Heat Waves, Wildfires, Ice Melt Lend Urgency to IEPR Workshop

Southwest: New Line Proposed for Wyoming Wind Power

Potomac: Court Strikes Down BLM Fracking Rule

Tesla Makes $2.7 Billion Offer for SolarCity

Bottom Lines: What’s Killing the Electric Car?

CEC Shines Light on Behind-the-Meter PV

AES Targets Year-End Approval of Huntington Beach Plant

State Lawmakers Urge Congress to Act on SONGS Waste

Pacificorp, CAISO to Extend MOU on ISO Expansion

CARB Develops Scenarios for 2030 GHG Emissions Target

Nevada Lawmakers Mull Green Banks, Energy Districts

PUCN Lawyer Resigns After Tweets on Rooftop-Solar Rates

PG&E Commits to Replacing Diablo Canyon Power With GHG-Free Resources

In a surprise move, Pacific Gas & Electric said it would retire the 2,240 MW Diablo Canyon power plant, California's only operating nuclear facility, in 2025, and replace it with a portfolio of energy efficiency, energy storage, and renewables. In a joint proposal with unions and environmental groups the utility had previously butted heads with, PG&E proposed a $350 million employee retention and retraining program, and said it would pay San Luis Obispo County $50 million for the loss of future tax payments.

CPUC Revamps SGIP, Interconnection; Approves IOU Rate Hikes

The CPUC this week adopted big changes to the Self-Generation Incentive Program to address program flaws and increase grid-reliability benefits. The commission also improved utility interconnection processes for distributed generation by adopting a so-called cost envelope; approved a big increase in Pacific Gas & Electric’s gas-transmission revenue requirement; and green-lighted a settlement for the San Diego Gas & Electric and Southern California Gas Co. rate cases.

CARB Reports Decline in State’s Greenhouse-Gas Emissions

California is on track to meet its 2020 goal for reducing greenhouse-gas emissions, according to the state’s latest GHG inventory. Overall, GHG emissions have dropped by 9.4 percent since peak levels in 2004, the California Air Resources Board reported. Impacts of less nuclear and hydropower, at [15].

Heat Wave Triggers Power Outages

With temperatures that soared well past 100 degrees, thousands of electricity customers in Southern California were left without power this week due to strain on utility distribution systems. The potential for outages is heightened in the region because of a moratorium on natural gas injections at the Aliso Canyon storage facility. To reduce the risk, the Los Angeles Department of Water & Power has begun offering incentives for customers to shift electricity usage to off-peak times.

More Heat Buoys Western Energy Prices

Go to www.EnergyJobsPortal.com for the latest in regional energy career opportunities.

Energy regulators, climate researchers and representatives of electric utilities met this week in Sacramento to consider how the power system can adapt to climate change. The June 21 workshop—part of the CEC’s 2016 Integrated Energy Policy Report update—coincided with several scorching reminders of the issue’s immediate urgency. [Wildfires, heat waves and rising sea levels at [13].](#)

[6] **Pinnacle West, Berkshire Propose Line for Wyoming Wind Power**

TransCanyon, a joint venture between Pinnacle West Capital and Berkshire Hathaway Energy, is proposing a 215-mile, 500 kV transmission line to link California to Wyoming wind. The Cross-Tie project is the second large line proposed to bring Wyoming wind to California. [At [16], moving wind across the West](#).

[7] **Court Strikes Down BLM Fracking Rule; Producers Cheer**

Congressional Republicans and oil and natural gas producers cheered a federal court’s June 21 decision striking down the Bureau of Land Management’s hydraulic-fracturing regulations. [Producers “overjoyed,” at [17].](#)

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**NEWS IN BRIEF**

[8] **Tesla Makes $2.7 Billion Offer for SolarCity**

Tesla made a $2.7 billion offer for SolarCity in a deal that has analysts shaking their heads.

Tesla CEO Elon Musk is the chairman and largest shareholder of both companies, and Barclays analyst Brian Johnson was quoted as saying the “combined entity is likely to magnify the losses and cash burn that both were seeing individually.”

In announcing the deal, however, Tesla said its lithium-ion batteries—including the 3.3 kW Powerwall for homes and the 50 kW Powerpack for businesses—complement SolarCity’s rooftop PV systems.

“It’s now time to complete the picture,” Tesla said in its announcement. “Tesla customers can drive clean cars and they can use our battery packs to help consume energy more efficiently, but they still need access to the most sustainable energy source that’s available: the sun.”

Tesla and SolarCity are both active participants in California’s Self-Generation Incentive Program, which pays incentives for distributed energy. SolarCity often installs Tesla li-ion systems under the program.

Analysts, however, are concerned that Tesla has been burning cash. The company recorded revenues of $4 billion for 2015 and a net loss of $888 million for the year. Its cost of revenue came in at $3.1 billion, and it spent $922 million on sales, general, and administrative expenses and $717 million on research and development.

Sales, general, and administrative expenses, which rose more than $300 million on a year-over-year basis, were impacted by the “continued global expansion of our customer support and Supercharger infrastructure,” Tesla stated.

Tesla sold 25,202 Model S sedans in 2015, which the company considers its “affordable” car for now at a $70,000 price point. Last year’s sales grew 51 percent compared with 2014. From January through May of this year, however, Model S sales are down by about 410 vehicles year over year. In general, the EV market has been harmed by low gasoline prices (see story at [9]).

Tesla, however, has also started selling the Model X sport utility vehicle, and plans to sell the $25,000 Model 3 next year. An expanded $1.26 billion factory in Fremont, Calif., will support Model X production.

For 2015, SolarCity saw revenue of $399 million, which was split between solar operating leases and PV systems ($293 million) and sales of solar PV systems ($106 million). The two biggest expenses, however, were sales and marketing ($457 million) and general and administrative ($244 million).

SolarCity’s sales and marketing expense jumped by $218 million on a year-over-year basis, or 92 percent, as the company increased its sales and marketing staff to increase solar deployments. SolarCity deployed 778 MW of solar panels in 2015 compared to 502 MW in the previous year.

“In the future, we expect to reduce our sales and marketing expenses, on a per-Watt basis, by focusing on our more efficient sales channels, renegotiating or eliminating our higher cost sales channels and other cost efficiency initiatives,” SolarCity stated. [C. R](#)

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**Corrections and Clarifications**

The CPUC on June 14 issued a proposed decision for regulated utilities to test “matinee pricing” as a means of reducing energy and water use at times of high demand. The commission could consider the decision at the commission’s July 14 business meeting, according to Administrative Law Judge Karen Clopton. An article in CEM No. 1390 on the proposed decision, “Eyeing Water-Energy Nexus, CPUC Enters ‘Matinee Pricing,’” incorrectly identified the July 14 meeting as the CPUC’s “next” business meeting, which was actually June 23. ~CEM

Even as the economy continued to gain steam, sales of electric vehicles and plug-ins dipped between 2014 and 2015.

