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BILLBOARD No. 1281

Western Price Survey

[1] For 'Shared Renewables' Program, Devil Is in the IOU Program Details

Hashing out the complexities involved in the implementation of SB 43—the "shared renewables" bill—won't be easy. The bill was designed to allow those without rooftops to access renewables such as solar power through special tariffs and receive bill credits, but speakers at an April 30 meeting in San Francisco homed in on some of complexities. Those include the premium charged for green power versus the bill credits, utility use of pre-existing contracts for renewables, and whether customers could contract with one specific project or a pool of projects.

Photo courtesy Brad Topar, flickr.com.

Shared renewables lacks shared vision at [14].

[2] Commission Rejects Extra RECs for PG&E

The CPUC rejected a proposal from Pacific Gas & Electric to buy extra renewable-energy credits to bank for later use. At a business meeting, the commission raised concerns over whether the surplus RECs that PG&E sought might impede growth of actual renewable generation. Other commissioners, however, said that such contracts can help utilities meet renewables goals while managing costs to customers.

At [13], missing the larger purpose?

[3] Sonoma Clean Power Flips Switch on New CCA Program

Sonoma Clean Power began serving more than 20,000 electric customers in Sonoma County on May 1, marking the successful launch of the state's second community-choice aggregation program. Enrollment in the upstart CCA is better than expected, with an opt-out rate of about 5 percent of all customers that were targeted for service. The celebratory mood is being tempered, however, by a proposed state law that could impact SCP's future success. ***At [16], a "clean start" for SCP customers.***

[4] San Francisco Looks to Link With Marin Clean Power

San Francisco officials are taking a serious look at the possibility of hooking up with Marin Clean Energy as a means of launching community-choice aggregation service in the city. A proposed ordinance supported by several members of the San Francisco Board of Supervisors calls for formally analyzing the feasibility of joining MCE, or having the CCA provide services through a yet-to-be-determined arrangement. Legislation to facilitate a CCA-related agreement between San Francisco and MCE has also been introduced at the state level. ***At [15], a path forward for CCA in San Francisco?***

[5] PG&E Reports 5 Percent Drop in First-Quarter Earnings

Despite posting higher revenue, PG&E Corp. reported a 5 percent drop in first-quarter earnings as expenses rose. First-quarter profit includes the impact of $40 million in natural gas pipeline-related charges. Spending on gas issues continues to weigh on PG&E, which faces up to $2.25 billion in fines and penalties at the CPUC over the San Bruno explosion, and $6 million in fines from federal criminal charges. ***At [20], Carmel incident could also provoke fines.***

[6] Edison Stresses Spending on Wires, Distribution, Emerging Markets

Edison International's earnings suffered in the first quarter from a settlement agreement related to the San Onofre Nuclear Generating Station, but the holding company stressed its core profits at utility subsidiary Southern California Edison and future growth from distribution and transmission spending. ***At [19], Edison also notes alternative-energy invesments.***

[7] Study: Desert Soil Captures and Stores Lots of Carbon

A group of environmental scientists has discovered that arid areas, among the biggest ecosystems on the planet, capture and store an "unexpectedly large amount of carbon as CO_2 levels increase in the atmosphere." The study has raised questions about preserving deserts or using the land to develop renewables. ***At [17], deserts as a carbon sink.***

[8] Nevada Power Ratepayers May Face Higher Basic Service Charge

Nevada stakeholders are balking at a proposal to consider special net-metering rates in Nevada Power's general rate case. If not considered in the rate case, however, consumer advocates fear that regulators would raise Nevada Power's basic service charge, as it did with Sierra Pacific Power, where the basic service charge rose from $9.25 to $15.25. ***Also at [18], Ormat considers selling power plants.***

[9] Industry Groups Urge Senate Vote on Energy-Efficiency Legislation

One hundred industry trade groups and manufacturers wrote Senate leaders April 30 urging a floor vote "as soon as possible" on a wide-ranging energy-efficiency bill, but political complications could stand in the way. Meanwhile, the House Energy and Commerce Committee reported out a heavily amended bill to speed up permitting of natural gas exports. ***Supreme Court decision upholding EPA transport rule draws cheers, jeers at [21].***

News In Brief

[10] SDG&E Looks to Test EV Charging Rates Through Pilot Program

In an effort to gauge benefits to customers from integrating electric-vehicle charging loads to the grid, San Diego Gas & Electric wants to start a pilot program involving an hourly time-variant rate and EV charging infrastructure.

The program's costs would total about $102.7 million. SDG&E aims for 50 site installations of 10 charging stations in 2015, 100 site installations of 10 stations in 2016, and 200 site installations of 10 stations in both 2017 and 2018. The utility would analyze program and rate data from 2015 through 2025.

The utility aims to contract with third parties to build, install, operate and maintain EV charging facilities, which would be built at workplaces and multi-unit dwellings, where charging can take place around the clock and potential EV customers may not otherwise have convenient access to charging.

Multi-unit homes make up about half of the homes in the San Diego region, yet most EV owners live in single-family homes and own their own homes, SDG&E noted in its April 11 application at the CPUC.

"This demonstrates that prospective EV customers who could benefit from [multi-unit home] and workplace charging sites may be currently underserved," SDG&E said.

The pilot program also "has great potential to increase EV ownership and zero emission miles driven per EV" and to provide opportunities to examine the benefits of grid-integrated charging and multi-unit home and workplace siting, SDG&E said.

The program would test and measure the flexibility of EV charging loads and the degree to which efficient integration of EV loads can yield cost savings to all customers by avoiding future utility infrastructure additions, SDG&E said.

A pilot rate will include a variable commodity component based on Cal-ISO's day-ahead hourly price; a dynamic-pricing signal to recover commodity capacity costs; and a dynamic-pricing signal to recover distribution-circuit peak costs and address local capacity concerns.

Customers using the rate could enter their preferences for charging price and quantity through a mobile phone or website. Hourly pricing would be available a day ahead. Hourly charging prices would correspond with the expected changing hourly price of electricity. Prices would aim to encourage charging at times of the day that minimize peak load, integrate renewables and avoid charging on system peaks.

SDG&E wants to set up a balancing account to record costs and revenue from the program ***[H. C.].***

Bottom Lines

[11] CEM's Silver Anniversary

They say if you live long enough you get to see every trend repeated. *California Energy Markets,* which turns 25 this week, has either lived for a long enough time to see the resurrection of power trends, or state energy policy hasn't fully let go of those Pearl Jam CDs and flannel shirts. I think the latter—at 25, *CEM*'s had quite a history, but we're also in our prime.

Our first edition appeared on May 5, 1989. The newsletter was launched by Energy NewsData's publisher emeritus, Cyrus Noë, and in the early days it was printed, mailed, and run out of the San Francisco home of founding editor Arthur O'Donnell, now a program supervisor at the CPUC.

The publication's stated purpose, articulated in the first issue, was to cover the Southwest energy industry in a comprehensive way that niche industry publications did not, and without advocacy, tilt or hidden agendas. That same purpose lives on today, even if market dynamics and policies have evolved.

Notably, however, some issues persist. The inaugural issue of *CEM*, which arrived at 20 pages and was five hours past due, carried news of the expansion of the Pacific DC Intertie, which today remains a crucial conduit of hydropower from the Pacific Northwest—especially this summer, as California remains in a devastating drought. There was also news of a CPUC hearing on utility demand-side management efforts—will the DR issue ever be solved in California?—and the restart of Unit No. 1 of the San Onofre Nuclear Generating Station. The unit had issues related to seismic retrofits, and was permanently shut down in 1992 because of exorbitant costs to repair its damaged steam generators. *Déjà*-nuke.

State energy policy hasn't fully let go of those Pearl Jam CDs and flannel shirts.

The lead story in the first issue reported on Southern California Edison's plans to merge with San Diego Gas & Electric, which had considered merging with Tucson Electric Power. The merger, which was prompted by expectations of consolidation in a scattered electric industry, never happened, though SDG&E later did merge with Southern California Gas, both of which are Sempra Energy subsidiaries.

CEM at the time likened Edison's announcement to a declaration of love to someone already betrothed. These days, perhaps the big utility players are more concerned about losing market share to distributed power such as solar and storage, though they are certainly dating the sector through investments in DG companies. MidAmerican Energy Holdings' recent acquisition of NV Energy is noteworthy, however, as is the merging of neighboring grids through energy imbalance markets. There's a sense that grids need to hold hands, at least, to integrate renewables, but also a fear that solar and energy storage could homewreck the IOU business model.

Throughout the 1990s, *CEM* covered the race to construct transmission and gas pipelines to serve California, including the 500 kV California-Oregon Intertie and Southwest Powerlink projects; the pricing of power as a commodity; the emergence of independent power producers; and the struggle to incorporate independent power into the system.

The publication earned National Press Club honors for analytic reporting for its work during the energy crisis, which, from a news-gathering perspective, was like being "in a whirring blender, with bits and pieces of information flying around," as O'Donnell put it.

I joined *CEM* in 2005, after a career in journalism and a graduate-school thesis on the environmental and economic impacts of a liquefied natural gas export project in Peru. I recall coming across one of the first large-scale RPS contracts in the state, a 500 MW agreement between Edison and Stirling Energy Systems, signed in 2005.

SES later filed for bankruptcy, and its projects, acquired by other companies, never got off the ground. But those were the early days of the 20 percent RPS, with hazy technologies. It's been exciting to see renewable-energy projects flock to the grid since, and to cover related issues such as net-energy metering, capacity contracting, and environmental concerns of large-scale renewables.

As markets evolve, so will *CEM*: In my time here we've added coverage of greenhouse-gas regulations, distributed generation, energy storage, and community-choice aggregation. Last year we revamped our weekly price report and included two charts that now show renewable-energy production on a weekly basis in the Cal-ISO and Bonneville Power Administration areas. One of the charts is quite tricky to produce, but worth it.

As always, we strive to be accurate and fair, and include various points of view, whether from IOUs, municipal utilities, power producers, energy traders, or environmental/customer advocates. Looking ahead, we'll be covering themes including the IOU business model in an age of distributed generation; flexible capacity; and how the state's GHG policies are working or not. Think of us as intelligence for the Southwest energy industry, without the flannel shirt.

I'd be remiss if I didn't mention, as our production supervisor pointed out late on Friday, that the current issue of *CEM* also runs 20 pages. It could have run 24—it almost always can—but I prefer not to maim our hard-working staff, myself, or readers.

We welcome feedback, and if you have any questions or suggestions on *CEM*, feel free to contact me at 510-932-8029 or chris@newsdata.com ***[Chris Raphael].***

Western Price Survey

[12] Power Prices Remain Low, but Parched Summer Lies Ahead for California

Despite a small jump midweek on a mini heat wave, Western energy prices started May generally lower.

