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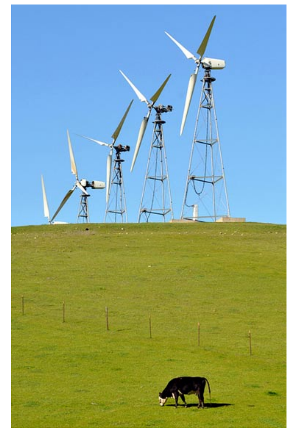
CALIFORNIA ENERGY MARKETS

◆ Friday, April 19, 2013 ◆ No. 1228 ◆

BILLBOARD No. 1228

Western Price Survey

[1] PG&E's New 'Green Option' Tariff Now Offers Bundled Renewables



Under an updated "green option" tariff, customers of Pacific Gas & Electric could opt to pay a premium each month for a greener energy supply, one that relies on bundled renewable energy from existing or new facilities in the utility's service territory. PG&E previously proposed using renewable-energy credits to supply the program. The new proposal, submitted to the CPUC, has the blessing of several key consumer, environmental and business groups, but is eliciting concern from community-choice aggregators that see the move as anti-competitive. Costs of the PG&E program are estimated to start at 3.5 cents/kWh. ***At [12], undercutting aggregation?***

[2] Legislature Moves Bills on Rate Increases, Merced Hydro Exemption for RPS

With policy committee hearings in full swing, the Assembly Utilities and Commerce Committee passed a number of measures this week, including a bill that would repeal rate-increase restrictions, giving the CPUC discretion to raise rates as necessary. The Legislature also moved forward a bill that would give customers who opt into a community renewables program a bill credit. ***Also at [14], an RPS backdoor for large hydro?***

[3] LADWP Moves Forward With 'Bundled' FIT Program

Under a plan approved by the Los Angeles Department of Water & Power Board of Commissioners this week, developers awarded contracts to build and sell power from portions of the 200 MW Beacon Solar Project in the Mojave Desert will also be obligated to build a FIT solar project within the Los Angeles Basin. LADWP officials believe bringing large developers to local projects will lower costs, but some FIT proponents say the approach is ill-conceived. ***At [15], a good or bad FIT?***

[4] BPA Issues Proposal on Allocating Oversupply Costs

The Bonneville Power Administration received nine proposals from customers on how to comply with FERC's directive for a more equitable allocation of oversupply costs, but rejected them all. Instead, it proposed transmission users pay proportionally to their system use during oversupply events, when all non-hydro generators, including wind and thermal, receive payments to curtail production. ***Cost allocation at [16].***

Photo: Altamont Pass wind turbines. *Courtesy jasleen_kau, flickr.com.*

[5] CPUC Boosts Demand Response

The CPUC this week approved changes to utilities' demand-response programs in an effort to prepare for another summer without the San Onofre Nuclear Generating Station. The commission also approved about $10 million annually for the Flex Alert Program this year and next year. ***DR gets a boost at [13].***

[6] Bright Ideas: Storage Startup Would Use Railroad Cars

A California startup run by energy-industry veterans uses decades-old railroad technology to create grid-scale energy storage with little environmental footprint. The system moves railroad cars up an incline using off-peak renewables; then, when needed, the cars move downhill and spin a generator. ***No water, fossil fuels or emissions at [18].***

[7] Navajo Council Tables Action on Power-Plant Lease Proposal

The Navajo Nation Council tabled action on a proposed lease extension for the Navajo Generating Station, a coal-fired plant near the Grand Canyon; the tribe wants a new lease to include more environmental protections. ***Navajo negotiations at [19].***

[8] Energy Companies Ask for Stability on Federal Tax Breaks

Energy organizations have sent the House Ways and Means Committee pleas for tax preferences benefiting their industries. The production tax credit, for instance, expires in 2014. ***IRS issues guidance on "physical work" for PTC qualification at [20].***

News In Brief

[9] SDG&E Signs Five Renewables Contracts

San Diego Gas & Electric has signed five power-purchase agreements for a total of nearly 62 MW of solar and wind energy. Two of the contracts, for a total of 27 MW of solar power, will be located in San Diego County, the utility announced on April 17.

SDG&E signed two contracts for a total of 14.7 MW with TerraGen Development Co. for two wind projects located in Kern and Riverside counties, and a 20 MW solar contract with E.ON Climate and Renewables for a facility to be built in Kern County. Finally, SDG&E signed a 7 MW solar contract with Northlight Power and another 20 MW contract with Silverado Power, both for solar-photovoltaic projects in San Diego County.

In 2012, approximately 20.3 percent of the energy that SDG&E delivered to retail customers was provided by renewable energy sources. In 2011, the company reported renewable-energy deliveries representing a total of 20.8 percent. The utility said it is on track to meet or exceed the state's mandate that 33 percent of its retail sales be produced from renewable-energy projects by 2020 ***[C. R.].***

[9.1] Pacific Legal Foundation Files Lawsuit Targeting Cap and Trade

The Pacific Legal Foundation on April 16 sued the California Air Resources Board, alleging that revenues collected through the cap-and-trade program amount to an illegal tax on carbon.

In a petition filed with the Sacramento Superior Court, PLF seeks a writ of mandate that would halt enforcement of the auction and revenue-generating provisions of the cap-and-trade regulation. The suit was filed on behalf of several California businesses and interest groups, including the Morning Star Packing Company, Merit Oil Co., the California Construction Trucking Association and the Loggers Association of Northern California.

The lawsuit's allegations closely mirror assertions made in a lawsuit filed by the California Chamber of Commerce in November. Like the Chamber suit, the PLF's argues that CARB does not have the legal authority under AB 32 to auction carbon allowances to generate revenues for the state, and that money raised in this matter constitutes an illegal tax that will ultimately be passed on to consumers in the form of higher-cost products and services.

Creating this new "tax," according to the suit, would have required a two-thirds vote of the Legislature. "The 'cap and trade' auction program is a new state tax that will generate billions of dollars for the state on the backs of California taxpayers," PLF put forth in a media statement. "Because it was not passed by at least a two-thirds majority vote of the Legislature, it is unconstitutional. Case closed."

The PLF and Chamber lawsuits may be consolidated due to their similarities, noted Kevin Poloncarz, an attorney with Paul Hastings who represents energy producers.

"If the cases aren't consolidated, there is a risk of inconsistent judgments, which means that the largely duplicative nature of the claims may not completely eliminate any market uncertainty created by this lawsuit," Poloncarz said.

CARB spokesman Dave Clegern commented that the cap-and-trade regulation was developed in full accord with all state laws. "ARB will continue moving forward with this important program to fight climate change and develop a clean energy future for California," Clegern said.

Susan Frank, director of the California Business Alliance for a Green Economy, issued a statement dismissing the PLF suit. "Some folks are being dragged kicking and screaming into the new clean energy economy," Frank said, "but the economic advantages of transitioning to a more efficient economy are indisputable" ***[L. B. V.].***

Western Price Survey

[10] Power Values Follow Gas Higher

National natural gas prices continued their upward trajectory this week, gaining sharply after the U.S. Energy Information Administration in its weekly storage bulletin reported stocks were lower compared with last year and five years ago.

Working gas in storage reached 1,704 Bcf as of Friday, April 12, according to EIA estimates, a net increase of 31 Bcf from the previous week. This is the first net increase of the injection season. But storage is now 31.8 percent less than a year ago and 4.2 percent less than the five-year average. The West was the only storage region to post a decline, down 1 Bcf.

The report sent front-month gas futures to a fresh 21-month high, noted *Enerfax* in its April 19 report. "Over the past 2 months, colder-than-normal temperatures have raised heating demand, leading to a sharp decline in storage supplies that has pushed prices higher."

Henry Hub spot natural gas values jumped 17 cents since last Friday, trading April 19 at an average of $4.38/MMBtu. Western prices followed suit, with PG&E CityGate gaining 15 cents to $4.39/MMBtu and Southern California Border up 13 cents to $4.30/MMBtu by April 19. Much of the gain came after release of the storage report.

