

Military leaders conclude aging power grid poses serious threat to national security

by [Glen Boshart](#)

Building upon a 2007 report on how the threat of climate change can impact national security and long-term global stability, a panel of retired senior military officers issued a new report asserting that current U.S. energy policy constitutes a serious and urgent threat to national security.

In the report, "Powering America's Defense: Energy and the Risks to National Security," the military advisory board found that fossil

fuels, as well as the fragility of the nation's electricity grid, "pose significant security threats to the country as a whole and the military in particular."

Going beyond the often-discussed security and political implications of continuing U.S. dependence on foreign oil, the report said the country's reliance on carbon-based fossil fuels can also negatively impact national security by undermining economic stability.

The board noted that the market for fossil fuels will be shaped in the future by finite supplies and increasing demand, which will drive up the costs of those fuels. Costs also will be driven up, both economically and geopolitically, by the regulatory frameworks that are being developed to address climate change concerns. Additionally, the board predicted that global destabilization driven by ongoing climate change could "add sig-

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by [Glen Boshart](#)

Presenting its 2009 Summer Energy Market Reliability Assessment during FERC's May 21 regular agenda meeting, commission staff reported that forward prices for generation to be supplied during the upcoming summer are almost half of what was projected at the same time last year for 2008 summer supplies, with price drops ranging from 40% to 49% for most of the nation's major trading hubs.

In fact, staff said forward wholesale power prices in many regions have dipped to levels

not seen in many years. Forward prices in New York and the PJM Interconnection LLC are the lowest they have been at this time of year since 2004, staff reported, while the last time forward prices were this low at the SP-15 trading hub in Southern California, the Mid-Columbia trading hub in the Northwest and the Palo Verde trading hub in Arizona was in 2002.

Staff attributed the lower prices to "weaker market fundamentals" affecting loads and

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FERC conditionally approves Exelon's acquisition of NRG

by [Marcy Crane](#)

Exelon Corp.'s attempt to acquire NRG Energy Inc. moved one step closer to fruition May 21 after FERC conditionally approved the transaction (EC09-32).

Voting unanimously to approve the deal during its May 21 regular agenda meeting, the commission signed off on Exelon's acquisition of NRG's voting securities and of control over NRG and its public utility subsidiaries, as well as the subsequent restructuring and consolidation of the generation

operations of the two companies to establish a more efficient corporate structure for the combined company.

Briefly addressing the development, Exelon issued a release applauding FERC for approving the transaction.

"While we need to review the order and its conditions carefully before commenting further, the approval of our application by FERC is a major step in the regulatory approval process," said Elizabeth Moler, Exelon execu-

tive vice president, government and environmental affairs and public policy. "The combination with NRG remains on track for closing in the fourth quarter of 2009."

NRG also issued a statement, noting that "there are many other regulatory and other hurdles that remain." Nevertheless, the company lamented that regulatory authorities appear not to be addressing the nature of the hostile takeover attempt or NRG's contention that Exelon is refusing to offer appropriate value to NRG's stockholders.

Exelon's takeover attempt

Exelon first proposed in October 2008 to buy all of NRG's outstanding stock, but that unsolicited bid was rejected by NRG's board of directors the following month. Exelon then took its case directly to NRG's stakeholders, offering them 0.485 of a share of Exelon common stock for each share of NRG common stock, which prompted NRG to mount a fierce opposition to the takeover effort.

Despite NRG's objections, Exelon on Dec. 18, 2008, sought FERC's approval, to the extent the agency has jurisdiction, of its offer to purchase NRG. Acknowledging that NRG and Exelon each own a significant amount of generation in both the Texas and PJM East markets, Exelon agreed to divest some generating capacity in those two regions to protect and enhance competition and mitigate any potential market concentration.

Specifically, Exelon proposed to divest its three generating facilities in the Electric Reliability Council of Texas Inc. region — Mountain Creek, Handley and LaPorte, also known as ExTex LaPorte — totaling about 2,200 MW of capacity, and to transfer long-term contract rights for an additional 1,200 MW of capacity in Texas to a third party. The application also explained that the combined company would divest NRG's three generation facilities in the PJM East market: the 784-MW Indian River, 170-MW Vienna and 104-MW Dover plants.

While Exelon explained that it was committed to implementing the transaction regardless of the opposition of NRG's management, it also said it would continue efforts to reach a negotiated agreement with NRG based on its belief that such a deal would result in certain benefits that would not necessarily result from the tender offer. Either way, Exelon asked FERC to approve the substance of the transaction, whatever form it ultimately takes.

Asserting that Exelon was using its filing at FERC to "gain a strategic advantage in pursuit of its highly conditional and speculative hostile takeover," NRG subsequently urged the commission not to waste its time approving a proposed transaction that was unlikely ever to be consummated in its present form.

Since then, Exelon has continued its efforts to acquire NRG, and NRG's management has persevered in its opposition to that move. Most recently, Exelon CEO John Rowe said he is prepared to file suit if need be to force NRG to have a shareholders meeting that would act as the stage for a crucial showdown in Exelon's unsolicited acquisition bid.

FERC conditionally approves transaction

In the instant order, the commission made little mention of the fact that Exelon's takeover attempt is contested by NRG's management, other than to express its appreciation for "NRG's concerns regarding efficient use of Commission resources."

FERC also stressed that its actions "should not be construed as favoring or disfavoring [the] tender offer. The ultimate question before the Commission is not whether [the] proposal will or should be consummated. Rather, the question is whether this proposed merger, if consummated, is consistent with the public interest."

Finding that the transaction indeed is consistent with the public interest, FERC approved Exelon's application conditioned on

the company's providing further details regarding the transaction within 10 days of its closing. The commission also said it wants to be informed within 30 days of any change in the circumstances presented in the merger application, and within 10 days if another regulatory agency directs Exelon to modify its proposed mitigation measures in any way.

As is its policy when considering merger applications, FERC said it looked at whether the transaction would adversely affect competition, rates or regulation, or would result in any inappropriate cross-subsidization, pledge or encumbrance among affiliates. In this case, the commission said it found that the proposal raised no concerns in any of those areas, after taking into account the mitigation measures that Exelon agreed to implement.

NRG responds

Responding to FERC's action, NRG said that its board and management team "continue to believe that Exelon's proposal significantly undervalues NRG and remains highly conditional, including the need to obtain financing, and very risky because of rating agency and other concerns."

The company also noted that Exelon "has faced similar regulatory review in two previous failed transactions," including its attempted acquisition of Public Service Enterprise Group Inc., which the company was unable to consummate even after it received approval from FERC.

Far from sharing Exelon's confidence that the transaction likely will close near the end of 2009, NRG noted that the proposed transaction still must garner the approval of the stockholders of both companies, as well as the U.S. Department of Justice, the Nuclear Regulatory Commission, and state regulators in California, New York, Pennsylvania, Texas and possibly Massachusetts.

COMPANIES REFERENCED IN THIS ARTICLE:

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FERC approves transmission project to deliver Canadian hydropower to New England

by [Glen Boshart](#)

FERC on May 21 voted to approve the transaction structure (EL09-20) of an international transmission project being designed to deliver low-cost hydroelectric power from Quebec to consumers in the New England region.

In jointly asking FERC to approve the transaction structure, Northeast Utilities subsidiary Northeast Utilities Service Co. and NSTAR subsidiary NSTAR Electric Co. told FERC that it involves a new participant-funded transmission line with at least 1,200 MW of capacity that will cross over the U.S.-Canadian border and connect to ISO New England Inc.'s backbone 345-kV transmission system.

Hydro-Quebec's wholly owned subsidiary, HQ Energy Services (U.S.) Inc., intends to use the line to deliver low-carbon hydroelectric power from the Des Cantons substation in Quebec to a yet-to-be-determined point in southern New Hampshire, to be sold at HQUS' market-based rates.

The New England utilities explained that they had signed a memorandum of understanding with Hydro-Quebec to pursue the project on an exclusive basis. Hydro-Quebec is developing more than 4,000 MW of new hydroelectric generation in Quebec to supplement its existing vast system of hydroelectric power plants, which the petitioners said will leave plenty of surplus power available for export to the United States for at least the next two decades.

Under the proposal, NU and NSTAR would own the U.S. portion of the line, but they would not seek regional cost recovery for the project under ISO New England's open access transmission tariff because it is to be funded initially by HQUS, which would then recover those costs in the rates it charges for power. As a result, HQUS is taking responsibility for any of the project's risks.

NU and NSTAR also told FERC that the proposed project is not intended to be a "merchant" transmission line because service over the line will be provided at cost-of-service rates to be reviewed by FERC, rather than pursuant to negotiated rates.

The proposed transactional structure proved to be very controversial, with competitive power suppliers claiming that it violates FERC's policies regarding open access to transmission and is ripe for discriminatory and self-dealing abuses. Particularly troubling to the suppliers is that only a small amount of the line's capacity will be made available through an open season process, with the rest being sold through bilaterally negotiated agreements.

ISO New England supported the plan, however, asserting that the proposed transactional structure is the type of arrangement that appears to have been contemplated by FERC when it reformed its transmission policies in 2007, and is consistent with principles espoused by many New England stakeholders. The grid operator further noted that the proposed arrangement avoids the difficult cost allocation issues that usually surround the building of a new transmission project because here, only the parties contracting to take the Canadian power will pay for the cost of the transmission line.

Also supporting the petition, National Grid plc subsidiary National Grid USA praised NU and NSTAR for having found an innovative way to confront the widely known "anchor tenant" problem, where transmission developers experience difficulty financing a participant-funded transmission project because potential offtakers understand that the transmission capacity will ultimately be subjected to open access requirements and made available to other parties.

FERC's approval

Voting to approve the proposed transaction structure during FERC's May 21 regular agenda open meeting, several commissioners cited the many benefits the project will offer the New England region, including offering access to clean, low-cost energy. Several of the commissioners also praised the project because it will greater diversify the fuel sources of New England's power supply, which is very dependent on natural gas.

While the order was not immediately available, a staff presentation of a draft order explained that in addition to the benefits it will offer New England, the project is attractive because HQUS is assuming all the cost and risk of the project. In addition, the project is expected to cut greenhouse gas emissions somewhere between 4 million and 6 million tons annually, and therefore help meet regional environmental goals and drive down the retail price of power in New England.

The proposed transactional structure is rather complicated because it involves three core agreements that are still being negotiated. The first is a joint development agreement that would provide for the design and construction of the new transmission line. A long-term bilateral service agreement would allow HQUS to acquire 1,200 MW of firm transmission rights over the U.S. portion of the line, and require the company to pay NU and NSTAR for constructing, operating and maintaining the line. Finally, a power purchase agreement would dictate the terms under which HQUS will sell 1,200 MW of firm power to NU, NSTAR and other interested entities for at least 20 years pursuant to HQUS' market-based rate tariff.

Staff said that the draft order found several factors of the proposed arrangements that should mitigate the concerns raised by the protesters. First, staff noted that FERC will have to review the rates, terms and conditions of the transmission service agreement once it is finalized to ensure that it meets the agency's requirements. Moreover, staff said the arrangement will not lead to undue discrimination or preference because the transmission owners have the obligation to expand their transmission systems, including the new transmission line, upon request.

As for the protesters' affiliate abuse concerns, staff explained that the draft order rejected them because NU, NSTAR and HQUS are not affiliated, and the transactions on the Canadian side of the border must comply with Canadian open access transmission tariff requirements.


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Staff said the draft order finds no bundling concerns because separate agreements will govern the project's service and rates, and the rates for transmission service and power will be stated separately. Finally, the draft order determined that the project promotes competition by allowing greater access to ISO New England markets, according to staff.

In response to a question posed by Commissioner Phillip Moeller, staff stressed the consumer protections inherent in the proposed arrangements, including that power purchase agreements that NU and NSTAR are expected to sign with HQUS will be subject to review by New England state regulators, and that retail ratepayers in those two utilities' service territories have the ability to choose other power suppliers.

Commission staff also explained after the meeting that if enough interest is shown by potential power buyers in New England, the line's capacity could be boosted significantly beyond the 1,200 MW that is being contemplated.

Before voting on the order, Commissioner Suedeen Kelly noted that ISO New England will take control of the new line once it becomes operational, which should eliminate any discrimination, reliability and operational concerns about the project. Kelly also stressed that FERC's approval of the proposed transaction arrangement is conditioned on the agency finding that the project's transmission rates, once they are filed, are just and reasonable.