The prime reason: low gasoline prices. Retail gasoline, for all formulations, started off in January 2014 at $3.31 a gallon, according to the U.S. Energy Information Administration. By the end of 2015, average retail gas was around $2. Sales of EVs and PEVs followed the trend and fell by more than 5,000 units from 2014 to 2015 (see chart at right).

That drop came despite a record year for vehicle sales in general, according to a January 2016 article from Automotive News. With low gas prices, U.S. consumers instead bought gas-guzzlers. According to Automotive News, sales of trucks, SUVs and crossovers led the pack, jumping 15 percent in 2015.

Looking ahead, the road is steep for California’s goal to put 1.5 million zero-emission vehicles on the roads by 2025. The EIA has forecast that gas prices will average $2.13 in 2016 and $2.27 in 2017. (California drivers, of course, pay a bit more for reformulated gasoline.)

And so far this year, sales of minivans are up 30 percent, and SUVs/crossovers and light-duty trucks are up by around 8 percent each, according to a Wall Street Journal chart with data from motorintelligence.com.

The other piece of bad news is that the state’s Clean Vehicle Rebate Project (CVRP) has run out of money. Under the program, California residents can get up to $6,500 for the purchase of a zero-emissions vehicle. To date, about 152,000 rebates have been issued for battery-electric vehicles and plug-in vehicles, with $523 million in approved or issued funding, according to the California Center for Sustainable Energy.

But the program is funded by auctions of greenhouse-gas allowances, and the last GHG auction in May yielded very little revenue. Allowances hit the floor price of $12.73, and only 7.2 million of 67.6 million current-vintage allowances offered were sold. More than 10 million future-vintage allowances were offered, with just 914,000 sold. The quarterly auctions also fund high-speed rail, affordable housing, energy-efficiency programs, and other low-carbon transportation programs.

As a result, Gov. Jerry Brown’s budget includes no funding for the CVRP. (High-speed rail, which had been expecting $150 million, got only $2.5 million from the auction.) Environmental advocates are now urging Brown to spend $1.4 billion in stockpiled auction funds.

Perhaps it’s time to “unleash the carbon markets,” argues Meredith Fowlie in a post on UC Berkeley’s Energy Institute at Haas blog. The cap-and-trade auction covered just 15 percent of the state’s emissions reductions when it was launched. An updated plan calls for 70 percent of the state’s targets to be met by command-and-control measures, including the renewables portfolio standard, energy efficiency, the Low Carbon Fuel Standard, and clean-vehicle rebates.

“No one factor in offsets and the potential for emissions leakage and reshuffling, there’s not much work left for the carbon market to do,” Fowlie explains.

Many of these prescriptive measures achieve costly GHG reductions—it’s been estimated, Fowlie noted, that emissions reductions under the California Solar Initiative cost $130 to $196 per metric ton. My own back-of-the-envelope calculations indicate that the CVRP costs between $45 and $69/ton for emissions reductions.

Fowlie explains that when most of the GHG reductions are achieved by high-cost programs, the carbon market then prices remaining reductions at a low cost. And, as the May GHG auction indicated, those low auction prices in turn reduce the revenue needed to fund the high-cost programs in the first place. It’s a recipe for market dysfunction.

With low gas prices, U.S. consumers bought gas-guzzlers.

Sources: Inside EVs, EIA.
More Heat Buoys Western Energy Prices

With another round of intense heat—well above the century mark in some parts of Central California—expected the week of June 27, peak power prices spiked between $11 and almost $21 in trading June 23 to June 24.

Although the increases were significant, prices failed to best highs reached June 17 ahead of a heat wave in Southern California and Southwestern states. Overall, Western daytime prices fell between $2 and $20.90 in June 17 to June 24 trading. Prices June 24 ranged from $33.20/MWh at Mid-Columbia to $44.75/MWh at South of Path 15.

Average off-peak power prices generally lost $3 by the end of trading. South of Path 15 added 65 cents to reach $32.20 by June 24.

In the week ahead, CAISO expects demand of roughly 44,100 MW both June 27 and 28. Warmer, dry weather is expected across the West starting Monday, when Seattle highs should surpass the 80-degree mark, according to the National Weather Service. Tuesday and Wednesday are the hottest days anticipated in Northern California, when some areas may see 105 °F.

Working natural gas in storage was 3,103 Bcf as of June 17, according to U.S. Energy Information Administration estimates. This is a net increase of 62 Bcf compared to the previous week and the earliest time on record that working gas in storage has exceeded 3,000 Bcf.

“Natural gas consumption during this period has exceeded both year-ago and 2012 levels, a trend driven by growth in power-sector consumption,” noted the EIA weekly report. Natural gas for power generation is now at 26 Bcf/d, a record high for this time of year, according to the agency.

Henry Hub gas spot values gained 7 cents in Thursday-to-Thursday trading, ending at $2.68/MMBtu June 23. On Wednesday, Henry Hub hit $2.78/MMBtu—the highest price the hub has posted since August 2015.

Western natural gas values surpassed the benchmark price, with average prices jumping between 14 cents and as much as 47 cents. Sumas posted the greatest gains, adding 47 cents to end at $2.30/MMBtu June 23.

Consumption was also higher during the EIA report week, with a 7 percent increase in natural gas used for power generation. This was 6 percent greater than the year-ago levels.

EIA states that the “incentive to inject natural gas into storage remains high.” Injections into working gas, to date, are roughly 15 percent ahead of the 2012 injection pace, primarily because of the growth in natural gas supply compared with demand.

Demand peaked on the CAISO grid at 44,454 MW June 20, which was the high for the week.

Total renewables production on the CAISO grid reached 13,579 MW June 22, and total solar production reached 7,870 MW that same day. Thermal generation peaked June 20 at 23,440 MW.

Average Off-Peak Prices

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Henry Hub
Sumas
Alberta
Malin
Opal/Kern
Stanfield
PG&E CityGate
SoCal Border
EP-Permian
EP-San Juan

Average Natural Gas Prices ($/MMBtu)

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Power/gas prices courtesy ICE (www.theice.com) and Enerfax

Linda Dailey Paulson
CPUC Makes Significant Changes to SGIP, Improves Interconnection Rule
(from [2])

The CPUC adopted significant changes to the Self-Generation Incentive Program to address program flaws, increase grid-reliability benefits, and help deliver greater greenhouse-gas emission reductions. Commissioners adopted the SGIP on a vote of 5-0 at a June 23 business meeting. The commission also unanimously approved a decision laying out a new model to improve and speed up interconnection processes for renewable and distributed generation.

