that area. FERC approved the 83 reliability standards on March 16, 2007, in Order No. 693.

NERC last year asked for an additional three years to work on the severity levels, but FERC refused and said that the national reliability organization should have them prepared by March 1 so the commission could consider them before this summer when electricity demand peaks in many parts of the country.

NERC's development procedures for the rules dictate that two-thirds of NERC members approve them for adoption. The reliability organization's rules for emergency operating procedures did not receive this majority approval, but NERC asked FERC to approve them anyway for compliance purposes while NERC works on a new proposal for these rules that will later be submitted to FERC. *— Jason Fordney*

Kansas legislators approve compromise bill that denies GHG challenge to coal-fired plant

Kansas legislators last week gave final approval to a bill that allows Sunflower Electric Power to build two 700-MW coal-fired plants, placing the issue in the hands of Governor Kathleen Sebelius.

Governor Kathleen Sebelius, a Democrat and opponent of the $3.6 billion Sunflower project, is expected to veto Senate Bill 327. She has 10 days to act on the measure. Stripping Kansas Department of Health and Environment Secretary Roderick Bremby of authority to deny air permits for power plants is totally unacceptable to the Democrat chief executive, said Sebelius' press secretary, Nicole Corcoran.

The bill both allows Hays, Kansas-based Sunflower, a generation and transmission co-op, to reapply for the permit denied by Bremby last October and prevents the secretary from using the same rationale for his decision.

The Kansas Senate made quick work of the bill, taking less than a half-hour to pass S.B. 327 by a veto-proof margin of 31-7. A day earlier, the House of Representatives also approved the bill, 75-47, falling nine votes short of the 84 votes needed for a gubernatorial override.

State Senator Jay Emler said lawmakers did their part to endorse legislation that facilitate an expansion of Sunflower's 360-MW Holcomb baseload coal plant.

"Part of what we do is compromise," he said in an interview. "This is a compromise between the House and Senate. The Senate's position was a lot tougher than the House position and we're trying to offer something that is acceptable to the House. It was acceptable to the House."

In addition to the power plant language, the bill also provides for a mandatory renewable portfolio standard. It calls for Kansas to secure at least 10% of its power from renewables by 2012, 15% by 2016, and 20% by 2020. However, the bill contains no penalties for non-compliance. *— Bob Matyi*

Ohio governor suggests 10-year transition to market-based rates for state's utilities

Dismayed that his comprehensive energy plan has bogged down in the General Assembly, Ohio Governor Ted Strickland last week proposed a 10-year transition to market pricing for the state's electric utilities and reaffirmed his demands for the Public Utilities Commission to continue to play a key role in regulating retail electric service.

In an eight-page memo distributed to lawmakers, the governor, a first-term Democrat, also proposed stripping out benchmarks for renewable energy development in the 2009-2014 time frame, effectively delaying enforcement until 2015.

The state Senate last October approved S.B. 221, based largely on the governor's plan. It included options for utilities to return to a regulated environment or attempt to go to market in 2009 once existing rate stabilization plans for all of the major utilities, except Dayton Power & Light, expire. DP&L's plan runs through 2010.

S.B. 221 also provides for a renewable portfolio standard that requires the state to get at least 25% of its power from traditional renewable resources such as wind, solar and biomass and advanced energy sources such as coal and nuclear by 2025, with at least half coming from in-state sources. But the bill does not set out renewable interim targets. Recently filed legislation, H.B. 487, includes benchmarks. It is supported by House Speaker Jon Husted, a Republican.

Strickland outlined a plan where utilities would transition to market rates over 10 years. "In each succeeding year, an additional 10% of the load would shift to market pricing; the balance of the load would be provided under the terms and conditions established" through a so-called electric security plan. *— Bob Matyi*

Massachusetts passes law to cut GHG to 20% below 1990 levels by 2020

The Massachusetts Senate last week passed a bill that requires the state to cut greenhouse gas emissions by 20% below 1990 levels by 2020. The measure, S.B. 2531, requires additional multi-sector cuts of 80% by 2050.

If approved, Massachusetts stands to become the first Northeast state to set mandatory climate change targets.

The bill, approved March 6, essentially bans new conventional coal-fired power plants by limiting plant emissions to no more than 1,100 pounds of carbon dioxide per MWh, a limit that cannot be reached by coal plants. California has adopted a similar limit. An expansion of an existing plant would have to meet the emissions limit, under the bill. The limit applies only to baseload plants and would not apply if an existing plant expanded its capacity without increasing its carbon emissions.

Stationary sources that release more than 5,000 tons of carbon a year would be required to report their emissions to a registry that would be established under the bill.

The bill requires the secretary of Energy and Environmental Affairs to adopt a plan for achieving the 2020 GHG emissions limit by 2010. The bill also gives Massachusetts the ability to expand the Regional Greenhouse Gas Initiative to sources besides power plants.

The bill moves to the Massachusetts House for action. It has already been approved by the joint Environment, Natural Resources and Agriculture Committee. It will likely head to the House Ways and Means Committee and then to the House floor, according to Jeremy McDiarmid, an attorney with Environment Northeast, an environmental group that supports the bill. *— Ethan Howland*

Rhode Island introduces bills to spur renewable energy development in state

Rhode Island Senate leaders introduced a package of bills last week that aim to spur renewable energy development in the state.