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FERC OKs large batch of regional transmission plans, announces plan to hold regional conferences

by [Glen Boshart](#)

FERC on May 21 approved with certain conditions numerous transmission plans submitted in compliance with Order 890, a February 2007 final rule reforming the agency's open-access transmission policies and requiring each transmission provider to engage in an open, coordinated and transparent transmission planning process.

To ensure that the transmission planning processes are accomplishing their intended goals, FERC also announced May 21 that it will convene a series of regional conferences later this year. According to FERC, the conferences will examine whether existing transmission planning processes "adequately consider needs and solutions on a regional or interconnection-wide basis to ensure adequate and reliable supplies of electricity at just and reasonable rates."

The commission said it also wants to evaluate whether the existing transmission planning processes can handle emerging challenges, such as the development of interregional transmission facilities, the integration of large amounts of location-constrained generation and the interconnection of distributed energy resources.

"The conferences will determine the progress and benefits of each transmission provider's planning process, gather customer and other stakeholder input, and discuss any areas that may need improvement," the commission added.

FERC said it will announce the specific dates, times and agendas of the technical conferences later.

Turning back to the instant orders, FERC acted on nine separate filings submitted by the Maine Public Service Co. (OA08-21), PJM Interconnection LLC (OA08-32), Xcel Energy Inc. and Southwestern Public Service Co. (OA08-35), MidAmerican Energy Co. (OA08-

41), Midwest ISO and American Transmission Co. LLC (OA08-53; OA08-42), ISO New England Inc. (OA08-58), Southwest Power Pool Inc. (OA08-61), California ISO (OA08-62) and Southwestern Power Administration (NJ08-3).

All nine orders accepted compliance filings that were submitted in response to previous orders. In most cases, however, FERC conditioned its acceptance on the transmission providers' making additional compliance filings, further fine-tuning their transmission planning processes.

Reflecting FERC's desire expressed in the concurrent release, the orders also reiterated calls the agency previously made for the transmission providers to pursue ways to improve their planning processes, based on the experience gained through actual implementation of the processes.

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FERC acts on proposed reliability standards related to transmission relay loadability, time error correction

by [Marcy Crane](#)

On May 21, FERC announced its intention to approve a proposed mandatory reliability standard aimed at addressing a problem that contributed to the cascading power outages that plunged much of the Eastern Interconnection into darkness in August 2003.

However, the commission sought comment on its plan to direct the North American Electric Reliability Corp. to make certain changes to the "Transmission Relay Loadability" reliability standard, explaining that it may not go far enough in addressing other concerns expressed by the joint U.S.-Canada task force that investigated the blackout.

The agency also issued two final rules related to mandatory reliability standards applicable to the nation's bulk power system — one addressing NERC's interpretation of two of those standards, and the other establishing a regional reliability standard related to time error correction.

Both of those final rules stem from notices of proposed rulemaking that FERC issued on Nov. 20, 2008.

RM08-13

FERC proposed to approve a mandatory reliability standard (PRC-023-1) requiring certain transmission owners, generator owners and distribution providers to set load-responsive phase protection relays according to specific criteria. In a May 21 NOPR, the commission explained that the standard would help ensure that the relays detect and protect the electric network from fault conditions without limiting transmission loadability or interfering with the ability of system operators to protect system reliability.

The joint U.S.-Canada blackout task force found that the unnecessary operation of protection relays contributed at the start of the August 2003 outages "and accelerated the geographic spread of the cascade," FERC recounted. The task force subsequently recommended that steps be taken to ensure that protective relays do not play a part in future blackouts, and the proposed reliability standard represents NERC's response to that recommendation, the commission explained.

Although FERC proposed to approve the standard as "a significant step toward improving the reliability" of the bulk power system, the

agency also said it planned to direct NERC to make certain modifications to the standard, such as broadening the pool of facilities to which the standard would apply.

NERC had proposed that the standard “apply to transmission owners, generator owners, and distribution providers with load-responsive phase protection systems ... applied to: (1) all transmission lines and transformers with low-voltage terminals operated or connected at 200 kV and above; and (2) those transmission lines and transformers with low-voltage terminals operated or connected between 100 kV and 200 kV that are designated by planning coordinators as critical to the reliability of the bulk electric system,” the commission explained.

Concerned that such an approach “will effectively exempt a large percentage of bulk electric system facilities that should otherwise be subject” to the standard, FERC proposed that the standard be made applicable to all such facilities operated at or above 100 kV, with case-by-case exemptions made for facilities operated between 100 kV and 200 kV that are not critical to bulk power system reliability.

The commission also disagreed with NERC that facilities operated below 100 kV should be automatically exempted from the standard just because they are not included in NERC’s standard definition of the bulk electric system. Accordingly, the agency proposed to direct NERC to have the standard apply to all facilities operated below 100 kV that have been found by a regional entity to be critical to the reliability of the bulk electric system.

FERC further proposed that the standard be modified to address, among other things, generator step-up and auxiliary transformer relay loadability; the reach of certain relays applied as remote circuit breaker failure and backup protection; and issues related to load increases, overload and stable power swings that occur under recognized system conditions.

Finally, the NOPR proposed to direct NERC to make certain changes to the violation risk factor and violation severity levels it proposed to assign to some of the requirements and subrequirements of the standard.

RM08-16

In one of FERC’s Nov. 20 NOPRs, the agency said it intended to approve NERC’s interpretation of certain specific requirements of its “Frequency Response and Bias” reliability standard (BAL-003-0), which ensures that a balancing authority’s frequency bias setting is accurately calculated to match its actual frequency response.

The Electric Reliability Council of Texas had requested the interpretation because it said the standard’s requirements appeared to be in conflict because an entity’s compliance with one requirement of that standard could result in its violating another requirement of the same standard under certain circumstances.

According to NERC, however, the requirement allowing the use of a variable bias setting does not conflict with another stating that the frequency bias setting for balancing authorities serving native load should be at least 1% of yearly peak demand. FERC’s May 21 final rule, Order 724, affirmed that assessment.

FERC also followed through on its plan to remand NERC’s interpretation of its “Voltage and Reactive Control” reliability standard (VAR-001-1), which was provided at the request of Dynegey Inc.

NERC had suggested that the voltage and reactive power output schedules that transmission owners provide to generator operators do not have to have a sound technical basis, but FERC disagreed, explaining in the NOPR, and again in Order 724, that all reliability standards “must be designed to achieve a specified reliability goal and must contain technically sound means to achieve this goal.”

RM08-12

A second May 21 final rule, Order 723, approved for the Western Electricity Coordinating Council a regional reliability standard, “Automatic Time Error Correction” (BAL-004-WECC-01), designed to reduce the number of manual time error corrections imposed on the Western Interconnection and minimize accumulated inadvertent interchange energy between balancing authorities.

Specifically, the standard requires balancing authorities that operate synchronously in the Western Interconnection to automatically correct for their contribution to time error so that Interconnection frequency remains within a predefined frequency profile.

When FERC initially proposed to approve the regional reliability standard in November 2008, the agency noted that the standard is more stringent and covers matters not addressed by NERC’s continentwide reliability standards, and that the automatic time error correction procedure appropriately places the responsibility to correct time errors on the balancing authorities that cause them.

In its final rule, the commission approved the regional reliability standard as mandatory and enforceable, for the same reasons set forth in the NOPR. However, FERC also directed the WECC to use its standards development process to clarify certain aspects of two of the standard’s requirements, and to change from “lower” to “medium” the violation risk factors assigned to four of the standard’s requirements.

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NERC, regional entity agree to help Quebec utility regulator develop mandatory reliability standards

by [Marcy Crane](#)

Relying on its experience as the United States’ sole electric reliability organization, the North American Electric Reliability Corp. has agreed, in conjunction with regional reliability entity Northeast Power Coordinating Council Inc., to assist Quebec’s utility regulator, Regie de L’Energie, in developing and implementing mandatory reliability standards applicable to the province’s bulk power system.

The agreement, which was executed May 8 but only recently made public, also calls for the establishment of a compliance monitoring program and procedures for the province.

“We firmly believe that a common set of reliability standards and appropriate enforcement mechanisms are needed across the continent to ensure the reliable generation and delivery of electricity to the nearly 400 million people we serve,” NERC President and CEO Rick Sergel said in a release. “This agreement is a critical step toward achieving these goals.”

Pursuant to the agreement, the provincial regulator retained the services of NERC and the NPCC, which acts as the crossborder regional reliability entity for the Northeastern United States, “as experts in the development of electric power transmission reliability standards.” As such, the agreement requires NERC and the NPCC to use their standards development process to craft standards applicable to Quebec, which will then be submitted to the province’s reliability coordinator for adoption by Regie de L’Energie.

NERC and the NPCC also will develop an appropriate compliance monitoring program, "taking into account Quebec's legal and regulatory environment and in accordance with their applicable compliance monitoring procedures," the agreement said. Once developed, that program will undergo a "consultation with the entities subject to the reliability standards" and, if subsequently approved by the provincial government, will become the subject of a second agreement that will set out how NERC and the NPCC will support the Regie in monitoring and enforcing standards.

Both reliability entities have agreed to provide, at the Regie's request, opinions or recommendations during proceedings related to the standards and associated sanctions, and to supply technical experts to testify at hearings in those proceedings.

The agreement recounted that the legislation establishing the provincial utility regulator specifically authorizes the Regie to enter into such an agreement "with a body that proves it has the expertise to establish or monitor the application of electric power transmission reliability standards." In this case, the agreement noted that the Regie has concluded that NERC has such expertise, having been certified by FERC as the electric reliability organization, or ERO, for the entire United States. Moreover, based on the NPCC's "four decades of international reliability assurance," the agreement said the provincial regulator is convinced that the regional entity has the necessary expertise to address issues that are unique to the region.

According to the agreement, the provinces of Ontario, New Brunswick, Manitoba, British Columbia, Alberta, Saskatchewan and Nova Scotia all have made, or will make, NERC's reliability standards mandatory. A NERC representative said the ERO has formal agreements in place with Canada's National Energy Board and all provinces with Canada-U.S. interties except British Columbia and Alberta, and that each of those agreements "is built on the particular regulatory authority structure of the jurisdiction."

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FERC solicits additional comments on rate recovery aspect of its smart grid policy statement

by [Marcy Crane](#)

Even though the industry recently submitted numerous comments in response to FERC's call for input on its proposed smart grid policy statement (PL09-4), the agency still wants more. This time, however, the commission has asked that the comments specifically address the implications of two recently announced U.S. Department of Energy programs as they relate to FERC's proposed interim rate policy.

On March 19, FERC issued its proposed policy statement and action plan in compliance with Congress' mandate in the Energy Independence and Security Act of 2007 that the commission, in conjunction with other federal and state agencies, modernize the nation's electricity transmission and distribution system. Among other things, the policy statement stressed the importance of developing standards that ensure both the physical and cybersecurity of the smart grid, as well as key "interoperability" standards for smart grid devices.

Of particular importance here, FERC also proposed to adopt an interim rate policy for smart grid investments under which it would accept single-issue rate filings from public utilities seeking

to recover the costs of smart grid projects involving jurisdictional facilities. Pursuant to that policy, entities making investments that will ensure system security, comply with commission-approved reliability standards, have the ability to be upgraded and meet certain other specified criteria would be assured of timely cost recovery and other special rate treatments.

The DOE subsequently announced plans for distributing approximately \$4 billion allotted for its smart grid investment grants and demonstration project programs under the American Recovery and Reinvestment Act of 2009. Specifically, the first program would provide matching grants of up to 50% for investments planned by electric utilities and other entities to deploy smart grid technologies, and the second would fund up to 50% of smart grid demonstration projects. Parties seeking funding under either program would be required to identify the source of non-DOE funds that would be used for their projects and to provide evidence regarding the certainty of those funds.

Meanwhile, numerous parties submitted comments on the proposed policy statement, with many expressing concern regarding FERC's plan to use single-issue ratemaking in lieu of its standard ratemaking procedures for addressing requests for recovery of smart grid expenses.

In its May 19 notice requesting supplemental comments, FERC explained that it needs more input from stakeholders, given that applicants for the DOE programs "might include jurisdictional public utilities that seek rate recovery through FERC-jurisdictional rates for the [non-DOE] portion of funds for transmission-related projects."

