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CALIFORNIA ENERGY MARKETS

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BILLBOARD No. 1248

Western Price Survey

[1] Municipal Utilities Take Advantage of 'Buyer's Market' for Solar PPAs

A solar plant at Fort Hunter Liggett. *U.S. Army photo by John Prettyman.*

California's municipal utilities are continuing to lock in bargain deals for long-term power-purchase agreements for solar projects as a confluence of factors facilitate a buyer's market for solar purchasing. Riverside Public Utilities has approved 20-year PPAs that offer solar power from projects in Kern County at prices that dip below \$70/MWh. RPU and other utilities report that recent offers from developers are well below—as much as 30 percent in some cases—the prices they paid for solar at the end of last year. ***At [11], a dawning era for competitive solar?***

[2] Energy-Efficiency Incentive Tool Advances at CPUC

The CPUC this week approved a new tool meant to incentivize utilities to produce energy savings from efficiency programs. The latest tool replaces one that wound up rewarding utilities with hundreds of millions of dollars that consumer groups have called unearned. The new tool looks to reward actual savings as well as utility efforts in other energy-efficiency areas that support longer-term savings. It also caps rewards in each category. ***At [10], new profit tool for efficiency.***

[3] Rate-Restructuring Bill Gains Support With Net-Metering Amendments

Recent amendments to AB 327, a bill that would restructure residential electric-rate design in California, would extend and expand the state's net-metering program. Those changes have garnered support in the solar industry, but some groups are still pushing for elimination of a fixed charge for all residential customers. ***At [12], fixed charges and net metering.***

[4] Draft Reliability Plan for SoCal Released

State energy agencies on Aug. 30 released a draft plan for maintaining reliable electric service in Southern California that calls for more than 6 GW of preferred resources and conventional generation, as well as transmission upgrades and contingency permitting for new resources. ***Reliability plan at [13].***

[5] New Mexico Supreme Court OKs Utility Profits on Energy Efficiency

The New Mexico Supreme Court said state utility regulators may allow PNM to earn a profit on energy-efficiency programs. Meanwhile, Tres Amigas proposed a 2,000 MW underground direct-current transmission line to open New Mexico energy resources for export. ***Linking grids at [14].***

[6] DOE Caught Up in Budget Disputes as Congress Returns From Recess

Congress returns from recess Sept. 9 facing a host of unresolved fiscal issues, including disputes over the 2014 budget and another threat of a federal-government shutdown in mid-October. Meanwhile, the Environmental Protection Agency agreed to partial reconsideration of standards limiting hazardous air-pollutant emissions from reciprocating internal combustion engines. ***NRC seeks input on reopening Yucca Mountain license review at [15].***

News In Brief

[7] San Francisco Supervisors Go on the Offensive Over CleanPowerSF

Members of the San Francisco Board of Supervisors are demanding that the city's utilities commission set rates for the community-choice aggregation program, CleanPowerSF, or they will find an alternate way to move the program forward.

A resolution introduced by Supervisor London Breed on Sept. 3 says that if the San Francisco Public Utilities Commission fails to set "not-to-exceed" rates and implement CleanPowerSF in a timely way, the board shall, "whether at the Board Chambers or the ballot, exercise every means at its disposal to enact its policy objective and preserve its role as the elected policymaking body of San Francisco."

Supervisor John Avalos, who called it a "constitutional crisis," has said the board may seek an amendment to the city charter in order to work around the situation, which he said is fraught with politics.

San Francisco's mayor, Ed Lee, opposes CleanPowerSF. Members of the SFPUC are appointed by the mayor.

"Commissioners have actually been lobbied by the mayor's office very vociferously" to vote against or delay the program, Avalos said at Tuesday's board meeting.

Last September, the Board of Supervisors approved a 30 MW contract for the CCA program with Shell Energy North America and $19.5 million in startup funding. Under San Francisco's city charter, the SFPUC is charged with setting utility rates.

But after several months of deliberations, the commission has failed to approve proposed rates for CleanPowerSF due to a number of outstanding concerns about the CCA related to cost, job creation and whether it will be a green enough alternative to Pacific Gas & Electric.

The board asserts that the SFPUC is undermining its policymaking authority. The contract with Shell cannot move forward before a rate cap is finalized.

The board will vote on Breed's resolution next week. There is currently no agenda item before the SFPUC to discuss CleanPowerSF ***[L. B. V.].***

[7.1] CPUC Draft Decision Sets 1.3 GW Energy-Storage Target

A draft decision at the CPUC would require investor-owned utilities to procure more than 1.3 GW of energy storage, formalizing a proposal from earlier the spring.

In June, CPUC Commissioner Carla Peterman laid out a structure for utilities to procure the 1.3 GW by 2020, using a reverse auction mechanism (see *CEM* No. 1236 [12]). A draft decision released this week calls for utilities to apply by January with a proposal for their first solicitation *[R10-12-007]*. Community-choice aggregators would need to procure storage equal to 1 percent of their annual peak loads by 2020; energy-service providers would need to do the same by 2016.

The draft decision specifies goals for utilities. For instance, Southern California Edison and Pacific Gas & Electric must each procure a total of 580 MW—including 90 MW in 2014, 120 MW in 2016, 160 MW in 2018 and 210 MW in 2020. San Diego Gas & Electric must get 20 MW, 30 MW, 45 MW and 70 MW in those respective years for a 165 MW total.

The draft decision breaks those goals into categories of transmission-connected, distribution-connected and customer-side storage. The first solicitation would occur in December 2014.

The decision would let utilities defer up to 80 percent of their procurement target to a later solicitation if they can show that they have not received bids that are economically or operationally viable or have not received enough bids to meet procurement targets. But they must procure a minimum level for each procurement period to ensure storage becomes part of their resource portfolios. Parties can comment on the decision by Sept. 23 ***[H. C.].***

[7.2] Quick Bites: Energy News Roundup

The U.S. Bureau of Land Management said Aug. 30 it would prepare an environmental impact statement for the proposed Blythe Solar Power Project. Initially proposed as a 1 GW solar parabolic-trough facility, the project was permitted and approved in October 2010 on 6,831 acres of BLM-administered public land a few miles west of Blythe. After former developer Solar Millennium filed for bankruptcy protection in 2012, the Blythe project was acquired by NextEra Energy Resources. NextEra is proposing to develop a 485 MW solar-photovoltaic project on a reduced footprint of 4,138 acres ***[M. S.].***

Bottom Lines

[8] Ratepayers Should Not Remain in the Dark on Power Costs

Most California ratepayers have little idea how much their utilities are paying for power and how much their bills will increase as a result.

Renewable energy, especially, is a public investment—one being made to achieve the public benefit of reduced emissions, including greenhouse gases. Energy companies, traders and utilities all profit from the investment and, not surprisingly, want to keep pricing data secret. But the public deserves to know how much it is paying.

Currently, prices of power contracts are released by the CPUC *three years* after the project becomes operational. On this score, the CPUC lags FERC, which releases price data after the first quarter in which a facility begins selling power. In fact, it can take the CPUC up to 12 years after a contract is signed to release data.

The CPUC does issue aggregated data in an annual SB 836 report—the Padilla report, named after the bill's author, Sen. Alex Padilla (D-Pacoima). It also lists current-year total costs of RPS procurements though a so-called Section 910 report. These reports are a step in the right direction, but more needs to be done. The public should know how much, in total, their bills are going to rise now and in the future from power purchases and the costs of different technologies and energy carve-out programs, such as for distributed generation.

'There is not routine reporting on future RPS procurement costs.'

Somebody at the CPUC agrees. A commission proposal issued in July suggests that, for contracts submitted via application, utilities would have to disclose the contract price, the total expected contract cost, how they evaluated the contract under least-cost and best-fit criteria, any indirect costs, and the rate impact *[R11-05-005]*. Prices would also be revealed when a contract is approved via a resolution or submitted through an advice letter. (Prices of certain contracts, such as for community-choice aggregators and energy-service providers, would be released six months after the contract is signed or 30 days after deliveries of energy commence.)