Since April 25, Western power prices moved lower with peak prices falling between $6.40 and about $9/MWh. Palo Verde was the exception, adding 70 cents to reach $42.30 in Friday-to-Friday trading. By May 2, average peak prices ranged from $33/MWh at Mid-Columbia to $46.20/MWh at South of Path 15.

Off-peak prices also moved lower, led by Northwestern hubs, which dropped about $17 on average. By May 2, nighttime prices ranged from $6.50/MWh at Mid-C to $37/MWh at SP15.

Working gas in storage reached 981 Bcf as of April 25, according to U.S. Energy Information Administration estimates, a jump of 82 Bcf from the previous week. Storage levels are now 44.6 percent less than a year ago and 50.1 percent below the five-year average.

Henry Hub natural gas values lost 3 cents since last Thursday, trading May 1 at $4.78/MMBtu. Western prices generally moved lower during the week, with Stanfield dropping 17 cents to $4.58/MMBtu and Sumas losing 15 cents to $4.56/MMBtu. Southern California Border gas was up a cent to $4.89 and PG&E CityGate stayed even at $5.30.

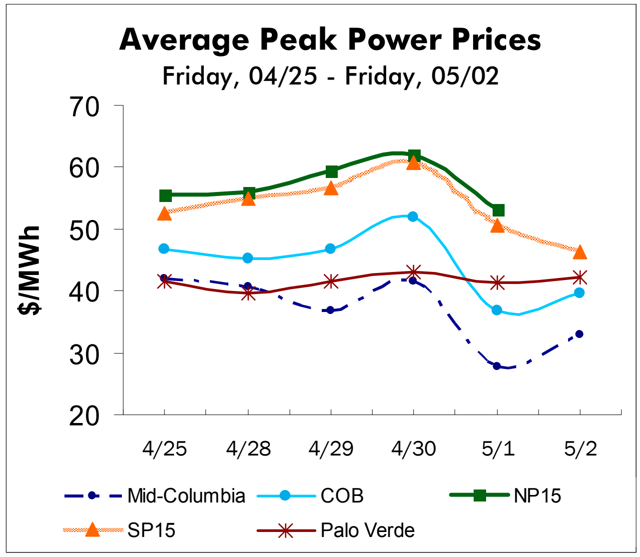
U.S. supplies are flat, with natural gas production down slightly and imports increasing, according to the EIA; the uptick in imports was attributed to Western demand. Operations at the Opal Hub, which suffered a fire, have restarted, which should resolve lingering supply issues.

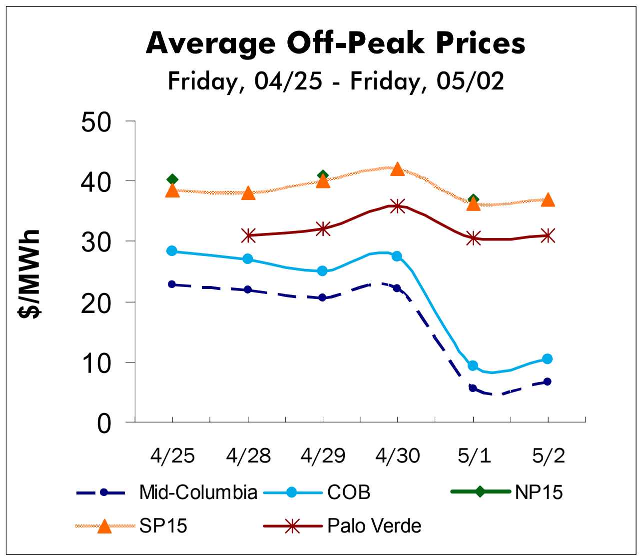
In its final snow survey of the year, the California Department of Water Resources reported that as of May 1, the statewide snow-water equivalent was at 4 inches, or 18 percent of normal for this date.

"California's reservoirs obviously will not be significantly replenished by a melting snowpack this spring and summer," stated the agency. "With most of the wet season behind us, it is highly unlikely late-season storms will significantly dampen the effects of the three-year drought on parched farms or communities struggling to provide drinking water."

Last year Cal-ISO derated hydropower production by more than 1,000 MW. This year's derate will appear in the grid operator's forthcoming summer assessment.

After soaring heat across the West—the Portland metro area saw record highs and Southern California temperatures climbed into the 90s on May 1—temperatures have started dropping. Starting May 5, Portland will see daytime highs in the mid-60s, Seattle will be around 60, and Southern California highs retreat into the 70s ***[Linda Dailey Paulson].***



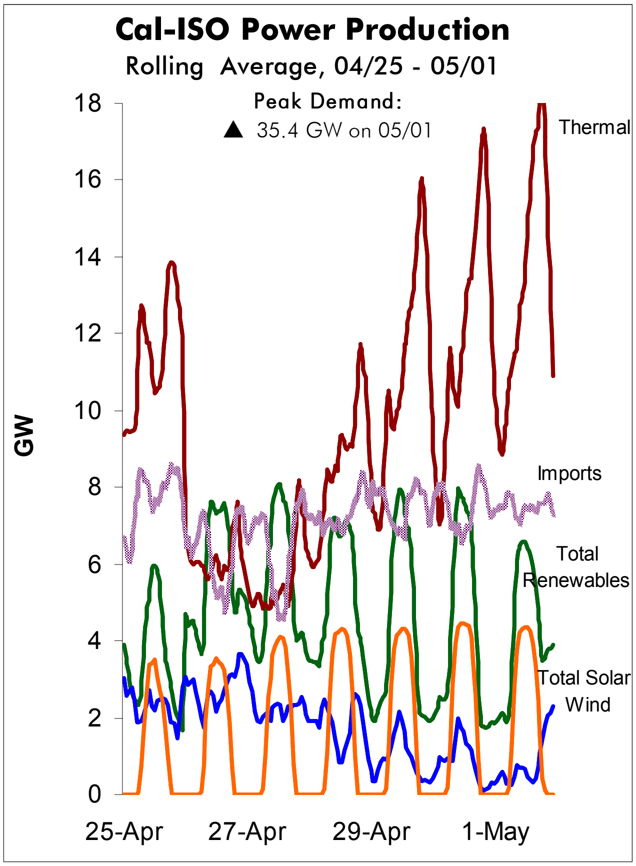


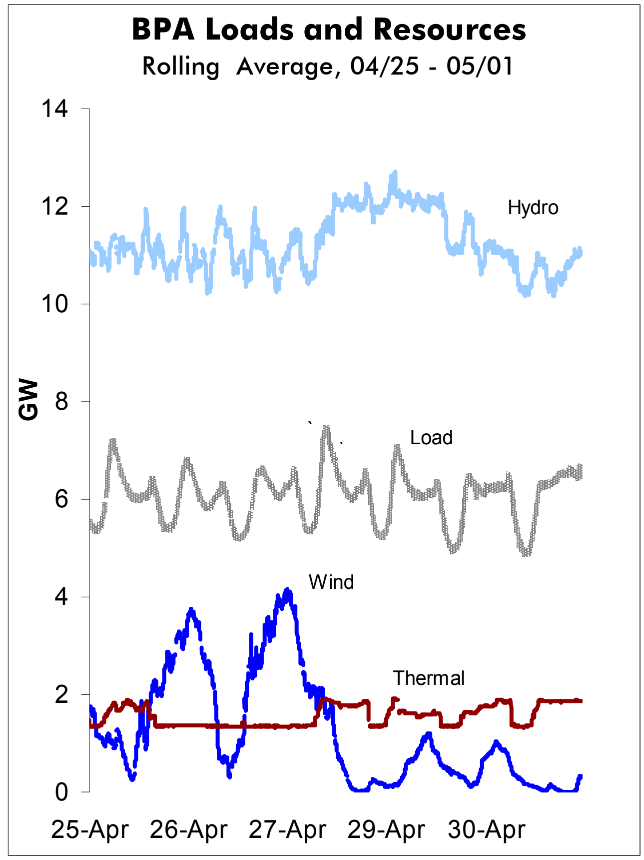
Average Natural Gas Prices ($/MMBtu)

	Thu, 04/24	Tue,04/29	Thu, 05/02
Henry Hub	4.81	4.82	4.78
Sumas	4.71	4.56	4.56
Alberta	4.30	4.21	4.20
Malin	4.88	4.69	4.71
Opal/Kern	4.74	N/A	4.65
Stanfield	4.75	4.58	4.58
PG&E CityGate	5.30	5.25	5.30
SoCal Border	4.88	4.85	4.89
EP-Permian	4.69	4.65	4.65
EP-San Juan	4.70	4.65	4.65

Power/gas price sources: ICE at www.theice.com and *Enerfax*

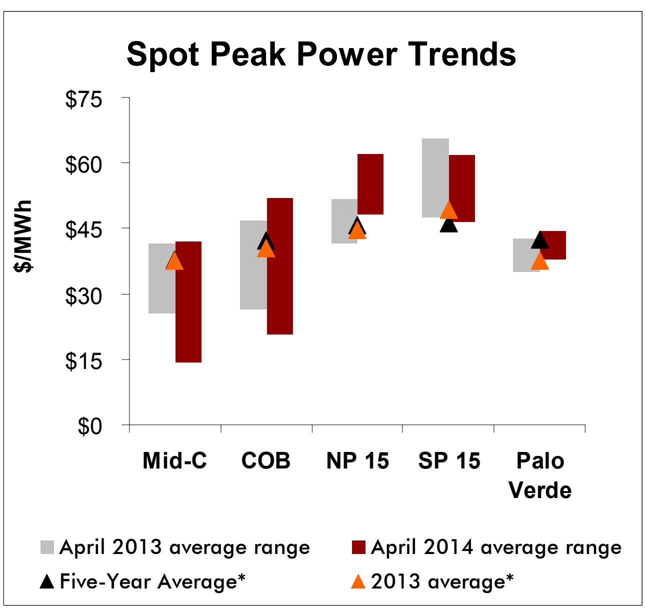
Power Gauge

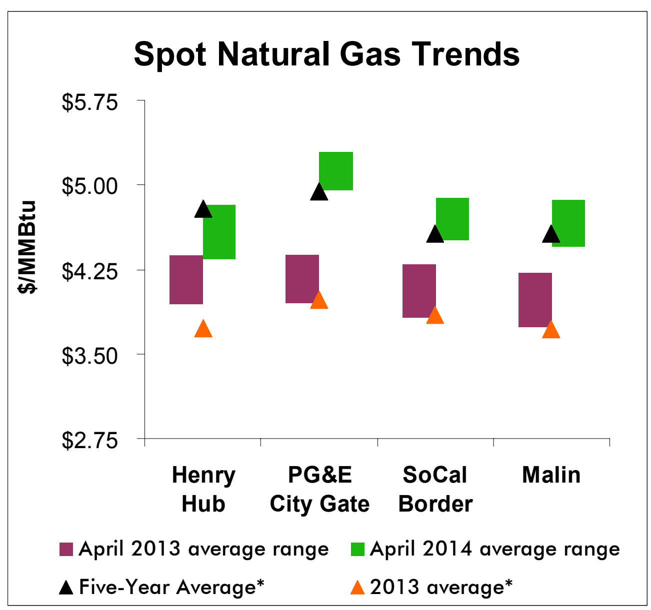




Sources: Cal-ISO and BPA

Price Trends





* Preliminary FERC data. Source: ICE, www.theice.com

Regulation Status

[13] Rules Let PG&E Bank RECs, but CPUC Says No *(from [2])*

The CPUC has rejected Pacific Gas & Electric's contracts for renewable-energy credits, saying the surplus RECs may add unnecessary costs and impede progress for actual generation from renewables.