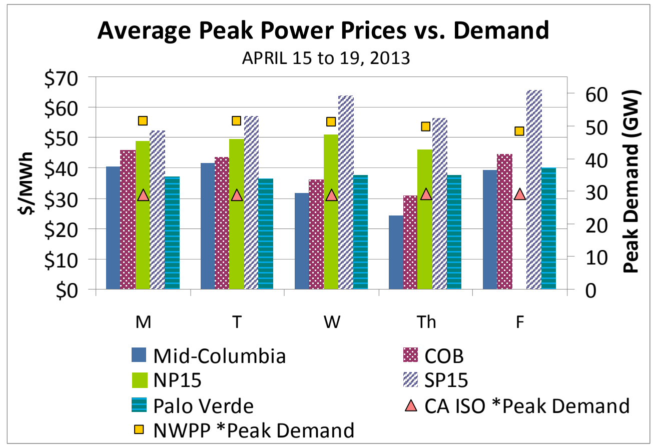
Western power prices generally followed natural gas values higher. South of Path 15 average peak prices soared $12.50 to $65.50/MWh in the April 12 to 19 trading period.

Western Electricity Prices
Week of April 15-19, 2013
($/MWh)

	Peak	Off-Peak
Alberta Pool ($C)	29.50 – 401.95	12.39 – 70.28
Mid-Columbia	23 – 42.50	10 – 33
COB	30.50 – 46.50	17.50 – 33
NP15	46 – 51	35 – 35.75
SP15	51.50 – 67	37.50 – 53
Palo Verde	35.50 – 40.50	27.30 – 32.75

Western Natural Gas Prices
($/MMBtu)

Permian Basin, TX	4.00 – 4.20
San Juan Basin, NM	3.96 – 4.16
Southern California Border	4.13 – 4.37
Malin, OR	4.04 – 4.21
Alberta Hub	3.44 – 3.53



Here's how average peak values at other Western hubs have fared since last Friday:

- **Mid-Columbia:** Up 25 cents to $39.20/MWh.
- **California-Oregon Border:** Lost $2.35 to $44.40/MWh.
- **North of Path 15:** Last traded April 18 at $46/MWh.
- **Palo Verde:** Rose $1.90 to $40.25/MWh.

Average off-peak power prices in the West increased between $1.30 and $9.25 in the trading period save for Palo Verde, which lost about 30 cents to $31.15/MWh. Prices April 19 ranged from $28.50/MWh at Mid-C to $51.25/MWh at SP15.

Peak demand on the Cal-ISO grid reached 29,110 MW Thursday, April 18. The week's high use was expected to occur Friday when the grid operator forecast demand could reach 29,212 MW. Northwest Power Pool peak demand reached 51,410 MW Monday, April 15.

What's ahead: Northern California should get some of its warmest weather so far this year as temperatures in San Francisco reach highs of 73 ˚F by Tuesday, April 23, on a par with expected highs in Los Angeles. Sunny conditions are expected throughout the Pacific Northwest starting April 22, with Seattle temperatures increasing to 72 ˚F by Thursday and Portland reaching 81˚F.

The National Weather Service forecasts an increased probability of above-normal temperatures and below-median rainfall from Washington into Southern California and Arizona between April 24 and May 2 ***[Linda Dailey Paulson].***

The Western Price Survey is now on the Web at http://www.newsdata.com

Bottom Lines

[11] Growing a Solar Park in California's Central Valley

An ambitious project to build one of the world's largest solar-energy complexes on contaminated farmland in California's Central Valley has finally moved from the drawing board to the review process. And unlike with some other sizable solar-energy ventures, there likely will be few objections to the site.

California's largest irrigation supplier, the Westlands Water District, recently announced the long-anticipated start of the Westlands Solar Park's environmental review under the California Environmental Quality Act. Planned for an area near Fresno, the Westlands Solar Park would be located in what is arguably the least environmentally sensitive place in the state.

This is a landmark event because the solar photovoltaic project, planned for approximately 24,000 acres of agricultural land contaminated by selenium and salt resulting from years of irrigation on drainage-impaired soils in the southern San Joaquin Valley, provides an alternative to the development approach of building large projects on more fragile sites, including those in the desert. And as water resources become more scarce, and competition for them grows more fierce, the Westlands model could provide an alternative for these types of farmland while helping California meet its climate goals with clean, renewable energy and creating opportunities in one of the most economically distressed parts of the state. When complete, the project could power between 216,000 and 270,000 average California homes with clean energy.

A 'smart from the start' development.

The Westlands Solar Park also represents an innovative approach to large-scale renewable-energy development. Along with its planned 12-year phased buildout, eventually culminating in as many as 3,000 MW worth of solar arrays, the project incorporates related infrastructure improvements—transmission lines—into the plan. This could potentially open up tens of thousands of additional acres in more northern parts of the Central Valley that also have drainage and contamination problems and may need to be retired from farming.

The transmission improvements also will add capacity to an increasingly congested part of the state's grid, improving power reliability for millions of Californians. The project will be near the Pacific Gas & Electric-owned Helms pumped-storage facility, making it useful for balancing the variable energy from Central Valley solar projects rather than firing up gas-powered plants. For instance, renewable electricity generated at the Tehachapi wind farms in the evenings could be balanced with the Valley's daytime solar, and vice versa, as needed.

Finally, solar development in the Central Valley will provide more geographic diversity to the state's resource mix. This is important for managing variable generation and meeting California's mandate of generating at least one-third of its electricity from renewable energy by 2020 under its renewables portfolio standard.

Considering generation and transmission together represents a best practice because it can help reduce environmental resource conflicts and optimize the location of both resources. Planners and developers can scale transmission for present and reasonably expected future needs, identifying and using existing corridors when possible, or using geospatial information to locate new corridors in the least impactful places like the Central Valley, where industrial agriculture has been practiced for decades, so there are fewer environmental and cultural impacts.

The Westlands Solar Park is a terrific example of using renewable-energy zoning to plan for present and future generation and transmission needs. It squeezes much more value out of existing infrastructure and serves multiple societal needs (climate, economic development, environmental and agricultural). It is a "smart from the start" development ***[Carl Zichella is director of the Western Energy Transmission Program for the Natural Resources Defense Council].***

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Regulation Status

[12] PG&E Proposes Revamped 'Green Option' Program *(from [1])*

Pacific Gas & Electric announced it has reached a consensus agreement with several stakeholder groups concerning the details of a proposed "green option" program that would provide a means for customers to satisfy up to 100 percent of their electricity demand with renewable power.

PG&E and the groups, including The Utility Reform Network, the Coalition of California Utility Employees, the Latino Business Chamber of Greater Los Angeles and Sierra Club California, filed a joint motion last week with the CPUC seeking approval of the revamped proposal.

The key difference in the new proposal versus the original submitted to the CPUC a year ago is the type of energy that would be used to supply the voluntary program.

PG&E previously proposed using renewable-energy credits from in-state or Western facilities to supply the program, while the updated proposal calls for using bundled energy from small to medium-sized solar facilities (20 MW maximum) located within the utility's service territory.

Initially, "until new resources are developed to serve green option customers," PG&E would source energy from existing renewable-energy facilities that are already producing power for PG&E under long-term contracts. Contracts for new facilities may be signed by PG&E when subscriber demand equals 30 MW, the proposal notes.

'There were a lot of customers interested in having tangible, steel-in-the-ground projects, particularly solar.'

The switch from Western RECs to in-territory bundled energy comes in response to concerns expressed by customers and stakeholder groups who were skeptical that purchasing credits would result in any additional renewable generation.

"We still think RECs are a valid way to supply renewable energy," said PG&E spokesman Jonathan Marshall. "But there were a lot of customers interested in having tangible, steel-in-the-ground projects, particularly solar."