"As a result of the current system, no public discussion of the actual price of RPS procurement contracts that may extend for 20 years and cost hundreds of millions of dollars over the life of the contract occurs prior to commission approval or rejection of the contract," the proposal stated. "The general public interest in RPS costs overall and the commission's obligations to report to the Legislature about the RPS program, including its costs, support disclosure."

In comments filed in late August with the CPUC, utilities warned of market manipulation. Southern California Edison went as far as to reference the energy crisis and the recent gaming of Cal-ISO markets by J.P. Morgan—two events that had absolutely nothing to do with price disclosure of renewable-energy contracts. (We could say Edison employed a well-worn logical fallacy in California power markets—*reductio ad crisisarium*.)

Utilities also argued that price disclosure would harm contract negotiations. Edison referenced the Solar Photovoltaic Program, or SPVP, which contains a utility self-build element and one in which third parties bid to build distributed PV projects. The program set a price cap of $192/MWh, so bidders just bid slightly under the cap, Edison said. In addition, the same project bid one price in the renewables auction mechanism program and a higher price in the SPVP, which has less competition.

That doesn't sound like a problem with price disclosure, however, as not a single contract price was revealed. It sounds like a problem with price caps and the SPVP, which may not be competitive. If anything, if bids come in just under the cap at uncompetitive prices, it's that kind of price transparency that invites necessary examination of whether or not the program is working.

Edison's fear that price disclosure would establish price "floors," causing power producers to bid higher, is unsupported by market evidence. For years municipal utilities, as well as some states such as Nevada, have been releasing prices of RPS contracts. Even with such disclosure, the costs of most renewable-energy technologies have been falling, as seen in recent low-priced deals for municipal solar and wind. Censors always like to think that data release will monkey-wrench the markets, but renewable-energy prices have a lot more to do with supply, demand and technology than with price disclosure.

One comment from Edison struck me as somewhat clueless on the subject of transparency. The utility stated it didn't object to releasing actual costs of current and forecast RPS procurement in aggregated form, and said it already provides such information. In a footnote, Edison said this information could be found in its "2012 Preliminary Annual 33 Percent RPS Compliance Report" and its 2013 renewables procurement plan.

The preliminary 33 percent RPS report, however, consists of more than 200 pages of dense tables in small type and is impossible for a member of the public to understand. Closer examination of Edison's spreadsheet labyrinth reveals no coherent data on RPS procurement costs. The only price data at all arrives at somewhere past page 100 (one has to scroll through to get there, as the report has no index) and

Continued on page 6

Western Price Survey

[9] Northwest Power Prices Skyrocket

After an August lull, daytime power prices in the West are starting off strong in September.

Mid-Columbia added $20.70/MWh in the Aug. 30 to Sept. 6 trading period, ending today at $69.45. California-Oregon Border prices gained $17.15 to $72.30/MWh.

California daytime prices jumped about $10 in the Friday-to-Friday trading period, with South of Path 15 finishing at about $62/MWh.

Forecasts are calling for hotter weather in Seattle and Portland starting on Monday, with Portland highs climbing into the 90s by midweek.

Meanwhile, the SCADA system responsible for feeding load and generation data to the Bonneville Power Administration's website failed Thursday, Sept. 5 at about 10:30 a.m.

"After the system was brought back up, we started receiving zeros for all input data," said the agency's Michael Hansen, who added that the problem was corrected Friday morning. "Unfortunately, we are often not able to backfill lost information following source system failures."

Looking back at last month, peak-power prices at Western hubs have been more stable than in August 2012, when a few peak days contributed to price volatility, particularly in the Northwest. Gas prices, meanwhile, trended higher as a whole last month compared with August 2012's (see "Price Trends," next page).

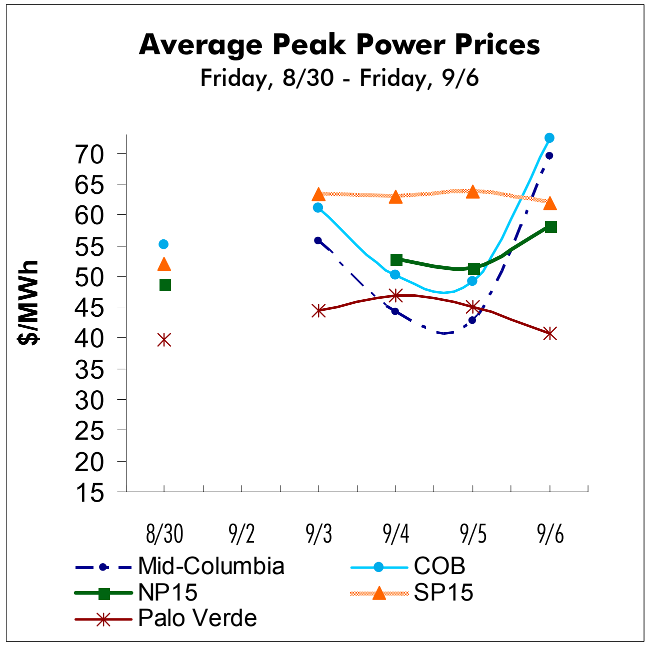
Working gas in storage reached 3,188 Bcf as of Aug. 30, according to U.S. Energy Information Administration estimates, a net increase of 58 Bcf from the previous week. Storage levels are now 6.2 percent less than a year ago and 1.4 percent greater than the five-year average.

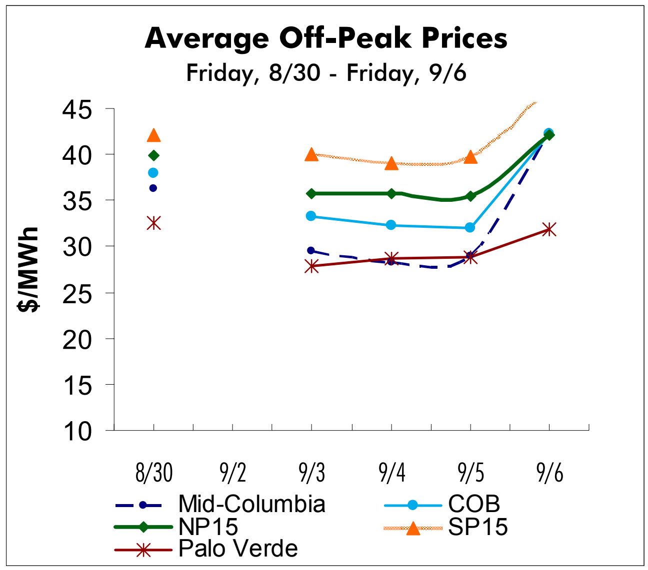
The storage addition dragged on natural gas prices. Henry Hub gas values shed 2 cents since last Friday, trading Sept. 6 at $3.54/MMBtu. Western prices also moved a few cents lower, except at Southern California Border, which added 7 cents to almost $3.87/MMBtu (see table at right).

Natural gas prices should stay near $3.50/MMBtu in the short term, according to Barclays analysts. Values may reach $3.80/MMBtu in the fourth quarter of 2013, the analysts forecast in their weekly commodities report.

Markets were closed Monday, Sept. 2, in observance of the Labor Day holiday.