The SGIP, launched in 2001 to boost deployment of distributed generation resources, will now be operated on a continuous basis rather than year by year. Incentive budgets will now be divided into two broad categories—energy storage and generation—and program reservations will be taken through a lottery system, rather than on a first-come, first-served basis.

The changes are “aimed at delivering greater greenhouse-gas reduction and grid-reliability benefits,” CPUC President Michael Picker said at the meeting, while also addressing serious flaws in the program design. The modifications all apply to the remaining $290 million in the SGIP, he said.

The revamped program includes a “developer cap” of 20 percent of the available funding for a given category’s total, to replace the current 40 percent manufacturer cap. And starting next year, generation projects that use natural gas must use a minimum of 10 percent biogas in order to qualify for incentives, with that minimum requirement climbing to 100 percent in 2020.

Under the newly adopted incentive structure, incentives for generation technologies now range from 60 cents to 90 cents per kW of capacity, depending on technology; those incentives decline in three steps, with Step 3 incentives ranging from 40 cents to 70 cents per kW of capacity. Each step includes an adder for biogas.
Incentives for energy storage start at 50 cents per watt-hour for storage projects greater than 10 kW, and 60 cents/Wh for projects of 10 kW or smaller. Storage incentives step down in five steps, to 50 cents for large projects and 40 cents for smaller projects. Current rebates range from 42 cents to $1.49.

Under the revamped structure, the program will focus on energy storage and generation, with storage allocated 75 percent of program funds; within that allocation 15 percent is allotted to small projects of 10 kW or less. The remaining 25 percent is allotted to generation projects, with 10 percent of the generation budget carved out for renewables.

“In the end, the staff proposal’s 75%/25% split strikes the right balance of program goals of reducing GHGs, providing grid support, and enabling market transformation,” the [Decision] from President Picker, said. “Energy storage is the fastest growing source of projects for SGIP and represents the most scalable set of technologies to achieve the program goals.” (Decision numbers were not available at press time.)

As Commissioner Mike Florio pointed out, “The history of this program in some cases has not been pretty.”

In the most recent example of a flaw in the SGIP, Stem Inc. was accused of gaming the CPUC’s SGIP online-reservation system in a solicitation earlier this year by monopolizing the portal in the first minutes after it opened. Stem was able to submit 56 applications before any other company submitted any.

Florio applauded the changes, especially the declining incentive. “It draws on our experience with [the California Solar Initiative],” Florio said, and moves the state in the right direction of stimulating technology.

Echoing Florio’s comments on difficulties the CPUC has had in administering the program, Commissioner Liane Randolph said the decision “will have significant improvements that will really allow the market to have improvements and push the technology.”

Commissioners also unanimously adopted a decision that makes improvements to Electric Tariff Rule 21, which includes rules and regulations governing utilities’ interconnection of generation. The changes are meant to make it easier for small renewable and energy storage systems to connect to the distribution system.

The approved [Decision] an alternate decision written by Commissioner Catherine Sandoval, comes in a long-running case opened in 2011 to review interconnection rules [R11-09-011].

One of the big issues with the current interconnection process was that it led to uncertainties over actual interconnection costs.

As Sandoval explained, initial interconnection agreements state that the costs are estimates, subject to true-up after the resource is interconnected.

“That ends up fostering uncertainty about how much it will cost,” she said. “We have heard from developers all over the country that interconnection is one of the most frustrating parts” of getting projects up and running.

The new model requires better data going in, Sandoval said, which leads to better analysis.

“By changing the process to a more data-driven process I think we are going to create more information about the grid,” she said, thus making projects more financeable.

The decision adopts a five-year “cost envelope” pilot policy, through which utilities will be held to plus or minus 25 percent on their estimates.

Under current rules, distributed energy resource developers are required to pay for any distribution-grid capacity upgrades to accommodate two-way power flows as a result of the new distributed generation. The Rule 21 study process calls for utilities to develop cost estimates for any identified system upgrades, but the developer is liable for any cost overruns, even if they stem from unforeseen circumstances.

“One party cites instances of ten-and-thirteen-fold variations in interconnection costs over the original estimate, and describes such [a] degree of uncertainty as ‘crippling for private developers and discouraging for public agencies that are working with the state to achieve its climate and clean energy goals,’” Sandoval’s decision said.

“Today’s decision reduces cost uncertainty, diminishes risk for project development, and is calculated to spur investment needed to meet California’s statutory GHG reduction and renewable procurement and integration goals.”

The decision also establishes new data-collection requirements for tracking overestimates and underestimates, as well as new reporting metrics designed to help the commission and other parties evaluate utilities’ progress in modernizing the interconnection study process and producing what the decision calls “high-confidence” cost estimates.

**[11.1]** Commission Approves Big Bump in PG&E Gas Transmission Rates

The CPUC on June 23 approved a $1.25 billion cumulative increase over three years in Pacific Gas & Electric’s revenue requirement for gas transmission and storage services. In approving PG&E’s 2015-2017 gas transmission and storage rate case, the commission said the new revenue requirements would ensure that needed safety improvements are made.

The adopted increase, which is well below what the utility requested, will bring PG&E’s gas-transmission revenue requirement to $908 million for 2015 (about a 27 percent increase compared with 2014), $1.2 billion for 2016, and $1.3 billion in 2017. PG&E’s 2017 authorized revenue requirement is 83 percent higher than 2014’s authorized revenue requirement of $715.4 million. (The 2014 figure includes amounts authorized under a rate-case settlement and PG&E’s pipeline safety-enhancement program.)
Commissioners approved an alternate proposed decision from Commissioner Carla Peterman on a 4-0 vote, with Commissioner Mike Florio recusing himself. In its initial 2015 application, PG&E had proposed a cumulative increase of $2 billion over the rate-case period.

“Parties representing customers made strong arguments that the requested rate case is too high,” Peterman said in discussing the decision at the meeting. “There is also broad consensus that investments are needed to ensure safety.”

The decision, initially issued in early May, disallows certain costs for work PG&E had proposed, orders PG&E to provide a report within 60 days on gas-storage risk management and safety initiatives, and penalizes PG&E almost $164 million for ex parte violations that delayed the proceeding (see CEM No. 1584 [12.1]).