TURN, for example, in a filing with the CPUC last year, said that "PG&E has not provided any evidence that the short-term procurement of RECs will stimulate new development, or that these purchases will cause any existing project to generate renewable electricity that would not have otherwise been produced."

TURN's position on the updated proposal, by contrast, is that it "will provide a meaningful opportunity for PG&E customers to link their energy usage to the development of new local renewable energy projects."

The renewable-power rate charged for participating green-option customers would initially be set at $107/MWh, to be adjusted to reflect actual costs of new incremental renewable resources that are procured for the program. Any costs, including those incurred from administration, would be borne by green-option customers only, not by all ratepayers.

PG&E estimates that the cost to residential customers who participate in the green-option program will start at 3.5 cents/kWh, resulting in a total rate of 11.5 cents/kWh when PG&E's standard generation rate of about 8 cents/kWh is factored in.

The program, if approved by the CPUC, would provide direct competition to community-choice aggregation programs in the state, potentially blurring the lines of differentiation between investor-owned-utility and CCA generation service.

San Francisco is slated to launch a CCA program, CleanPowerSF, which will serve all customers with a 100 percent renewable-energy supply, at a maximum residential rate of about 14.5 cents/kWh. Conceivably, rates for PG&E's green-option program could undercut the CCA's generation rates by 3 cents/kWh.

Charles Sheehan, a spokesman for the San Francisco Public Utilities Commission, said "it's difficult to speculate on what the effect will be on either program," given that rates for either program have not been finalized.

The cost of the 20 to 30 MW procurement that has been authorized for CleanPowerSF, Sheehan explained, will depend on market conditions when the purchase is made, and the final design of the CCA program, which is still in the works.

It is also unclear how PG&E's green-option program might impact the state's only operating CCA, Marin Clean Energy, said Beth Kelly, legal director for the Marin Energy Authority, which administers the aggregation program.

Marin Clean Energy, which is undergoing a major expansion with a rollout of CCA service in Richmond in July, offers a standard "light green" energy mix that is 50 percent renewable, and a voluntary 100 percent "deep green" option that is available at extra cost.

Is PG&E "going to use these types of programs as a marketing tool" against CCAs? Kelly asked. "There's a lot of uncertainty."

The fact that clean-energy advocates pushed PG&E to create a program that closely mirrors a CCA offering should not be viewed as an attack on aggregation efforts, noted Eric Brooks of the San Francisco Green Party.

"We knew it was sort of a contradiction to make PG&E do a better program and one that will compete with CCA," Brooks said. "But I think it makes sense to have PG&E do the right thing and then compete with that, rather than have PG&E compete with CCAs unfairly with a faux product."

Sheehan maintains that customers will be attracted to CleanPowerSF because the benefits of a planned local buildout of renewable resources will be "realized locally in San Francisco."

The green-option program "applies to all of PG&E's service territory and the benefits may not be tangible to individual customers," Sheehan said. "There's a dilution effect. We're a much more concentrated program on the local level."

More broadly, MEA's Kelly believes that significant legal and policy questions are raised by IOUs offering "differentiated procurement products" such as the green-option program, or San Diego Gas & Electric's proposed SunRate and Share the Sun pilot programs, in a competitive market.

The CPUC "has consistently acknowledged that an IOU's role as an existing monopoly raises power market concerns because of the large number of customers it serves," MEA noted in a recent CPUC filing. "The commission should question whether it is an appropriate use of a monopoly's resources to create products which can—and likely will—dissuade competitors' participation in the market, including those who have the opportunity to have a greater green impact" ***[Leora Broydo Vestel].***

[13] CPUC Boosts Utility Demand-Response Programs *(from [5])*

The CPUC this week approved changes to utilities' demand-response programs to help mitigate the outage at San Onofre Nuclear Generating Station.

The 2,300 MW nuclear plant was taken off line in early 2012 after a steam-generator tube in one unit leaked reactor coolant and steam-generator tubes in both units showed significant wear. Southern California Edison is the operator and majority owner of the plant; San Diego Gas & Electric owns a minority stake.

The CPUC's Energy Division late last year had requested DR program changes before summer 2013.

SDG&E responded by seeking to change its Demand Bidding Program, which offers incentives to nonresidential customers to reduce energy use and demand during specific DR events, to a day-of, 30-minute trigger product. SDG&E also asked to issue a request for proposals to expand the use of load-control technologies; increase funds for the Community Partners Initiative in order to expand outreach to SONGS-affected areas; and eliminate the Peak Time Rebate program for small commercial customers (see *CEM* No. 1214 [10.1]).

Edison sought to increase DR capacity by up to 58 MW by 2014. Changes include consolidating some commercial programs of the Summer Discount Plan into a single year-round program with a new economic-based trigger, shorter anticipated event durations and fewer cycling options. The Summer Discount Plan involves a day-of air-conditioner cycling program—with remote-controlled devices installed on air conditioners—for residential and commercial customers.

Proposed changes also included increasing Summer Discount Plan enrollment through targeted marketing; increasing incentives in the Auto Demand Response Technology Program; increasing community-based outreach efforts; performing studies of emerging technologies; and expanding the Save Power Day Program to include a day-of reminder and larger incentives. The program gives residential bundled-service customers a bill credit to reduce energy use during event-day afternoons.

The commission at an April 18 business meeting approved the changes, except for Edison's proposal to increase incentives and add a day-of notification to the Save Power Day Program *[D13-04-017, A12-12-016/A12-12-017]*.

The utilities will pay for the changes largely through shifting funds in DR programs. SDG&E can collect an additional $1.63 million from ratepayers. The Energy Division will continue reviewing DR program data and report later this month on any additional recommended changes.

The commission also approved budgets for the Flex Alert Program for 2013 and 2014 *[D13-04-021, A12-08-007]*. The emergency-alert campaign helps during system emergencies and power shortages.

The annual budgets include $2.5 million for Pacific Gas & Electric; $6 million for Edison; and $1.5 million for SDG&E.

The commission approved a 20-year solar power-purchase agreement between PG&E and Recurrent Energy subsidiary RE Kansas LLC *[Res E-4577]*.

The PPA is for a 20 MW photovoltaic facility in Kings County, with delivery starting in January 2018. The contract stems from a 2011 renewables portfolio standard bid solicitation. The resolution found the deal reasonably priced, compared to other shortlisted projects.

Also at the meeting, the commission approved a settlement on PG&E's service fees for direct access and community-choice aggregation *[D13-04-020, A11-12-009]*.

The utility charges various fees related to billing, metering and other services for DA and CCA. PG&E had sought to update the fees, which had not changed in years. The settlement updates about a dozen different charges for various services. It also approves an annual escalation rate before reconsideration in a 2017 general rate case.

The commission also voted in a closed-door session to dispose of applications to rehear its previous approval of PG&E's deal for a gas-fired power plant in Oakley. The commission has not yet released Thursday's decision to the public *[D13-04-032, A12-03-026]*.

Commissioner Catherine Sandoval dissented, as she did in the earlier vote. Commissioner Mike Florio recused himself, as he did in the earlier vote.

Californians for Renewable Energy, the Independent Energy Producers Association, Communities for a Better Environment, The Utility Reform Network and Western Power Trading Forum had all sought rehearing over the controversial decision late last year (see *CEM* No. 1217 [12.1]) ***[Hilary Corrigan].***

[14] Assembly Grapples With Rates, Hydro, Community Renewables *(from [2])*

A lawmaker who last year opposed a community-renewables bill has this year introduced his own measure.

Roger Hernandez (D-West Covina) said at an Assembly committee hearing on his bill and others that he could not support the measure last year because it would shift costs to customers who did not choose to participate.

His bill, AB 1295, would require utilities to provide an option for community renewables and allow for those who participate to receive a bill credit.

Under the bill, utility customers could elect to receive electricity from an independent renewables developer that has a facility under contract with the utility. Such facilities would be designated community renewables, and the payments a utility would ordinarily make to the developer would instead be made to the customer in the form of a bill credit. The Assembly Utilities and Commerce Committee approved the measure on April 15.