What's ahead: The National Weather Service forecasts an increased probability of above-normal temperatures across the West between Sept. 11 and 19 ***[Linda Dailey Paulson].***

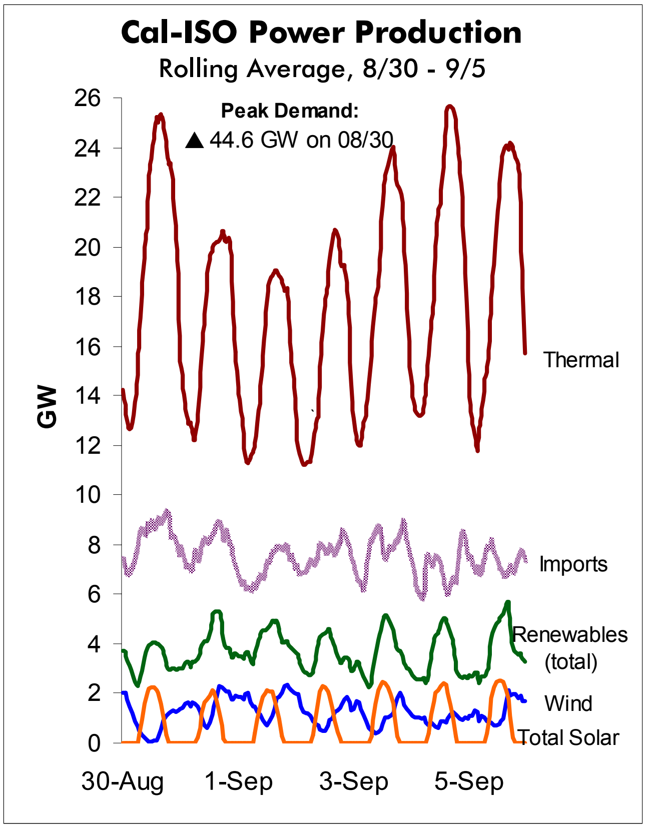


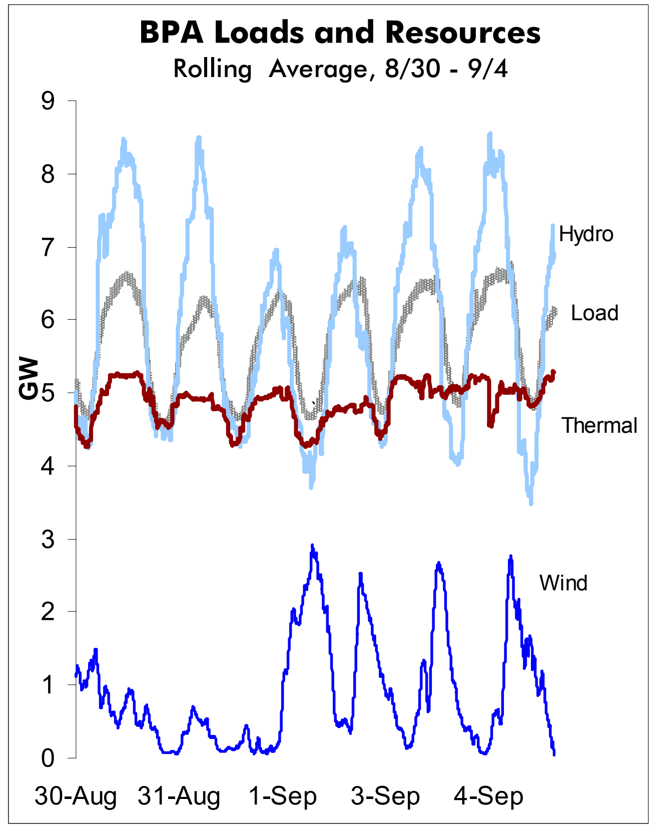


Average Natural Gas Prices ($/MMBtu)

	Fri, 8/30	Wed, 9/04	Fri, 9/06
Henry Hub	3.56	3.68	3.54
SoCal Border	3.79	3.96	3.86
PG&E CityGate	3.99	4.10	3.95
Malin	3.53	3.69	3.50
Alberta	2.22	2.20	1.94

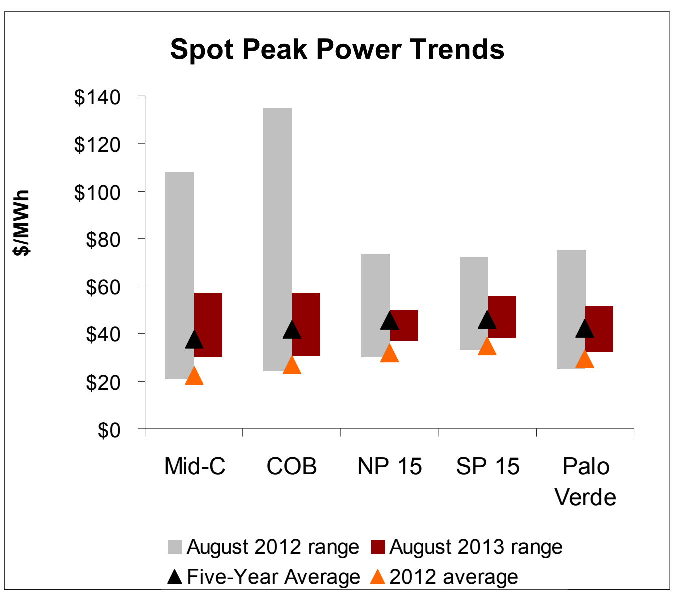
Power Gauge

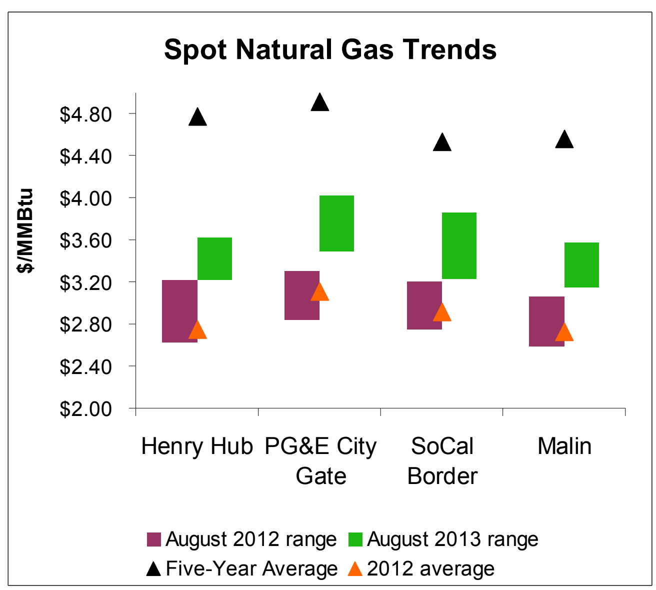




Sources: Cal-ISO and BPA. Sept. 5 data unavailable for BPA at press time.

Price Trends





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when this data finally appears, it concerns individual contract prices and most of it is blacked out or listed as "not applicable."

As for the 2013 RPS procurement plan, some useful information can be found in "Public Appendix D," but it arrives on page 141 of Edison's 150-page plan—barely a service to the public. A "joint IOU cost quantification table" indicates expenditures of $1.5 billion to $2 billion a year between now and 2017, with cost breakdowns by technology, but rate impacts for the next few years have been blacked out and there is no differentiation by energy program.

And when we get to PG&E's report, looking at the same "cost quantification" table, much of the same information has been blacked out.

"There is not routine reporting on future RPS procurement costs," CPUC spokeswoman Terrie Prosper said.

The Section 910 report indicates that investor-owned utilities spent a combined $2.52 billion for 2011 RPS deliveries. The report, however, does not forecast future renewables expenditures or rate impacts. Nor does the report break down costs by types of renewable-energy program (RAM, solar PV, ReMAT)—information that would help the public gauge how renewable-energy programs are working.

I am not convinced a three-year hold on contract price disclosure is necessary at all. The CPUC should at least drastically reduce the confidentiality window for all contracts to no more than a year after a contract is signed. The state is considering a capacity auction anyhow, presumably under which prices would be transparent.

At the very least, the CPUC should also require load-serving entities to report yearly how much they are paying in total for renewable, natural gas and other forms of power. Such a report, which could replace all the piecemeal, inconsistent, and blurry reporting that goes on now, would also include cost figures by program, technology type, rate impacts, and future forecasts of costs and rate effects. Such data could easily be folded into reports that are readily accessible to the public, such as the Padilla or 910 reports—not buried in a 200-page spreadsheet in a remote cybercorner of the CPUC website.

The public is paying for a number of different energy programs, and it simply deserves to know what it is paying and whether these programs are working ***[Chris Raphael].***

Regulation Status

[10] CPUC Looks to New Tool to Prompt Energy-Efficiency Gains *(from [2])*

The CPUC adopted a new tool this week, aiming to prompt utilities to invest in energy efficiency and reward them in a sufficient and predictable way—without the controversy and questions that a previous incentive tool has generated.