One of the bills requires National Grid to issue requests for proposals to buy electricity for at least 5% of their overall load from large renewable energy projects for terms of 10 to 15 years. The Rhode Island Public Utilities Commission would approve the final projects. National Grid supports the measure.

National Grid would resell the output from the renewable projects into the wholesale market. In a move that shifts the risks from the projects, the net proceeds or loss would be spread over all state customers. If a project leads to cost increases, customers would pay a surcharge. If National Grid saves some money, customers would receive a credit. Further, once a project is online, National Grid would receive payments equal to 4% of the annual contract payments it makes to the developer, similar to a Massachusetts incentive, according to Senate President Joseph Montalbano.

Three other bills provide for state coordination of renewable energy policies, expanded net metering and a requirement that state electricity purchases match Rhode Island's renewable portfolio standard, which climbs to 16% by 2019. *— Ethan Howland*

Utah passes bill setting portfolio standard on a voluntary basis for renewable power

The Utah Legislature last week unanimously passed a bill that sets a voluntary 20% by 2025 renewables goal.

"It's a first step, but it doesn't go anywhere near as far as we could go in the state," said Tim Wagner, a Sierra Club official.

The measure, S.B. 202, introduced by Senate Majority Leader Curtis Bramble, a Republican, is modeled on a proposal made by Rocky Mountain Power in October. The proposal called for establishing a low-carbon portfolio standard for Utah's utilities instead of a traditional renewable portfolio standard.

"We're very pleased," said David Eskelsen, a spokesman for Rocky Mountain Power. Utah Governor Jon Huntsman, a Republican, has indicated that he supports the bill, Eskelsen said.

Typically, RPSs are based on total retail sales, however, under S.B. 202, utilities will start with total retail sales and deduct from them various "zero-carbon" sources like hydroelectric plants, energy efficiency programs, carbon capture projects and nuclear power. Also renewable resources like biomass and landfill gas projects could be included. The utility would then base its 20% target on the remaining MWh after the low-carbon sources are subtracted. Renewable energy credits could be used to meet the 20% goal.

S.B. 202 faced competition from a more traditional RPS bill, S.B. 173, introduced by Senator Scott McCoy, a Democrat. The bill ramped up to 25% by 2026 and called for noncompliance penalties. It died in committee.

The Sierra Club's Wagner believes S.B. 202 will not help Utah develop a renewable market, while neighboring states will move ahead in adding renewable capacity and developing renewable-related industries. Nevada has a mandatory RPS of 20% by 2015. Colorado and New Mexico have mandatory RPS laws of 20% by 2020 and Arizona has a 15% by 2025 mandatory standard.

Utah, which gets about 90% of its electric power from coal-fired plants, is also setting itself up for future cost increases when federal climate change regulation is enacted, Wagner predicted. In the end, issues like climate change may trump a portfolio standard in pushing Utah's utilities toward renewable resources, according to Wagner. "There are larger forces at play," he said. "Rocky Mountain Power will have to go full out and build new renewable projects to meet market demand and keep costs low." *— Ethan Howland*

Washington would cut greenhouse gas emissions to 1990 levels by 2020 under Senate-approved bill

A bill that mandates accelerating efforts to cut greenhouse gas emissions cuts in the state of Washington was approved by the Senate last week, and Governor Chris Gregoire is expected to sign it next week.

"Global climate change is the greatest challenge our generation and future generations face; we must take bold steps to address it now," said Gregoire, a Democrat.

"This bill will help guide Washington State in working toward a cleaner environmental future and sustainable economic development by laying the groundwork for creating green collar jobs," she said.

Firming up the requirements of a bill approved in 2007, H.B. 2815 mandates that Washington reduce its GHG emissions to 1990 levels by 2020, to 25% below 1990 levels by 2035 and to 50% below 1990 levels by 2050.

The state Department of Ecology must submit a GHG reduction plan, in which it will detail actions needed to reach the reduction goals, for review and approval by the legislature by December 1 as a result of the bill.

The Senate approved the measure in a 29-19 vote, following a supportive 64-31 House vote on February 19.

Introduced in mid-January, the bill also seeks to prepare Washington for participation in the Western Climate Initiative, a partnership between western states to regionally cap GHG emissions and create a trading market.

Although it does not reference WCI specifically, the bill states that if Washington elects to participate in a regional multi-sector market-based system, it should be in place by January 1, 2012.

The regional system also must recognize the state's unique hydro-focused generation portfolio, as well as the carbon offset opportunities presented by its forest and agricultural resources, it said.

Market-related revenue, the bill said, must go toward offsetting global warming's impact on the environment and increasing investment in the state's clean energy economy.

The bill also directs the directors of the state departments of ecology and community, trade and economic development to present the Legislature with recommendations on implementing the preferred design for a regional trading system by 2012 by December 1.

Among these recommendations will be actions Washington should take to prevent market manipulation, it said.

— *Christine Cordner*

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