Under the bill, starting in 2016, the CPUC would be required to evaluate demand for a community renewables option and, if demand is lacking or if the commission finds the community option should be discontinued, the CPUC could do so. Public utilities would also be required to offer a community option starting in 2015, and would be able to evaluate demand starting in 2020.

'If it doesn't work out the way we intended, we need to shut it down or make other changes.'

Utilities appeared to largely favor the bill.

"This bill would allow those customers who wish to procure more renewables [to do so] without increasing mandates under the [renewables portfolio standard], and we are very supportive of that," said Cindy Howell, director of state legislative policy at Southern California Edison.

Russell Lowry, a lobbyist for Pacific Gas & Electric, said the utility could not take a position on the bill formally at this point, but was supportive of the lack of cost shifting in the measure. It's also important that as policies are implemented "we need to create off ramps," he said. "If it doesn't work out the way we intended, we need to shut it down or make other changes."

PG&E has filed a settlement with the CPUC to allow a community option, Lowry added, and "we wouldn't want a bill to delay that settlement."

The committee passed several other measures, including AB 793, which would allow the Merced Irrigation District to comply with the state's 33 percent RPS by procuring only enough renewables to satisfy electric demand not met by its large hydroelectric facilities. The bill is authored by Adam Gray (D-Merced).

The bill is narrowly tailored to meet the needs of MID, although it does not specify MID by name.

There is related legislation from Sen. Anthony Cannella (R-Modesto), SB 591, that passed out of the Senate Energy, Utilities and Communications Committee on April 2 (see *CEM* No. 1226 [16]).

Like SB 591, Gray's bill would allow MID to subtract its hydroelectric generation when determining how much renewable generation it needs to satisfy RPS requirements. The small utility has about 8,000 electric customers and saw peak load of 90 MW in 2011. It owns and operates the McSwain and New Exchequer dams. The output of the 94.5 MW New Exchequer dam is under contract to PG&E until July 2014; once the contract expires the electricity supply will revert to MID, which wants to use it to satisfy its RPS requirements rather than go out and buy renewables that the district has said will drive up rates.

"This is not about Merced Irrigation District not wanting to be part of the RPS," Gray said. Rather, it is about the district finally being able to receive the benefits of a hydro dam that it owns.

"As we have said, we've been waiting for this project to come back to the people of Merced," said Mike Jensen, public and government relations officer with the district. "We're simply looking for a little help here and hope you can provide that."

Several witnesses testified in opposition to the measure.

Melissa Cortez-Roth, a lobbyist representing the California Wind Energy Association, noted that all utilities have to meet the RPS procurement obligation, and CalWEA does not believe there is a reason to reduce the obligation for this particular utility.

The committee ultimately passed the bill on a vote of 12-0, but committee members had different reasons for supporting the bill. Assm. Brian Jones (R-Santee), for example, said he would support the bill today, but asked for an amendment to apply the measure state-wide.

And Assm. Das Williams (D-Santa Barbara) also supported the bill, but noted that he would not support a broader application of it ***[Mavis Scanlon].***

[14.1] Lawmakers Eye Pumped Storage for Flexible Capacity

The Assembly Utilities and Commerce Committee on April 15 passed a measure requiring energy agencies to assess the potential of pumped-storage facilities to help integrate renewables.

AB 1258 from Assm. Nancy Skinner (D-Oakland), would require the CPUC to determine the potential for existing hydro and pumped-storage facilities in the state to be used to provide additional operational flexibility for integrating renewables. The bill would apply to five pumped-storage facilities in the state—Helms, Balsam Meadow, Oroville, Castaic and San Luis.

"If we had the capacity to utilize stored generation, where water can be moved uphill and stored, then deployed at peak moments, that could potentially lead to less construction of [gas-fired] peaker plants," Skinner said.

The CEC's Integrated Energy Policy Report is a good place to look at this issue, said V. John White, legislative director of the Clean Power Campaign, who testified in support of the bill.

But a number of water districts and public utilities oppose the bill, saying it could impact the mission of the State Water Project, which is to ensure safe and reliable water delivery. Some of the facilities the bill specifies supply water through the SWP.

"The primary purpose of the State Water Project is water delivery, not power generation," said Kathy Cole, executive legislative representative with the Metropolitan Water District of Southern California.

In spite of the opposition, the committee passed the bill 15-0 ***[M. S.].***

[14.2] Legislature Moves Bill on Rate Reform

The Assembly Utilities and Commerce Committee on April 15 passed AB 327, which would repeal current limitations on raising electricity rates, including rates for low-income customers in the California Alternate Rates for Energy, or CARE, program. The bill's author is Assm. Henry Perea (D-Fresno).

"The goal is to update an outdated rate structure," Perea said at the hearing.

CARE customers receive 20 percent off their electricity bills, but proponents of changing the rate structure say that CARE customers who use larger amounts of electricity get a much higher effective discount, because of caps on Tier 1 and Tier 2 rates.

In a committee analysis of the bill, Perea said that "absent rate reform, the gap between Tier 2 and Tier 5 will double to nearly 29 cents per kWh by 2022, causing tens of thousands of customers to pay rates significantly higher than the actual cost of electricity. Without legislative changes, the CPUC has only very limited ability to fix this unfair residential electric rate structure."

A bill in the Senate, SB 743, also seeks to implement a "fix" for what lawmakers said was an unintended consequence of earlier legislation. But the Senate measure seeks to implement the fix by eliminating the CalWORKS index that CARE rate increases are tied to and instead tying those increases to the Consumer Price Index, with a maximum cap on increases of 4 percent a year (see *CEM* No. 1226 [16]).

Perea's bill is broader than SB 743 in that it repeals limitations on raising rates for all electric customers, and instead directs the CPUC to develop the rates following rate principles established in the bill. (A CPUC proceeding started last year is looking at rate structure.)

AB 327 calls for the CPUC to find any rate increases it approves to be "reasonable, including determining that the changes are necessary in order to ensure that the rates and charges paid by residential customers are fair, equitable, and reflect the costs to serve those customers."

A committee analysis of AB 327 notes the measure does not alter existing residential rates. "Rather, AB 327 provides the PUC the authority and principles to design and set residential electricity rates, including providing protection and affordability for low income households."

Stephanie Chen with the Greenlining Institute and Lenny Goldberg with The Utility Reform Network noted concerns that AB 327 could wipe out consumer protections.

"We are looking for a vehicle we can all agree on," Goldberg said, noting the Senate bill.

With passage by the utilities committee, the bill moves on to the appropriations committee ***[M. S.].***

Regional Roundup

[15] LADWP Bundles 50 MW Feed-In Tariff Program With Utility-Scale Project *(from [3])*

The Los Angeles Department of Water & Power Board of Commissioners approved on April 16 an unusual plan to solicit proposals from developers for both a utility-scale solar project and a 50 MW feed-in tariff program in a "bundled" fashion.

LADWP now has the authority to issue a request for proposals later this year to solicit competitive bids to design and build a portion of the planned 200 MW Beacon Solar Project, on the western edge of the Mojave Desert, together with an in-city solar FIT project. LADWP owns the land and permits for Beacon.

The RFP will offer developers the opportunity to build four solar-photovoltaic generation facilities at Beacon ranging in size from 40 MW to 56 MW. Developers that are awarded the rights to develop one of the Beacon sites will also be obligated to develop a corresponding FIT project, ranging in size from 10 to 14 MW, to be located within the Los Angeles Basin.

LADWP believes there are a number of benefits to the bundled approach, including attracting large developers with strong financing and contracting experience—and access to low-cost solar panels—to local projects.

"We're trying to achieve that economy of scale," noted Mike Webster, assistant director of power-system planning and development at LADWP, at Tuesday's board meeting.