The commission voted 4-0 at a Sept. 5 business meeting to approve the tool, laid out in a decision by Administrative Law Judge Thomas Pulsifer *[D13-09-023, R12-01-005]*. Commissioner Mike Florio was absent.

The Efficiency Savings and Performance Incentive replaces the Risk Reward Incentive Mechanism. ESPI "differs from the prior approach by placing greater emphasis on capturing deeper, more comprehensive, and longer lasting energy savings," the decision stated.

The new tool stems from a proposal by Commissioner Mark Ferron and seeks to encourage longer-lasting and deeper savings that extend beyond the 2013-2014 cycle (see *CEM* No. 1244 [10.1]). It calls for offering incentive awards in four categories—for actual energy-efficiency resource savings; for a review process on expected savings; for savings from building codes and standards programs; and for non-resource programs that support savings-based programs but produce no direct energy savings.

The new tool caps incentives for resource savings at 9 percent of resource-program spending and caps incentives for the review process on expected savings at 3 percent of resource-program spending, minus funding for administrative and other activities. The tool provides management fees equal to 12 percent of approved codes-and-standards program spending and 3 percent of non-resource program spending, excluding administrative costs.

The previous mechanism had sought to maximize net economic benefits, which reduced energy savings and lessened support for longer-term policy objectives, Pulsifer's decision said. Parties had fought for years over the RRIM, as utilities collected hundreds of millions of dollars in rewards that consumer groups called unearned and CPUC administrative law judges had not always recommended.

The RRIM wound up relying on expected savings rather than actual savings, as originally intended, and parties argued over how to calculate savings—an evaluation, measurement and verification process that should have provided factual information but became a source of controversy itself.

At the meeting, Ferron stressed a goal to make investments in energy efficiency equal to investments in supply-side resources. Shareholders need to see earnings that are both big enough and predictable enough in order to make such investments, he said.

The new tool rewards every aspect of utility administration of efficiency programs, Ferron said. It is structured so that most of the incentives would stem from actual savings. A real stream of incentives for real savings will prove that efficiency is a significant source of earnings over time, Ferron said.

CPUC President Michael Peevey called the tool "a step in the right direction." Commissioner Carla Peterman said it gives utilities a reasonable chance to earn incentives, but noted that uncertainty always exists in trying to measure something that did not occur from programs.

Also at the meeting, the commission approved a consent-agenda item that lets Southern California Edison build its proposed Lakeview Substation project in the Riverside County community of Lakeview, despite significant environmental impacts *[D13-09-004, A10-09-016]*.

Edison had sought a permit for the project, which includes a new 115/12 kV electric substation, two subtransmission source line segments, two underground 12 kV distribution line segments, telecommunications infrastructure work, and the decommissioning of two existing substations. The project aims to serve existing and long-term projected electrical demand needs and improve reliability and system operational flexibility.

Construction could increase nitrogen oxides and particulate matter enough to violate air-quality standards. The work could also harm special-status plants, the Stephens' kangaroo rat and other wildlife ***[Hilary Corrigan].***

[10.1] San Bruno Continues Push for Reforms

Approaching the third anniversary of a fatal gas-pipeline explosion in its community and following recent disclosures of inaccurate pipeline information, the City of San Bruno this week reiterated calls for Gov. Jerry Brown to remove two CPUC leaders and noted the possibility of criminal charges against Pacific Gas & Electric.

PG&E disclosed in late August it once again had relied on inaccurate information to set the maximum operating pressure for its natural gas transmission lines.

In an Aug. 30 filing at the CPUC, PG&E said it found "gaps" in the early stages of its work to validate maximum operating pressures for lines.

A gas leak discovered in October 2012 prompted a visual inspection of a segment (Segment 109, installed in 1957) of Line 147, a short connector pipeline that runs through San Carlos. The engineer who performed the visual inspection discovered that the long-seam weld in the segment appeared to be different from what PG&E records stated it was.

After the leak was repaired in November and the engineer notified various other departments at PG&E of the discrepancy, the utility undertook a "re-review" of all pipeline specifications for Line 147, PG&E said in the Aug. 30 filing.

As a result of the re-review, PG&E also uncovered record-discrepancy errors for three other segments of Line 147. PG&E ultimately revised maximum operating pressures for six segments on Line 147, four of them to correct errors, the utility said.

The PG&E filing, which expands on a related filing the utility made in July (see *CEM* No. 1246 [12]), also comes just days before the third anniversary of the fatal San Bruno gas-pipeline explosion approaches. The September 2010 rupture of a PG&E gas line in San Bruno killed eight people, injured dozens and destroyed a neighborhood. Since then, the city has worked to repair homes and various types of infrastructure in that section. The city has also worked to keep pipeline issues in the spotlight, taking part in CPUC proceedings and spearheading national efforts with other communities and regulatory entities.

"The tragedy in San Bruno could have—and it should have—been prevented," said Mayor Jim Ruane at a Sept. 3 press conference.

Ruane called PG&E's latest revelation about errors in pipeline records "disgusting."

"I thought, 'Here we go again,'" he said.

> **'I believe that there's enough gross negligence on the part of PG&E to file manslaughter charges.'**

The city has previously called for financially penalizing PG&E to the maximum extent possible; requiring independent monitoring of PG&E's pipeline work; establishing a pipeline safety trust to fund pipeline-safety advocacy work; and installing automated shutoff valves throughout the pipeline system.

San Bruno has long complained that the CPUC had gotten too cozy with utilities. The city has noted that the commission tried to set up a pipeline conference with PG&E despite its ongoing investigations into the utility's pipeline practices; had botched its own legal staff's attempts to recommend a penalty during those investigations; and had overstepped its legal bounds by trying to impose mediation last year in those investigations (see *CEM* Nos. 1203 [11] and 1237 [14]).

The city also wants Brown to replace CPUC President Michael Peevey and Executive Director Paul Clanon.

"I'm very unhappy with Mr. Peevey and the way he has conducted himself," Ruane said.

The city has gotten no response from Brown.

"It's not acceptable, to put it mildly," Ruane said after the press conference of Brown's lack of response. Brown's office did not return a call for comment.

San Bruno had asked the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration to audit the commission and now awaits results of that audit (see *CEM* No. 1242 [10.1]). The city is also awaiting completion of an investigation of PG&E by various local, state and federal law-enforcement agencies, said City Manager Connie Jackson after the press conference.

"Everything we have seen allows us to believe there's at least evidence of criminal negligence," Jackson said.

"I believe that there's enough gross negligence on the part of PG&E to file manslaughter charges," said Britt Strottman, an attorney representing San Bruno in CPUC cases. Strottman formerly worked as an attorney with the San Mateo County District Attorney's Office, the entity that would file any criminal charges.

The San Mateo County District Attorney's Office has until Sept. 9 to file criminal charges related to the San Bruno explosion. Karen Guidotti, chief deputy district attorney at that office, said she was not prepared to make any statements. At the federal level, prosecutors at the U.S. Attorney's Office have another two years to file any charges. PG&E spokeswoman Brittany Chord said PG&E continues to cooperate with investigations.

Jackson said the city was "horribly disappointed" in the CPUC's actions so far—including ignoring any discussion of even considering the option of revoking the utility's monopoly.

PG&E said it has since enhanced its work to include additional third-party review, testing of engineering assumptions, and implementation of a computerized engineering data-validation tool. It has also reduced pressure on the two lines. The CPUC planned to review issues related to the error findings at hearings on Sept. 6.

In response to San Bruno's press conference this week, Chord of PG&E said the utility has aimed from the start to try to help the community rebuild and to make its system safer and more reliable for customers. PG&E knew it had to do better and has worked to hydrotest and replace lines, install automated valves and make the system safe throughout its service area, she said.

"Overall, we're working to be better as a company and really be a company that our customers trust," Chord said ***[H. C.].***

Regional Roundup

[11] Munis Reaping Benefits of 'Buyer's Market' for Solar PPAs *(from [1])*

Municipal utilities in California are continuing to score bargain deals for long-term solar contracts as they look to fulfill their renewables portfolio standard requirements.