In 2014, PG&E disclosed a series of improper ex parte contacts between its executives and CPUC officials regarding the judge assigned to the gas rate case. The ex parte-related penalty “will strongly dissuade PG&E and others from similar behavior in the future,” Peterman said.

PG&E’s massive gas transmission system includes more than 6,000 miles of large-diameter gas transmission pipelines. This is the second gas rate case since the deadly 2010 San Bruno pipeline explosion, which killed eight people, injured dozens, and destroyed 38 homes. PG&E is currently on trial in federal court in San Francisco for federal pipeline-safety violations that stemmed from the San Bruno case. The case also includes a charge of obstruction. PG&E is facing more than $500 million in penalties in that case.

Many of the significant safety-related regulatory and legislative changes in recent years are a direct result of the San Bruno explosion.

Safety investments approved under the decision include hydrostatic testing of nearly 660 miles of pipeline over the rate-case period, although expenses to hydro-test 97 miles of pipeline installed between 1956 and mid-1961 were disallowed.

In disallowing some of the hydro-testing expenses, “we are ensuring ratepayers are not paying double for work that should have been done,” Commissioner Liane Randolph said.

The decision also funds the replacement of 60 miles of vintage pipe. PG&E expects to replace 570 miles of vintage pipe by 2025, Peterman said.

PG&E is authorized to make a number of other system improvements under the decision, including undertaking system upgrades to be able to perform in-line inspections on 551 miles of pipe over the rate-case period. The utility had proposed a 10-year plan to upgrade its system in order to be able to conduct in-line inspections on over 4,273 miles of transmission pipe by the end of 2024, but the decision slows the pace of that work to 12 years rather than 10.

The decision also funds upgrades for control systems, databases, and risk-analysis programs.

“While we don’t agree with all aspects of the commission’s decision, we want our customers to know that the dedication to our mission of becoming the safest, most reliable gas company in the country is as strong as ever,” said PG&E spokesperson Donald Cutler in a prepared statement.

Approved increases dating back to January 2015 will be applied retroactively, starting in August. PG&E said that based on preliminary calculations the average residential customer bill will increase about $7 a month, including the retroactive increase plus interest on the retroactive amount.

The CPUC, meanwhile, estimates the rate case will result in average residential customer bills rising to $56.79 by 2018, up from $50.89 in January 2015, an increase of 11.6 percent.

“The residential bill impact still poses challenges for California families that rely on gas for heating, cooking and hot water,” Commissioner Peterman said.

But that blow may be softened somewhat as the commission implements a penalty imposed on PG&E last year as a result of the San Bruno explosion.

The CPUC San Bruno penalty decision required PG&E shareholders to absorb $850 million in costs for future pipeline-safety upgrades. The $850 million, which PG&E must track in a separate account, and which the CPUC expects to be expended over the course of this rate-case cycle, includes up to $161.5 million for project or program expenses, and a minimum of $688.5 million that would be applied to capital expenditures, according to the rate-case decision. Specific allocation for the shareholder portion will be made in a separate phase of the proceeding, and will be used to offset increases under the rate case.

The Utility Reform Network took the commission to task for the decision.

“PG&E’s rates are already among the highest in the U.S.,” TURN Executive Director Mark Toney said in a statement. “These high rates have not guaranteed safety or reliability, but instead resulted in well over a quarter of a million households being shut off in 2015,” he said, referring to the high number of disconnections PG&E reported last year.

The Office of Ratepayer Advocates, meanwhile, had recommended a cumulative increase of $483 million.

[11.2] CPUC Adopts Rate-Case Settlement for SDG&E and SoCal Gas

The CPUC on June 23 adopted a modified settlement agreement that sets out modest increases in revenue requirements for San Diego Gas & Electric and Southern California Gas Co.

Both utilities, subsidiaries of Sempra Energy, had applied at the CPUC in 2014 for 2016 revenue requirements of $1.9 billion and $2.3 billion, respectively, and subsequent increases in the rate-case cycle [A14-11-003, A14-11-004].
The commission in May issued a proposed decision approving a settlement among the utilities, the Office of Ratepayer Advocates, The Utility Reform Network and other parties. The settlement approved 2016 revenue requirements of $1.8 billion for SDG&E and $2.2 billion for SoCal Gas, with attrition increases of 3.5 percent in 2017 and 3.5 percent in 2018 (see CEM No. 1386 [11.2]).

The decision approved Thursday adopts the settlements, but makes two income-tax-related adjustments for deductions related to repairs and bonus depreciation, and another adjustment for off-site storage costs related to the San Onofre Nuclear Generating Station.

With the adjustments, SDG&E is authorized a 2016 revenue requirement of just under $1.8 billion, including $1.5 billion for electric operations and $508.9 million for gas operations. The decision cut SDG&E’s request by $104 million, and will result in a $50 million increase in revenue requirement this year compared with what is currently authorized.

The adjustments result in a 2016 authorized revenue requirement for SoCal Gas of $2.2 billion, about $127 million lower than what the gas company had requested. For SoCal Gas, the decision authorizes $38.4 million for operations and maintenance costs for the utility’s underground gas-storage facilities, and a total of $236 million for capital improvements over the rate-case cycle, including funding for SoCal Gas’ proposed Storage Integrity Management Plan.

SoCal Gas had proposed the SIMP as part of its rate-case application in 2014. The application included testimony from Phillip Baker, director of storage for SoCal Gas, in which Baker warned of several safety issues at Aliso Canyon.

The attrition increases of 3.5 percent for both utilities for 2017 and 2018 were approved.

The increases will result in average bills for SDG&E customers rising this year by a little more than 1 percent, and about 3.4 percent for SoCal Gas customers.

Commissioners approved the settlement decision on a vote of 5-0.

The adopted decision denies a request by the parties to the settlement to add 2019 as an additional attrition year. –M. S.

[12] PG&E to Retire Diablo Canyon, Replace Power With Clean Energy (from [1])

In a surprise move, Pacific Gas & Electric said it would retire the 2,240 MW Diablo Canyon power plant, California’s only operating nuclear facility, when federal operating licenses expire in 2024 and 2025, and replace it with a portfolio of energy efficiency, energy storage, and renewables. The move comes as the utility faces high costs to continue operating the plant, potential big declines in plant utilization, and opposition to renewing the plant’s federal licenses.

The utility on June 21 announced a joint proposal with Friends of the Earth, the Natural Resources Defense Council, Environment California, the International Brotherhood of Electrical Workers Local 1245, the Coalition of California Utility Employees, and the Alliance for Nuclear Responsibility to retire the plant when its current licenses expire in 2024 and 2025.