The RFP will require bidders to submit two competitive prices for energy, one for the FIT component and one for Beacon. The price cap for FIT projects is set at $140/MWh, subject to a 20-year power-purchase agreement, and the cap for the Beacon projects is $85/MWh under a 25-year PPA.

Developers whose bids are selected will have to put down a security deposit of $200/kW in the form of a letter of credit. The deposit, officials said, is tied to achieving certain milestones, and will be used to purchase replacement energy if the developer fails to meet them.

"If you can't deploy the first year, and you can't deploy the second year, we're going to make the assumption that you're not serious," Webster said. "And we're not going to wait until the end to find out you've failed. We're going to take all of your security deposit and redeploy that."

Webster noted that the deposit is four times higher than what LADWP requires for its 100 MW FIT program, which was approved in January and is now under way. The 100 MW FIT program targets projects ranging from 30 kW to 3 MW in size, and has a fixed price starting at 17 cents/kWh that will decline over time (see *CEM* No. 1215 [16]).

Frederick Pickel, ratepayer advocate for the City of Los Angeles, sharply criticized the design of the 100 MW FIT program, arguing the prices set by LADWP are far too high.

On Tuesday, however, Pickel spoke in favor of LADWP's bundled approach to the subsequent 50 MW program, which allows the market to dictate the price. "I support this FIT 50 program, especially the competitive bidding nature," he said.

'If you can't deploy the first year, and you can't deploy the second year, we're going to make the assumption that you're not serious.'

Some experts, however, are questioning the wisdom of tying local FIT development to a remote utility-scale solar project.

Craig Lewis, executive director of the Palo Alto-based Clean Coalition, cited numerous concerns about LADWP's "ridiculous mix-and-match" approach, including the lack of a guarantee that developers will deliver on the FIT projects.

Developers "can walk away from the FIT project and absorb the costs in the Beacon project," Lewis said. "You can build one and take the penalty on the other."

Lewis also said that soliciting competitive bids, rather than offering a pre-defined price as LADWP did with the 100 MW FIT program, is inconsistent with FIT policy.

"This does not qualify as a FIT program, and in fact undermines the predictability, simplicity, and certainty that have made FIT programs so successful," stated Lewis. "It's also discriminatory in that it will only be applicable to extremely large players."

Toby Couture, director of renewable energy for IFOK GmbH in Berlin, Germany, also made the point that LADWP's move to large-scale competitive bidding "can be read as a step away from the 'democratic spirit' of FIT policies, and a step closer to the top-down decision-making of traditional utility procurement."

In terms of the efficiency gains touted by LADWP, Couture noted that the competitive approach does not always yield lower prices than well-designed FITs due to higher risk factors.

"These higher risks have to be priced into individual bids, which raises the cost of capital and pushes up the required PPA price," Couture said. "Under a FIT, there's less risk because you know the price, you know the terms, and you don't have to sink a lot of money in without knowing whether you'll get to build in the end" ***[Leora Broydo Vestel].***

[15.1] Blythe Project Downsized to 485 MW

NextEra Energy Resources has scaled back its plans to build a 1 GW solar-photovoltaic plant in the California desert.

The Blythe Solar Power Project was approved in 2010 as a 1,000 MW solar parabolic-trough project, near the City of Blythe, on public land in Riverside County. A NextEra subsidiary last year acquired the proposed project from bankrupt Solar Millennium. In June of last year NextEra petitioned the CEC to convert the project from concentrating solar power to photovoltaic. On April 17, NextEra revised that petition, stating it now plans to build a phased PV project up to 485 MW.

"The use of a previously permitted site as reconfigured to further lessen environmental impacts with an approved Large Generator Interconnection Agreement is a responsible approach to helping California achieve its Renewable Portfolio Standards and beyond," the developer said in the revised petition to amend ***[Mavis Scanlon].***

[16] New BPA Oversupply Cost Allocation Differs From Customer Suggestions *(from [4])*

The Bonneville Power Administration's new proposal for allocating oversupply costs is based on a customer's use of the transmission system during oversupply events.

Under the proposal, "each of the users, including BPA Power Services, bears its proportionate share of the costs." The plan retains BPA's commitment to an $8 million monthly cap on oversupply charges, rolling over any excesses until paid off.

"This framework helps move us forward," said BPA Administrator Bill Drummond in a press release. "Our efforts to have a final proposed rate by late August are on schedule."

The new, so-called Oversupply Charge rate schedule would cover administrative expenses ($248,844 in 2012) and would compensate participating generators for the loss of renewable-energy production tax credits and renewable-energy credits when curtailing power output during oversupply events.

BPA described the plan in a supplemental proposal filed April 12 in the OS-14 rate proceeding; the new plan takes the place of the one BPA filed in its initial proposal last November. Under the old plan, half the cost to displace generators during oversupply events would have been allocated to power rates and the other half to generators electing to receive benefits under the Oversupply Management Protocol (OMP).

BPA in March 2012 filed the OMP terms and conditions and gave FERC a heads-up on the 50-50 cost allocation it later filed in OS-14. The new protocol, in turn, replaced the BPA Environmental Redispatch policy, under which BPA curtailed wind and thermal generation when hydro generation was high. FERC rejected that policy in December 2011 in response to a complaint from wind generators that said it violated BPA's voluntary open-access transmission tariff (OATT).

BPA's rehearing request for that ruling is still pending, as is a related lawsuit.

Last December, FERC accepted the OMP's terms and conditions, but didn't like BPA's 50-50 allocation proposal. It approved the OMP contingent on BPA filing an allocation "to all firm transmission customers based on their respective transmission usage during oversupply events" or some other formula ensuring "comparability."

After a round of discussions, OS-14 parties filed "narratives" staking out their factual and legal positions. Narratives were submitted by the Renewable Northwest Project; Southern California Edison; Avista; Western Public Agencies Group; Turlock Irrigation District; M-S-R Public Power Agency; Powerex; and two joint customer groups—one representing Iberdrola and three Northwest investor-owned utilities, and another representing Alcoa and a large group of preference customers.

In its supplemental proposal testimony, BPA said the narratives fell into three categories: "(1) locating all costs to the transmission function and melding the costs into existing transmission rates; (2) allocating all costs to the power function and melding the costs into existing power rates; and (3) allocating all the costs to the transmission function and developing a new rate based on the generation within BPA's balancing authority area that is on line during the hours of oversupply events."

But the agency did not select any of the proposals outlined in the narratives. It is "not prudent to burden either the existing power or transmission rate case[s]" with the issue because it is contentious and liable to generate more litigation. BPA does not want to have to rely on forecasts of transmission usage during oversupply events, or of the events themselves until it has more experience doing so. It also argues that "spreading the costs to all transmission users spreads the cost of oversupply too broadly."

The agency is proposing to "functionalize all oversupply costs to the transmission function and to charge the costs to transmission customers proportional to their use of the transmission system during oversupply event hours."

It said the 50-50 allocation proposal recognized two cost-causation elements: "fish and wildlife obligations and the fact that renewable generation requires compensation payments when it is curtailed . . . [but] did not account for the fact that all generation on line at the time of an oversupply event contributes to the oversupply problem."

But the supplemental proposal also recognizes that BPA's voluntary OATT is the "causal factor that led to such widespread use" of its transmission system.

BPA noted its Environmental Redispatch policy "acknowledged that parties could well argue that oversupply costs 'should not be viewed as a fish and wildlife cost, occasioned by environmental limits, but as a transmission cost, since the cause of payments would be BPA's open access transmission regime.'" If not for open transmission access, BPA "would not be paying negative prices to meet its environmental responsibilities."

"This reasoning supports functionalization of all oversupply costs to transmission, and appears to be aligned with the commission's guidance to allocate costs to all firm transmission use during the oversupply event," BPA stated.

OS-14 rate-case parties are due to file their direct cases May 8 and rebuttals May 29; initial briefs will follow on June 27.