Riverside Public Utilities, which serves power customers in the City of Riverside, has approved two solar power-purchase agreement offers, both under $70/MWh. The deals, brokered by the Southern California Public Power Authority on behalf of RPU and other member utilities, were approved by the utility's Board of Public Utilities on Sept. 6 and will now be forwarded to the Riverside City Council for final consideration.

One of the PPAs is a 20-year contract for 26 MW from Recurrent Energy's Clearwater and Columbia 2 solar projects, to be located in Kern County. The all-in price for the energy, capacity and environmental attributes is fixed at $69.98/MWh over the term of the contract.

'The state has developed a very robust solar industry that is delivering low-cost power.'

Another 20-year PPA for 14 MW of power from First Solar's Kingbird Solar Photovoltaic Project, also in Kern County, is moving forward. The all-in price for the Kingbird deal is $69/MWh.

"We're seeing some very, very attractive pricing" for select renewables projects, noted Reiko Kerr, utilities assistant general manager at RPU.

Kerr said the solar projects approved by the board this week fit particularly well in RPU's resources portfolio given Riverside's consistently high summer temperatures, which can lead to a doubling of load during summertime peak periods due to high air-conditioning use and other factors.

"This increase matches very well with output from solar facilities," Kerr observed.

The Recurrent and First Solar offers are 10 to 15 percent lower than other projects recently bid to SCPPA, and about 30 percent lower than similar photovoltaic projects that Riverside contracted with in late 2012, according to the utility.

Under a 20-year SCPPA contract announced in December, for example, the Los Angeles Department of Water & Power will purchase 210 MW of solar power from Sempra U.S. Gas & Power's Copper Mountain Solar 3 project in Boulder City, Nev., at a fixed price of $95.75/MWh.

A 25-year PPA Riverside signed with SunEdison in November for 20 MW from the Lake I solar plant in western Riverside County has a levelized cost of about $95/MWh.

Dropping costs for solar PV contracts are reflected in deals that have been sealed by cities across the state in recent months.

In August, the City of Roseville announced a 10-year PPA with First Solar for 32 MW of electricity from the planned Lost Hills project in Kern County.

The cost of the contract is about $75/MWh, or $24 million in total. This is about $6.5 million less than similar renewable-energy purchase offers Roseville received in 2012, the utility said.

In June, the City of Palo Alto agreed to buy 80 MW of solar power at a cost of about $69/MWh from three in-state projects under 30-year purchase agreements.

The price for the contracts—at the time hailed by solar advocates as "mindblowing"—is lower than that of any renewable-energy project Palo Alto has approved in the last eight years (see *CEM* No. 1238 [14]).

"It's definitely a buyer's market," confirmed Kelly Nguyen, director of energy systems at SCPPA.

RPU attributes the competitive prices for offers it has received to several factors, including the continuing decline of equipment and labor costs for solar PV projects; lower-than-anticipated transmission and interconnection costs for projects in Kern County; and the "in-fill" nature of the projects (they will be part of a larger site that is in the advanced stages of development).

Palo Alto has also cited a shift in supply and demand factors that favors the likes of municipal utilities. The shift is due to investor-owned utilities having contracted for enough renewable energy to meet their midterm needs, leaving developers vying for contracts with a relatively small pool of buyers.

"As a result, renewables prices—particularly for solar—have been driven down recently to near parity with long-term brown market prices," notes a report by Palo Alto's utility.

Another factor in falling solar-contract prices, according to Adam Browning of Vote Solar, is the pending expiration of the federal investment tax credit for solar projects at the end of 2016.

"Now's a great time for solar purchasing given the timeline for bidding, interconnection and construction," Browning said.

The confluence of factors that is creating a buyer's market in California has been fueled by policy directives that aim to bring the cost of solar energy down by achieving scale, Browning said.

"The state has developed a very robust solar industry that is delivering low-cost power," he added.

Municipal utilities say another benefit of the current market is that top solar companies with established track records are competing for their attention.

"Over the last two years more and more of the guys that you have confidence will deliver have lowered their prices," said Mike Wardell, power-supply manager at Roseville's utility, Roseville Electric.

With investor-owned utilities having largely filled their RPS buckets, at least for now, and many municipal utilities well on their way to satisfying their need for renewables, solar developers are looking beyond the long-term utility PPA paradigm.

Sheldon Kimber, chief operating officer for Recurrent Energy, said that as solar achieves price parity with conventional generation sources, solar projects will look to sell their output in traditional energy markets through shorter-term agreements on the wholesale market.

"We're getting to the end of renewable demand-creation programs," Kimber said. "The era of competitive solar is dawning" ***[Leora Broydo Vestel].***

[12] Net-Metering Changes in Rate Bill Garner Support *(from [3])*

Changes to a bill that would restructure residential electric-rate design in California have garnered support in the solar industry, but some groups are still pushing for the elimination of a fixed charge for all residential customers.

Some solar advocates cheered recent amendments to AB 327, from Assm. Henry Perea (D-Fresno), that extend net metering in California. But some groups, such as Vote Solar, want to see more certainty in the way the bill handles net metering after 2016, and would like the fixed-charge provision eliminated.

The bill would repeal existing restrictions on the CPUC's ability to raise electric rates, including those for low-income customers in the California Alternate Rates for Energy (CARE) program. The commission would have to ensure CARE customers are not "jeopardized or overburdened" by monthly energy bills and adopt CARE rates that correctly reflect their level of need, as determined by a needs assessment that would be performed every third year.

When the Perea rate bill passed the Assembly in June, it did not contain some of the controversial provisions such as the fixed charge, which would add as much as $10 a month to all residential electric bills, or $120 a year, to cover a portion of the fixed costs of providing service. Customers in the CARE program would be charged up to $5 a month. Beginning in 2016, the fixed monthly charges could be adjusted upward by the percentage increase in the Consumer Price Index.

"The charge will hurt the economics of investing in solar and energy efficiency by reducing the value of lowering one's electric bill since the fixed charge will remain in place no matter how energy efficient or self-reliant a consumer becomes," the California Solar Energy Industries Association stated.

'The charge will hurt the economics of investing in solar and energy efficiency.'

But the bill has garnered widespread support, including that of the state's three investor-owned utilities, SEIA, The Utility Reform Network, and the Alliance for Solar Choice.

The inclusion of monthly fixed charges, which would reduce the benefit that solar customers derive from rooftop panels that offset electric bills, led to petitions and protests by local and environmental groups outside the offices of Southern California Edison, a main proponent of the fixed charges. Edison has said the charges would help defray fixed expenses for the utility's distribution system and a loss of revenue from customers with rooftop solar. Edison, Pacific Gas & Electric and San Diego Gas & Electric support the bill.

AB 327's net-metering provisions were the latest amendments. California's current net-metering program, which allows eligible customer-generators to receive a bill credit for the amount of solar generated from rooftop panels, was slated to expire at the end of 2016, and was capped at 5 percent of a utility's aggregate customer peak demand. The CPUC in 2012 changed the methodology for calculating the cap, in essence expanding the program, but the decision was controversial.

Under the Perea bill, large electrical corporations, defined as those with more than 100,000 service connections, would be required to provide net-energy metering through July 1, 2017, or until the service provider reaches its NEM program cap. The bill specifies per-utility net-energy metering program limits of 607 MW for SDG&E; 2,240 MW for PG&E; and 2,409 MW for Edison. And the CPUC would be required to develop a standard contract or tariff for eligible customers that would go into effect beginning July 1, 2017, or before that date if the utility met its program limit.

The extension of the net-energy metering program and the new standard net-energy metering tariff or contracts would serve to soften the blow from the inclusion of fixed charges, but Vote Solar, for one, is advocating for further amendments.

The group would like to see further protections for net-metering customers after 2016, for example. And Vote Solar is also pushing for the bill not to include any potential new charges for solar customers when the NEM program is expanded.

With less than a week left for each house to pass bills, time is running out for changes.

Minnie Santillan, a spokeswoman in Perea's office, said she expected the bill could be heard on the Senate floor on Sept. 6 or Sept. 9.