Applicants for the DOE's programs must submit commitment letters from third-party backers of their projects, and FERC said it anticipates that public utilities planning to match federal funds with fees assessed to ratepayers "may seek to obtain an order addressing rate recovery from this Commission for charges subject to this Commission's jurisdiction."

Accordingly, FERC asked for supplemental comments "on how it should address requests for rate recovery that may be necessary for public utilities to qualify for awards under these programs." The commission also requested that stakeholders weigh in on whether "some form of conditional approval could be useful" to those utilities, as well as on whether the agency "should adopt processes for public utilities that may apply for funding" under the DOE's smart grid programs.

Supplemental comments are seven days after the notice is published in the Federal Register.

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FERC allows California ISO to delay posting of settlement prices still being verified

by [Glen Boshart](#)

On May 21, FERC conditionally accepted revised tariff sheets (ER09-241) submitted by the California ISO allowing the grid operator to delay posting settlement prices that exceed the applicable price cap or floor until after those prices have been either verified or corrected.

The temporary cap and floor on market prices for energy and ancillary services was established in conjunction with Cal-ISO's launch earlier this year of its new market redesign. Specifically, the

Cal-ISO applies a \$2,500 safety cap to what it actually pays generators and entities providing demand response. That cap kicks in at rare times when prices spike due to local supply or transmission capacity limits.

A similar negative \$2,500 safety floor applies to the amount generators receive when they keep running their units when the ISO does not need their power. Sometimes, generators do not want to back down their units because of equipment limits or upcoming demand requirements and are willing to pay the ISO to get the power reductions needed to balance the system from another generator.

In approving the cap and floor on Jan. 30, FERC directed the grid operator to submit a compliance filing eliminating the price cap and floor 12 months after the market redesign's launch, which took place March 31. The grid operator also was told to meet with its stakeholders to determine the specific procedures it will use to determine when to delay the publication of settlement prices that may be subject to revision under the price cap and floor tariff provisions.

On March 2, the Cal-ISO submitted the requested compliance filings in the form of revised tariff sheets, under which it would delay for up to 48 hours the posting of prices suspected to be incorrect, and include all prices that exceed the price cap and floor in its weekly price-correction reports. The filing also would terminate the price cap and floor provisions on March 31, 2010.

In conditionally accepting the Cal-ISO's proposal, FERC rejected, without prejudice, the grid operator's plan to add six screens for identifying prices that may be subject to revision. FERC found several problems with the proposal, such as that it is overly vague, unsupported, and has the potential to produce unjust and unreasonable results.

COMPANY REFERENCED IN THIS ARTICLE:

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California ISO approves 1st renewable energy transmission line under new financing rules

by [Jeff Stanfield](#)

The California ISO Board of Governors on May 18 approved the first project considered under new rules that allow the ISO to designate a remote renewable energy resource area for transmission service.

The Highwind project consists of about 10 miles of 230-kV transmission lines from the existing Highwind substation to a new substation named Windhub, to be built in the Tehachapi area of Southern California. Under FERC's Location Constrained Resource Interconnection process, the ISO is allowed to approve a transmission project to access remotely located wind, solar, geothermal or other renewable areas. The process sets up a cost recovery and project approval mechanism that the ISO said breaks the "chicken-or-egg" dilemma so that the first renewable energy developers do not have to pay most of the costs of building a transmission line that other, later developers would use.

"The remote areas in California with the most potential for wind, solar and geothermal resources often do not have the transmission infrastructure in place to get the green power on the grid," ISO board Chairman Mason Willrich said in a news release. "The ISO proposed and FERC approved a new mechanism that paves the way for easier

financing and development of needed renewable power projects. Smaller developers no longer bear the brunt of the upfront costs of investing in the transmission lines. This is a big step in meeting California's renewable energy goals."

In order to avoid the "you go first" issue, participating transmission owners will provide up-front financing to construct a radial transmission "trunk" line for connecting remote wind farms. The connected generators will then reimburse the cost of the trunk line based on their pro rata share of the facility, according to an ISO staff presentation to the board. There are three separately owned generation projects with 759 MW of total capacity in the ISO interconnection queue located in the Tehachapi resources area that would be connected to Highwind, according to a staff memo to the board.

Southern California Edison Co. will be directed to proceed with necessary permitting and engineering of the transmission line project. When the tariff requirements for commercial interest in Highwind have been met, the project will be eligible for final approval by ISO management, and the Edison International subsidiary can proceed with construction, according to a memo to the board recommending approval.

On April 19, 2007, FERC granted the ISO's petition to file tariff language for implementing this financing initiative. FERC agreed that the Tehachapi resource area was an example of an area where insufficient interconnection capacity appeared to be preventing the development of resources. The Tehachapi region has been identified as the largest wind resource in California, with the potential for about 4,500 MW of installed capacity.

Under the ISO's tariff, it is up to a state agency such as the California Public Utilities Commission or California Energy Commission to designate "energy resources areas" in the state. Until one of those agencies can make that designation, the ISO can do so on an interim basis, which is what it did for the Tehachapi region.

The Highwind project, at an estimated cost of \$46.1 million, would not ordinarily need board approval, as it is under the ISO's \$50 million threshold. The interim approval process, however, requires board designation as a renewable area.

The ISO board's designation allows SoCalEd to proceed with permitting and engineering for the Highwind line.

COMPANIES REFERENCED IN THIS ARTICLE:

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Maine utility: Statewide grid operator may be feasible alternative to ISO New England

by [Corina Rivera](#)

Under certain conditions, a statewide transmission grid operator is a feasible alternative to Maine's continued participation in ISO New England Inc., according to a new report prepared for the state's largest electric utility.

The report, "Assessment of a Maine ISA Structure as a Possible Alternative to ISO-NE Participation," was prepared for Iberdrola SA unit Central Maine Power Co. and the Industrial Energy Consumer Group by consulting firm The Brattle Group in coordination with the Northern Maine Independent System Administrator. It was sent to the Maine Public Utilities Commission on May 13.

State legislators had requested that the PUC prepare a preliminary design of an alternative to continued participation in ISO New England and had urged the commission to order Central Maine Power and Emera Inc. subsidiary Bangor Hydro-Electric Co. to fund the work. Central Maine Power and the Industrial Energy Consumer Group subsequently agreed to pay for a study to assess a Maine-based alternative to continued participation in ISO New England based on a Maine-only regional transmission operator.

According to the report, assuming cooperation from the New Brunswick government and the New Brunswick System Operator, a Maine-only independent system administrator is a feasible alternative to Maine's continued participation in ISO New England and would have some advantages over the status quo.

Among those advantages would be a stakeholder board with Maine's interests, in areas such as system planning, cost allocation and market design, as its priority, the report said.

The Maine ISA would be based on a combination of features from the Northern Maine Independent System Administrator, which manages the grid for Maine & Maritimes Corp. subsidiary Maine Public Service Co., and the New Brunswick System Operator, which manages the grid in the Canadian province of New Brunswick.

However, the report added, implementation of a Maine ISA would expose ratepayers to several risks and, from a total retail electricity rate perspective, may not yield significant savings. A more detailed cost-benefit analysis is required to determine the magnitude of any long-term savings. Savings in ISO New England administrative costs would not likely amount to more than 0.25% of current retail rates for residential customers, but a detailed cost-benefit analysis would be required to confirm that estimate, the report said.

The report also noted that the Maine ISA option may not lead to lower transmission costs given the significant cost of planned transmission investments in Maine. For instance, unless roughly 45% of Bangor Hydro's and Central Maine Power's combined transmission costs — including CMP's \$1.5 billion Maine Power Reliability Project — could be allocated to ISO New England and others under the Maine ISA alternative, customers in the "Rest of Maine" service area would pay higher transmission charges under the Maine ISA option than under continued ISO New England participation.

Alternative believed to be able to pass FERC review

While the Maine ISA may not satisfy FERC standards for independent transmission system operators or RTOs, the fact that FERC does not mandate ISO/RTO participation and that the agency has approved the current Northern Maine Independent System Administrator structure suggests that a Maine ISA organizational structure can be designed to satisfy FERC requirements, the report concluded.

The report further noted that while transmission owners would have operational control over their transmission facilities, the Maine ISA would administer the tariff and provide transmission access, administration, information and reliability planning-related functions on a nondiscriminatory basis. The Maine ISA and Maine transmission owners would jointly constitute the Maine Transmission Operator, which would provide transmission reservations and scheduling functions, including implementation of transmission curtailments.

The Maine ISA's market functions would be structured based on the Northern Maine Independent System Administrator and the

New Brunswick System Operator market design to support a bilateral market model under which market participants would submit balanced day-ahead schedules that can be revised up to 30 minutes before delivery.

Market-based costs for energy and capacity in Maine could decrease, at least in the near term, as the Maine ISA alternative could increase transaction costs for exports to ISO New England. For example, the report continued, transmission through-and-out charges, if implemented and acceptable to FERC, and other seams issues created by the difference in market designs between Maine and southern New England would make exporting energy and capacity more expensive, thereby lowering market prices in Maine. However, the potential reduction in market prices would at least in part be offset by less efficient market operations and less competition. Even if market prices were reduced in the near term, the report added, such a reduction in market prices could be short-lived because of increased generation retirements and less generation investment, particularly lower levels of renewable generation investments.

The report said the creation of a Maine-New Brunswick market area would likely make wind development in Maine more challenging, as Maine has a goal of being a center of wind energy development in New England and more than 1,300 MW in Maine are already in the ISO New England transmission interconnection queue. However, the combined peak load for Maine and New Brunswick is only about 5,200 MW, meaning it may be difficult to integrate more than 1,000 MW of wind resources in the combined Maine-New Brunswick footprint.

ISO New England spokeswoman Erin O'Brien said May 18: "This report comes as part of Maine's ongoing examination of its options to participation in ISO New England. We respect the state's needs to evaluate its future course, and in our view, a logical and mutually beneficial relationship exists between Maine and the rest of the New England states as well as ISO New England."

Central Maine Power corporate spokesman John Carroll said May 18 that the report will be considered in the context of the PUC's proceeding, Docket No. 2008-156.

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FERC makes minor modifications to reporting requirements

by [Glen Boshart](#)

FERC on May 21 issued a final rule (RM07-21) addressing the discrete issue of the new reporting requirements that will apply to the transfer of outstanding voting securities to "any person" other than a holding company.

The reporting requirements are tied to another FERC final rule, Order 708, that established five limited blanket authorizations aimed at facilitating investment in the power industry, including one that permits a utility to dispose of less than 10% of its voting securities to a public utility holding company if the holding company and any associate company together would still own less than 10% of that utility.

In Order 708-A, FERC extended this blanket authorization beyond holding companies to permit a utility to transfer voting shares to "any person," subject to the same 10% aggregate limitation imposed

on holding companies. While the transfer of less than 10% of a utility's shares generally will not result in a change of control of the utility, FERC acknowledged that in some cases it might. The agency therefore said it would adopt a reporting requirement for entities that transact under this blanket authorization.

The instant final rule, Order 708-B, adopts such reporting requirements, which reflect those proposed by the Financial Institutions Energy Group. Specifically, FERC will require utilities using the blanket authorization to file a report with the commission listing certain details of the transaction, as well as a statement on cross-subsidization.

A separate May 21 order (AD09-7) clarified the reporting requirements for utilities that have received waivers of Order 889's requirement that certain types of information regarding their transmission operations be posted on an open access same-time information system, or of related standard of conduct requirements.

"It has come to the Commission's attention that some utilities may continue to rely on these waivers even after they no longer qualify for them," FERC stated in the instant order.

Accordingly, the commission clarified that such reliance is inappropriate if a material change has taken place in the underlying facts on which the waiver was granted, and stated that it must be notified within 30 days after such a change has occurred.

FERC explained that a "material change" includes situations in which a utility no longer meets the sales threshold applied to determine eligibility for the waiver, or the facilities owned or controlled by the utility are no longer "limited and discrete."

Because the reporting requirement is new, FERC gave any utility that had already been granted a waiver 45 days to notify the commission of any change in material facts upon which the commission relied in granting that waiver.

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House energy committee passes landmark cap-and-trade bill to combat global warming

by [Kathleen Hart](#)

By a vote of 33-25, the House Energy and Commerce Committee on the evening of May 21 approved a bill that would for the first time set a national renewable electricity standard and place a mandatory cap on carbon dioxide emissions from U.S. power plants.