PG&E voluntarily committed to increasing its own renewables portfolio standard target to 55 percent effective in 2031 through 2045.

The agreement proposes a $350 million, ratepayer-funded employee retention and retraining program to ensure a skilled workforce to operate and then decommission the nuclear plant, as well as a $50 million payment to San Luis Obispo County to compensate for the loss of future property tax payments. PG&E will also seek cost recovery of $50 million for costs related to the license-renewal process to date.

“The proposal reflects California’s changing energy landscape,” said Tony Earley, chairman, CEO and president of PG&E’s parent, PG&E Corp., on a June 21 conference call.

PG&E expects the joint proposal will result in a lower cost than relicensing and operating the plant for another 20 years, and as a result Earley said he does not believe rates will increase.

The agreement brings together several groups that have until now battled PG&E over relicensing efforts; required seismic studies for the plant, which is situated in an area near Avila Beach that is crisscrossed with fault lines; and storage of nuclear fuel.

“This agreement brings together parties who are usually fighting,” said Tom Dalzell, business manager for Local 1245. “It is a generous, thoughtful, outside-the-box agreement.”

Negotiations with PG&E demonstrated the utility’s strong commitment to its workforce and to keeping as many high-skilled workers on site as possible for the duration, he said.

“Today is a very historic day,” said Rochelle Becker, executive director of the Alliance for Nuclear Responsibility. “It’s taken a village to get to where we are.”

Erich Pica, president of Friends of the Earth, said the plan “is a clear blueprint for fighting climate change by replacing nuclear power with clean, GHG-free” resources.

Underpinning the retirement plan is a recognition of California’s energy policies, including last year’s SB 350, which raised the RPS to 50 percent by 2030 and doubled state energy-efficiency goals, Earley said, coupled with continued growth in distributed energy, particularly rooftop solar, and expected growth in community choice aggregation, which reduces load on PG&E’s system.

San Luis Obispo County is exploring CCA in cooperation with Santa Barbara and Ventura counties; all seven cities in San Luis Obispo County are participating in a financial feasibility study, with results expected this summer.

PG&E is also facing fierce opposition to a relicensing effort, the need for additional seismic studies if
it does seek a license extension, and costs as high as $14 billion to replace once-through-cooling infrastructure at Diablo Canyon as the state phases out such equipment to protect marine life.

The utility had been pushing for an exemption from the state’s OTC policy, a move that was opposed by many stakeholders, including a subcommittee of the State Water Resources Control Board’s Review Committee for Nuclear Power Plants.

In a special study of options for compliance with the OTC policy, Bechtel Corp. estimated costs for replacement solutions at Diablo Canyon could range from $435 million for offshore modular wedge wire screens to more than $14 billion to replace the current cooling system with dry cooling. Retrofitting the plant with closed-cycle cooling technology could cost $8 billion to $14 billion, according to Bechtel.

PG&E’s position has been that cooling towers are not technically or economically feasible, and the utility has warned investors that it may be forced to cease plant operations if the water board requires their installation. The water board is expected to make a decision by January 2017.

Last year the CPUC requested PG&E do a thorough cost-effectiveness study on reliability and safety issues in light of the plant’s proximity to numerous fault lines.

The announcement marks a turnaround for PG&E, which started the relicensing process at the U.S. Nuclear Regulatory Commission in 2009, and then suspended those activities in 2011 following the Fukushima Daiichi nuclear disaster, which was initiated by a magnitude 9.0 earthquake and subsequent tsunami.

Earley said PG&E would only need to replace about half of the plant’s capacity, citing early estimates of a reduced need for the plant’s capacity in 2025.

Last year Diablo Canyon produced about 16,000 GWh, accounting for 22.6 percent of the utility’s total annual GWh. Under the joint proposal, PG&E plans to procure 2,000 GWh of energy-efficiency savings in the 2018-2024 time period; another 2,000 GWh of GHG-free resources in the 2025-2030 time period; and additional purchases of RPS-eligible power starting in 2031.

In its 2012-2013 transmission-planning process, CAISO determined there would be no long-term or medium-term grid impacts if Diablo were shuttered, if renewable generation in California developed at its current trajectory.

The early decision to retire also means PG&E has time to plan the shutdown in an orderly way.

“The beauty of this agreement is that it gives us almost a decade to work through these issues,” Earley said. “We are not scrambling. We can do it thoughtfully.”

Geisha Williams, president, electric, for the utility, said a thorough decommissioning estimate will be developed over the next couple of years. In March, PG&E estimated Diablo decommissioning costs would be $3.8 billion, but that estimate was based on a financial model rather than a site-specific plan, according to the company.

As of March 31, PG&E had $2.8 billion in its decommissioning trust fund; Earley said the utility would collect enough additional funds before the retirement to cover decommissioning costs, as well as the utility’s remaining investment in the plant, which stood at $2.5 billion at year-end.

As Earley and Williams pointed out, the plan is contingent on a number of regulatory actions, including CPUC approval and State Lands Commission approval of lease extensions for the submerged lands used by the plant from 2018, when they expire, to 2024 and 2045, when the reactors would retire. At issue is whether PG&E would need to conduct an environmental impact report; stakeholders had expected the commission would require it had the utility sought an extension of its operating licenses for the reactors.

The lands commission could consider the request at a June 28 meeting. A revised staff report from the lands commission on June 24 recommended a finding that the lease request be exempt from CEQA, meaning no new environmental impact report would be required, and said granting a lease through August of 2025 will not substantially interfere with public trust needs and value at the site.

“With respect to State Lands this does make it highly likely they will approve it,” Earley said.

PG&E expects to file an application with the CPUC within 30 days after it receives State Lands Commission approval.


California energy regulators, climate scientists, and representatives of the state’s five largest electric utilities met this week in Sacramento to consider the risks of climate change, including potentially accelerating sea-level rise in the second half of the century, and how to adapt the power system amid scientific uncertainty.

But the June 21 joint-agency workshop on the energy system’s climate adaptation and resiliency—part of the CEC’s 2016 Integrated Energy Policy Report update—coincided with several scorching reminders of the issue’s immediate urgency.

Held amid an intense heat wave across California and the Southwest, and the onset of an already active fire season, participants couldn’t help but note the meeting’s perfect timing.

“You can see how this is turning into a world of disaster management,” said Christina Curry, a deputy director at the California Office of Emergency Services.
While record-setting temperatures are forecast for Sacramento next week, the state’s most immediate heat-related concerns center on Southern California.