The commission voted 3-2 at a May 1 business meeting against the proposal. CPUC President Michael Peevey and Commissioner Michael Picker supported the draft resolution that would have approved the PG&E contracts.

But Commissioner Carla Peterman argued that the proposal "misses the larger purpose" of the state's renewables portfolio standard—to increase actual renewable generation. And while the proposal may meet current rules, PG&E does not need the extra insurance—or the "unnecessary expense"—provided by the RECs, Peterman said.

PG&E had sought approval of three purchase-and-sale agreements for unbundled RECs from Sterling Planet, Iberdrola Renewables and NextEra Energy Power. The contracts involve more than 1 million RECs from more than 1 million MWh of energy generated by renewable resources deemed eligible under RPS rules (see *CEM* No. 1278 [11]).

'I'm more concerned about the principle of the thing' than the cost involved.

Most of the RECs were delivered in the 2011-2013 compliance period. PG&E wanted to bank them as excess procurement for future RPS compliance. The move would hedge any shortfalls from project failures, curtailments and production variability, PG&E has argued. The draft resolution would have approved the proposal, since the deals' 10-year terms make them long-term contracts that count toward the RPS and can be banked *[Res E-4649]*.

Commissioner Mike Florio agreed with Peterman, adding that the deals may later prove expensive. Renewable generation by 2020 may actually cost less than conventional generation—meaning the deals wouldn't represent cost savings, Florio said.

Also, many contracts for renewable generation will soon end, and the commission wants to encourage such facilities to re-contract or repower. Deals like PG&E's may hinder that from happening, Florio said.

"I'm more concerned about the principle of the thing" than the cost involved, Florio said.

Commissioner Catherine Sandoval also noted the possibility that the added RECs may wind up forestalling development of other renewable generation.

Meanwhile, Peevey called the deals "a very reasonable price" and argued that the move meets current rules and would let PG&E defer the need to procure some capacity.

Any concerns about rules and policies should be taken up in a separate RPS proceeding, Peevey argued. The commission should stay open to procurement options to help PG&E manage procurement costs and stay on track to meet RPS targets, he said.

Picker argued that someone would buy the RECs and that the move helps build confidence in the market, and that the utility could deploy them in a tight market and help benefit rates. But he also noted "sort of a tortuous path" and a need for greater clarity in the rules.

Also at the meeting, the commission approved provisions to let academic institutions and local governments collect data on customers' energy use *[D15-05-016, R08-12-009]*.

The decision from Peevey directs utilities to give educational institutions private customer data for research purposes. It also directs utilities to post the total monthly sum and average of customer electricity and natural gas use by zip code and by customer class, and the number of customers in the zip code by customer class. Utilities will also give local governments yearly, quarterly and monthly use data. State and federal agencies can also seek data from the utilities.

Commissioners praised the decision as a way to provide researchers with energy data while also protecting customers' privacy. The data and the research can eventually help improve energy-related programs and policies, commissioners said ***[Hilary Corrigan].***

[13.1] No Need to Reduce Lines' Pressure, Draft Decision Says

A draft decision at the CPUC would uphold a move to lift restrictions on pressure levels of certain gas pipelines.

The April 25 draft decision from Administrative Law Judge Maribeth Bushey found that Pacific Gas & Electric has pressure-tested lines 101, 132A and 131-30 and the Topock Compressor Station and that there is no need to suspend earlier CPUC decisions lifting the pressure restrictions on those facilities.

The commission had ordered PG&E to reduce pressure on certain gas lines after the rupture of a PG&E gas transmission line in 2010. The explosion in San Bruno killed eight people, injured dozens and destroyed a neighborhood.

The commission later allowed PG&E to restore pressure on certain lines, after showing proof of pressure testing on them. But PG&E found errors in the material it had submitted in support of restoring pressure on one line, prompting the commission to then question the basis for restoring pressure on other lines (see *CEM* No. 1249 [11]).

The draft decision said that PG&E has submitted valid and verified pressure-test results in support of its requests to lift the maximum operating pressure limits on the lines and at the Topock station *[D11-10-010, D12-09-003, D11-12-048]* ***[H. C.].***

[14] For Shared Renewables, Policy Details Remain Hazy *(from [1])*

Hashing out the complexities involved in the implementation of SB 43—the "shared renewables" bill—won't be easy, especially considering the conflicting interests of developers, power generators, utilities, ratepayer and renewables advocates, and a community-choice aggregation program, all of which have a stake in the outcome.

Speakers at an April 30 meeting in San Francisco homed in on some of the challenges and opportunities created by the bill, which Gov. Jerry Brown signed into law last September. The meeting, held at the law offices of Morrison & Foerster, was sponsored by clean-tech firm Agrion, SF Environment, and the California Center for Sustainable Energy.

SB 43, from Sen. Lois Wolk (D-Vacaville), aims to expand access to renewable energy to a broader group than those that benefited from the California Solar Initiative, and to facilitate a large and sustainable market for off-site renewable generation. Seventy-five percent of California households cannot participate in the burgeoning rooftop-solar market because they are renters, or their roofs are not suitable, or they have low credit scores.

SB 43 establishes a 600 MW statewide cap for a new green-tariff shared renewables program, or GTSR, from facilities no larger than 20 MW. Within that cap, 100 MW is allocated to residential customers, and 100 MW to facilities up to 1 MW in disadvantaged communities. In addition to expanding access to renewables to all ratepayers, legislative goals of the bill include facilitating the market for off-site renewables; fairly compensating utilities for the services they provide; and ensuring so-called ratepayer indifference, so customers that choose not to participate in a green tariff are not saddled with costs of the program. The bill also specifies that community-choice aggregators may offer a similar program.

Under SB 43, customers receive economic benefits in the form of a bill credit. The bill also states that participating utilities "shall provide support for enhanced community renewables programs to facilitate development of eligible renewable energy resource projects located close to the source of demand."

But the term "enhanced community renewables" is not specifically defined in the legislation, said Gabe Petlin, a senior regulatory analyst in the CPUC's Energy Division. That lack of specificity has led to one of the key flash points of the debate over SB 43.

The term "covers the concept of what some see as the central aspect of the bill, and what some others see as an additive," Petlin said. At the heart of the issue is whether a customer can support one specific project, or whether a customer would only be able to support a pool of projects.

The programs proposed by Southern California Edison and San Diego Gas & Electric would allow customers to support a specific project; Pacific Gas & Electric's program would allow customers to support a smaller group of local projects, but would not allow support of a specific project (see story at [14.1]).

As Petlin noted, different stakeholders have very strong views on the different investor-owned-utility proposals.

The Vote Solar Initiative, for example, opposes the premium that PG&E would charge participating customers. The premium comes out to 2.5 cents to 3 cents per kWh more than the credit a customer would receive, said Susannah Churchill, West Coast regional director for Vote Solar.

"High premiums are just going to mean the program is slow to take off," she said. The premium has to be fair and accurate, she added.

The charges have ended up higher than the credits in part because the IOUs have not attached proper value to some of the items that should be included in the credits, Churchill said. In a filing earlier this month at the CPUC, Vote Solar said that "because SCE's and the other IOUs' proposed calculation of bill credits for customers do not provide a fair and balanced calculation of value, including long-term benefits, their proposals violate the SB 43 ratepayer indifference requirements since net benefits flow to the IOUs and their ratepayers." The so-called ratepayer-indifference provision in the bill means that nonparticipating customers would not be saddled with any of the program costs.

'High premiums are just going to mean the program is slow to take off.'

Vote Solar has also urged flexibility by allowing customers to subscribe to a specific project, rather than a pool of renewables projects.

"The devil is in the details," Churchill said, adding that she is hopeful the CPUC will agree that it is important to get the program charges and credits right.

From the developer perspective, however, having customers subscribe to a pool of projects would be far easier than on a project-by-project basis.

The green-tariff model "has the highest potential of being the lowest-cost renewable energy provided" to program participants, said Michael Wheeler, senior director of policy at solar developer Recurrent Energy.

And Marin Clean Energy, which opposed SB 43, remains concerned about the fact that the proposals from PG&E and SDG&E would kick off with power from pre-existing contracts utilities signed to meet the state's renewables portfolio standard and that have been paid for by all bundled customers. "The commission should not approve the [green tariff] programs without any criteria or standards for the cessation of RPS resources because it would be unreasonable and subvert the purpose of SB 43," MCE said in an April 9 filing with the CPUC.

"In our view there needs to be advance procurement" of resources for the SB 43 programs, said Jeremy Waen, a regulatory analyst with Marin Clean Energy. MCE's concern with the SB 43 proceeding is the intent of utilities to use existing resources to meet the needs of new green-tariff programs. Waen noted that a young CCA program such as MCE has no portfolio of existing RPS resources to draw from that has been paid for by bundled customers.

The community aggregator stated in its brief at the commission that "by allocating existing RPS resources to their GTSR customers, PG&E and SDG&E are planning to exercise their market power in competition with providers who have no such resources."

The Office of Ratepayer Advocates has argued that the green-tariff programs may not actually result in any new renewables procurement beyond what is already contracted for in the RPS, while Shell argues that the use of RPS resources would violate the ratepayer-indifference clause in the bill ***[Mavis Scanlon].***

[14.1] Details Differ Among IOU Green Tariff Programs

For its Green Tariff Shared Renewables program, Pacific Gas & Electric proposed allowing its residential and business customers to voluntarily purchase renewable power to satisfy 100 percent of their electrical demand.

PG&E would contract for new renewable generation from facilities up to 20 MW within its service territory, and, the utility said, preferentially close to customer electrical demand.

Participating customers would receive bill credits for avoided generation costs, and would pay charges to fully cover the costs of procurement for the program.

Within its green-tariff program, PG&E proposed an "Enhanced Community Renewables" element that would allow customers to elect to support specific projects within PG&E's portfolio of green-tariff projects, with limitations. For example, the project would need to be sized no larger than 3 MW, and be located no more than 10 miles from the customer's service address.

PG&E's green-tariff customers would pay a per-kWh premium for the green option.