Sierra Club is opposing the bill. In addition to fixed charges adding up to $120 a year to electric bills, Sierra Club said AB 327 would slow adoption of rooftop solar and energy efficiency ***[Mavis Scanlon].***

[13] Preferred Resources, New Generation Recommended for SoCal *(from [4])*

State energy agencies on Aug. 30 released a draft plan for maintaining reliable electric service in Southern California that calls for thousands of megawatts of preferred resources and conventional generation, as well as transmission upgrades and contingency permitting for new resources. The plan calls for developing or procuring about 3,250 MW of preferred resources such as energy efficiency, renewables, demand response, combined heat and power and energy storage, and another 3,000 MW of conventional generation.

The CPUC, the CEC and Cal-ISO prepared the plan in the wake of Southern California Edison's June 7 announcement that it would permanently close the 2,250 MW San Onofre Nuclear Generating Station. SONGS supplied power to about 1.4 million homes served by Edison, San Diego Gas & Electric, and the City of Riverside.

As the agencies noted, SONGS was especially important since it was located on a critical transmission path between Orange County and San Diego, and provided crucial voltage support that was necessary to move power between Los Angeles and the Orange County/San Diego regions. In assessing the need for replacement power, regulators also had to consider expected load growth of about 400 MW a year in the region and regulatory deadlines for phasing out approximately 5,000 MW of once-through-cooling units at aging gas-fired plants.

"These are large numbers and involve a complex mix of regulatory challenges," the agencies stated in the draft plan.

Developed with input from the State Water Resources Control Board, Edison, SDG&E and the South Coast Air Quality Management District, the recommendations are made with a goal of ensuring reliability. They stress the importance of beginning to plan now, as the specific actions called for in the report would be implemented through decisions either in a CPUC proceeding, in the Cal-ISO planning process, or through the CEC's power-plant siting process.

The plan looks at near-term needs (2013-2017) and long-term needs (2020 and beyond), and uses previous technical studies done this year and last as the basis for recommendations.

Specific recommendations for preferred resources include maintaining the Flex Alert program and extending funding beyond 2013-2014. The CPUC will review funding needs once it wraps up an effectiveness study, according to the agencies. The CPUC will also take steps next year to accelerate authorization and procurement of additional preferred resources in the regions affected by the SONGS closure.

The agencies recommended the CPUC take steps to allow for the development of near-term options to provide larger amounts of preferred resources in the Los Angeles Basin and San Diego. "Traditionally preferred resources programs are statewide and geographically neutral," the agencies stated. "Therefore the CPUC will need to consider rule changes that can allow resources authorization to better address local reliability needs."

> **'These are large numbers and involve a complex mix of regulatory challenges.'**

Edison plans to seek CPUC approval to adjust its existing energy-efficiency and demand-response programs to get more competitively priced preferred resources, with a target focus on loads in the West LA Basin and south Orange County, while Cal-ISO is looking into the feasibility of implementing a pilot multi-year auction for efficiency and DR programs in the region.

To provide additional reactive power, Cal-ISO earlier this year approved two projects: synchronous condensers at the Talega Substation that are expected to be in service before next summer, and the installation of a Static Var compensator at the San Onofre Mesa Substation. This project also requires CPUC approval; SDG&E expects to file an application at the commission by the middle of next year, according to the agencies, and the project could be on line by summer 2016.

Cal-ISO also approved a new 230 kV line from the Sycamore Canyon Substation to the Penasquitos Substation to improve east-west power flows in northern San Diego. To meet a target on-line date of 2017, a sponsor will have to be chosen from among multiple applicants, and the CPUC also must approve it. The agencies recommended the CPUC process and approve the application by mid-2015.

The agencies also recommended pursuing a reduction in the minimum-voltage criteria in the area around San Onofre, a move that will require U.S. Nuclear Regulatory Commission approval; converting one of the generators at San Onofre into a synchronous-condenser unit; and extending the reliability-must-run contracts for the synchronous condensers at Huntington Beach.

Generation recommendations include maintaining existing peaking generation in San Diego by delaying the retirement of the 188 MW Cabrillo II peaker until 2015; accelerating the procurement of already-authorized near-term resources; and authorizing additional conventional generation.

Both Edison and SDG&E would like to pre-license sites in their service areas that they would then bid out to developers based on predetermined resource needs.

"This proposal will require flexibility within the various state rules on licensing and development time frame, but could facilitate the addition of new generation in significantly shorter time frames if and once the need is authorized by the CPUC," the plan states. The option would require a CPUC review of funding needs for development work; CEC cooperation and substantial review of preliminary applications for certification; and potential action by local air boards to ensure emissions offsets are available, the plan added.

Looking out to 2020 and beyond, the retirement of as much as 3,800 MW of conventional once-through-cooling generation comes into play. Cal-ISO has identified a need of about 4,600 MW post-2020, but an estimated 1,000 MW of distributed generation, an estimated 1,000 MW of energy-efficiency savings (from not-yet-authorized programs) and 200 MW of demand response would reduce that need.

The plan says varying combinations of generation and reactive power support could meet this need, as could preferred resources "with appropriate capabilities and in the proper locations." A high-voltage transmission line between the LA Basin and San Diego could also reduce overall needs by about 1,000 MW.

Additional proceedings, such as Cal-ISO's annual transmission-planning process—expected in the first quarter of next year—and the CPUC's long-term procurement-planning proceeding, will also be used to help refine the plan.

The agencies are holding a workshop Sept. 9 in Sacramento to field input on the plan ***[Mavis Scanlon].***

[13.1] Coalition Urges Fracking Freeze

Dozens of environmental and health groups want Gov. Jerry Brown to halt hydraulic fracturing in California, linking the practice to climate change, air and water pollution and harm to human health.

"There's no safe way to frack," said Becky Bond, political director of social-change organization CREDO in an Aug. 28 conference call. "It can't be proven to be safe."

Los Angeles City Council members Paul Koretz and Mike Bonin joined the call this week and proposed a city law to ban fracking in the city, citing water-supply and environmental concerns.

The groups warned that methane emissions from the fracking process and emissions from burning extracted oil could wipe out the progress that California has made in reducing greenhouse-gas emissions. Oil companies are drawn to the estimated 15 billion barrels of oil in the Monterey Shale in central California (see *CEM* No. 1227 [14]).

The groups also blasted a proposed bill, SB 4, as insufficient. Among other actions, the legislation from Sen. Fran Pavley (D-Agoura Hills) would require the Department of Conservation's Division of Oil, Gas & Geothermal Resources to set rules on well stimulation, including fracking and acidization, which involves applying acids into wells to create channels in underground formations so that oil and gas can reach wells.

Bond of CREDO called it a "sad day in California" when state lawmakers need to be told that they should not allow "massive amounts" of acid to be dumped into the ground.

The offices of Brown and Pavley did not return calls for comment. The Western States Petroleum Association called fracking safe and discounted the moratorium call, noting Brown's recognition of the importance of energy production ***[Hilary Corrigan].***

Southwest

[14] New Mexico Appeals Court Affirms Energy-Efficiency Rate Regulation *(from [5])*

The New Mexico Supreme Court on Aug. 29 unanimously affirmed the New Mexico Public Regulation Commission's decision to let PNM earn a profit on its energy-efficiency and load-management program. The court ruling upheld a November 2011 NMPRC decision to allow PNM to earn a 7.7 percent, or $1.4 million, annual return on its energy-efficiency program.

It was the second time in three years that the state Supreme Court has ruled on utility energy efficiency rates. The court's earlier ruling had vacated a 2010 energy efficiency rate case decision from the PRC for all three electric utilities serving New Mexico.

In the recent ruling, the court observed that the New Mexico Legislature in 2008 amended the New Mexico Efficient Use of Energy Act to require the NMPRC to give utilities an opportunity to earn profits on demand-side management programs.

New Mexico Attorney General Gary King and the New Mexico Industrial Energy Consumers group unsuccessfully argued that the 2011 NMPRC decision in PNM's energy-efficiency case was inconsistent with New Mexico law.