Just days before the workshop, on June 17, the CEC and the Department of General Services issued a call to managers of all state buildings in the region to reduce their energy use.

“I am asking you to take all reasonable actions necessary to conserve electricity and natural gas at Southern California facilities,” CEC Chair Robert Weisenmiller requested in an email to building managers. Weisenmiller said the “exceptional need for conservation now” was the direct result of surging temperatures “and the limited availability of natural gas from the Aliso Canyon storage area.”

California’s largest natural gas reservoir, Southern California Gas Co.’s Aliso Canyon facility, was drawn down to emergency-only levels in the wake of a massive methane leak plugged in February (see CEM No. 1385 [15.1]).

Adapting to Change

The state’s just-begun wildfire season, which already is taking a toll on energy systems, further contributed to a sense of urgency at the June 21 IEPR workshop.

Brian D’Agostino, meteorology program manager at San Diego Gas & Electric, pointed to “a very active wildfire” in the southeastern portion of the utility’s service territory, near the California-Mexico border, which this week damaged a portion of its electric distribution system and led to an outage for several hundred customers.

The blaze started Sunday and had burned nearly 7,000 acres by Thursday afternoon, according to the California Department of Forestry and Fire Protection. It remained only about 20 percent contained. The Border Fire is one of four currently uncontained wildfires in California.

“We used to focus only on wildfire risk in the fall. Now we have huge fires in June,” D’Agostino said, citing climate change. “It’s real. It is happening,” he added, showing a map of wildfires in SDG&E’s service territory since 2000. These covered nearly half of San Diego County.

“We have been working to adapt to wildfire risk,” D’Agostino said, noting that the utility has undertaken “84 actions to improve climate resiliency” to date.

Among these are the development of “the largest utility weather network in the United States,” which includes 170 weather stations across its network; the creation of the Santa Ana Wildfire Threat Index to prepare for wildfires and assist fire agencies; and the Wildfire Risk Reduction Model, a simulation tool to help prioritize efforts to “harden” SDG&E’s system against fires.

Using the model as a guide, SDG&E has been converting wooden electric poles to steel across its entire service territory. “This year, we’ve spent over $80 million on that,” D’Agostino said.

Representatives of other utilities echoed the sentiment that climate change is underway and requires immediate attention.

“We see potential disasters happening and we are trying to get ready for them,” said Tim Tutt, a government affairs representative for the Sacramento Municipal Utility District. “There’s really a need for a lot of innovation.”

“These types of things are happening all the time on our system,” added Barry Anderson, vice president of electric distribution at Pacific Gas & Electric.

Anderson highlighted several collaborations to assess vulnerabilities to PG&E’s infrastructure assets. In a research project funded by the CEC, for instance, PG&E is working with the Center for Catastrophic Risk Management at UC Berkeley to explore possible impacts of sea-level rise and extreme storms on its natural gas transmission system.

Decision Realities, Climate Uncertainties

Several scientists presented a variety of scenarios depicting the extent of climate change utilities may confront in the future.

Daniel Cayan, director of the climate research division at Scripps Institute for Oceanography, presented “probabilistic sea-level rise projections” for San Francisco through the end of this century. These differed based on various assumptions about greenhouse-gas emissions reductions and showed a wide divergence in results in the second half of the century—ranging from less than half a meter of sea-level rise to more than two meters.

But given the discrepancies in the scenarios and “an exploding set of new scientific findings,” according to Cayan, estimating ice melt is a moving target. Some newer models, for instance, indicate “uncontrolled ice loss from Western Antarctica” that could propel California “into the higher amounts of sea-level rise,” the scientist said.

Commissioner Karen Douglas, who is leading the IEPR update, called for ways to “make climate science actionable” for regulators who must make decisions, as well as utilities “in the thick of climate adaptation.”

Susanne Moser, a social-science research fellow at Stanford University’s Woods Institute for the Environment, focused her presentation on linking climate science to such practical needs.

While simulating many possible outcomes is “like a game” for climate scientists, “from a practitioner’s point of view that is a nightmare,” Moser said. She suggested that “a new way of thinking” based on more collaborative “trans-disciplinary work” among research and practical experts could best address how “scientific uncertainty can become decision-relevant.”

But, she added, “We don’t have endless amounts of time.” —Garrett Hering
CEC Shines Light on Behind-the-Meter PV Growth, Impacts

California Energy Commission staff, utility representatives, and energy researchers on June 23 discussed their efforts to more accurately track the adoption of customer-located solar PV and assess its impacts on the grid.

One thing was obvious: small-scale solar’s oversized impact has taken them all by surprise.

As part of its 2016 Integrated Energy Policy Report update, the CEC hopes to get a better handle on behind-the-meter PV growth forecasting and improve its understanding of its impact on energy systems, including its shift of utility peak demand to later in the day.

After the commission in 1998 launched its pioneering Emerging Renewables Program, which offered upfront rebates to homeowners and businesses for installing PV, “It took 12 years to get to 1 GW, then two years for the next gigawatt and then one year for the next gigawatt,” said Asish Gautam, an analyst at the CEC.

The commission’s PV program was largely incorporated into the statewide California Solar Initiative, launched in 2007 with the target of reaching 3 GW of PV at homes and businesses by the end of this year. Instead, the CEC now anticipates around 4.5 GW. “Here we are and we have kind of blown past that [3 GW] goal by a wide margin,” Gautam said.

CEC staff “became aware of discrepancy” between incentive-program data and investor-owned utility PV interconnection data during its 2015 IEPR update, said the analyst, with the latter reporting much larger installed-capacity figures.

The gap was due to “installs happening but not going through the rebate program,” Gautam said. That’s because, even with state rebates subsiding, distributed PV was able to “keep the momentum going” thanks to federal tax credits and falling PV costs, he added.

To address the information gap, as part of its 2015 IEPR, the CEC began requesting detailed PV interconnection data directly from investor-owned utilities. It is making the same request of large publicly owned utilities as part of its 2016 update.

Accurate data on customer-located solar is necessary “to properly reflect PV impacts in long-term demand forecasts,” Gautam said.

Utilities agreed the growth of behind-the-meter solar needs to be better tracked in terms of raw installation data and impacts.

“The growth of retail solar has really exceeded expectations,” said Melanie McCutchan, a policy and strategy analyst at PG&E, adding that it “is already having material impacts on system load.”

Representatives of Southern California Edison, San Diego Gas & Electric and CAISO also confirmed such impacts. Each has observed a shift in peak system demand from late afternoon to early evening, triggered by large volumes of PV installed on the distribution grid.