"We're taking a decisive and historic action to promote America's energy security" and create millions of clean energy jobs, Rep. Henry Waxman, D-Calif., chairman of the committee and chief sponsor of H.R. 2454, the American Clean Energy and Security Act, said prior to the final vote. He noted that the legislation has gained substantial support from more than 60 major companies and organizations, including utilities, the Edison Electric Institute, the Environmental Defense Fund and the Sierra Club, as well as from many U.S. labor unions.

"This is an important bill, maybe one of the most important bills that we will consider in this Congress," Waxman said.

The legislation calls for reducing U.S. emissions of CO2 and other greenhouse gases by 17% in 2020 compared to 2005 levels, by 42% in 2030 and by 83% in 2050. The bill also establishes a national

renewable electricity standard requiring that by 2020 electric utilities obtain 15% of their electricity from renewable energy sources and to demonstrate annual electricity savings of 5% from energy efficiency measures. If the governor of a state determines that local utilities cannot meet the 15% renewable requirement, the governor may reduce the renewable requirement to 12% and increase the efficiency requirement to 8%.

Four of the 36 Democrats on the committee voted against the bill: Reps. John Barrow of Georgia, Jim Matheson of Utah, Charlie Melancon of Louisiana and Mike Ross of Arkansas. Of 23 Republicans on the committee, Rep. Mary Bono Mack of California cast the only vote in favor of the legislation.

Waxman committed to holding further committee hearings on portions of the bill dealing with the allocation of carbon emissions allowances. He also said he wants to work with members of the committee to craft a transmission siting provision for the bill.

After other House committees, including the Ways and Means Committee and the Agriculture Committee, consider the bill, it will move to the House floor for a vote, Waxman said. The Democratic leadership plans to bring the bill to the floor by the end of summer. While passage in the House is not assured, many analysts believe that the climate change legislation has a better chance of gaining approval in the House than in the Senate. The likelihood of a cap-and-trade bill passing this year in the Senate, where 60 votes are needed to prevent a Republican filibuster, appears slim at the moment.

Throughout more than 37 hours of debate over the course of four days, the committee considered 94 amendments, 38 from Democrats and 56 from Republicans. "I believe the amendments have improved the bill," Waxman said. Democrats defeated numerous amendments offered by Republicans designed to place "off-ramps" on the cap-and-trade title of the bill in the event that electricity or gasoline prices rise too high or the United States loses too many manufacturing jobs.

Rep. George Radanovich, R-Calif., proposed an amendment calling for the cap-and-trade title, Title III, to cease to be effective if the average retail price of electricity in the residential sector increases by more than 100% above 2009 levels. An amendment offered by Rep. John Shimkus, R-Ill., called for Title III to cease to have force if two or more coal mines close as a result of implementation of the cap-and-trade provision. An amendment offered by Rep. Lee Terry, R-Neb., would have rolled back the law if the average U.S. retail price of gasoline rose above \$5 per gallon as a result of implementation of the act. Democrats defeated the three amendments.

"We've had this discussion over and over again," Rep. Edward Markey, D-Mass., chairman of the committee's Subcommittee on Energy and Environment and co-sponsor of H.R. 2454, said during the debate on one of the Republican off-ramp amendments on May 21. Markey pressed the Democratic position that the legislation is going to create new green jobs and that off-ramps would destroy the confidence that investors will need to have in the long-term stability of a cap-and-trade system.

Despite the stark division between committee Democrats and Republicans over the merits of imposing a cap-and-trade system on the nation's carbon-emitting industries to combat global warming, members of both parties praised Waxman for the way he conducted the markup, by allowing a fair amount of time for amendments to be offered and debated.

There were moments of levity during the final day of the markup, as well. Democrats had hired a speed-reader in case committee Republicans had asked for the final version of the bill, which totals

more than 900 pages, to be read aloud. Republicans did not ask for the bill to be read, so his services were not needed. However, Rep. Joe Barton, R-Texas, ranking member of the committee, asked for the speed-reader, who identified himself as Douglas Wilder, to read the first pages of an amendment aloud, just to hear what the young man would sound like. The committee room erupted into applause and laughter as the speed-reader rattled off the material at the rapid-fire pace of a seasoned auctioneer.

Solar industry applauds committee action on bill

Solar Energy Industries Association President and CEO Rhone Resch said that in passing the bill, the House “took a major step forward today in cutting pollution while putting our economy back on track, thanks to the leadership and persistence of Chairman Waxman, Ranking Member Barton, Sub-Committee Chairman Markey and Ranking Member [Fred] Upton [of Michigan]. This bill will invest in clean energy for the future, while creating jobs and fueling investment in the solar industry.”

American Gas Association Executive Vice President Rick Shelby said the AGA looks forward to working with Congress as it considers climate change legislation aimed at improving the nation’s environment and energy security, while encouraging the increased use of domestic natural gas. “As the cleanest fossil fuel, emitting only one carbon atom when burned, natural gas can play a major part in quickly reducing carbon emissions,” Shelby said.

The U.S. Climate Action Partnership also congratulated Waxman and Markey on approving the bill. The group said the vote “demonstrates the urgency we face in addressing global climate change and our ability to do so in a way that protects the environment while safeguarding our economy.”

However, a coalition of environmental, consumer and community advocacy groups, including Greenpeace USA, Friends of the Earth, Public Citizen, the Center for Biological Diversity and Citizens Action Coalition of Indiana, released a statement opposing the bill. “While a week of debate failed to adequately strengthen protections for consumers, communities, and the climate in this bill, it erased all doubt of who will benefit most from it: Big Business,” the coalition said. “The resulting bill reflects the triumph of politics over science, and the triumph of industry influence over the public interest.”

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Point Carbon: Allowances to merchant coal units could level field with gas

by [Wayne Barber](#)

The Waxman-Markey climate change bill will distribute between 200 million and 260 million tons of free allowances annually to merchant coal generators over the first 15 years of the program, which could level the playing field between coal and gas “rather than letting the price of carbon incentivize the use of lower-emitting natural gas,” carbon market analyst Point Carbon said May 22.

Late May 21, the House Energy and Commerce Committee approved a bill that would for the first time set a national renewable electricity standard and place a mandatory cap on carbon dioxide emissions from power plants.

Point Carbon said the free allowances would be worth a total of \$61 billion between 2012 and 2030, covering one-third of merchant coal generators’ compliance costs.

Coal generators located where natural gas is on the margin would break even under that setup, while generators in regions where coal

and natural gas alternate as the marginal fuel would make a profit of \$4 per MWh to \$5 per MWh.

The bill defines a merchant coal generator as a covered entity deriving at least 85% of its heat input from coal or petroleum coke. Federal- or state-owned facilities are excluded, as are electricity sales for which retail rates are directly regulated by public utility commissions, electricity cooperatives or other state agencies. Under U.S. Energy Information Administration definitions, which break down generation into utilities and independent power producers, the portion of coal generation that can be considered “merchant” represents a quarter of total U.S. coal-fired power generation, Point Carbon said.

Almost all coal generation is merchant in restructured electricity markets, such as California, New England and the mid-Atlantic region.

EIA data indicate that annual emissions of merchant coal units entitled to allowances under the proposal are roughly 500 million tons, or one-fourth of all coal emissions. While some bill summaries indicate a flat 5% of total U.S. allowances will go to merchant coal units, Point Carbon said the actual bill text uses a more complex formula.

The formula, Point Carbon said, initially covers exactly half of the emissions from merchant coal generators in 2012, decreasing to zero through 2030. The rate of decrease parallels that of the allocation to local power distribution companies, relatively 2016 to 2025, and then decreases rapidly over five years to reach zero after 2030.

The measure is designed to allow coal generators to break even relative to power producers using less-emitting fuels. Pulverized coal plants tend to emit about twice as much CO₂ as combined-cycle gas plants, so coal plants would be at a disadvantage in regions that have natural gas as the so-called “marginal fuel,” meaning where electricity from natural gas-fired plants sets the price of all power on the market, Point Carbon said.

A typical coal plant in the PJM Interconnection LLC market, for example, would incur a carbon cost of \$12.22 per MWh, reflecting the fact that each megawatt-hour generated emits a metric ton of CO₂ (assuming \$13/ton carbon price). Exactly half of that would be returned via the free allocation to merchant coal generators during the first year of the program. “The average marginal rate of 0.83t/MWh translates into a wholesale power price impact of \$10.79/MWh, more than offsetting the cost of carbon for a net profit of \$4.68/MWh,” Point Carbon said.

The question of whether coal plants will break even will vary by region, Point Carbon said.

Merchant coal units in the regions with natural gas on the margin will break even under the proposed allocation. Those in areas where coal is more frequently on the margin are likely to earn a profit in the early years.

“There are, however, two caveats to the simple conclusion that merchant coal generators are set to earn windfall profits from this free allocation,” Point Carbon said. The first is that the role of coal as a marginal fuel is likely to decrease over time as new electricity demand is increasingly met by new natural gas-fired generation. The second is that natural gas generators will also likely see windfall profits in the regions with mixed marginal fuels.

Point Carbon also noted that the Waxman-Markey bill requires FERC and the U.S. Environmental Protection Agency to complete a study by 2014 to determine whether the merchant coal provision leads to windfall profits in the industry, or between regions.

“The only true winners in the program are power plants that use non-emitting fuels: Hydro, nuclear and renewable energy producers

will benefit fully from the power price increase without incurring any compliance costs," Point Carbon concluded.

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Senate panel considers further energy bill amendments; House bill requires FERC consumer advocate

by [Glen Boshart](#)

While the House Energy and Commerce Committee made major news recently by passing the first bill ever to establish a national renewable electricity standard and place mandatory caps on carbon dioxide emissions, the Senate Energy and Natural Resources Committee has quietly been making progress on its own energy bill.

Having voted May 14 on amendments to an electric transmission title, the Senate panel on May 19 began considering amendments to additional draft measures that will be combined into a comprehensive energy bill to be voted on by the committee sometime in June. However, Republicans and Democrats continue to be at odds over key provisions of the bill, and those battles are expected to continue as a final bill winds its way through the approval process.

One such disagreement is over a mandatory renewable portfolio standard title. A draft of the measure would require major utilities to obtain 3% of their electricity from renewable energy resources or from energy efficiency improvements beginning in 2011, with that figure rising to 15% in 2021. Sen. Jeff Sessions, R-Ala., introduced an amendment to kill the title altogether, but on May 21 the committee voted 9-13 against the proposal. Approximately 50 other amendments to the standard have also been introduced, and the committee will have to deal with those amendments when it resumes marking up the bill in June after its members return from their Memorial Day recess.

The committee also considered a number of proposed changes to a cybersecurity title that would give FERC and the U.S. Department of Energy more emergency authority to deal with cybersecurity threats to the nation's power grid. The committee voted to add amendments to that title directing FERC and DOE to consult with utilities and other stakeholders before issuing emergency directives, and ensure that stakeholders receive all the information needed to comply with federal directives on cybersecurity.

Additional amendments approved by the Senate committee include one directing FERC to establish a cost recovery mechanism for compliance with DOE emergency orders. The amendment requires the expiration of emergency FERC rules on cybersecurity once stakeholder-developed standards are implemented, and aims to ensure that the remote regions of Alaska, Hawaii and Guam work with the U.S. Defense Department in developing emergency cyberdefense plans for department installations.

The Senate panel also rejected an amendment, proposed by Ranking Member Lisa Murkowski, R-Alaska, to a measure drafted by Chairman Jeff Bingaman, D-N.M. Under Bingaman's proposal, a blue ribbon committee would be convened to study what should be done with the spent nuclear waste that has been piling up at utility sites around the country now that the Obama administration has moved to cut funding for a planned storage facility at Yucca Mountain, Nev.

"I'm concerned that the proposed blue ribbon commission on its own will not move quickly enough and is too narrowly focused," Murkowski said in introducing her amendment. Murkowski therefore

proposed to require the creation of a nuclear advisory council within DOE, and to establish an inter-agency working group to coordinate federal programs promoting nuclear energy. The amendment also would have given the secretary of energy authority to enter into cost-sharing agreements with private industry and provide benefit payments to local and state governments for hosting spent nuclear fuel storage facilities.

The amendment failed on an 11-11 vote, however, with Sen. Mary Landrieu, D-La., and all 10 Republicans on the committee voting in favor of the proposal. Sen. Blanche Lincoln, D-Ark., did not vote on the amendment.