The public will have until May 22 to submit comments on BPA's revised proposal. The agency plans to issue a final record of decision on Aug. 28, 2013 ***[Ben Tansey].***

[17] FERC Moves to Broaden Cybersecurity Standards

FERC has proposed improving cybersecurity standards and extending the scope of the systems protected by such standards.

The proposal to improve the standards, submitted in January 2013 by the North American Electric Reliability Corporation, constitutes Version 5 of NERC's Critical Infrastructure Protection Reliability (CIP) standards. At its April 18 business meeting, FERC opened a rulemaking on the proposed rules to seek comment *[RM13-5]*.

The rules include 12 requirements with new cybersecurity controls, including electronic security perimeters (CIP-005-5); systems security management (CIP-007-5); incident reporting and response planning (CIP-008-5); recovery plans for bulk electric-system cybersystems (CIP-009-5); and configuration change management and vulnerability assessments (CIP-010-1).

'Just when you think you have the latest, greatest version, something new comes along.'

The proposal would also use a new, tiered approach to identifying and classifying BES cyberassets to better protect the bulk electric system. The "high impact" category covers large control centers, similar to those identified as critical assets in CIP-002-4. The "medium-impact" category covers generation and transmission facilities, similar to those identified in CIP-002-4, along with other control centers not identified as critical assets in CIP-002-4. The "low impact" category covers all other BES cybersystems.

"The Version 5 Standards require, for the first time, that all cyber systems receive some level of protection based on their impact on the grid," Commissioner Cheryl LaFleur said in a statement.

LaFleur drew an analogy between the CIP standards and the iPhone. "Just when you think you have the latest, greatest version, something new comes along—something that has more coverage, a better user interface, or more features. The same is true with the CIP Standards. There is always room for improvement. There is always a way to better distinguish or capture more assets."

FERC, however, is seeking comments about the proposed standards, especially their enforceability. For example, LaFleur noted, language in the standards requiring entities to "identify, assess and correct" deficiencies "may result in requirements that are unclear and difficult to audit or enforce." The commission also wants comment on whether a two-year implementation period for "medium" and "high impact" assets and a three-year period for "low impact" assets are necessary or can be accomplished more quickly.

"Right now, I am focused on implementation rather than compliance," Commissioner John Norris said in a statement. "While I believe that compliance with Reliability Standards is crucial, I also believe that, on the whole, industry fundamentally wants to do the right thing. We must do everything possible to help industry succeed. This will be an ongoing, evolving process because cyber threats are constantly evolving."

In addition to its action on the CIP standards, FERC largely affirmed its final rule, Order No. 773, approving a new definition of the bulk electric system for purposes of compliance with reliability standards *[RM12-6, RM12-7]*. In December, the commission modified the definition of BES by establishing a "bright line" threshold by which any facilities operated at 100 kV or above would be considered part of the bulk electric system, though exclusions would be available for certain transmission configurations. FERC also retained the right to designate sub-100 kV facilities as part of the BES.

'Right now, I am focused on implementation rather than compliance.'

At its Thursday business meeting, the commission granted in part and denied in part rehearing requests on Order No. 773. FERC affirmed that certain configurations on the transmission network do not qualify as "radial" for the purpose of being excluded from the definition of BES (exclusion E-1). But these facilities may qualify as "local networks" (exclusion E-3). The commission said that NERC is free to develop alternatives to modifying the radial exclusion to include the configurations that are not eligible for the local-networks exclusion.

FERC also clarified that unregistered entities or facilities included in the BES for the first time as a result of the new definition do not have to comply with newly relevant reliability standards while their exception requests are pending. The commission expects entities to file, and NERC to decide, any exception requests during the two-year transition period approved in the final rule. In addition, state regulators may participate in local-distribution determinations, but the question of whether a facility is "local distribution" will be decided by FERC. The commission expects the number of local-distribution determinations to be small, about eight a year.

FERC also proposed to modify four reliability standards to clarify that they apply to generator-lead lines *[RM12-16]*. The standards include vegetation management (PRC 004-2); facility interconnection requirements (FAC 003-3); and two related to protection systems (PRC004-2.1a, PRC 005-1.1.b) ***[Chris Raphael].***

[17.1] FERC Partially Accepts Cal-ISO Regional Transmission Plan

FERC has accepted Cal-ISO's plans for regional transmission planning and cost allocation under Order No. 1000, though it directed the grid operator to make some clarifications *[ER13-103]*.

Order No. 1000 requires that each public-utility transmission provider participate in a regional transmission-planning process that produces a regional transmission plan. Such a plan must consider transmission needs driven by public-policy requirements; remove federal rights of first refusal to build transmission; and improve coordination between neighboring transmission-planning regions for new interregional transmission facilities.

Other Order No. 1000 reforms include a regional or interregional cost-allocation method for new transmission facilities selected in a regional transmission plan or located in two neighboring transmission regions.

FERC directed Cal-ISO to make some minor revisions in its Order No. 1000 tariff, including:

- On the subject of public-policy transmission plans (such as for renewables), Cal-ISO must take municipal and local plans into account.
- In eliminating the federal right of first refusal to build transmission, Cal-ISO must clarify terms such as "project," "solution," "element," "upgrade," and "addition" when explaining which transmission facilities are subject to competitive solicitation and which are not.
- Establish fair and non-discriminatory criteria for determining an entity's eligibility to submit a proposal in its competitive solicitation process. Each potential transmission developer must be given the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop, construct, own, operate, and maintain transmission facilities. "It is unclear what qualification criteria a transmission developer must meet to submit a proposal in CAISO's competitive solicitation process," FERC stated.
- Explicitly state what information requirements must be satisfied for a transmission developer to submit a proposal to finance, own, and construct a regional transmission facility in its comprehensive transmission plan.
- Create a process under which Cal-ISO will decide which transmission developer is eligible to use the regional cost-allocation method for a transmission project selected in the regional plan.
- Explain how it will determine which are the "key" selection factors for each transmission facility selected in the transmission plan and how it will ensure the key factors produce more efficient or cost-effective regional transmission solutions.
- Clarify that a siting authority's authority to impose cost-containment measures, and its history of doing so, will be considered by Cal-ISO only in instances where none of the competing transmission developers has accepted specific and binding cost-control measures ***[C. R.].***

Bright Ideas

[18] Storage Startup Uses Old Technology *(from [6])*

Imagine pumped-storage hydropower, but with railroad cars on tracks instead of water in pipes, and what you've got is the brainchild of a California startup.

Santa Barbara-based ARES North America is proposing to use weighted railroad cars on tracks to create grid-scale energy storage needing no water, hazardous materials or fossil fuels, and producing no emissions.

According to the company, ARES (short for Advanced Rail Energy Storage) "is a rail-based technology that stores energy by raising the elevation of mass against the force of gravity and recovering the stored energy as the mass is returned to its original location."

The technology uses off-peak energy—preferably generated by renewable resources—to run a full-scale electric locomotive, pulling four flatcars loaded with concrete on railroad tracks up a hill to an upper rail yard. There the unit would remain until it was called upon to return its stored energy to the grid. Then, when the energy was needed, the four-car unit would be released back down the hill to a lower rail yard, and its motion would be used to spin a generator.

'The simplicity of the application is just absolutely beautiful.'

Each four-car unit could generate about 2 MW over 30 minutes, with as little as a few seconds' notice by a grid operator, and the system would be infinitely scalable, from about "100 MW with 200 MWh of storage capacity up to large 2-3 GW regional energy storage systems with 16-24 GWh of energy storage capacity," according to the company.

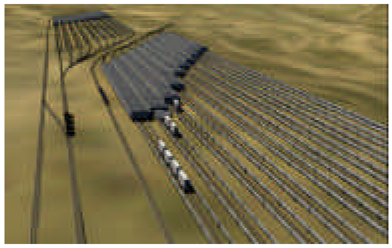
The system, of course, would require sloped terrain on which to lay the tracks. "A 6 to 8 percent grade is our sweet spot," said ARES CEO James Kelly, an energy-industry veteran who worked for Edison International for 38 years, most recently overseeing Southern California Edison's 50,000-square-mile grid as its senior VP of transmission and distribution.