While new projects are being developed, PG&E proposed to serve its green-tariff customers from its existing renewable-resources pool, i.e., from facilities it is already buying power from to satisfy its renewables procurement requirements. PG&E said when it submitted testimony at the CPUC on its program that its existing renewables pool includes 87 contracts totaling 260 MW.

San Diego Gas & Electric, for its share of the green-tariff program, has proposed two programs: SunRate, which would allow bundled and business customers to buy renewable power from local solar projects, and Share the Sun, which would allow customers to work directly with solar developers.

SunRate customers could participate on a monthly basis with a minimum commitment of one year, or customers could elect two-, three-, five- or 10-year contracts. In the program's 10 MW pilot phase, only 3 MW to 10 MW new solar projects in SDG&E territory would be eligible (see *CEM* No. 1164 [11.1]).

Under Southern California Edison's proposed green-tariff program, customers can sign up to receive either 50 percent or 100 percent of their energy needs from renewable power. Customers would be charged a green rate—which, like the other investor-owned utility proposals, includes renewables costs plus other program costs and charges—and would be provided a generation credit for each kilowatt-hour of their subscription (see *CEM* No. 1266 [12.1]).

Edison expects it will have about 26,000 SunRate participants, reflecting an adoption rate of 50 percent.

SB 43 calls for the CPUC to issue decisions on the IOUs' applications for their green-tariff programs on or before July 1 ***[M. S.].***

[14.2] Assembly Committee Passes CCA 'Course Correction' Bill

The Assembly Utilities and Commerce Committee on April 28 unanimously passed AB 2145, a bill that would end the practice of switching customers to a community-choice aggregation program without their explicit consent.

Under existing law, customers within the service territory of a CCA—there are now only two operating CCAs in the state, Marin Clean Energy, or MCE, and Sonoma Clean Power—are automatically enrolled in the aggregation program, and if they do not want to participate, they must take specific steps to opt out. AB 2145 would require customers wanting to join a CCA to opt in. The bill does not impact existing customers.

According to bill author Steven Bradford (D-Inglewood), CCA has not lived up to its promise of providing a community with lower rates, more renewable energy, and jobs.

"I believe it is time for some mid-course corrections to ensure that communities can know how well the community choice aggregator will meet these goals," Bradford said in a statement included in a committee analysis of the bill. "AB 2145 promotes consumer choice and transparency for future community choice aggregator customers."

Bradford's bill comes as MCE is actively expanding its customer base, and as the second CCA in the state, Sonoma Clean Power, starts operations (see stories at [15] and [16]).

The committee analysis cites news reports that have detailed lengthy wait times MCE customers encountered when calling to opt out, and questions the actual amount of clean-energy generation—as opposed to renewable-energy credits—MCE is supplying, whether rates are actually lower than incumbent utility Pacific Gas & Electric's, and the job and greenhouse-gas reduction benefits from the CCA.

"Proponents of this measure assert that most people are unaware that a CCA was formed and have little understanding of the implications when they receive a form letter in the mail that says they don't have to do anything," the analysis states.

The analysis also cites a detailed rate comparison prepared jointly by MCE parent Marin Energy Authority and PG&E that shows monthly residential bills under varied scenarios are very comparable.

AB 2145 now moves to the Assembly Appropriations Committee ***[M. S.].***

Regional Roundup

[15] San Francisco Looks to Marin Clean Energy for Path Forward on CCA

(from [4])

San Francisco Supervisor John Avalos has proposed a city ordinance that calls for studying the feasibility of implementing a community-choice aggregation program through an agreement with Marin Clean Energy.

The ordinance, co-sponsored by five other supervisors on the 11-member board, is the latest attempt to move aggregation forward in San Francisco.

CCA supporters including Avalos are frustrated that CleanPowerSF, a program that has been under development for a decade, has gone nowhere due to political gridlock.

The San Francisco Public Utilities Commission, Mayor Ed Lee, and labor groups, including the union representing Pacific Gas & Electric workers, oppose the program. CleanPowerSF was to compete with PG&E for customers and offer a 100 percent renewable energy supply.

The SFPUC's refusal to set a rate cap for CleanPowerSF led to the effective cancellation of a power-supply contract for the initial 30 MW launch of the program.

'What we may be able to offer is temporary support for CCAs that want to launch under our structure.'

Upon introducing the ordinance at an April 22 board meeting, Avalos said the failure to implement CCA in San Francisco is at odds with the city's climate-action goals. He calculates that each day the city delays CCA, 149 tons of carbon dioxide are emitted into the atmosphere.

"Mayor Lee and the Public Utilities Commission objected to CleanPowerSF, but they have offered no other solution to provide San Franciscans with 100 percent renewable electricity," Avalos stated. "With this ordinance we can either join Marin or we can implement our own program, but we can no longer afford to do nothing."

If the ordinance is approved by the board, the city would work with MCE to study the practicality of San Francisco joining MCE, or having the CCA provide services through a yet-to-be-determined arrangement.

The SFPUC would be asked to review the MCE analysis, and to compare the benefits of MCE's service to CleanPowerSF, "including price, the potential resource mix of power purchases, and the ability to fund construction of local renewable energy resources," the ordinance notes.

The SFPUC would have to green-light any arrangement with MCE, as under the city charter, the commission has exclusive jurisdiction over municipal energy programs.

MCE has two potential avenues for cities or counties to join its CCA program. The first is through an already-established "affiliate membership" process, designed for communities with a customer base of 40,000 or less that are located no more than 30 miles from its service territory, which currently covers Marin County and the City of Richmond in the East Bay.

Albany, San Pablo, and Napa County have applied to join MCE through the affiliate-membership process.

Larger cities such as San Francisco may be able to join or receive services from MCE through a "special consideration membership," for communities with a customer base of greater than 40,000 or located more than 30 miles from MCE territory.

The MCE Board of Directors has yet to establish a process for joining under a special-consideration membership, but the passage of Avalos' ordinance would likely create an impetus for setting the policy, according to Dawn Weisz, executive officer of MCE.

Weisz said it would be technically possible for a jurisdiction the size of San Francisco to become part of the joint-powers authority that administers MCE, but "it would really be a policy decision of our board if we wanted to expand at that scale or not."

MCE may also be able to offer its program—which provides customers with 50 percent and 100 percent renewable energy-supply options—in another community such as San Francisco on a provisional-contract basis.

"What we may be able to offer is temporary support for CCAs that want to launch under our structure and then potentially helping them transition to a structure that they control locally once they are up and running," Weisz said. "But we're not in a position to run different types of programs for different entities."

To gain entry to MCE through the affiliate process, an analysis by MCE has to show that providing service in a new community will result in a projected net rate reduction for the existing customer base, and will increase the amount of renewable energy consumed in California's energy market, among other criteria.

The analysis for a special-consideration membership "would be more multi-faceted and include additional elements," Weisz said. "We can't yet define what those are because we need to have a structure in mind for how [a community] might be served and then use that to drive the study."

Assm. Tom Ammiano (D-San Francisco) has also introduced legislation to facilitate a CCA-related agreement between San Francisco and MCE (see *CEM* No. 1280 [14]).

Ammiano's bill, AB 2159, would give the San Francisco Board of Supervisors the authority to enter into a joint-powers agreement to implement CCA, and also allow another public agency to be the community-choice aggregator for San Francisco. Ammiano said that if the bill passes, such CCA-related agreements would still need the SFPUC's approval ***[Leora Broydo Vestel].***

[16] Sonoma Clean Power Begins Serving Customers *(from [3])*

Sonoma Clean Power flipped the switch on its community-choice aggregation program on May 1 as it began providing service to more than 23,000 electric accounts in Sonoma County.

"This is a very exciting day for all of us," said Geof Syphers, chief executive officer of SCP, at a May 1 Sonoma Clean Power Authority Board of Directors meeting.

At the start of the meeting, supervisors participated in a small ceremony to mark the launch of SCP service. It entailed Board Chair Susan Gorin inserting an outsized plug into a socket to light up an LED display.

"This is the sign of things to come," Gorin said. "Efficiency, lighting, power."

Syphers took credit for creating the ceremonial socket and light display "for like $50 bucks in my garage." He said he put the contraption together after a vendor quoted a price of $3,800 for a prop light switch.

"They said, 'Maybe we'll negotiate down to $2,600 because you're a public agency,'" Syphers recalled. "I said, 'No.'"

'This is the single largest step that Sonoma County has taken so far to address climate change.'

While clearly still in startup mode, the first phase of SCP's rollout appears to be going off without a hitch, with higher-than-expected participation rates.

SCP is serving 16,845 commercial accounts and 6,225 residential accounts. About 5.2 percent of individual customers, or 7 percent of targeted accounts, chose to opt out of SCP and continue receiving generation services from incumbent utility Pacific Gas & Electric.

Power for the first phase of SCP service is provided through contracts with primary supplier Constellation Energy, and with Calpine Energy Services for geothermal power from The Geysers.

The fledgling aggregator had forecast that the opt-out rate would be higher at this point in the enrollment process, and ultimately reach about 20 percent at the end of 2014. The 20 percent figure is based on the experience of Marin Clean Energy, the state's first operational CCA.

"In general, Marin's program reportedly has seen long-term participation rates of about 80 percent of residential customers and 75 percent of commercial customers," Syphers noted in a report to the board. "The early data appear to indicate that SCP may have somewhat higher rates of participation, perhaps by a margin of 3 to 5 percent. However, it is too soon to know for certain."

Given a PG&E rate increase that went into effect on May 1, the total electric bill of SCP customers will be about 4 to 5 percent lower than PG&E's, according to Syphers. This equates to $6 million in bill savings for Phase 1 customers over the course of the next fiscal year, he said, and a 67,000-ton reduction in greenhouse-gas emissions.

"This is the single largest step that Sonoma County has taken so far to address climate change," Syphers said.

SCP's standard CleanStart service is 33 percent renewable, while PG&E's energy supply at present is about 20 percent renewable. SCP customers can also sign up for EverGreen service, a 100 percent renewable power supply from local sources that costs about 20 percent, or 3.5 cents/kWh, more than CleanStart, and requires a 12-month commitment.

Close to 260 customers have signed up for the EverGreen option thus far. SCP plans to launch a campaign to advertise EverGreen in late summer.

The celebratory mood at the SCP meeting was dampened somewhat by the introduction of AB 2145 by Steven Bradford (D-Inglewood).

If the bill passes, customers would have to opt in to CCA programs beginning in 2015. Under current state CCA rules, customers in a given service territory are automatically enrolled in an aggregation program and must take steps to opt out.

SCP, MCE and a long list of environmental groups and California cities are opposed to the bill, which some have dubbed the "Monopoly Protection Act," arguing it would effectively prevent new CCAs from launching in California. PG&E and the union representing its workers, IBEW Local 1245, support the bill.

"It would take away the only form of collateral that a community-choice program has," Syphers said. "How do you buy power? You buy it based on the opt-out provision of the law."