House panel requires consumer advocate at FERC

Meanwhile, buried deep within the House's 932-page landmark carbon emissions cap-and-trade bill, the American Clean Energy and Security Act of 2009, H.R. 2454, is a requirement that a new office of consumer advocacy be created within FERC.

The provision, introduced as an amendment to the bill by Rep. Jan Schakowsky, D-Ill., would require the new FERC office to act as an "advocate for the public interest." A director of the office would be appointed by the president, subject to Senate confirmation.

The new office would be charged with representing consumers in rate and other proceedings before FERC, as well as before the courts and other federal regulatory agencies and commissions. In addition, the office would "monitor and review" energy customer complaints and grievances on matters concerning rates or service provided by public utilities and natural gas companies under FERC's jurisdiction. Another duty for the new office would be to investigate the services provided or rates charged by such companies.

The amendment also says the director of the new office would appoint a five-member advisory committee, to be made up of four state utility consumer advocates and an "individual, from a nongovernmental organization, representing consumers."

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NREL report: Impact of RES bills minimal on prices; Bingaman's bill falls short compared to others

by [Jennifer Zajac](#)

A May 2009 report by the National Renewable Energy Laboratory that analyzes the three renewable energy standard draft bills concluded that none of the bills will have a significant impact on consumer electricity prices at the national level and each bill aims to avoid preempting or interfering with existing state RES mandates that meet or exceed the federal requirement.

The 30-page report, commissioned by the U.S. Department of Energy, focuses on draft bills introduced individually by Senate Energy and Natural Resources Committee Chairman Jeff Bingaman, D-N.M., and House Subcommittee on Energy and Environment Chairman Edward Markey, D-Mass., and a joint bill by Markey and House Energy and Commerce Committee Chairman Henry Waxman, D-Calif.

Bingaman's bill did not fare as well as the others in terms of raising renewable capacity and reducing emissions, according to the report.

To assess the potential impacts of the proposed standards on the U.S. electricity sector, NREL used a least-cost optimization model

capable of simulating the special attributes of variable sources such as wind and solar power. The proposals were compared against a baseline in which only currently enacted laws are considered. Using its Regional Energy Deployment System model, NREL evaluated the impacts of the proposed RES requirements on the U.S. energy sector in four scenarios:

- A base case in which only currently enacted legislation is simulated.
- A 20% by 2021 RES target, with 25% of the RES assumed to be met with qualifying energy efficiency projects, which is the Bingaman bill.
- A 25% by 2025 RES target, with no energy efficiency substitutions allowed, under Markey's proposal.
- A 25% by 2025 RES target, with 20% of the RES assumed to be met by efficiency, and a cumulative 15% reduction in load by 2020, under the Waxman-Markey bill.

The costs calculated in the Waxman-Markey bill are significantly less than the base case, although the costs involved in implementing energy efficiency projects were not factored into the equation. More states see a decline in calculated electricity prices than an increase in the Markey bill, and no state sees an increase of more than 5% compared to the base case in 2022, the year of peak impact on prices, according to NREL.

Overall, Bingaman's legislation has an RES requirement of 20% in 2021, but the effective renewable energy requirement is only 12.1% of total U.S. retail sales in that year, according to NREL, due to the small-utility exemption and the assumption that 25% of the target is met by using the energy efficiency compliance option. As for the Markey and Waxman-Markey bills, the effective renewable requirements are about 22% and 17%, respectively, of total retail sales in 2025.

The analysis also indicated that the current versions of the Markey and Waxman-Markey legislation may address renewable energy certificate market design issues more clearly than the Bingaman draft. In addition, estimated national REC prices peak in 2022 in the Waxman-Markey legislation at less than \$25/MWh, while they reach about \$15/MWh in the Markey case.

In terms of adding renewable capacity, qualifying renewable energy capacity reaches approximately 208 GW in 2030 in NREL's base case scenario. In comparison, the Bingaman bill results in 197 GW and the joint bill reaches only 183 GW. The Markey bill comes out on top with an estimated 261 GW in 2030.

Bingaman's bill also came in third when looking at emissions reductions, resulting in an estimated 95 million metric ton annual reduction in carbon dioxide emissions in 2030, according to the report. The Markey legislation saves an estimated 150 MMT per year in 2030, exclusively from expanded renewable energy use. The joint Waxman-Markey proposal reduces annual carbon dioxide emissions in 2030 by 435 MMT.

The results assume that the required transmission capacity is built, and NREL noted that its analysis would differ if transmission projects were delayed. The report also said that Western states would exceed their RES requirements based on renewable energy deliveries due to the abundance of wind and solar in that region, whereas states in the Southeast generally rely on biomass co-firing and purchasing RECs.

"This is the first credible and objective comparison of the proposed national renewable portfolio standards," Douglas Arent, director of NREL's Strategic Energy Analysis and Applications Center, said in a May 18 news release.

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EIA: Energy CO2 emissions declined in '08

by [Jay Hodgkins](#)

Carbon dioxide emissions from U.S. energy sources fell 2.8% in 2008 to 5.80 billion tons of CO2 from 5.97 billion tons of CO2 in 2007, the U.S. Energy Information Administration said in a May report.

The EIA attributed the emissions drop to all-time high energy prices for most of the year and the U.S. economic downturn that swiftly worsened toward the end of the year.

Energy consumption dropped 2.2%, petroleum-related emissions declined 6%, natural gas-related emissions increased 1% and coal-related emissions fell 1.1%, the EIA said.

Focusing solely on the electric power sector, CO2 emissions decreased 50 million tons, or 2.1%, while energy generated only fell 1%, the agency said. Natural gas-related emissions in the power sector fell 2.6%, compared to a 1.3% drop in coal-fired power emissions and a 28.1% drop in petroleum-fired power emissions.

Non-carbon-emitting generation use rose 1.7% to 28.5% of the total U.S. share of generation in 2008, the EIA said.

With cleaner energy options in the power and other energy sectors, the EIA said the CO2 intensity in the United States fell in 2008 as energy-related CO2 per unit of GDP fell 3.8% from 2007, and the CO2 intensity of the energy supply fell 0.6%.

The EIA's new raw numbers on U.S. CO2 emissions in 2008 come at roughly the same time the House Energy and Commerce Committee approved a landmark bill proposed by Reps. Henry Waxman, D-Calif., and Ed Markey, D-Mass., that would set up a mandatory federal cap-and-trade system to reduce CO2 emissions.

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Duke Energy claims victory in split decision over Midwest power plant upgrades

by [Wayne Barber](#)

Duke Energy Corp. said May 20 that a federal district court in Indiana ruled in favor of the company on four of six proceedings in a lawsuit filed by the federal government nearly a decade ago.

A jury in the U.S. District Court for the Southern District of Indiana on May 19 ruled against Duke in two other proceedings, the company said.

The legal proceeding dates back to 1999, when the U.S. Environmental Protection Agency and the U.S. Department of Justice filed enforcement actions against a number of U.S. utilities, saying they were in violation of the New Source Review provisions of the Clean Air Act by upgrading power plants without also installing updated pollution controls.

Among the utilities hit with the complaints was Cinergy Corp., which was acquired by Duke in 2006. The federal government alleged that upgrades done at power plants in Indiana and Ohio did not qualify as routine maintenance, and Cinergy should have predicted the upgrades would increase emissions from the plants.

The district court jury found in favor of the company for three projects at its Gibson plant near Princeton, Ind., its Walter C. Beckjord plant in New Richmond, Ohio, and one project at its R. Gallagher station in New Albany, Ind. The jury ruled against two other Gallagher projects.

The next step is a “remedy” phase of the trial at which U.S. District Judge Larry McKinney will decide what steps Duke should take at Gallagher, said Duke spokeswoman Angeline Protogere. “We also will have the option at that time to appeal both the jury verdict and the remedy decision,” she said.

Duke Energy Chief Legal Officer Marc Manly said in a news release: “We are pleased that after nearly 10 years of litigation, the company’s position has been vindicated on the vast majority of the projects about which the government originally complained.”

Between 1998 and 2010, Duke Energy will have invested nearly \$5 billion across its five-state service area to substantially reduce emissions of sulfur dioxide, nitrogen oxide and other pollutants from its coal plants, Manly said. The net result of these investments will be a reduction of SO₂ and NO_x by approximately 70%.

The case number is Civil Action No. 1:99-cv-1693-LJM-JMS.

In April 2007, the U.S. Supreme Court ruled against Duke Energy on the hourly emissions test at several Duke plants in North Carolina and South Carolina. That case was remanded back to a federal district court in North Carolina.

COMPANY REFERENCED IN THIS ARTICLE:

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Economists launch climate change policy Web site with state emissions report

by [Kerry Bleskan](#)

A group of economists has launched a Web site to support efforts to pass climate change policies and dispute what they call “junk economics.”

“Junk economics has replaced junk science as the cause of inaction on climate change issues,” said the news release from RealClimateEconomics.org, organized by the E3 Network and funded by Ecotrust, a Portland, Ore.-based think tank. “Some claim that it is too expensive to take more than token action on key initiatives.”

The site was launched with the release of a report that analyzes state-by-state per capita greenhouse gas emissions. The report, “Greenhouse Gases and the American Lifestyle: Understanding Interstate Differences in Emissions,” concludes that some, though not all, factors leading to high per-person emissions can be changed at reasonable costs. The lowest-emitting states “all provide a U.S. lifestyle with European levels of greenhouse gas emissions,” authors said.

They analyzed U.S. Energy Information Administration data on electricity generation, electric consumption by sector, average electricity price by kilowatt-hour and the share of electricity generated by coal. They factored out electricity produced for export and assumed electric imports all have the same emissions intensity. They then factored out commercial activity, reasoning that goods produced in one state could be used in all 50. That leaves transportation and residential carbon emissions.

“These are the emissions for which each state’s residents bear the most direct responsibility,” authors said.

The results are about what one could expect to see: States that use less coal for power generation and have households that use

less electricity altogether have lower emissions profiles. With respect to energy, several states tied for the lowest-emitting titles: Vermont ranked first, New York and Oregon ranked second and California, Rhode Island and Washington tied for third. All six get less than 30% of their power from coal. Several of them rely heavily on nuclear and hydroelectric power. That is the case in Vermont, where homes are often heated with nonelectric sources; the state had a strikingly low residential electricity emissions rate of .02 metric tons of CO₂ per person, compared to the national average of 3 tons and North Dakota’s 6.48 tons.

Other high-emitting states are Alaska, Wyoming, Louisiana and coal-heavy Indiana, Kentucky and West Virginia. A graph with residential electric emissions on one axis and consumption on the other shows that the measures generally track together but there are some outliers. South Carolina households use more electricity than anybody else except Florida, but per capita emissions are just under the national average. New Mexico residential customers are the fifth-most efficient users but emissions are greater than the national average.

Though climate is an important factor in electricity use, researchers noted that all six of the lowest-emitting states have “heating degree days,” a measure of how often and by how much the temperature dips below a comfortable temperature, that are higher than the national average. “Cold climates are an obstacle to lowering greenhouse gas emissions, but they need not be an insurmountable one,” the report said. Of factors “more readily addressed by climate and energy policies,” authors recommend focusing on increasing energy efficiency measures and decreasing reliance on coal power. They dismissed the idea of paying high-emissions states to offset the costs of complying with carbon regulation, saying it would eliminate the incentives that are the basis of market-based reduction programs.

The report also addressed transportation emissions and related policy questions. Researchers said they intentionally did not include information on greenhouse gases other than carbon, nor did they consider the effects of natural carbon sequestration.

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Initial Burger CO₂ storage test a disappointment, but yields important lessons

by [Barry Cassell](#)

The Midwest Regional Carbon Sequestration Partnership has generally seen disappointing results so far, but there is some cause for optimism based on a field test related to possible CO₂ capture and storage at FirstEnergy Corp.’s R.E. Burger coal-fired plant in Ohio.

The Midwest partnership is one of seven regional partnerships created by the U.S. Department of Energy to advance carbon capture and storage technologies. It has completed a preliminary geologic characterization and sequestration field test at Burger. “The project provided significant geologic understanding and ‘lessons learned’ from a region of the Appalachian Basin with few existing deep well penetrations for geologic characterization,” DOE said in a May 20 announcement.