Edison “has observed that our peak hour has already shifted, from hour 16 to 17,” said Hongyan Sheng, a manager at the utility. Edison is exploring scenarios of PV adoption that could further push its peak system demand later into the evening.

“We know peak shift is occurring,” said CEC analyst Cary Garcia. Past IEPR load forecasts, which the CPUC and CAISO rely on for their own procurement and transmission planning, have not included the phenomenon.

Not including peak shift, however, “injects biases” into planning, Garcia said. In addition to accounting for the impact of customer-located PV, the CEC is beginning to explore issues related to electric-vehicle charging, energy storage, and “other load modifiers,” he added. [–G. H–]

AES Targets Year-End Approval of Huntington Beach Plant

Citing contractual obligations with Southern California Edison, representatives of an AES Corp. subsidiary this week called for the CEC to approve the developer’s Huntington Beach Energy Project by the end of this year.

The project is one of three new natural gas-fired power plants AES has pitched at the sites of existing gas-fired facilities in Southern California (see CEM No. 1389 [14.1]).

Originally licensed in 2014 as a 939 MW combined-cycle plant to replace AES’ aging, once-through-cooled Huntington Beach Generating Station, AES Southland petitioned the CEC to amend the project in September 2015 after Edison awarded it a contract that required a change in configuration.

The now 844 MW project consists of a 644 MW combined-cycle unit and a 200 MW simple-cycle unit. Both are air-cooled.

During a June 22 project status conference, CEC staff indicated it could be difficult to meet the developer’s request for final approval by year-end.

Earlier this month, the South Coast Air Quality Management District issued its preliminary determination of compliance, while CEC staff planned to publish its preliminary assessment on June 24. However, a series of hearings, followed by final reports, must still be completed before the commission can consider approving the project.

The Huntington Beach Wetlands Conservancy, which raised concerns over the original project in 2013, did so again in an April letter to the Energy Commission. The letter cited numerous concerns over ecosystem impacts and alleged “the tendency of AES to misrepresent the current state of the wetlands.”

Attorneys for AES denied the charge in a rebuttal letter.

The developer plans to begin demolishing the existing Huntington Beach Generating Station this year and start constructing the new plant in the first quarter of 2017. [–G. H–]
[13.3] State Lawmakers Urge Congress to Act on SONGS Nuclear Waste

California’s Assembly on June 23 unanimously approved the Interim Consolidated Storage Act of 2016: San Onofre Nuclear Generating Station—a joint Senate-Assembly resolution that calls on the U.S. Congress to pass HR 4745.

Currently in a House of Representatives subcommittee, the bill would enable the federal government to move nuclear waste from Southern California Edison’s shuttered nuclear facility in San Diego County to a safer interim location.

California’s Senate approved the joint resolution by unanimous vote in April. The resolution is from Sen. Patricia Bates (R-Laguna Niguel) and cosponsored by Assm. Rocky Chavez (R-Oceanside).

The resolution, which does not require Gov. Jerry Brown’s signature, urges the U.S. Department of Energy “to implement the prompt and safe relocation of spent nuclear fuel from the San Onofre Nuclear Generating Station to a licensed and regulated interim consolidated storage facility.” No interim storage site for high-level nuclear waste has been licensed to date.

According to Bates, the bill is needed to address immediate concerns over the location of SONGS’ spent nuclear fuel near an active earthquake fault.

“It’s way past time for the federal government to move the nuclear waste stored at San Onofre to a location away from densely populated and environmentally sensitive areas,” Bates said when the bill passed the Senate.

DOE has lacked a long-term storage location since the cancellation of the Yucca Mountain Nuclear Waste Repository in Nevada, forcing utilities to maximize spent-fuel pools and store waste on-site in dry casks.

—G. H.

[14] Record Temperatures Trigger Power Outages in Southern California (from [4])

With soaring temperatures exceeding 100 degrees and record electricity demand, thousands of Los Angeles Department of Water & Power customers were left without power this week due to strain on the public utility’s distribution system.

LADWP saw a peak of 6,080 MW on June 20, over 50 percent higher than typical daily energy demand for June, the department said.

About 76,000 of LADWP’s 1.4 million customers lost power June 20-21. Outages were triggered by overloaded transformers and failed underground cables, according to the department. All power was restored by the afternoon of June 22.

CAISO issued a Flex Alert for June 20 for Southern California, urging customers to conserve electricity from 10 a.m. to 9 p.m.

Southern California Edison also experienced power losses due to extreme heat conditions, with about 25,000 customers impacted. The San Diego Gas & Electric and Imperial Irrigation District service territories also experienced outages, but they were less widespread.

While a shortage of natural gas was not a factor in the outages, the potential for outages in Southern California is heightened this summer because of a moratorium on natural gas injections at the Aliso Canyon Natural Gas Storage Facility, operated by Southern California Gas Co. Injections were halted following a massive leak that began at the site in October, and was eventually capped in February.

LADWP and other utilities in the region rely on Aliso Canyon to maintain reliability when high temperatures cause spikes in energy usage.

“We greatly appreciate our customers’ enthusiasm for this program.’

‘We greatly appreciate our customers’ enthusiasm for this program and willingness to partner with us in reducing the risk of outages,” noted a statement by LADWP General Manager Marcie Edwards. “We have introduced the program to several groups of large commercial customers over the past few weeks and received a positive response.”

Meanwhile, on June 15, the South Coast Air Quality Management District hearing board granted LADWP a limited variance to use diesel fuel in three of four of its in-basin power plants—the Harbor Generating Station in San Pedro, Haynes Generating Station in Long Beach, and Valley Generating Station
in the northeast San Fernando Valley—if needed to reduce the risks of rolling blackouts this summer.

The exemption will allow LADWP to use diesel, rather than natural gas, as an alternative fuel for up to 14 days this summer where significant risk of gas curtailments from SoCal Gas would result in power outages. It applies to 12 generating units at the three plants, collectively capable of generating 1,500 MW.

“Running the plants on diesel fuel as a last resort can help minimize the risk to all of our customers from traffic accidents resulting from signals affected by outages, and protect the sick and elderly who are at risk without air conditioning,” LADWP said. “It will also result in lower emissions than those that would result from the over 3,000 known, permitted diesel backup generators located in LADWP’s service area that would be used by critical facilities such as hospitals and businesses should rolling blackouts occur.”

On June 16, a new coalition, dubbed the Energy Providers of Southern California, launched Conserve Energy SoCal, an education program designed to promote energy and natural gas conservation. Members of the coalition include CAISO, Edison, LADWP, Riverside Public Utilities, SDG&E, SoCal Gas, and the Southern California Public Power Authority.