The Assembly Utilities and Commerce Committee unanimously passed AB 2145 on April 28 (see story at [14.2]).

While the first phase of SCP's rollout will be completed this year, the second and third phases are scheduled to take place in 2015 and 2016.

Syphers said that accelerating the start of the second and third phases to this December "is one of the options we have to have on the table" given the possibility that AB 2145 may pass.

The cities of Windsor, Cotati, Sebastopol, Santa Rosa, Sonoma and Sonoma County's unincorporated areas are participating in SCP, representing about 80 percent of the county.

The county's remaining "holdout" cities—Petaluma, Rohnert Park and Cloverdale—have yet to sign on to the SCP's joint-powers authority, and could be impacted by AB 2145 if they decide to join in the future ***[Leora Broydo Vestel].***

[16.1] CARB Approves Amendments to State's Cap-and-Trade Regulation

The California Air Resources Board approved a number of amendments to the state's cap-and-trade regulation on April 25, and adopted a new offsets protocol for mine-methane capture projects.

"The amendments will provide additional market oversight and extend transition assistance for the industrial sector through the second compliance period (2015-2017) as businesses undertake needed investments to cut their emissions," CARB said in announcing the changes.

Under the amendments, natural gas suppliers will receive free allocations of carbon allowances for most of their compliance obligations through 2020, for the benefit of ratepayers.

Natural gas investor-owned utilities would be required to consign at least 25 percent of the allowances to auction in 2015, gradually leading to a minimum of 50 percent consignment by 2020.

Allowance allocations for legacy contract generators will also be provided through the second compliance period, or for the duration of the contract.

Legacy contracts were executed by electric-generation and combined-heat-and-power facilities prior to the passage of AB 32 in 2006. The contracts do not have provisions that allow plant operators to pass through the added costs of complying with cap and trade to counterparties.

CARB also officially eliminated the cap-and-trade regulation's resource-shuffling attestation requirement, whereby importers of electricity into the state are required to sign an affidavit saying they did not engage in the practice.

Resource shuffling is defined as "any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving delivery of electricity to the California grid."

The requirement was suspended following threats from market participants that they would refuse to sign the attestation given that the definition of resource shuffling lacked clarity (see *CEM* No. 1194 [13]).

CARB also approved additional information-disclosure requirements for market participants. For example, allowance-auction applicants are now required to disclose information regarding market rule-violation investigations concerning other entities with which they share a corporate association.

The mine-methane capture protocol will allow for the issuance of carbon-offset compliance credits for reduction of fugitive methane emissions achieved at underground and surface mines.

"This protocol addresses the two primary sources of methane from active mining: methane released through ventilation shafts, and methane released from drainage systems," CARB noted. "Emission reductions will be achieved through methane capture and use or destruction of methane from these sources" ***[L. B. V.].***

[16.2] New Challenge for Stalled HECA Project

The Hydrogen Energy California Project, a proposed coal-gasification plant and fertilizer-manufacturing facility that is almost two years into an environmental review at the CEC, faces another challenge with a new lawsuit by the Sierra Club over a coal-depot expansion project.

The Sierra Club sued the City of Wasco over its approval of an amendment to issue a conditional-use permit for the Savage Coal Depot that would let the depot expand its capacity by more than 50 percent, to 1.5 million tons of coal per year. All of the coal would be destined for the HECA project, which is proposed on a site outside Bakersfield, about 27 miles from the coal depot.

The April 23 suit, filed in Kern County Superior Court, seeks a writ of mandate and an order setting aside the city's approval on the grounds the city did not conduct an adequate environmental review of the proposed expansion as required under the California Environmental Quality Act.

The city first approved the construction and operation of the depot in 1990 based on what is known as a mitigated negative declaration, which does not require a full environmental review. The facility was initially built to handle 1.5 million tons a year of bituminous coal, although the conditional-use permit issued by the city limited coal throughput to 900,000 tons. In recent years the facility has handled only about 100,000 tons of coal a year, according to the Sierra Club complaint.

'The city's approval of the project without adequate environmental review is particularly egregious.'

The HECA project would gasify a blend of 75 percent coal and 25 percent petcoke—a by-product of oil refining—to form a syngas. The syngas would be purified to form a hydrogen-rich fuel, which would then be used to drive a gas combustion turbine. About 90 percent of the project's carbon-dioxide emissions would be captured and transported via pipeline to the nearby Elk Hills Oil Field—owned and operated by an Occidental Petroleum subsidiary—where it would be sequestered in deep underground oil reservoirs. Occidental would use the CO_2 for enhanced oil recovery.

At full gross capacity of between 405 MW and 431 MW, HECA would use 4,850 short tons of coal a day, or about 162 million tons a year.

HECA project developer SCS Energy has proposed two options to transport coal to the site—a five-mile railroad spur that would connect the site to a nearby railway, or trucking the coal from the Wasco depot. It would take 400 round trips a day to truck the coal to the site, according to the CEC.

In earlier comments at the CEC on the proposed coal-depot expansion, the Sierra Club noted a provision of the depot's current conditional-use permit that states an expansion could be approved, providing that the project the coal is intended for is approved by the lead agency reviewing it, in this case the CEC.

The Sierra Club noted in its complaint that the CEC's environmental review is still in a preliminary stage. "Accordingly, at the time the City Council approved the [coal depot project] it did not fully understand the environmental impacts of the project and therefore could not adequately address the true environmental cost of the project," the club stated in its complaint. "The city's approval of the project without adequate environmental review is particularly egregious and raises serious environmental justice concerns because the project will disproportionately impact low-income populations and people of color." The complaint goes on to note the potential serious health impacts an expansion of the coal depot could generate from increased emissions of diesel-fuel exhaust from additional coal-transfer trucks.

The CEC's review of HECA has already stretched well beyond the 12 months power-plant licensing cases are supposed to take. SCS Energy acquired the project in September 2011 from BP and Rio Tinto, and submitted a revised application at the CEC in May 2012.

The CEC committee overseeing the case in January laid out a revised schedule calling for a final staff assessment to be published on March 31. The FSA has not yet been published, and it is unclear when it will be published.

CEC staff is still awaiting a large amount of data from the project developer that it needs to complete the FSA.

One of the outstanding items CEC staff has said it needs is a contract—or the contractual terms SCS proposes with Occidental for the oil-field activities and carbon sequestration. Staff needs this information to conduct a full analysis of the carbon-sequestration component of the project.

Staff noted in an April 7 status report for the project that the Occidental board of directors authorized subsidiary Occidental California to split from the parent and become a separately traded company. That is expected to happen in the third quarter; the changes could further impact the HECA project schedule, staff said ***[Mavis Scanlon].***

[16.3] Last Year's Power Prices Followed Lead of Natural Gas

Total wholesale electric costs in the Cal-ISO area increased by 31 percent last year to about $46/MWh, primarily driven by a hike in natural gas prices, the grid operator said in its Annual Report on Market Issues and Performance.

After controlling for the gas-price increase, however, Cal-ISO estimates that total wholesale energy costs increased from $42/MWh in 2012 to $44/MWh in 2013—a jump of almost 5 percent. That increase was primarily a result of implementation of the state's greenhouse-gas cap-and-trade program, which adds about $6/MWh to wholesale energy costs.

The total estimated cost of serving load in 2013 was $10.7 billion, according to the report from Cal-ISO's Department of Market Monitoring.

Other factors affecting prices last year included decreased hydro resources during the summer months and decreased imports from the Southwest and Northwest during the second quarter of 2013.

About 2,000 MW of summer peak-hour generating capacity from renewables was added in 2013, with most of this coming from solar. Energy from wind and solar resources directly connected to the ISO grid provided about 8 percent of system energy, compared to about 5 percent in 2012.

"Energy from new wind and solar resources is expected to increase at a much higher rate in the next few years as a result of projects under construction to meet the state's renewable portfolio standards," the report noted.

'Energy from new wind and solar resources is expected to increase at a much higher rate in the next few years.'

Meanwhile, more than 3,500 MW of natural gas-fired capacity came on line in 2013, though these additions were offset by the retirement of 2,900 MW of thermal generation, the biggest piece of which was the 2,200 MW San Onofre Nuclear Generating Station.

Other factors affecting prices included decreased regional congestion and increased net virtual supply, which lowered day-ahead prices and brought them closer to real-time prices.

The report found that overall, prices in Cal-ISO energy markets in 2013 were highly competitive, averaging very close to what DMM estimated would result under highly competitive conditions.

Price convergence also increased during the year. Day-ahead prices averaged just over $2/MWh higher than real-time prices for the year, peaking in the second quarter at almost $6/MWh higher. This "trend marks a reversal from prior years" and "is largely attributable to a decrease in brief but high real-time price spikes caused by limitations in ramping energy. This trend is also partly attributable to additional unscheduled generation in real time, particularly from wind and solar units and from other sources" ***[Chris Raphael].***

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[17] Study: Desert Soil Captures and Stores Lots of Carbon *(from [7])*

A group of researchers led by a Washington State University biologist has found that the top meter of soil in arid landscapes captures and stores a surprising amount of carbon as CO_2 levels increase in the atmosphere.

The findings, published in *Nature Climate Change* on April 6, are the result of a decade-long experiment in the Mojave Desert, where researchers exposed plots of land to elevated CO_2 levels, similar to those projected to occur by 2050. They also exposed other plots of land to air with current levels of CO_2, and others to no extra air.

The researchers then analyzed the top meter of soil in all of the samples, to measure how much carbon it had absorbed. They found that desert soils may increase their carbon uptake enough in the future to account for 15 to 28 percent of the amount being absorbed by land surfaces, according to a WSU release announcing the study results.

Under current atmospheric CO_2 levels, the researchers found that arid lands increase carbon uptake to account for 4 to 8 percent of current emissions.

While soils in forested areas hold much more carbon per square foot, desert soils (those found in areas with less than 10 inches of rain a year) and soils in semi-arid areas (found in regions with less than 20 inches of rain a year) cover nearly half of the earth's surface, according to WSU.

'We don't know what [development of these lands] is going to do to the carbon budget of these systems.'

That means that the top layer of soil—called the "cryptobiotic layer" or "biological soil crust"—in those arid and semi-arid areas can play a big role in the mitigation of atmospheric carbon dioxide. That's because it's not just dirt, but a complex community of plants and microorganisms that ramp up their appetites for carbon when exposed to increasing levels of CO_2.

The study results have "pointed out the importance of these arid ecosystems," said lead WSU researcher R. Dan Evans, in a release announcing the public a-tion of the study. "They are a major sink for atmospheric carbon dioxide, so as CO_2 levels go up, they'll increase their uptake of CO_2 from the atmosphere. They will help take up some of that excess CO_2 going into the atmosphere. They can't take it all up, but they will help."