The initial targets for the geologic storage of CO₂ at the site were the Oriskany and Clinton sandstones at depths between 5,500 and 8,000 feet in the Appalachian Basin. The region is geologically

complex, and little is known about the formations, especially in the western portion of the basin, DOE said. Since the nearest well penetrations are more than 20 miles from the Burger injection well, any data collected from the region is useful in determining the suitability of potential field test locations for CO₂ storage in the future.

Test results indicated that the porosity, void space and permeability of the target formations were lower than expected, DOE said. The pressure in the formations also rose unexpectedly with very low injection rates. "This does not mean that the entire western flank of the Appalachian Basin will show these same rock properties; instead, it confirms the complex nature of the formations within the basin," DOE said. "The work demonstrates the importance of extensive drilling, formation evaluation, and testing to characterize and identify appropriate formations for CO₂ storage within the Appalachian Basin prior to injection."

Although the Burger site was determined not to be the optimal location for CO₂ storage from a geologic perspective, it was an excellent place to drill and test because of the cooperation provided by FirstEnergy and the potential to co-locate the storage site with the plant, DOE said. "Data derived from rock property models and characterization information suggested that the site would have good geologic storage potential; however, the pressures necessary to inject CO₂ into the target formations proved to be much higher than anticipated. Additional testing methods must be developed to provide more information about the character of geologic formations chosen for injection testing." DOE said power plants in the Appalachian region may eventually need to transport CO₂ relatively short distances to areas that have adequate storage formation characteristics.

Because of the geologic complexity of the region, DOE said a robust wire line logging, imaging and testing program should be designed and implemented at every potential geologic storage site considered in the region. "Stakeholder understanding of the type of data collected from the various logging and testing tools and its interpretation will benefit future siting decisions," DOE said. "This evaluation plan will decrease overall costs at future field test sites. If economically feasible, drilling a pilot hole prior to drilling the injection hole would be ideal to develop a robust logging, coring, and testing program."

As part of the project design process, project developers should request the ability to hydro-fracture the formation to create fractures that extend from a borehole into the targeted formation, DOE said. That could provide a better injection rate into rocks that have moderate porosity and low effective permeability.

Project developers also should consider plans to complete the well at the target formation, DOE added. "Given the low permeability and porosity that exist at some areas in the Appalachian Basin, care should be taken so that well drilling and construction operations do not reduce or eliminate the effective permeability that is naturally present."

DOE said it will continue to collect pertinent geologic information as part of its characterization phase in the Appalachian and other basins. Drilling wells into proposed injection zones, performing formation evaluations to understand their rock properties and testing injection capability within the zones are all necessary to develop a clear understanding of the overall potential of geologic formations to store CO₂.

The Midwest Regional Carbon Sequestration Partnership is managed by the Battelle Memorial Institute, headquartered in Columbus, Ohio. The characterization and test were sponsored by the DOE Office of Fossil Energy's National Energy Technology Laboratory, with support from FirstEnergy, Praxair Inc. and the Ohio Geological Survey.

FirstEnergy on April 1 announced that it plans to convert two coal-fired units at Burger to burn biomass as part of a greenhouse gas reduction and renewable energy initiative.

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Southern to demonstrate CCS technology at Barry plant in Alabama

by [Barry Cassell](#)

Southern Co., one of the biggest coal-fired generators in the United States, announced on May 21 plans to demonstrate carbon capture and sequestration at its Barry coal-fired power plant in Alabama to support the development of technologies for reducing greenhouse gas emissions.

Along with the U.S. Department of Energy, Mitsubishi Heavy Industries Ltd., the Electric Power Research Institute and other partners, Southern will build a demonstration facility to capture CO₂ emissions from an existing unit at Barry. Beginning in 2011, between 100,000 and 150,000 tons of CO₂ per year — the equivalent of emissions from 25 MW of the plant's generating capacity — will be captured for permanent underground storage in a deep saline geologic formation.

The CO₂ will be supplied to DOE's Southeast Regional Carbon Sequestration Partnership, which will transport it by pipeline from the plant and store it underground at a site within the area of the Citronelle Oil Field, about 10 miles from the plant, which is operated by Denbury Resources Inc. The Southern States Energy Board is leading the SECARB effort.

"This project will help increase our knowledge of carbon capture and sequestration, technology we must demonstrate at a commercial level in the effort to reliably generate electricity using coal with reduced greenhouse gas emissions," Southern Co. Chairman, President and CEO David Ratcliffe said. "The main challenge facing deployment of carbon capture and sequestration technology is demonstrating its effectiveness at a large scale. Our involvement in this and other related projects is part of our commitment to be a leader in finding solutions that make technological, economic and environmental sense."

The CO₂ capture technology to be used in the project, called KM-CDR, was jointly developed by MHI and Kansai Electric Power Co. Inc. It deploys an advanced amine-based solvent that reacts readily with CO₂ in flue gas before being separated and compressed so that it is ready for pipeline transport.

The MHI process offers improved performance and lower cost than other existing capture technologies, Southern said. The process has been demonstrated at smaller scale at a coal-fired generating station in Japan, and is currently being deployed commercially on natural gas-fired systems around the world. The Barry project represents the largest coal-fired demonstration of the technology.

"We are excited to be a partner in this important project that will help further the global goal of reducing carbon dioxide emissions for the benefit of everyone," said Shunichi Miyanaga, executive vice president and representative director general manager of MHI's

Machinery & Steel Structures Headquarters. "The confidence our partners have shown in the MHI CO2 capture technology is a testament to the research and development efforts we have undertaken during the past 20 years. Together with our partners, we are ready to deploy and demonstrate to the world the safety and viability of commercial-scale CCS."

Through this project and others, Southern said that it and its partners seek to support the goal of better understanding the impacts of reducing CO2 emissions from electricity generation. The project in Alabama is designed to demonstrate start-to-finish CCS technology, an important step toward commercialization, Southern added.

Barry, located in Bucks, Ala., has a total capacity of 2,525 MW and includes seven generating units — five coal-fired units and two natural gas-fired combined-cycle units.

Southern said it is working with the federal government and other partners in several major CCS research projects. In one, Southern subsidiary Mississippi Power Co.'s Victor J. Daniel Jr. plant is the host site for a demonstration in which 3,000 tons of CO2 recently were injected into a deep saline rock formation 8,500 feet below ground. Monitoring of its movement deep in the ground and under multiple geological seals is under way.

There has been a big uptick in CO2 CCS activity in the past couple of years in the United States, Canada and other countries, as governments implement and move toward implementation of greenhouse gas reduction laws. Being marked up the week of May 18 in the House Energy and Commerce Committee is the Waxman-Markey bill, which seems like the leading blueprint for an eventual U.S. national greenhouse gas reduction program. Rep. Rick Boucher, D-Va., said May 18 that the latest version of the bill has key changes that make it more coal-friendly and supportive of development of CCS technologies.

With 4.4 million customers and more than 42,000 MW of generating capacity, Atlanta-based Southern Co. owns electric utilities in four states and a growing competitive generation company, as well as fiber optics and wireless communications.

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Nuclear, renewable energy industries urge Obama to speed DOE loan guarantee rules

by [Kathleen Hart](#)

Leaders of the Nuclear Energy Institute, the American Wind Energy Association, the Solar Energy Industries Association and other renewable energy groups sent a letter to President Barack Obama on May 19, asking him to speed the rules needed for financing to flow under U.S. Department of Energy loan guarantee programs.

"Our organizations, representing thousands of clean energy technology companies, are writing now to urge the Executive Branch to act promptly to adopt regulations that will allow clean energy proj-

ects to participate in two loan guarantee programs administered by the Department of Energy ... the new Section 1705 loan guarantee program for renewable energy projects authorized by [the American Recovery and Reinvestment Act], and the existing Section 1703 loan guarantee program established in 2005 for innovative clean energy technology projects," the letter said.

Leaders of the renewable energy and nuclear power industries said, if properly implemented by workable regulations, the DOE loan guarantee programs would significantly increase access to debt financing for clean energy projects at a time when sources of capital in the private markets have been substantially reduced.

"With access to these loan guarantees, our member companies will be able to start construction of planned projects that would otherwise need to be delayed or cancelled due to current capital market conditions," the letter said. "Unfortunately, the regulations necessary to implement these programs effectively have not yet been developed."

The groups said, while DOE is "working diligently" to develop the rules, there are "disagreements" between the department and the Office of Management and Budget, "as evidenced by the fact that DOE's draft revised regulations for the Section 1703 program were submitted to OMB more than two months ago and have not been acted on. Three months have passed since enactment of ARRA, and we have little confidence that ongoing discussions between DOE and the Office of Management and Budget over these regulations will produce a satisfactory result in a timely manner."

The groups are not seeking additional funding in the budget for these loan guarantee programs. Rather, they are asking that funds already authorized be made available "expeditiously and under reasonable terms and conditions so as to facilitate the financing of worthy projects, in full compliance with appropriate government oversight, transparency and accountability."

The groups said action is needed quickly on the new Section 1705 program because it is only available to projects that begin construction by Sept. 30, 2011. They also argued that changes are required for the Section 1703 loan guarantee program, which is being implemented by DOE under regulations put in place by the Bush administration that have not generated the financing that the program was intended to promote.

"In the almost four years that have passed since enactment of the 2005 Energy Policy Act, no loan guarantees have been finalized under the Section 1703 program," the letter adds. "We would not take the unusual step of asking for your help in this matter if we believed that the Executive Branch departments and offices involved would reach agreement, with dispatch, on the rules necessary to implement these loan guarantee programs successfully."

In addition to NEI, AWEA and SEIA, industry groups signing the letter included the National Hydropower Association, the Geothermal Energy Association, the Biomass Power Association, and the United States Clean Heat and Power Association.

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MIT updates landmark 2003 report on nuclear power, is not impressed with progress

by [Wayne Barber](#)

The Massachusetts Institute of Technology has issued an updated version of its 2003 "Future of Nuclear Power" report and concluded

that, while global warming concerns have grown, the nuclear revival appears to be stuck in neutral.

“After five years, no new plants are under construction in the United States and insufficient progress has been made on waste management,” the report, done by the MIT Energy Initiative and released May 18, says. “The current assistance program put into place by the 2005 [Energy Policy Act] has not yet been effective and needs to be improved.”

The report goes on to say: “The sober warning is that if more is not done, nuclear power will diminish as a practical and timely option for deployment at a scale that would constitute a material contribution to climate change risk mitigation.”

Government energy policy since 2003 has been dominated, to a large extent, by renewable portfolio standards that do not include nuclear or coal power with carbon storage. Also, a long-term storage solution for nuclear waste remains elusive. “[N]o federal operated away-from-reactor surface, or near surface, spent fuel storage sites have been opened since they are not permitted by the Nuclear Waste Policy Act of 1987 until the Yucca Mountain repository is licensed,” the report said.

“The new administration has stated that Yucca Mountain is no longer an option for nuclear waste disposal. There is no plan for high-level wastes; but the administration has committed to a comprehensive review of waste management,” the report added.

The 2003 report and the updated version were both authored by a panel of experts, including two MIT professors and Washington, D.C. insiders, John Deutch, a former U.S. Defense Department official, and Ernest Moniz, a former high-ranking U.S. Department of Energy official.

The original study focused on cost, safety, waste management and proliferation risk. The 2003 report had a significant impact on the public debate both in the United States and abroad.

“While the intent to build new plants has been made public in several countries, there are only a few firm commitments outside of Asia, in particular China, India, and Korea, to construction projects at this time. Even if all the announced plans for new nuclear power plant construction are realized, the total will be well behind that needed for reaching a thousand gigawatts of new capacity worldwide by 2050,” the MIT authors say in the updated report.

Since 2003, one reactor at the Tennessee Valley Authority’s Browns Ferry station has been refurbished and restarted. But no construction has begun on new nuclear units in the United States. Meanwhile, construction is underway on 44 new nuclear plants in 14 countries, the report says.

That’s not to say that the news has been all bad since 2003. The performance of the 104-unit U.S. nuclear fleet has been “excellent.” The fleet-averaged capacity factor since 2003 has been maintained at about 90%. Nuclear reactors typically have initial operating licenses from the Nuclear Regulatory Commission for 40 years, however the earlier trend to obtain license extensions to operate existing nuclear reactors an additional 20 years, for a total of 60 years, has continued with the expectation that almost all reactors will obtain license extensions.