The attorney general and NMIEC told the state Supreme Court that New Mexico statutes only allow the NMPRC to use a return-on-rate-base method for setting rates. But nothing in the New Mexico Efficient Use of Energy Act required the commission to determine energy-efficiency profits based on capital investments through rate-base methodology, the Supreme Court wrote. In addition, the court said capital investments were not a significant factor in the cost of energy-efficiency programs.

The AG and NMIEC's rate-making procedure for energy efficiency "would have made the Efficient Use of Energy Act unworkable and impossible to administer," Steve Michel, chief counsel for Western Resource Advocates' energy program, told *California Energy Markets*.

"Had the decision gone the other way, you would have seen utilities pull back on their energy-efficiency programs," he said.

"We believed that the commission had properly applied the Efficient Use of Energy Act and the court's prior rulings when it granted PNM a financial incentive to conduct effective energy efficiency programs that do not involve capital investments," PNM spokeswoman Susan Sponar said in an e-mail.

The attorney general and NMIEC partially based their appeal on the New Mexico Supreme Court decision that nullified an April 2010 NMPRC energy-efficiency rate case for all three investor-owned electric utilities serving areas in New Mexico—PNM, El Paso Electric and Southwestern Public Service. The NMPRC had set the same rates for all three utilities, and the state's high court ruled that the commission's decision was not based on facts, not based on costs and not utility-specific ***[John Edwards].***

[14.1] Tres Amigas Proposes DC Line for New Mexico Power Exports

Tres Amigas on Aug. 28 announced plans for a 2,000 MW, direct-current underground transmission line that would cross New Mexico and open the state's renewable and natural-gas energy resources for development.

The line, dubbed the New Mexico Express, would link the company's Tres Amigas SuperStation in eastern New Mexico, which interconnects the nation's three electric grids, to the Four Corners Substation in northwest New Mexico. Tres Amigas did not disclose cost estimates or the length of the proposed line. Estimates for the Tres Amigas SuperStation have run as high as $1.6 billion.

The company said a second phase of the New Mexico Express would run from the SuperStation at Clovis, N.M., to the Eddy County, N.M. tie, which will link eastern and western grids.

The New Mexico Express would give developers of wind, solar and gas-fired power plants access to California and other western markets, David Stidham, senior vice president and chief operating officer of Tres Amigas, told *California Energy Markets*.

While sparsely populated New Mexico has electricity peak load of 4.5 GW, the state has more than 50 GW of generation capabilities, according to Tres Amigas.

The New Mexico Express, which would be the nation's first long-distance, underground DC line, would help developers tap unused energy resources, according to Tres Amigas.

The transmission line would be laid four feet underground, primarily along railroad and highway rights of way.

Underground DC lines offer several advantages. They are cheaper to maintain underground, suffer fewer line losses, and do not create electromagnetic fields, Stidham said.

The underground cable and equipment would cost four times more than overhead transmission lines on towers. However, Stidham said the underground line would be less expensive to install, protected from storms and out of sight of the public.

Tres Amigas has not established a schedule for the New Mexico Express.

Meanwhile, the SuperStation's first phase is scheduled to come on line in 2016, providing direct connections to the eastern and western electric grids, Stidham said. The second phase, linking the eastern grid with the Electric Reliability Council of Texas, is expected to come on line the following year ***[J. E.].***

[14.2] New Mexico Groups Suggest CO_2-Reduction Regulation

Western Resource Advocates, New Energy Economy and 32 other organizations on Aug. 28 petitioned the New Mexico Public Regulation Commission to require electric utilities to reduce carbon-dioxide emissions from power plants by 3 percent yearly until 2035.

The proposed Carbon Risk Reduction Rule would replace the "Optional Clean Energy Standard" organizations proposed in August 2012. Although that proposal didn't go anywhere, the new petition stated that comments from a workshop on the initial proposal were helpful.

The revised proposal also follows the same methodology that the U.S. Interior Department approved as part of a July 2013 settlement offer to the U.S. Environmental Protection Agency for reducing emissions from the coal-fired Navajo Generating Station in Arizona, said Steve Michel, chief counsel for Western Resource Advocates' energy program.

Interior agreed to implement a plan to reduce CO_2 emissions for the 350 MW it generates at Navajo. That power enables the Central Arizona Project to pump water around Arizona.

The proposed rule would allow utilities to decide how they reduce CO_2 emissions. A utility, for example, could satisfy the rule by improving a coal-fired plant's emissions controls, replacing coal power with gas-fired generation, or replacing coal- or gas-fired generation with renewables. In addition, the petitioners suggested that electric utilities later may be able to buy, sell and trade carbon credits or allowances created in other states.

The rule would require New Mexico's electric utilities to establish a base year between 2005 and 2012 for CO_2 emissions. Then, on July 1 each year, the utilities would file a verified statement of CO_2 reductions during the prior year.

Utilities could exit the CO_2 regime after 2023. In fact, the proposed retirement of two units at the coal-fired San Juan Generating Station would satisfy PNM's compliance obligation through 2023, according to the filing with the New Mexico Public Regulation Commission. The rule would continue until 2035 except for any electric utilities that exit early ***[J. E.].***

[14.3] New Mexico Panel Favors Plan to Lower San Juan Emissions

The New Mexico Environmental Improvement Board on Sept. 5 unanimously approved a proposal to shut down two units at the 1,800 MW, coal-fired San Juan Generating Station and to install emissions-reduction equipment on the remaining two units.

The New Mexico Environment Department, San Juan operator PNM and the U.S. Environmental Protection Agency agreed to the compromise in February 2013.

The EPA wanted to reduce nitrogen-oxide emissions that lead to regional haze, and New Mexico and utility officials sought to minimize compliance costs at the plant near Farmington.

Under the agreement, PNM will shut down Units 2 and 3 at San Juan by the end of 2017. The electric utility will start installing selective non-catalytic reduction equipment on Units 1 and 4 in early 2016.

The compromise plan will require $34.6 million in capital expenditures at San Juan and $10.1 million in annual costs, according to testimony from PNM. That contrasts capital investment of $844.4 million for the EPA's previous proposal, which would have required installation of far pricier selective catalytic reduction equipment on all four San Juan units.

PNM gets half of the 868 MW of generating capacity from Units 2 and 3.

To replace the power from the San Juan units, PNM has said it intends to build a gas-fired generation facility and draw nuclear power from the Palo Verde Generating Station, which PNM previously sold on the wholesale market.

"The state plan is better for New Mexico, because it reduces the cost impact on our customers and allows us to replace a significant amount of coal-fired generation with cleaner fuels," Pat Vincent-Collawn, PNM chairman and CEO, said in a statement Sept. 5.

Mariel Nanasi, executive director of New Energy Economy, earlier complained that PNM did not use renewables to replace the reduced capacity at San Juan and that the utility was "locking in" reliance on the remaining two coal plants.

San Juan County commissioners on Sept. 3 voted to support the agreement, but the Farmington City Council opposed the agreement on the same day.

The EPA and the New Mexico Public Regulation Commission must approve the agreement before it becomes final.

PNM owns 46 percent of San Juan. Other owners are Tucson Electric Power, the Southern California Public Power Authority, Tri-State Generation and Transmission Association, the M-S-R Public Power Agency, the City of Anaheim, the City of Farmington, Los Alamos County, N.M., and the Utah Associated Municipal Power System ***[J. E.].***

[14.4] Tucson Electric Outlines Plan to Replace Lost San Juan Generation

Tucson Electric Power announced it is negotiating to buy a 550 MW, gas-fired combined-cycle unit at the Gila River Generating Station in Gila Bend, Ariz. from Entegra Power Group.

TEP intends to use the gas-fired unit to replace generating-capacity losses at the 1,800 MW coal-fired San Juan Generating Station and also the 1,560 MW coal-fired Springerville Generating Station in eastern Arizona.

TEP expects to lose 170 MW of San Juan generating capacity under an agreement that San Juan plant operator PNM, the U.S. Environmental Protection Agency and the New Mexico Environment Department announced in February 2013 (see story at [14.3]).