The study included scientists from the University of Idaho, Northern Arizona University, Arizona State University and Colorado State University. The idea for the research came from scientists at the University of Nevada and the Desert Research Institute, and was funded by the U.S. Department of Energy and the National Science Foundation.

In stressing the important role the Earth's vast desert landscapes may play in the mitigation of climate change, Evans said that "we don't know what [development of these lands] is going to do to the carbon budget of these systems."

However, development of these lands in the West has, for several years, been a worry of desert conservationists, as in the case of the Obama administration's push to develop 10 GW of utility-scale solar power projects in six Western states by 2015, an initiative announced back in 2009 by then-Interior Secretary Ken Salazar, who said he was going to "put a bull's-eye on public lands" for solar-power development.

At the time of the announcement, the bull's-eye was on 677,000 acres of land managed by the U.S. Bureau of Land Management.

By August 2011, the Obama administration's preferred alternative for solar development on BLM land in Arizona, California, Colorado, Nevada, New Mexico and Utah had expanded to a potential 20 million acres, much of it pristine desert habitat.

Evans told *California Energy Markets* that his study had not addressed how disturbance of the soils—say, as in the case of solar-power project construction—or permanent shading of the soils, as in the case of an array of pole-mounted solar-photovoltaic panels—would impact their ability to capture and store carbon.

Jim André, a biologist specializing in desert ecosystems and the director of the University of California's Sweeney Granite Mountains Desert Research Center, said that the cryptobiotic layer of desert soils is extremely fragile—and by virtue of that fact, so would be its ability to capture and store carbon.

André said that if the vegetation on the top is removed—say, in the case of mowing—then the soils would start to emit carbon. If the soil is bulldozed, as in the case of construction of a concentrating solar-power project—which requires a very level site over thousands of acres—there is a direct release of carbon at a steady rate, over many decades.

"In both cases, the bare soils cease to sequester carbon," André said.

In the case of permanent shading of those soils, such as with pole-mounted PV panels, André said via e-mail that "the native plants that are adapted to lots of sun will die, the soil crusts (lichens, mosses, algae, cyanobacteria) die, soils will quickly lose their binding agents (the cryptograms) and begin to erode (wind and water erosion), and the carbon cycle goes quickly into reversal . . . carbon escaping the soils while not being sequestered through native vegetation."

André added that the science surrounding this issue "has been brought forward at every hearing on a solar project, but in each case the project is permitted, citing overriding considerations (ironically, the need to reduce the carbon footprint from burning fossil fuels!)."

Ray Brady, the manager of national renewable-energy development at the BLM, said that his office is not aware of any federal-level discussion to include the carbon-sequestration value of desert soils in the bureau's environmental impact analyses of renewable-energy projects on public lands.

Dick Bouts, the BLM's energy program analyst, suggested that the California-based Desert Renewable

Energy Conservation Plan—a component of California's renewable-energy planning efforts—may be considering that issue in its draft plan. The DRECP is considering which areas to peg for development of renewable energy beyond California's 33 percent renewables portfolio standard, and which areas to conserve.

By press time, officials from the DRECP had not returned calls for comment.

However, André said that the DRECP has loosely attempted to take into account rare plants and animals, and their corridors, but the DRECP's own science panel issued a scathing report blasting the DRECP's failure to incorporate the best science to site projects in areas where they would have fewer impacts on these ecosystems. On public lands, there are very few sites where there would be minimal impact, he noted.

Other than the DRECP—which hasn't yet been implemented—André said that there has been no planning effort for renewable-energy projects to take into account these ecosystems—and their intrinsic ability to sequester carbon ***[Penelope Kern].***

[17.1] Study: 17 GW of Untapped Run-of-River in NW, 3.4 GW in California

A federal study released April 29 estimates the U.S. has 65.5 GW of untapped run-of-river generation in areas not off-limits for development, with the Pacific Northwest accounting for nearly 30 percent of the corresponding generation and California 5 percent.

The estimated overall generation would be nearly 130 percent of the average 2002-2011 net annual generation from existing plants.

The survey was developed by Oak Ridge National Laboratory for the U.S. Department of Energy, and is based on federally funded geospatial datasets of social and environmental sensitivity, topography and hydrology.

The study looked only at potential "new stream-reach" development, on portions of rivers and streams not yet developed or associated with existing hydro projects or unpowered dams.

DOE said the new study follows one released in 2012 that found over 12 GW of hydropower potential at the nation's existing 80,000 non-powered dams. The new study shows even more hydro can be developed, mostly smaller run-of-river facilities that would use "new low-impact designs and technologies."

Among basins in the Lower 48 states, the Pacific Northwest dominates the estimate of developable generation potential, with 28 percent of the annual total of 347 terawatt-hours (TWh, or million MWh) and a capacity of more than 17 GW. The area comprises the Columbia River's watershed, and includes all of Washington, most of Oregon, Idaho and western Montana, and very small parts of northern Nevada, Utah and California.

This result swamps the runner-up Missouri River's 18 percent of total generation potential and 10.7 GW of capacity. The California region, which encompasses most of the state, ranks seventh with 5 percent of the total and a capacity of nearly 3.3 GW.

Looking only at technical potential, without regard to development issues, the Pacific Northwest still dominates with 32 percent of a total 460 TWh and a capacity of about 25.2 GW. The Missouri River watershed still ranks second, with 15 percent of the potential generation and nearly 11.7 GW of capacity, but California moves up to third place, with more than 8 percent of the total potential and about 7.1 GW of capacity.

Notably, Oregon and California lose about 50 percent of their technical generation potential when nominal restrictions due to social and environmental sensitivity are imposed.

Underlying the study's results is a mathematical model for the hydropower potential of stream and river segments, which are defined using hydrology and topography datasets. It uses the net hydraulic head of the simplified segments, monthly estimates of flow along them, and an empirical 85 percent factor converting hydraulic energy to electricity. Segments are excluded for a variety of social and environmental reasons, such as falling within a national park or within areas restricted by fish concerns.

While the "reconnaissance level" results from the modeling efforts are not sufficiently accurate to determine project-specific feasibility or justify investments, the study said, it does spotlight areas that "should be regarded as worthy of more detailed site-by-site evaluation by engineering and environmental professionals."

Although the study aimed to include estimated hydropower costs, this was deferred "until more credible cost data and models have become available," the report noted, likely from efforts started last year by the Oak Ridge research team ***[Rick Adair].***

Southwest

[18] Parties Say Nevada Rate Case Wrong Place for Solar Debate *(from [8])*

The Nevada Bureau of Consumer Protection ran into unanimous opposition April 30 to its proposal to consider special rates for net-energy-metering customers during Nevada Power's general rate case. The utility expected to file the GRC May 2.

If the Public Utilities Commission of Nevada sides with the majority of stakeholders, the bureau apparently fears the commission will raise the basic service charge for all single-family residential customers in order to collect more in fixed costs from single-family, residential net-metering customers.

The commission may decide to dramatically increase the current $10 monthly, basic service charge for all single-family residential customers of Nevada Power. That would lock in a higher basic service charge for three years until Nevada Power files its next general rate case.

In the PUCN's December 2013 decision in Sierra Pacific Power's general rate case, the commission was concerned that Sierra Pacific's net-metering customers were not paying their full share of utility fixed costs, because Sierra Pacific recovered some of its fixed costs for residential customers through the kilowatt-hour rate component and net-metering customers get credits for the kilowatt-hours generated by their own solar panels.

The commission boosted the $9.25 Sierra Pacific basic service charge to $17.50, a level that the consumer-protection bureau considered onerous for many single-family residential customers who do not have rooftop solar panels. At the same time, the commission lowered the amount of fixed costs recovered through the kilowatt-hour rate component.

In response to objections from the consumer-protection bureau, the commission later lowered the Sierra Pacific basic service charge to $15.25.

That rate-design change ensured that each net-metering customer would pay a minimum amount for Sierra Pacific's fixed costs—even if the customer got most of its power from rooftop solar panels.

The PUCN could take a similar approach in rate design for Nevada Power's GRC. The consumer-protection bureau instead suggested the commission use the Nevada Power general rate case to adopt special rates for residential net-metering customers. In that way, residents with rooftop solar would be charged more for fixed costs and single-family customers without rooftop solar would not be burdened with higher basic service charges.

PUCN staff, however, said it would be difficult to thoroughly review the cost of service for net metering in the general rate case, because the commission has only 210 days to review Nevada Power's general rates.

Staff also said the bureau's net-metering proposal was premature because of a pending, separate investigation of net-metering costs and benefits. Under the direction of a state bill, AB 428, the commission contracted with technical evaluation firm Energy and Environmental Economics (E3) to prepare the study, a draft of which is due on June 1.

Western Resource Advocates objected to the bureau's proposal on legal grounds. The bureau's proposal to establish separate rate classes for net-metering customers "would subvert the clear intent of [Nevada Revised Statute 704.773] that customers who choose to become generators of renewable energy cannot be subjected" to additional charges that other customers in the same class don't pay, Western Resource Advocates said.

The Alliance for Solar Choice, which represents SolarCity and other rooftop-solar companies, said the bureau's proposal "assumes that net-metering customers have unique costs of service and provide a reduced amount of fixed-cost recovery without waiting for completion of the [E3] study."

Nevada Power also opposed considering the bureau's net-metering proposal in the general rate case, but supported arguments the bureau made in suggesting separate rates for net-metering customers.

Rooftop-solar customers have "distinctly different load shapes" and load factors when compared to residential and small-business customers who buy all their energy from Nevada Power, the utility said.

Instead of setting up a different rate for net-metering customers, Nevada Power has proposed alternatives such as a net-metering rider within an existing customer class ***[John Edwards]***.

[18.1] NV Energy Gets State Approval to Shelve Utility Merger Plan

The Public Utilities Commission of Nevada on April 30 authorized NV Energy to withdraw its 11-month-old request to merge subsidiaries Nevada Power and Sierra Pacific Power.

However, the commission said it intended to order NV Energy to analyze the costs and benefits of operating two utilities versus operating one combined utility.

The commission also ordered an investigation and rulemaking case to review ways to allocate benefits and costs of the 500 kV One Nevada Transmission Line for NV Energy's retail customers. The 231-mile transmission line, which started operation in December 2013, connects Nevada Power and Sierra Pacific Power, running from the Harry Allen Substation near Las Vegas to the Robinson Substation west of Ely.

NV Energy owns a 25 percent interest in the power line, and an affiliate of LS Power owns 75 percent of the $552 million line.

NV Energy had proposed a series of separate meetings to discuss the ON Line with regulators and stakeholders. But the PUCN decided the investigation and rulemaking case will establish structure for communications between NV Energy and intervenors, eliminating the need for the separate meetings.