Kelly told *California Energy Markets* that in the western United States "there are a tremendous number of good sites," and the ideal terrain is alluvial-fan topography, typically formed by sediment deposited by water draining down a canyon from mountainous terrain onto a flatter plain below.

That type of topography often occurs in arid areas with great wind and solar resources, he added.

The system is also "light on the land," Kelly said. "There's little environmental impact—just railroad tracks. You can just pull up the tracks, rake it out, throw out some grass seed and you'll never know we were there."

The ARES system differs from pumped-storage hydro in that it does not require the damming of water



Above: An ARES demonstration system in Tehachapi with wind turbines in the distance. At left, an artist's rendering. *Photos courtesy ARES.*

resources—often in arid regions—and does not require boring pipes through rock. Because of this, ARES doesn't trigger the federal permitting required of dams, and doesn't have the complicated environmental and water-management issues that contribute to pumped-storage hydro's typically 10- to 15-year permitting cycle.

According to Kelly, an ARES system would take about 12 to 18 months to permit—about the same amount of time it would take to permit a railroad track. And the cost of an ARES system would be 50 to 60 percent less than a similarly scaled pumped-storage hydro project—which tends to be much cheaper than other storage technologies, such as batteries and flywheels.

Kelly told *CEM* that he views the ARES system as something complementary to, not in competition with, batteries and flywheels, because of the difference in the scale ranges of the technologies. And ARES technology has an average efficiency of about 85 percent, compared to 75 percent for pumped-storage hydro.

And because of its scalability and ability to respond to requests for generation within seconds, he said he views the technology as ideal for providing balancing services to regional grid operators, such as Cal-ISO.

According to the U.S. Department of Energy, more than 100 GW of new storage capacity will be needed in the U.S. by 2030, to integrate all the renewable energy required by state and national goals.

Within the next few weeks, Kelly said, ARES will be unveiling a demonstration project with a scaled-down locomotive and about a thousand feet of track near the Tehachapi Pass wind farm in Kern County, Calif., "purely as a test bed." Then, later this year, the company will install its first commercial, 50 MW phase in southern Nevada's Nye County, where there are renewable-energy projects totaling thousands of megawatts in various stages of development.

The Nye County project will be developed in cooperation with Valley Electric Association, which joined Cal-ISO in January of this year.

"The project is a natural fit for us, partly because of the terrain, and also because of the 1.4 GW of generation proposed in our service area," said Valley Electric CEO Thomas Husted. He said most of the projects are photovoltaic and solar thermal under development by independent power producers.

When ARES approached Valley Electric a year ago, it was "a Eureka moment for us," Husted said. "The simplicity of the application is just absolutely beautiful. We've seen a lot of projects come and go over the past several years, and this one really excites us" ***[Penelope Kern].***

Southwest

[19] Navajo Council Tables Lease Extension for Coal-Fired Power Plant *(from [7])*

Efforts to obtain Navajo Nation approval of a 25-year lease extension for the 2,250 MW, coal-fired Navajo Generating Station near Page, Ariz., have stalled.

The Navajo Nation Council on April 17 considered amending the proposed lease-extension agreement, but then voted 15-7 to table the lease-extension request until April 29. The council also asked for a meeting with owners of the generating station.

Earlier Wednesday, Navajo Nation President Ben Shelly in a letter urged the legislative body to approve the lease extension.

"It is a well-negotiated lease agreement," Shelly said.

The Salt River Project, which operates the plant, has said there is little if any room to negotiate further, Shelly said. "They consider the major points of the agreement to be exhausted, such as jurisdiction and money," Shelly said.

The lease extension would increase power-plant annual payments to the nation, including taxes, to $43 million from $3 million currently.

In addition, the agreement provides $150 million in additional economic benefits to the tribal nation prior to the current lease expiration in 2019, according to SRP.

However, members of the council on Wednesday discussed amendments to require covering fly ash with soil, to ensure that the extension does not limit Navajo Nation water rights, and to give job preferences to Navajos at the power plant.

SRP issued a statement saying it was disappointed the council tabled the lease extension.

For two and a half years, the plant owners and Navajo environmental, finance, natural resources and Department of Justice officials negotiated the lease extension, SRP said.

"Those negotiations addressed the issues raised at Wednesday's council and were fairly agreed to," SRP said.

SRP said it will confer with other owners of the plant on how to proceed.

The U.S. Bureau of Reclamation owns 24.3 percent of the plant, followed by SRP at 21.7 percent and the Los Angeles Department of Water & Power at 21.2 percent. Also, Arizona Public Service owns 14 percent; NV Energy, 11.3 percent; and Tucson Electric Power, 7.5 percent.

NV Energy and LADWP have discussed plans to sell their ownership interests in Navajo Generating Station. Separately, the U.S. Environmental Protection Agency in January proposed requiring selective catalytic reduction equipment to reduce nitrogen-oxide emissions at the plant, which would cost an estimated $1.1 billion ***[John Edwards].***

[19.1] Ormat's Enhanced Geothermal System Connects to the Grid

The U.S. Department of Energy on April 12 announced that Ormat Technologies' Desert Peak 2 project in Churchill County, Nev., became the nation's first commercial enhanced geothermal-system project connected to the electric grid.

The enhanced geothermal system increased power output at the nearby geothermal field by 38 percent or 1.7 MW to 4.5 MW, DOE said.

The project prolongs the life of previously unproductive wells, according to DOE.

Enhanced geothermal systems use directional or non-vertical drilling and pressurized water to capture energy from hot rocks thousands of feet below the surface.

DOE awarded a $5.4 million grant that was matched by $2.6 million from the private sector.

Since 2008, DOE has worked on the project with GeothermEx, Ormat Technologies, the U.S. Geological Survey and the Lawrence Berkeley and Sandia national laboratories to develop cost-effective technologies at Desert Peak 2.

The United States has the potential to develop 100 to 500 GW of geothermal resources, according to the USGS.

Nevada Power buys power from Desert Peak 2 through a power-purchase agreement that expires in 2027 ***[J. E.].***

[19.2] Utility Sees Difficulties With Natural Gas Vehicle Stations

New Mexico Gas, a local gas-distribution company, in a regulatory filing April 15 said it must solve regulatory and cost issues before extending gas transmission lines to natural gas fueling stations for vehicles.

The company made the comments in response to a decision of the New Mexico Public Regulation Commission in February to review NMG's gas-extension policies and their effect on businesses that want to convert gasoline-powered vehicles into natural gas-powered vehicles.

NMG said it would like to enable businesses to establish natural gas fuel stations for "quick fills" of cars and trucks with natural gas within three minutes.

However, the quick-fill stations would place "extreme demands" on a natural gas system.

A medium-sized compressed natural gas facility sometimes would require the same amount of gas as 30 medium-sized hotels at one location "but does so on an unpredictable schedule," NMG said.

The natural gas stations can be built next to existing high-pressure lines if those lines have the capacity required, the company said. But the cost of laying a high-pressure line for a vehicle fuel station can make a project uneconomical for NMG even if the customer pays a large portion of the cost, the company said.

Furthermore, Rule 16 of the NMPRC states that new customers should not create a burden on existing customers and that new customers must provide additional revenue to support incremental costs, NMG argued. Therefore, the natural gas stations must use slower pumping equipment to minimize changes in the gas-distribution system. But slow-fill facilities are less likely to provide effective service for large fleets of natural gas vehicles, the company said.

In addition, NMG reported the failure of a predecessor, Gas Company of New Mexico, with a five-year experimental program that the commission approved in 1993. The program was designed to encourage conversion of gasoline- and diesel-powered vehicles to natural gas, NMG reported, but the program cost $32 million and the utility "lost millions of dollars."

A federal requirement to convert federal and state vehicle fleets to natural gas was not enforced, and that dampened demand for natural gas vehicle fuel, the company said.