In a separate transaction, TEP expects to increase its ownership stake in Springerville Unit 1 but reduce reliance on the unit for energy.

The utility agreed to acquire an additional 96 MW of Springerville Unit 1 for $46 million, bringing its ownership stake in the unit to 151 MW.

In addition, TEP said it may exercise options to buy another 43 MW, increasing its ownership position to a maximum of 194 MW.

However, TEP has been receiving all 387 MW of generation from Springerville Unit 1 and will get power only from its ownership stake at Unit 1 when TEP's leases expire in January 2015 ***[J. E.].***

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Potomac

[15] DOE Caught Up in Budget Disputes as Congress Set to Return *(from [6])*

Congress returns from recess Sept. 9 facing a host of unresolved fiscal issues, including disputes over the fiscal year 2014 budget and another threat of a federal-government shutdown in mid-October.

The Republican-controlled House and Democrat-run Senate are far apart on spending levels for the fiscal year beginning Oct. 1, including proposed budgets for the Department of Energy and the Environmental Protection Agency.

Congress has 11 working days scheduled before FY 2013 expires Sept. 30. If the House and Senate cannot come to terms before then on the 2014 budget, federal agencies would run out of spending authority, unless Congress agrees to a continuing resolution extending fiscal 2013 budget levels.

In a related matter, Treasury Secretary Jacob Lew on Aug. 26 warned House Speaker John Boehner (R-Ohio) that the federal government faces default in mid-October unless Congress extends borrowing authority.

On DOE's budget, House and Senate appropriators are more than $3 billion apart. The House bill—which the Obama administration has threatened to veto—would budget $24.95 billion, down $2 billion from this year.

The House bill would cut research and development funding for energy efficiency and renewables in half, allocate $25 million for licensing the proposed Yucca Mountain spent-nuclear-fuel repository, and bar enforcement of efficiency standards for general-purpose incandescent lighting.

In addition, the bill would cut off funds to implement former Energy Secretary Steven Chu's 2012 directive to power-marketing administrations to adopt rate structures incenting efficiency, variable generation, and electric-vehicle deployment.

In contrast, the Senate's 2014 energy and water bill—reported out by the Appropriations Committee on June 27 and awaiting floor action—provides $28.21 billion for DOE. The total includes $2.28 billion for efficiency and renewables, nearly $1.5 billion more than the House legislation.

The two chambers are also $3 billion apart on EPA's fiscal 2014 budget. Senate appropriators last month proposed $8.5 billion, while a House bill, which was bogged down in the Appropriations Committee when Congress broke for its August recess, would cut EPA's budget by one-third, to $5.5 billion.

Meanwhile, the Senate has scheduled Sept. 10 for the start of floor debate on S. 1392, a bipartisan energy-efficiency bill directing DOE to help states, tribes and local governments update model building codes and authorizing $5 million each in rebates for industrial motor upgrades and efficient transformers.

However, the start of floor action on S. 1392 might be delayed by Senate debate over Syria. In a Sept. 4 interview with E&E TV, energy investment researcher Kevin Book of ClearView Energy Partners characterized the bill as the "Rodney Dangerfield of energy legislation" because of competing demands on the Senate's time from Syria and budget issues.

Meanwhile, energy bills awaiting House floor action include:

- HR 1934, directing the Interior Department to prepare a quadrennial energy strategy specifying fossil- and renewable-energy production targets for federal lands.
- HR 1963, lifting the Bureau of Reclamation's monopoly on rights to develop hydropower on conduits serving projects built under the 1939 Water Conservation and Utilization Act. The bill affects five projects in Montana and Idaho.
- HR 1965, giving Interior 30 days to decide on drilling permits on federal lands, with automatic approval granted if the department has not acted after 60 days.
- HR 2728, blocking Interior Department regulation of hydraulic fracturing on federal lands.

EPA Reconsiders Engine Air Standards

The Environmental Protection Agency on Sept. 5 announced partial reconsideration of standards limiting hazardous air-pollutant emissions from reciprocating internal-combustion engines.

EPA agreed to reconsider three issues raised in separate petitions filed by Calpine, a coalition of environmental organizations, and Delaware's Department of Natural Resources and Environmental Control. EPA finalized the standards last January, after reconsidering, at the request of utilities, a rule adopted in 2010.

EPA set a public comment deadline of Nov. 4.

The issues raised in the most recent reconsideration requests involve ultra-low-sulfur fuel and reporting requirements for diesel engines used or contractually obligated for reliability.

The standards adopted last January allow emergency engines to operate a combined total of 100 hours per year without meeting emissions limits under certain conditions: whenever voltage changes by 5 percent or more; for Level 2 energy emergencies; for testing; and up to 50 hours for heading off potential voltage collapse or line overloads that could cause local or regional power outages.

Beginning in 2015, diesel engines of 100 horsepower or more and used more than 15 hours per year for protecting reliability must use ultra-low-sulfur fuel.

Environmental organizations challenged the 2015 deadline for using ultra-low-sulfur fuel, arguing EPA provided no evidence that two years of lead time would be needed for compliance.

EPA indicated it disagreed with the argument, but said more public-comment time is justified.

In their reconsideration petitions, the environmental groups and Calpine challenged the rule's provision allowing for use up to 50 hours per year to head off voltage collapse or line overloads.

Calpine and the environmental groups argued that EPA's rule is too vague and would be difficult to enforce.

NRC Seeks Comments on Yucca Consideration

The Nuclear Regulatory Commission on Aug. 30 made public an order seeking public comment on reopening consideration of a license for the proposed Yucca Mountain spent-nuclear-fuel repository.

NRC set a Sept. 30 deadline for taking comments on making "the most efficient and productive use" of $11 million in commission coffers for resuming consideration of the license application.

On Aug. 13, a three-judge panel of the U.S. Court of Appeals' D.C. Circuit ordered NRC to resume review of the application. The court ruled the commission overstepped its authority when it halted licensing proceedings in 2010, which Judge A. Raymond Randolph said resulted from a "systematic campaign of noncompliance" led by then-NRC Chairman Gregory Jaczko.

NRC stopped the review after DOE withdrew its license application. The states of Washington and South Carolina went to court, arguing that the Nuclear Waste Policy Act designated Yucca Mountain as the sole candidate repository for high-level nuclear waste.

Legislation to institute "consent-based" siting of interim and permanent spent-fuel disposal sites is pending before the Senate Energy and Natural Resources Committee.

In a related matter, the House Energy and Commerce Committee's environment panel scheduled a Sept. 10 hearing on "implementing the Nuclear Waste Policy Act." NRC Chairwoman Allison Macfarlane has agreed to testify.

FERC Mulls Two-Year Licensing for Some Hydro

FERC scheduled an Oct. 2 workshop in Washington, D.C., to begin assessing a two-year licensing process for installing generation at non-powered dams and closed-loop pumped storage projects.

FERC was directed to study two-year licensing in the Hydropower Regulatory Efficiency Act, HR 267, which President Barack Obama signed into law Aug. 9.

FERC asked for comments on structuring a two-year licensing process, criteria for suitable projects, and potential pilot projects for testing two-year licensing.

The legislation—sponsored by Rep. Cathy McMorris Rodgers (R-Wash.)—also exempts from FERC licensing requirements conduit-hydropower projects with capacity of 5 MW or less on non-federal canals and ditches.

Kitzhaber Touts Oregon Efficiency at Hearing

Oregon Gov. John Kitzhaber on Sept. 4 touted the state's energy-efficiency record while calling for greater "certainty" for clean-energy technology projects.

Kitzhaber testified at a Portland field hearing of the Senate Environment and Public Works Committee's green jobs panel, presided over by Sen. Jeff Merkley (D-Ore.).

Kitzhaber said Oregon's school districts need more financial support for efficiency-retrofit projects, noting many have finished "the most accessible projects," including windows and lighting.

In addition, he added, school districts in "dire" financial condition cannot afford "even the relatively low rates" of the State Energy Loan Program.

"A relatively modest infusion of granted dollars could launch a significant wave of projects, helping schools and other public buildings perform better," Kitzhaber told the subcommittee ***[Jim DiPeso].***