If NV Energy later decides to establish a permanent dispatch operation for the two utilities, rather than merge the utilities, the commission directed the company to get PUCN approval of the permanent dispatch agreement prior to filing for approval from FERC. NV Energy's March 14 motion mentioned four reasons for withdrawal of the merger application. The utility explained that Berkshire Hathaway acquired NV Energy in December 2013, the Nevada Legislature passed SB 123 in June 2013 calling for retirement of coal-fired generation, and the ON Line started ferrying power at the end of 2013 ***[J. E.]***.

[18.2] Geothermal Developer Exploring Sale of Power-Plant Equity Stakes

Ormat Technologies on April 30 confirmed a news report that it is reviewing possible sales of up to 49 percent of "a small number" of power plants located in the United States to institutional investors.

The Reno, Nev., company said the sales are being considered as part of a strategic planning review.

Ormat said it would continue to operate any plants in which it sells an interest.

"The process is still in an early stage and no binding investment offers have been received," Ormat Technologies said in a statement.

Globes, an Israeli financial daily, broke the story on April 30, citing an unnamed source saying Ormat

Industries intended to sell power plants for a total of $150 million to $250 million.

Ormat Industries of Israel owns 60 percent of Ormat Technologies; Ormat Industries is 20 percent owned by Bronicki Investments, a privately held family company. FIMI Opportunity Funds owns 23 percent of Ormat Industries' outstanding shares.

Ormat Technologies owns 100 percent of 11 geothermal plants in the United States totaling 420 MW in capacity. Ormat's portfolio includes six plants in Nevada and four in California. Also, Ormat owns four recovered energy generation operations in the United State with 53 MW of capacity.

Ormat Technologies reported $533 million in revenues and $41 million in profit in 2013. Customers include Pacific Gas & Electric, Southern California Edison and NV Energy ***[J. E.].***

[18.3] EPA Backs Compromise to Lower San Juan Power Plant Emissions

The U.S. Environmental Protection Agency on April 30 said it favored a revised proposal from PNM and New Mexico to reduce nitrogen-oxide emissions from the 1,798 MW, coal-fired San Juan Generating Station.

The state and electric utility in October 2013 revised their previous proposal and suggested retrofitting Units 1 and 4, which have a total of 894 MW in capacity, with selective non-catalytic reduction equipment. The retrofit is scheduled to be completed 15 months after EPA's final approval but no sooner than Jan. 31, 2016, according to EPA.

Also, PNM intends to close Units 2 and 3 by Dec. 31, 2017, rather than invest money in equipment to curtail emissions from those units.

The EPA in 2011 proposed installing selective catalytic reduction equipment on all four San Juan units, which PNM estimated would cost between $824 million and $910 million. But the agency said the elimination of two units and emissions controls on the remaining two—as PNM and New Mexico had previously proposed—would reduce nitrogen-oxide emissions by 62 percent.

Nitrogen oxides react with other chemicals and dust that are harmful to public health, according to EPA. Also, nitrogen oxides contribute to regional haze.

During the next 20 years, PNM alone expects to save $780 million from the revised emissions-reduction plan, including savings from avoiding upgrades to the coal-fired units that will be retired, spokeswoman Valerie Smith said in an e-mail.

PNM plans to depreciate the $205 million for the closed plants over those 20 years.

The New Mexico utility will split the costs of the SNCR retrofits and unit retirements with other owners.

To replace lost capacity, PNM intends to use 134 MW it owns in Unit 3 of the Palo Verde Nuclear Generating Station; 177 MW of gas-fired generation; and 40 MW of solar generation. It intends to purchase an additional 78 MW of generation from San Juan Unit 4. Other owners will make separate arrangements to replace generating capacity they will lose at San Juan.

"We believe the state plan is the best option for PNM customers and for the environment, and that the strength of the plan will lead to final EPA approval later this fall," Ron Talbot, chief operating officer of PNM Resources, said in a statement ***[J. E.].***

Financial News

[19] Edison Stresses Spending on Wires, Distribution, New Technology *(from [6])*

Edison International's earnings suffered in the first quarter from a settlement agreement related to the San Onofre Nuclear Generating Station, but the holding company stressed its core profits and future growth from distribution and transmission spending.

Net income at Edison International was $176 million for the first quarter, $95 million less than in the year-ago quarter. The company recorded charges of $96 million related to the settlement agreement for San Onofre and $22 million from discontinued operations.

Core earnings at Southern California Edison were $294 million, a jump of $42 million from the year-ago quarter. Edison officials attributed the rise to higher authorized revenue from rate base, labor reductions (including roughly 700 workers at SONGS), and income tax benefits.

The SONGS settlement agreement, which is pending before the CPUC, doesn't allow recovery of $542 million related to the San Onofre steam-generator replacement project, as well as $159 million in project revenues previously recognized. It does, however, allow Edison to recover costs for replacement power—approximately $1 billion—and certain other plant expenses.

Edison also is pursuing $4 billion in claims against Mitsubishi Heavy Industries, as well as $397 million from Nuclear Electric Insurance Ltd., and proceeds from any of those avenues would be split between ratepayers and shareholders.

Looking ahead, Edison stressed its capital-spending forecast of $15.1 billion to $17.2 billion in the 2014-2017 period. Of that, it has requested $9.3 billion in its 2015-2017 general rate case for distribution. "A central tenet of our strategy is that we should lead in modernizing the distribution system," said Ted Craver Jr., chairman and CEO of Edison International, during an April 29 earnings call.

On the transmission side, the utility has several high-voltage projects that will come into service between 2016 and 2020: Tehachapi ($3.1 billion); Coolwater-Lugo ($813 million); and West of Devers ($1 billion). Cal-ISO's 2014 transmission plan does not include any additional wires investment in SCE's service territory beyond 2018, but the grid operator is studying the need for the 500 kV Delaney-Colorado River line, with the project open to competitive bids.

"We would be interested in pursuing [it] if the project is economic," said Jim Scilacci, Edison International's chief financial officer.

Outside of the Delaney project, "we have interest if not through Southern California Edison [then] through the competitive side of the business to participate in transmission projects outside the Southern California Edison service territory," Scilacci said. "So there is potential if we lose at SCE, they may be able to pick it up through the competitive side of the business, but that's still very premature."

Transmission "is a core competency that we have," Craver added. Such projects could be done through SCE, he said, or through an independent partnership with other companies.

Edison officials also discussed investing in distributed renewables and energy storage. Nearly all of Edison's earnings have been driven by Southern California Edison following the 2012 bankruptcy of power-generation subsidiary Edison Mission Energy. The holding company, however, has recently acquired SoCore Energy, a solar-photovoltaics developer; and has made investments in Clean Power Finance, a financial-services and software provider, and Optimum Energy, a professional-services firm in the HVAC industry.

Transmission 'is a core competency that we have.'

The SoCore acquisition is "really the starting point for a platform to provide integrated energy services to commercial and industrial customers" and is "largely aimed outside of the SCE territory," Craver said. "Our sense is the residential rooftop solar business models largely require subsidies and shifting mechanisms to really be viable—that has not been appealing to us. We've really focused more on commercial and industrial distributed generation.

"We would not really look to try to put residential rooftop solar into our rate base," he added. "Our primary strategy is to provide . . . a modern distribution system that really facilitates . . . these distributed resources. Whether that's rooftop solar or whether its storage and anything else. That's the part that we are uniquely positioned to do well, and that's really where our investment dollars are focused."

Craver did say, however, that Edison is looking at some projects that would involve electric transportation, water reclamation, and water treatment—where "there is a strong nexus" between electricity use and water quality. It is also looking at pilot projects that would provide "preferred resources"—such as demand response, renewables and efficiency—in areas affected by the absence of SONGS. Craver also noted that the CPUC's 1.3 GW energy-storage target includes 600 MW in Edison's territory "and half of that can be actually owned and put in rate base by the utility."

However, "we prefer not to go out and ballyhoo all kinds of nifty ideas before we really . . . have a more factual rendition of what those growth opportunities would be," Craver said ***[Chris Raphael].***

[20] Higher Expenses Lead to Drop in PG&E Q1 Earnings *(from [5])*

Despite higher revenue, PG&E Corp. on May 1 reported a 5 percent drop in first-quarter profit as expenses offset revenue growth.

PG&E reported net income of $227 million for the quarter, or 49 cents a share, compared with $239 million, or 55 cents a share, in the same period last year. The company's net income includes the impact of $40 million in charges recorded for the quarter at subsidiary Pacific Gas & Electric related to the deadly 2010 San Bruno pipeline explosion, including legal costs and costs to upgrade the safety of its natural gas system.

Gas issues continue to weigh on the company. PG&E on April 21 pleaded not guilty to 12 criminal violations of the federal Pipeline Safety Act; the utility is facing fines of more than $6 million in the case. PG&E is also facing fines and penalties of up to $2.25 billion at the CPUC in three pending San Bruno-related investigative enforcement proceedings.

San Bruno-related costs to shareholders for natural gas pipeline safety-related work that the utility has incurred or committed to now top $2.7 billion according to current forecasts, the company said. PG&E Corp. has set aside $200 million for the amount of fines it has deemed probable that it will have to pay into the state general fund. PG&E said in a May 1 filing with the U.S. Securities and Exchange Commission it is unable to make a better estimate due to the many variables that could affect the final outcome at the CPUC.

"We have not waited to make significant improvements to the safety and reliability of our system," said Tony Earley, chairman, CEO, and president of PG&E Corp., on an earnings call with analysts. "It's vital that the commission's final decision recognize that we compensated victims in the civil proceedings and that we've made substantial improvements in safety at a very significant cost to shareholders."

Despite PG&E's efforts since San Bruno to ensure all of its pipeline records are accurate, a recent gas-pipeline incident appears to have been caused by the lack of verification of pipeline specifications before live work was performed.

On March 3, a house in Carmel was severely damaged by a natural gas explosion while utility workers were upgrading the main natural gas distribution pipeline in the area. No one was injured or killed in the incident. A third-party engineering firm PG&E hired to conduct an independent assessment concluded that the root cause of the incident was the "inadequate verification of system status and configuration when performing work on a live line," according to the SEC filing. The CPUC, the U.S. Attorney's Office, and local fire and police officials are investigating; PG&E said in its SEC filing it believes fines could be imposed and other enforcement actions could be taken in connection with the incident.

In the first quarter, pipeline-safety work continued. Since 2011, PG&E has successfully strength-tested 675 miles of pipeline, replaced 130 miles, retrofitted almost 400 miles to allow for in-line inspection, and installed nearly 150 remote-control shutoff valves, said Chris Johns, president of the utility. Employees have been finding and fixing issues in all areas of operations, he added. "This work is the most extensive in the United States."

PG&E's earnings from operations, which exclude charges, were $251 million, or 54 cents per share, down from $276 million, or 63 cents per share, during the same period last year.

Total operating revenue in the quarter was $3.9 billion, up from $3.7 billion last year. PG&E attributed the increase to higher authorized transmission revenue from FERC and the recovery of certain expenses from the company's Pipeline Safety Enhancement Plan.