Also, 17 applications have been filed for a combined total of 26 potential new nuclear reactors. Studies also seem to indicate greater acceptance of nuclear power among the general public.

“The challenge facing the U.S. nuclear industry lies in turning plausible reductions in capital costs and construction schedules into reality,” the report said, adding that “the first few U.S. plants will be a critical test for all parties involved.”

MIT is also starting a new report on the future of the nuclear fuel cycle.

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Economic woes could bring different wind financing options

by [Kelly Harrington](#)

The economic collapse and resulting credit crunch that slowed the pace of new wind power projects could have a bright side: more financing options for developers.

In an interview after moderating a wind finance panel at the American Wind Energy Association’s WINDPOWER 2009 Conference in Chicago on May 6, Ed Feo, a partner at Milbank Tweed Hadley & McCloy LLP said the financing hiatus has caused people to open their thinking about sources of capital and what kind of capital structures work for renewable energy.

“While the stimulus package, with the tax grant and with the loan guarantee program, changes the landscape and federalizes that financing to some extent, I think that is only part of the story,” he said. “The other part of the story is that it has opened the door for sources like private equity, investment funds, hedge funds, the bond markets, looking at different capital solutions which are not just bank-level debt, bank-level project tax equity as sources where you can go find some money to finance stuff. To me, that is maybe the bigger story than the federal stimulus.”

For most wind projects, financing has almost exclusively been done as a combination of a small amount of sponsor equity and a large amount of bank debt and then monetization of tax credits. The model provided \$13 billion of capital for the wind business, an amount too small to permit wind to get to the level needed to meet expected renewable energy goals.

“There’s probably more like \$50 billion has to be raised and that is not going to get there with just those two sources that have been the historic model,” Feo said.

Representatives from banks and consulting firms on the panel said with banks either making fewer investments or investing at a more cautious pace, and new financing opportunities from the federal government, developers could start looking at new options to fund wind projects.

John Plaster, a managing director in the global power group at Barclays Capital, said there may be a “new normal” for financial conditions. Among other things, Plaster said it is important for the wind sector to find ways to rely on the debt capital markets, as opposed to being fully reliant on the bank market.

“Insurance companies are natural buyers of long-dated duration assets; contracted energy has always been a sweet spot in that market,” he said. “Having the banks work with the wind industry to figure out how to bring projects from development construction into the capital markets is going to be a very important trend.”

Raymond Wood, managing director and co-head of the alternative energy group at Credit Suisse, said there are a number of places to get long-term capital aside from banks.

“There is an active leasing market, there are insurance companies,” he said.

Wood described his view as “guardedly optimistic.”

“It is obvious this sector is going to grow; it is a policy imperative and the unit economics are attractive and it will attract capital,” he said. “We think on the investment grade side there is money, on the BB side there is money. We believe there is tax equity through leasing and leverage partnerships and we think there’s also equity capital there for you.”

Gisela Kroess, director, global structured and project finance at HVB-HypoVereinsbank, said banks are slowly returning to activity, but are not willing to take on as much risk.

“Banks have higher requirements, in terms of being a part of the deal,” she said.

Sandip Sen, head of Citibank’s alternative energy group, said he does see a bit of loosening in the attitude of banks and investors in general. For Citibank itself, the bank is looking at a few projects for financing, but is going to be very careful in how it deploys capital.

“It’s going to be to clients where as a firm we’re able to deliver a full suite of services, not just the financing itself, and I suspect that’s probably how most financial institutions look at how they deploy capital,” he said.

DAI Management Consultants Inc. President Steve Dean said despite uncertainty about the impact of wind turbine values and natural gas prices, the industry is poised to again be a robust one.

“We’re having tremendous support from the federal government in the form of tax credits. Those credits will make it more economically feasible to develop these projects and I think as we look into the future, they’ll probably be a continuing support,” he said. “We’re in a period of a lull, but I think we can expect in the second half of the year, that as the federal tax program becomes more defined, that we’ll see projects get back into construction and development.”

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Revenue decoupling gaining traction among US power utilities

by [Rosy Lum](#)

Revenue decoupling, a mechanism predominantly employed by the gas utility industry, is quickly gaining traction among U.S. electric utilities.

As of March, 10 states had approved a revenue decoupling mechanism for electric utilities: California, Connecticut, Idaho, Maryland, Massachusetts, Minnesota, New York, Oregon, Vermont and Wisconsin. Three are pending approval — Delaware, Hawaii and New Hampshire — according to the Institute for Electric Efficiency.

“We have a lot of states that were just approved in the last year or so, so there’s definitely a trend moving more towards decoupling in the electric industry,” said Lisa Wood, executive director of the Institute for Electric Efficiency, a program of the Edison Foundation. “A couple of years ago there were maybe four states, so we’re definitely seeing a trend in that direction.”

One of the drivers behind decoupling is passed and pending federal legislation, namely the American Recovery and Reinvestment Act of 2009 and the revised climate change bill drafted by Reps. Henry Waxman, D-Calif., and Edward Markey, D-Mass., which is in debate this week.

“With the stimulus not exactly requiring decoupling, but saying words to the effect that the incentives have to be in place for utilities to do energy efficiency, there’s even more talk now in other states that weren’t doing decoupling before [about wanting] to move in this direction,” Wood said. “You’re going to see more of it.”

In an April 27 letter, the National Association of Regulatory Utility Commissioners and nine other groups urged Congress not to legislate a national decoupling mechanism, saying states should be allowed to implement energy efficiency goals “in the most cost effective manner possible.”

Anticipation that the Waxman-Markey bill, which includes targets for energy efficiency resource standards, renewable energy standards and a cap on carbon emissions, will be passed is also driving interest in energy efficiency.

“[N]ow that carbon [legislation] is on the horizon, energy efficiency is not only a low-cost resource for meeting demand requirements, but it’s also a great resource for meeting carbon reduction requirements,” Wood said. “All those things weren’t on table like they are now, there wasn’t as big a push, whereas now, it’s moved from, ‘We could do more of this’ to ‘We’re definitely doing more of this.’ ... Now it’s a real resource.”

Though carbon emissions from natural gas generation are comparatively lower than those from coal-fired generation, a reduction in emissions from the gas utility industry will need to come from curtailed usage.

“We’re not like the electric side of the business; we don’t have any generation that we can change from coal-burning to gas-fired generation,” said Roger Cooper, the American Gas Association’s executive vice president for policy and planning. “We can’t clean up our upside. We have to work on the customer side of the meter, so decoupling really was the first prong in what we have to do about climate change.”

Electric utilities have been slower than their gas counterparts to hop on the decoupling bandwagon. Gas utilities began to adopt the mechanism as a measure against a long-standing trend of falling natural gas consumption. Unlike electric utilities, which typically experience demand growth year over year, gas utilities have been experiencing an increase in more efficient and conservative customer behavior, resulting in a steady decline in demand. As one gas company experiencing this trend, Northwest Natural Gas Co. sought to address it.

“We were the first stand-alone gas [local distribution company] to adopt [decoupling],” Northwest Natural CFO David Anderson said. “It occurred in the 2003-2004 time frame ... and the impetus behind it was, ... like a lot of gas companies, we had seen declining use. Customers were being more efficient, using less natural gas, which is a good thing. And the team looked at that and said, ‘Why are we incented to have customers use more of a finite commodity?’”

Instead, Northwest Natural developed a business model that was a radical departure from that of the traditional natural gas utility: Rather than encouraging customers to consume more, they encourage customers to conserve more.

“It’s actually started a wave across the country,” Anderson said.

As of May, the states that have implemented revenue decoupling for gas utilities are Washington, Oregon, California, Nevada, Utah, Colorado, Arkansas, Illinois, Indiana, Ohio, Virginia, North Carolina, Maryland, New Jersey, New York and Massachusetts. Decoupling is pending in Minnesota, Wisconsin, Michigan and Connecticut, according to AGA.

“Decoupling has led to a change in the utility culture,” Cooper said. “Years ago, a gas utility would be saying, ‘How do I get customers to

increase the number of burner tips in their home, how can I get them to use more gas?" Now if you're a decoupled utility, you'd say, 'I don't need to increase consumption; in fact, it'll make customers happier if I can help them [reduce] consumption.'"

Despite the sense revenue decoupling seems to make, it has encountered resistance, from state legislatures and commissions to consumer advocates.

"It's a little confusing to me when I hear customer advocates and others not in favor of this because I think anything you can do to put the utility on the same side of the customer has to be a good thing," Anderson said.

Through decoupling, a utility will not see greater revenues from an increase in energy consumption. However, some opponents focus on the fact that, conversely, a utility will not suffer from lower usage.

"[T]he idea that the utility is not hurt by reduced consumption I think bothers people," Cooper said. "In a normal business, if your customers don't buy as much of your product, you're hurt, and people say, 'Why should utilities be different?' Well, it's a different business; it's a regulated business."

From a regulated company's perspective, decoupling entails filing a rate case.

"[A] rate case is a big undertaking for any utility," Cooper said. "Some utilities may do one every 10 years, so it's not something you do routinely, and there's always a risk when you file a rate case that you may end up worse than when you went into it."

However, with energy efficiency initiatives driving decoupling and like mechanisms, it will gain a stronger foothold in the U.S. utility industry.

"The long-term trend, I believe, decoupling is the way gas utilities for the most part will go, and surprisingly, electric utilities have gotten on that bandwagon as well," Cooper said.

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Maryland debate: Would EDF gain influence over utility in Constellation nuke deal?

by [Corina Rivera](#)

Maryland Public Service Commission staff and others have called for the commission to find that prior approval is required of Constellation Energy Group Inc.'s proposal to sell just under half of its nuclear business to EDF Group.

The PSC held evidentiary hearings in April on the effect the proposal might have on Constellation subsidiary Baltimore Gas and Electric Co. The latest round of briefs was submitted May 18.

PSC staff said the commission should find that EDF has acquired the power to exercise substantial influence over BGE's policies and actions. Under regulations, staff noted, a person may not acquire the power to exercise any substantial influence over the policies or actions of a gas and electric company, if the person would become an affiliate of that company. "Affiliate" is defined as "a person that directly or indirectly, or through one or more intermediaries, con-

trols, is controlled by, or is under common control with, or has, directly or indirectly, any economic interest in another person," staff said, explaining that in the acquisition of a partial ownership interest in Constellation Energy Nuclear Group LLC, EDF under that definition would become an affiliate of Constellation and BGE.

The specific terms and conditions proposed in the transaction documents extend EDF's interests beyond the nuclear facilities currently owned by Constellation subsidiaries, or developed through UniStar Nuclear Energy LLC with EDF, staff said. UniStar is a joint venture between subsidiaries of Constellation and Electricité de France, whose parent company is EDF. Possible consequences of EDF influence over BGE, staff said, include that the allocation of available capital to subsidiaries may result in funding Constellation's nuclear business at the expense of BGE projects.

The state and the Maryland Energy Administration said that EDF's various roles regarding Constellation, including as Constellation's largest shareholder and as its principal source of liquidity, together constitute "substantial influence" over Constellation under any fair definition of that term.

EDF's vision of using Constellation as a vehicle through which it can advance development of its U.S. nuclear business necessarily puts the goals and objectives of EDF and BGE at odds, they said, adding that decisions on whether to allocate scarce capital to constructing new nuclear plants at Constellation's Calvert Cliffs nuclear complex in Maryland and elsewhere will profoundly affect the entire Constellation enterprise, including BGE.

The Maryland Office of the People's Counsel cited testimony from expert witnesses who have concluded that "EDF was making such a large investment, larger than the current market capitalization of the CEG, that a conclusion that the transaction would provide EDF with the power to exercise substantial influence on the policies and actions of CEG and BGE is unavoidable."

EDF, Constellation and BGE respond

EDF, through affiliate EDF International SA, said the transaction will not give EDF, directly or indirectly, the power to exercise substantial influence over BGE's policies and actions, and as such, the commission's prior approval is not required. The transaction involves the acquisition of a nonjurisdictional company and not the direct or indirect acquisition of a Maryland utility, EDF said.

The parties urging the PSC to find that EDF would have substantial influence over BGE have focused more on what the effect on BGE might be if EDF were able to exercise such influence, EDF said. The French company said the primary concerns raised have been that EDF would somehow be able to influence Constellation to divert scarce capital resources away from BGE to fund the construction of new nuclear generation by UniStar or to fund capital expenditures by Constellation Energy Nuclear Group.