In 2004, the NMPRC permitted the company to sell most of its fueling stations to Clean Energy Fuels, in which T. Boone Pickens owns a 21 percent interest.

NMG said 14 natural gas stations in New Mexico now sell natural gas for use in vehicles and 10 companies have proposed stations. But 17 natural gas stations have closed. NMG sells gas to natural gas fueling stations for 5 cents/therm, a discount from the 15 cents/therm for other small commercial customers, according to the company ***[J. E.].***

Potomac

[20] Energy Industry Pleads for Tax Breaks; IRS Clarifies PTC 'Work' Criteria

(from [8])

Energy organizations have sent the House Ways and Means Committee pleas for tax preferences benefiting their industries.

The committee has established 11 working groups, including energy, to examine comprehensive tax reform.

A renewable-energy production tax credit lasting at least six years "could bring costs down to a competitive level and maintain a minimally viable industry," Rob Gramlich, the American Wind Energy Association's interim CEO, said in an April 15 letter, which took issue with the "stop/start nature of short-term PTC extensions." The current PTC expires in 2014.

In a March 26 submission, the American Petroleum Institute called for continuing intangible drilling-cost and Section 199 manufacturing deductions.

Meanwhile, Gramlich defended the production tax credit at an April 16 hearing of two House Science Committee panels where the credit came under fire from their Republican chairmen.

Gramlich took issue with a recent Government Accountability Office study reporting seven of 82 "wind-related" federal initiatives were duplicative.

Meanwhile, the Internal Revenue Service ruled on April 15 that "physical work of a significant nature" would qualify renewable-energy projects for the production tax credit this year.

In a guidance document, the IRS said qualifying work at a wind-energy facility would include digging a hole for the foundation, placing anchor bolts into the ground, or pouring the foundation's concrete pads.

Manufacturing of components offsite also would qualify, as long as the work is done under a "binding written contact," the IRS said.

"Preliminary activities," such as planning, design, securing financing, permitting or engineering, would not qualify a project for the credit, the IRS said.

Renewable-energy developers and congressional allies have pressed the IRS to determine how projects would qualify for the credit, after Congress early this year extended the credit until Jan. 1, 2014.

The extension legislation allows renewable-energy plants to qualify for the credit if they begin construction by the Jan. 1 expiration date. Under previous law, projects were required to enter service before the expiration date.

Panel Split on DOE Veto Power Over EPA Regs

Legislation giving DOE potential veto authority over EPA regulations costing more than $1 billion drew sharply divergent reactions along partisan lines at a House subcommittee hearing April 12.

The Electric Consumers Relief Act would force EPA to submit proposed regulations costing an estimated $1 billion or more to DOE for analysis. If DOE determined the regulation would raise energy prices, the department would carry out a second study. If the second analysis found "significant" economic impacts, EPA would be barred from finalizing the rule.

The legislation "simply requires a more thorough review of the costs and impacts on jobs and energy prices," Rep. Ed Whitfield (R-Ky.), chairman of the House Energy and Commerce Committee's energy and power panel, said at a hearing.

In response to questions from Rep. Jerry McNerney (D-Calif.), the Electric Reliability Coordinating Council's Scott Segal said analysis required by the bill could shed light on potentially less-costly technologies for reducing emissions.

Rep. Henry Waxman (D-Calif.), however, said the bill would result in "indefinite delays" of regulations he said are necessary to protect public health.

An EPA statement signaled Obama administration opposition, saying the bill "would waste limited analytical resources on duplicative analysis."

BPA Advises House Panel on Columbia Treaty

Bonneville Power Administrator Bill Drummond told a House subcommittee hearing April 16 that a "modernized" Columbia River Treaty should have reopener clauses allowing for changes to account for climate change or other contingencies.

A "sovereign review team" made up of state and federal agencies and 15 tribes is examining river-management alternatives involved with extending, modifying or terminating the treaty. After Sept. 16, 2014, either the U.S. or Canada could give a required 10 years' notice to end most of the pact's provisions.

In response to questions from Rep. Peter DeFazio (D-Ore.) at a hearing of the House Natural Resources Committee's water and power panel, Drummond said a top issue is the Canadian Entitlement, which he said "needs to be rebalanced."

The position of the treaty's "U.S. Entity," made up of BPA and the U.S. Army Corps of Engineers, is that the Canadian share of downstream power benefits after 2024 will be significantly lower than the 450 aMW forecast under current calculation methods.

Another important issue, Drummond said, is defining what the treaty's post-2024 flood-control provision "really means."

Regardless of whether the treaty is extended or terminated, its flood-control provision expires in 2024, which would force the U.S. to use all available domestic storage before calling on Canadian storage.

"We need to figure out ecosystem benefits, which were not included when the treaty was ratified in 1964," Drummond added.

DeFazio noted he is "very concerned the State Department might trade off something that has nothing to do with the Columbia River to Canada for something else they want somewhere."

The U.S. Entity plans to send recommendations about the treaty's future to the State Department by September.

House Passes Cyber Bill, Defies Veto Threat

The House passed cybersecurity legislation on April 18, defying an Obama administration threat to veto the legislation over privacy issues.

The House voted 288-127 to pass the Cyber Intelligence and Sharing Act, HR 624.

In a statement of administration policy, the White House said the bill "does not require private entities to take reasonable steps" to protect personal information if cybersecurity information is sent to federal agencies.

The bill seeks to foster cybersecurity information sharing between federal agencies and utilities and others in the private sector. The legislation would shield private parties from liability if they shared cyberthreat information with federal officials.

Senate Panel OKs Proposed DOE Chief

The Senate Energy and Natural Resources Committee reported out on April 18 the nomination of Ernest Moniz to be secretary of the Department of Energy. On a 21-1 vote, the committee sent Moniz's nomination to the floor. Moniz, who served as DOE undersecretary during the Bill Clinton administration, is an MIT physicist.

Proposed Hydro Cuts Bug Senate Panel

Senate Energy and Natural Resources Committee leaders scolded the Obama administration April 18 for proposing cuts to water-power research funds in its fiscal 2014 budget request.

Chairman Ron Wyden (D-Ore.) said at a hearing exploring the proposed DOE budget that he was "very troubled" by the administration's proposal to cut water-power R&D from this year's $59.15 million to $55 million.

"I want to add a 'me too' about hydro," said Sen. Lisa Murkowski (R-Alaska), the panel's ranking Republican.

"The area where everyone agrees we have so much potential for growth is hydro," Murkowski added.

Wyden also called for more research into natural gas well integrity, which he said would pay off "many times over" in reduced environmental cleanup costs.

EPA Misses Deadline for Power-Plant CO_2 Rule

The Environmental Protection Agency missed an April 13 deadline to finalize a proposed rule setting a carbon-dioxide emissions standard of 1,000 pounds per MWh for new fossil-energy power plants.

EPA has not said when the proposal would be finalized. At her April 11 Senate confirmation hearing, EPA administrator-nominee Gina McCarthy indicated the agency would be willing to consider separate standards for new coal and gas-fired plants.

Panel: 'Consent-Based' Nuke Waste Siting Hard

"Consent-based" siting of a spent-nuclear-fuel repository might be easier said than done, the head of a federal technical advisory board told a House subcommittee April 11.

Rodney Ewing, a University of Michigan engineering professor who chairs the Nuclear Waste Technical Review Board, said experiences of other countries with consent-based siting have been mixed.

Ewing testified before the House Appropriations Committee's energy and water panel.

Last year, DOE's Blue Ribbon Commission recommended using consent-based siting to develop a permanent repository.

Ewing said a "promising" consent-based process is under way in Canada. That country's Nuclear Waste Management Organization is working with 21 communities interested in learning more about hosting a repository. On the other hand, the mayor of a southern Japanese town who volunteered to participate in a siting process was recalled from office, and no Japanese community has since volunteered, Ewing testified ***[Jim DiPeso].***