Total operating expenses jumped to $3.4 billion, from $3.2 billion last year.

PG&E said it expects drought conditions will lead to less hydropower this year, which in turn could lead to higher prices for purchased power; higher natural gas costs could also impact the prices PG&E pays for purchased power. In the first quarter, PG&E bought 12,468 million kWh of electricity, at an average price of 8.9 cents/kWh. That compares to 10,886 million kWh it bought in last year's first quarter, at an average price of 8.4 cents/kWh.

On the regulatory front, the company expects a CPUC decision soon in its 2014 general rate case, Johns said. The utility has requested a $1.16 billion increase in its revenue requirement for this year, plus additional increases of $436 million in 2015 and $486 million in 2016.

PG&E is also awaiting decisions in its gas-transmission rate case and its 2015 electric-transmission rate case at FERC. In the FERC case, settlement discussions are ongoing, with the settlement conferences scheduled in mid-May. PG&E has requested an electric-transmission revenue requirement of $1.1 billion and a return on equity of 10.9 percent.

In the gas-transmission case, a final decision is scheduled for the first quarter of next year. PG&E requested a gas-transmission revenue requirement of $1.2 billion in 2015, an increase of $555 million compared with this year, plus additional increases of $61 million in 2016 and $168 million in 2017. The significant increases reflect expenses and capital to comply with new requirements, the company has said. A motion to collect revenues on a retroactive basis is pending at the CPUC, Johns said ***[Mavis Scanlon].***

[20.1] Tucson Electric Rate Case Pushes Profits Higher at Parent Company

UNS Energy on April 28 reported first-quarter net income soared 36 percent, driven mainly by a Tucson Electric Power general rate increase in July 2013 and lower interest expense on leases.

TEP reported first-quarter net income increased to $9.1 million from $1.5 million last year, despite mild weather that led to a 6.2 percent decrease in kilowatt-hour sales.

Also, "we performed critical maintenance on our generators and made $85 million of infrastructure investments to help provide reliable and safe service to our customers," Paul Bonavia, UNS Energy's board chair and CEO, said in a statement.

UNS Gas reported first-quarter profit plunged to $4.7 million from $7.4 million, because mild weather caused a 20 percent decline in retail therm sales.

UNS Electric's net income slid to $2.1 million from $2.4 million in the first quarter last year.

First-quarter electric retail sales for TEP and UNS Electric climbed 26.2 percent to $43.4 million from $35 million a year ago.

UNS Energy's overall operating revenues edged up 1.6 percent to $224.6 million from $220.1 million in the year-ago period ***[John Edwards].***

Potomac

[21] Senate Leaders Urged to Vote on Energy-Efficiency Bill *(from [9])*

One hundred industry trade groups and manufacturers wrote Senate leaders April 30 urging a floor vote "as soon as possible" on a wide-ranging energy-efficiency bill, but political complications, including a health-care amendment, could stand in the way.

The legislation, now numbered S. 2262 and sponsored by Sens. Jeanne Shaheen (D-N.H.) and Rob Portman (R-Ohio), has been reworked repeatedly in the past year.

The current version encourages states to update efficiency codes, authorizes $20 million in electric motor and transformer rebates over the next two years, and allows continued manufacture after April 16, 2015, of electric-resistance water heaters with 75 gallons or more of storage capacity and sold with an "activation key" for utilities to use for demand response.

Utility organizations have raised concerns that a Department of Energy efficiency standard taking effect next April 16 would hinder use of high-volume electric-resistance waters heaters for demand-response programs.

The bill faces political complications on its path to a final vote, however. On April 30, Sen. David Vitter (R-La.) filed for the second time a proposed amendment to the bill requiring all federal elected officials, congressional staff, and Executive Branch political appointees to buy health insurance through the Affordable Care Act exchange.

Last fall, a dispute over Vitter's amendment stalled a floor vote on the Shaheen-Portman bill.

In a related matter, Sen. Mark Udall (D-Colo.) said he plans to offer an amendment mirroring House legislation to speed up natural-gas exports permitting that the House Energy and Commerce Committee reported out April 30 (see story below).

In their letter to Majority Leader Harry Reid (D-Nev.) and Minority Leader Mitch McConnell (R-Ky.), industry groups said S. 2262 enjoys "broad support in the business community," noting bill sponsors "have worked with industry every step of the way in crafting and vetting this legislation."

Signatories included the Northwest Energy Efficiency Council, Edison Electric Institute, National Rural Electric Cooperative Association, American Gas Association, and American Public Gas Association, along with manufacturers including DuPont, Honeywell, Johnson Controls, and Owens Corning.

Obama to Back LaFleur for Full FERC Term

President Barack Obama on May 1 said he plans to renominate Cheryl LaFleur for a full five-year term at FERC.

LaFleur, the commission's acting chair since Jon Wellinghoff stepped down last year, has served on the commission since 2010. Her current term expires in June.

FERC nominations are subject to Senate confirmation. Commissioners serve five-year terms.

House Panel Moves LNG Export Permitting Bill

The House Energy and Commerce Committee on April 30 reported out legislation to speed up permitting of liquefied natural gas exports.

On a 33-18 vote, the committee sent to the House floor a heavily amended version of HR 6, which would require DOE to decide on all pending permit applications 90 days after the legislation takes effect.

An earlier version would have required DOE to wave through all pending applications and allow fast-track approval of permits to all World Trade Organization member countries.

The amended bill retains Natural Gas Act provisions allowing fast-track approval of exports to countries with which the U.S. has free-trade agreements requiring equal treatment of foreign and domestic gas customers.

Court Affirms EPA Cross-State Pollution Rule

Environmental organizations cheered and coal advocates jeered the Supreme Court's April 29 decision upholding an Environmental Protection Agency rule aimed at limiting power-plant emissions drifting across state lines.

The 6-2 decision reversed a 2012 appeals-court decision to toss the Cross-State Air Pollution Rule, also known as the transport rule. Under it, EPA requires 28 states east of the Rockies to limit upwind emissions of sulfur dioxide and nitrogen oxides that lead to violations of air-quality standards in downwind states.

While not applicable to Pacific Coast or Rocky Mountain states, a law professor who directs UCLA law school's Emmett Institute on Climate Change and the Environment said the decision indicates how EPA's proposed rule to limit greenhouse-gas emissions from new fossil-energy plants might fare in litigation.

In a blog post, Ann Carlson, the institute's co-faculty director, noted the majority opinion "heartily embraces deference to agency expertise."

In future litigation over greenhouse-gas emissions standards, the court might be called upon to pass judgment on EPA's interpretation of the Clean Air Act's complex requirements, Carlson added.

Environmental groups hailed the majority-opinion conclusion that the rule is a "permissible, workable and equitable interpretation" of the Clean Air Act section governing regulation of air pollution crossing state lines.

The American Coalition for Clean Coal Electricity, a group of coal producers, utilities and railroads, branded the high-court decision "dangerous and costly."

Sen. Barbara Boxer (D-Calif.), chair of the Environment and Public Works Committee, called the transport rule a "critical public health safeguard," while Republican leaders of the House Energy and Commerce Committee characterized the court decision as "the latest blow to jobs and affordable energy."

In writing for the majority, Justice Ruth Bader Ginsburg said pollution drifting across state lines poses complex problems for regulators. Ginsburg quoted the King James Version of the Bible, writing, "The wind bloweth where it listeth, and thou hearest the sound thereof, but canst not tell whence it cometh, and whither it goeth."

Justice Antonin Scalia, author of the dissent, said EPA overstepped its authority in crafting the rule.

EPA adopted a complex, cost-based formula assigning to upwind states the quantities of power-plant emissions they must curb.

Efficiency Role 'Major' in GHG Compliance

State energy-efficiency policies could result in power-plant carbon-dioxide emissions falling 26 percent from their 2012 level by 2030, according to an American Council for an Energy-Efficient Economy report detailing efficiency's potential role in complying with EPA's upcoming greenhouse-gas rule for existing fossil-energy plants.

In a report released April 30, the council said states could reduce national power demand 25 percent from 2012 levels by 2030 if they set savings targets of 1.5 percent per year, enact model building codes, facilitate development of combined-heat-and-power systems, and adopt efficiency standards for five power-using products.

Broken down by state, ACEEE's estimated electricity reductions total 23 percent for Idaho, Montana and Washington; 27 percent for Oregon; and 28 percent for California. In percentage terms, Arizona would achieve the biggest percentage reductions, at 39 percent, the report said.

Under the rule, which EPA is expected to formally propose next month, states would receive guidance under the Clean Air Act's Section 111(d) for complying with emissions standards.

While there is "little precedent" for using efficiency as a Section 111(d) compliance avenue, "EPA guidance" on other Clean Air Act programs "suggests a role for efficiency" as one way to meet standards, ACEEE said.

Since the law requires EPA to consider compliance costs, efficiency "should play a major role" in the rule, ACEEE said.

The report estimated state efficiency savings targets would achieve 75 percent of the estimated reductions.

Washington's efficiency standard, adopted as part of Initiative 937 in 2006, requires utilities subject to I-937 to acquire all cost-effective conservation, amounting to about 1.4 percent in savings per year, ACEEE estimated.

Oregon's efficiency standard is 1 percent savings for this year. California must achieve savings of about 0.85 percent per year through 2020.

Idaho and Montana do not have state efficiency targets.

House Panel Moves School, Fed Efficiency Bills

The House Energy and Commerce Committee on April 30 reported out two bills, on voice votes, to boost energy efficiency in federal facilities and schools.

HR 2689 would prod federal agencies to use energy-savings performance contracts to adopt energy and water efficiency measures.

HR 4092 would direct DOE to coordinate distribution of information about federal energy-efficiency technical assistance programs to schools.

DOE Issues Cybersecurity Guide

DOE on April 28 released a guide for the energy industry and technology suppliers to build cybersecurity into control-systems supply chains.

The guide includes strategies and suggested procurement language to incorporate cybersecurity into product manufacturing, delivery, and installation.

The guide includes suggested procurement language for programmable logic controllers, SCADA systems, and assembled delivery infrastructure, including substations and natural gas pumping stations.

Utility trade-association executives said the document would help reduce the risk of cybersecurity weaknesses creeping into product supply chains.

NRC OKs Study of Spent-Fuel Pool Risks

The Nuclear Regulatory Commission agreed May 1 to open a rulemaking to consider revising its reactor licensing regulations in light of what environmental petitioners called "new and significant information" about the risks of high-density pool storage of spent fuel.

NRC developed the information in reviewing reactor safety following the Fukushima accident in 2011.

NRC also agreed separately to consider suspending licensing proceedings until it studies the pool-storage information. NRC has suspended issuing licenses while it reworks its "waste confidence" rule governing storage of spent fuel after reactor closure ***[Jim DiPeso].***