Those parties' "concerns all rest on the unsupported assertion, based on the value of the assets EDF is acquiring or EDF's expertise in nuclear operations or on other amorphous factors, that EDF will acquire the power to exercise substantial influence over Constellation in order to cause Constellation to take certain actions that affect BGE," EDF said.

Nothing in the proposed Constellation Energy Nuclear Group governance provisions gives EDF any control or ability to affect Constellation's decisions; the governance is limited to the management and operations of Constellation Energy Nuclear Group, EDF said. "EDF has no interest in influencing BGE, and EDF would not have made its \$4.5 billion purchase of a 49.99% interest in CENG in the expectation that EDF would be able to influence Constellation's decisions regarding BGE without obtaining explicit contractual authority to do so," the company said.

Constellation and BGE called the proposed transaction “straight-forward,” noting that EDF is paying \$4.5 billion for 49.99% of Constellation Energy Nuclear Group and would obtain the rights to nominate to Constellation’s board one director, who will be prohibited from receiving any information confidential to BGE or voting on any matter primarily related to BGE.

Among other things, Constellation and BGE argued that commission preapproval is not required because the undisputed fact that EDF’s voting interests and contractual rights do not grant it the requisite “power” cannot be overcome by the intervenors’ speculation about supposed informal EDF “influences.”

According to the commission, reply briefs are due May 26 and an order on the issue of “substantial influence” is due to be issued by June 8. (Case No. 9173)

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FERC staff *continued*

fuel prices. Across the board, fossil fuel prices are 50% to 80% lower now than they were at this time last year, staff reported, with natural gas prices, like electricity prices, dropping to levels not seen in years. Recent bid week prices for natural gas have averaged less than \$4/MMBtu at every pricing point in the country, the report found, although prices have rebounded slightly over the past few months. When asked, staff could not explain the recent price increase because it is contrary to what market fundamentals would suggest.

Oil and coal prices also have declined from their unprecedented 2008 highs as inventories have grown, with U.S. crude oil stocks 14% above last year’s levels, and electric generator coal stockpiles exceeding last year’s levels by 17% and their 10-year average by 29%.

“With lower prices for gas, we have not seen much of a decline in gas demand,” staff said. “While industrial demand has fallen over the past several months relative to last year, demand for gas to fuel electric power plants has been increasing as gas prices have ... become increasingly competitive, not only with oil but also, on a regional basis, with coal.”

Natural gas-fired combined-cycle plants have been most competitive with coal plants in the Southeast, where natural gas prices are nearly the same as coal prices due to the high cost of transporting coal to that region. There also has been some displacement of coal generation with power produced by natural gas in the PJM region, though largely on the margins, staff said.

Staff suggested that natural gas prices should not rise dramatically anytime soon, given continuing abundant supplies. Storage levels of the fuel are 23% above the five-year average and only 3% below the all-time high for this early in the injection season, according to the report. Moreover, LNG imports are already twice as high as last

year, and the global LNG market has excess supply available due to lower worldwide demand, full overseas inventories and the addition of new LNG liquefaction capacity.

“Robust inventories mean less gas will have to flow to storage during those days that downstream gas-fired generators are running their hardest,” thereby keeping prices in check, staff explained.

Meanwhile, demand for power is expected to fall for the third straight summer, leaving all regions with adequate generation reserve margins. If outages are to occur this summer, staff said they most likely would be the result of issues related to vegetation management. “Of note, there has been little or no improvement” in the Southeast and the West since mandatory standards in that regard were enacted in 2007, the report stated.

On wind energy resources, the report said the expected average on-peak capacity for such resources during the upcoming summer is 15.2% of nameplate capacity, which represents an on-peak increase of 21.5%, or 805 MW, from the 2008 summer assessment. Moreover, total installed nameplate wind capacity for the upcoming summer should increase by 9,252 MW, or 45%, over 2008 levels, to 29,945 MW.

The large influx of new wind resources has important implications. For instance, staff said it can lead to different patterns in the use of transmission capacity, which in turn can create more transmission congestion, particularly during low demand periods. Some regions also have reported the need to provide additional ancillary services, such as operating reserves, to address the challenges of managing the variability of wind resources.

Staff is projecting that the availability of demand response will jump 8%, or by more than 2,200 MW, this summer compared to last. Most of the increase is expected to occur in the Northeast and Florida, however, while projections for most other regions remain relatively flat.

Staff said weather is “always the largest wildcard” going into the summer. Most forecasting services are predicting fairly normal temperatures across the country this summer, with the exception of the West and Eastern coastal regions, where above-normal temperatures are expected. Of course, staff reminded the commission, hurricanes can also have a strong impact on energy markets, although several meteorologists are forecasting that the hurricane season will be slightly less active than normal.

Finally, staff noted that it has been keeping a close eye on California’s transition to its new market structure. Thus far, staff said, the news is good, with the day-ahead market appearing to be functioning smoothly and prices reflecting system conditions.

However, staff said it has been troubled by intermittent real-time price spikes that have been occurring in the San Diego region. Asked about the problem during the meeting, staff said the spikes appear to stem from certain “technical issues” with the new market structure, including the algorithms being used to calculate prices, and not market manipulation or extreme supply/demand imbalances. Staff pledged to continue to monitor the situation, noting that the California ISO is working to resolve the problem.

COMPANIES REFERENCED IN THIS ARTICLE:

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Military leaders conclude aging power *continued*

nificantly to the mission burden of the U.S. military in fragile regions of the world." Thus, the board said, "continuing our heavy reliance on these fuels is a security risk."

With regard to the electricity sector, the board suggested that the nation's "outdated, fragile, and overtaxed national electrical grid is a dangerously weak link in the national security infrastructure." It also presents a security risk to domestic military installations, making their critical infrastructure "unnecessarily vulnerable to incident, whether deliberate or accidental," the board noted.

In support of its findings, the report cited the August 2003 blackout in the Eastern Interconnection that left 50 million people living in the Northeast, Midwest and Ontario in the dark. While power was restored relatively quickly in that case, the board said the rapid recovery was attributable to a lack of any significant equipment damage, and suggested that the situation might be different if the nation's electric grid were deliberately attacked.

Moreover, the report said the blackout exposed the vulnerability of the national security system, recounting that U.S. border check systems were not fully operational during the outage. In addition, water and sewage plants shut down, gas stations stopped working, rail service was curtailed, and many cellular phone providers, radio stations, and television stations were unable to provide service. In total, the blackout is estimated to have caused economic losses of between \$7 billion and \$10 billion, all because an Ohio utility failed to trim trees near a power line, according to the report.

"As the resiliency of the grid continues to decline, it increases the potential for an expanded and/or longer duration outage from natural events as well as deliberate attack," the board stated.

The consequences of longer power outages would be far more severe, according to the report. Military installations across the country, which are almost completely dependent on commercial electrical power delivered through the national electrical grid, are particularly vulnerable. The report explained that this can be bad news for military personnel deployed overseas, because missions can be impaired when logistics support and data analysis systems in the U.S. are affected by grid interruptions.

The report therefore called for the existing grid to be upgraded and expanded, and the regulations governing its construction and operations overhauled.

However, the board said the first priority for the Obama administration is to "clearly and fully integrate energy security and climate change goals into national security and military planning processes."

In addition, the board called on the U.S. Department of Defense to take on a leadership role in the effort to transform America's energy position by addressing its own energy security needs through technological innovation.

For instance, the report called on the defense department to transform the use of energy at its military installations through the aggressive pursuit of energy efficiency and smart grid technologies, as well as the electrification of its vehicle fleet. The board also called on the defense department to expand the use of distributed and renewable energy generation at its installations, and to transform its long-term operational energy posture through investments in low-carbon liquid fuels.

The retired military leaders also called on the American public to do its part to address its security challenges, much as it did during World War II by establishing victory gardens and reducing the use of energy and critical raw materials.

"Each of us can help make our country more energy efficient," the board stated in making a direct appeal to the public. "Using less electricity in our homes and offices reduces stress on a fragile electrical grid; it also reduces carbon emissions. Supporting efforts to rebuild our electrical grid can make us less vulnerable to domestic attacks, and can allow us to develop a rich diversity of non-carbon energy sources."

Continuing in the same vein, the board said, "Americans made clear sacrifices during World War II for reasons that are obvious in hindsight: they understood the stakes, and they were asked. With this report, we have tried to make known the current stakes by clearly articulating the need to establish energy security and plan for the effects of climate change. This will require a commitment to conservation and a willingness to reconsider old ways. It will require discipline and the broadest participation possible. All of us have a role to play in making our nation more secure."

The board was convened by CAN, a not-for-profit company that claims its purpose is to offer government officials and policymakers in-depth analyses about policy issues and potential solutions. Members of the board include retired 2-, 3- and 4-star flag and general officers from the Army, Navy, Air Force and Marine Corps. The board also includes a former Army Chief of Staff, commanders of U.S. forces in global regions, a former shuttle astronaut and a NASA administrator.

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Electric shorts

NOAA predicts near-normal Atlantic hurricane season

On the heels of last year's destructive hurricane season — which, after 2004 and 2005, was the third most costly on record in terms of dollars — the oil and natural gas industry is actively anticipating the onset of this year's storm season, which officially kicks off June 1.

Forecasters from the U.S. National Oceanic and Atmospheric Administration are projecting a near-normal Atlantic hurricane season this year. In its initial outlook for the 2009 Atlantic hurricane season, which runs through Nov. 30, NOAA's National Weather Service Climate Prediction Center calls for a 50% probability of a near-normal season, a 25% probability of an above-normal season and a 25% probability of a below-normal season.

Global weather patterns are imposing a greater uncertainty for the forthcoming hurricane season than in recent years, NOAA said. The agency's forecasters believe there is a 70% chance of having nine to 14 named storms, of which four to seven could become hurricanes, including one to three major hurricanes.

Shaping the NOAA seasonal outlook is the possibility of competing climate factors. Supporting more activity this season are conditions associated with the ongoing high-activity era that began in 1995, which include enhanced rainfall over West Africa, warmer Atlantic waters and reduced wind shear. But activity could be reduced if El Niño develops in the equatorial eastern Pacific this summer or if ocean temperatures in the eastern tropical Atlantic remain cooler than normal.

5 years ago this week

Paula Rieker, formerly the number two investor relations officer of now-bankrupt Enron Corp., pleaded guilty on May 19 to insider trading, admitting she sold stock after learning the company's floundering broadband unit was going to report a large quarterly loss.

During the court proceeding, prosecutors Kathryn Ruemmler said Rieker illegally sold Enron stock on July 5, 2001, after learning that the company's broadband division was going to report a second-quarter loss of \$102 million a week later. That was far more than the \$65 million full-year loss Enron had projected in January for the

broadband unit, which, unbeknownst to investors, was facing major technical and financial challenges.

According to a related action by the U.S. Securities and Exchange Commission, Rieker also violated federal securities laws by helping Enron's top management — including former CEO Jeff Skilling and former Chairman Ken Lay — disseminate "false and misleading information" to the public about Enron's energy services and broadband divisions. Rieker helped prepare Enron's first- and second-quarter 2001 earnings presentations and releases, the SEC noted, which allegedly hid losses and the true financial condition of Enron's business units.

10 years ago this week

In a recent answer filed in the District of Columbia Superior Court, Nicholas Bush — former president of the Natural Gas Supply Association — conceded that many allegations listed in a complaint initially filed by NGSA last February were true.

In that initial complaint, NGSA accused Bush of misappropriating more than \$2.4 million of NGSA funds since 1987 through phony consulting contracts. NGSA's complaint was amended on April 26 to include further charges and revise certain details, and to increase the request for damages. In particular, the amended complaint said Bush essentially tried to buy the silence of Margaret Martin, an economic counselor at the Canadian Embassy in Washington in 1990-1991 who "cohabited" with Bush for six or seven months at his Washington, D.C., Palisades Lane home.

Bush admitted in his response that he tried to persuade Martin to remain silent by making certain purchases for her (including a mink coat and jewelry), and giving her \$250,000 to help her pay for a vacation home in Canada near her family. Further, Bush admitted that he "caused NGSA to pay certain funds to consultants who did not provide services to NGSA, and that he obtained those funds for his own use, because [he] believed that Martin might reveal [account information] if [he] did not purchase the Canada home for Martin."

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