—Leora Broydo Vestel

[14.1] **PacifiCorp, CAISO to Extend MOU on Expanded ISO**

PacifiCorp and CAISO are in the process of extending a memorandum of understanding that explores the feasibility, costs and benefits of PacifiCorp joining the CAISO balancing authority as a participating transmission owner, PacifiCorp confirmed this week.

The original agreement, signed April 13, 2015, will be extended another six months, PacifiCorp spokesman Bob Gravely said. “After this six months is up, we will likely extend in the same manner.” He said there were no changes to the terms of the MOU besides the dates.

The original agreement established a process for the parties to “negotiate terms and conditions” of a transition agreement by Dec. 31, 2015, a target later extended to July 1, 2016. But the parties need more time to execute and deliver the agreement, and have agreed to extend negotiations through the end of 2016, according to language in the MOU.

The MOU set the stage for “a joint study on the feasibility and benefits” of the union. That study showed benefits during the 2020-2059 period ranging from $1.6 billion to $2.5 billion for PacifiCorp and between $1.8 billion and $6.8 billion for the ISO.

The extension comes as proceedings on a set of initiatives related to the merger continue, including the creation of a regional transmission access charge structure, resource-adequacy rules, and an update to metering rules. Two other processes, one on California greenhouse-gas emissions compliance and another on transition principles for a grid-management charge, are set to get underway in August and September, respectively.

Discussions on the appropriate governance structure for an expanded West-wide ISO are also ongoing. CAISO released a set of proposed principles for regional governance June 9.

Other work, including an evaluation of PacifiCorp’s existing service agreements and rate schedules, is also underway. PacifiCorp had the second of two regional integration customer meetings on June 24 in Portland.


California is on track to meet its 2020 goal for reducing greenhouse-gas emissions, according to the state’s latest GHG inventory, issued June 17 by CARB. The inventory covers the 2000-2014 time period. Total GHG emissions in 2014 were 441.5 million metric tons of carbon dioxide-equivalent, a decrease of 2.8 MMTCO2-e compared to 2013. Overall, GHG emissions have dropped by 9.4 percent since peak levels in 2004, CARB reported.

Per capita GHG emissions in California continue to decline, from a peak of 13.9 metric tons per person in 2001 to 11.4 metric tons per person in 2014—an 18 percent decrease.

“This declining trend, coupled with programs that will continue to provide additional GHG reductions going forward, demonstrate that California is on track to meet the 2020 target of 431 MMTCO2-e,” CARB noted.

**Emissions from** the electric power sector, comprised of both in-state generation and electricity imports and making up about 20 percent of statewide GHG emissions, declined by 1.6 percent in 2014 compared to 2013. This decrease has largely been driven by the renewables portfolio standard, CARB said.

GHG emissions from in-state electricity generation, specifically, increased from 49.59 MMTCO2-e in 2013 to 51.81 MMTCO2-e in 2014, according to the inventory. Emissions from electricity imports decreased, meanwhile, from 40.24 MMTCO2-e in 2013 to 36.56 MMTCO2-e in 2014.

The closure of the San Onofre Nuclear Generating Station in 2012, along with lower hydropower production due to drought, has impacted the state’s emissions profile as natural gas-fired facilities kicked in to generate replacement power.

“Although renewable generation continues to increase, reaching nearly 25 percent of total electricity supplied by utilities in 2014, hydropower continues its decline due to the prolonged drought (at its third year in 2014),” CARB said. “Gains in new renewable generation were offset by a roughly equivalent loss in hydropower.”

Total solar generation doubled between 2013 and 2014, with rooftop photovoltaic solar generation increasing by 39 percent, while in-state wind-energy generation was similar to 2013 levels.

Emissions from California’s industrial sector, representing 21 percent of total GHG emissions in 2014, increased from 103.75 MMTCO2-e in 2013 to 104.22 MMTCO2-e in 2014.

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Industrial-sector emissions stem from fuel combustion at refineries, oil and gas extraction operations, cement plants, and other stationary sources, as well as the portion of cogeneration emissions attributed to thermal-energy output (cogeneration emissions from electricity production are attributed to the electric-power sector).

Emissions attributed to useful thermal output in the industrial sector dropped from 10.99 MMtCO2-e in 2013 to 9.64 MMtCO2-e in 2014, reflective of industrial cogeneration facilities increasing electricity generation in 2014 while reducing useful thermal output.

“With the onset of the economic downturn around 2009, cogeneration facilities used more of their capacity to generate useful thermal energy (such as steam for industrial processes); however, useful thermal energy production has been on a downward trajectory since that time,” CARB said.

Emissions from the commercial and residential sectors, driven by the use of natural gas and other fuels for space heating, cooking and hot water, or steam generation, decreased by 12 percent in 2014, primarily due to a decline in residential gas use.

CARB noted that changes in annual fuel-combustion emissions in this sector “are primarily driven by variability in weather conditions and the need for heating in buildings.”

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[151] CARB Develops Scenarios for Achieving 2030 GHG Emissions Target

The California Air Resources Board released June 17 a [concept paper](#) to inform the development of a scoping plan for achieving a 40 percent reduction in greenhouse-gas emissions by 2030, as called for in Executive Order B-30-15.

The plan presents four potential high-level concepts, or scenarios, for achieving the 2030 target. Three of the four scenarios do not include a cap-and-trade program post-2020—no compliance instruments, no linkage with Quebec or other jurisdictions. All include the state-mandated 50 percent renewable portfolio standard.

Some key features of Concept 1 include continuation of the cap-and-trade program with a 4 percent annual cap decline; further reductions in the carbon intensity of fuels under a continuing Low Carbon Fuel Standard program; a 40 percent reduction in methane and hydrofluorocarbon emissions, as required under the state’s proposed short-lived climate pollutant strategy; and 1.5 million zero-emission and plug-in hybrid light-duty electric vehicles on the road by 2025.

Concept 1 “builds on the successful programs that have put California on the path for reaching the 2020 GHG statewide limit mandated by AB 32,” the paper notes.

In place of the cap-and-trade program, Concept 2 requires more-ambitious targets for other GHG emissions-reduction strategies, such as the LCFS or one that focuses on sustainable communities, established under SB 375.

Industrial entities currently regulated by cap and trade would still be expected to each reduce their GHG emissions, however.

Industrial facility caps, to decline at a maximum rate of 4 percent per year, “would be established by identifying a baseline annual GHG emissions level for each regulated entity in permits, and requiring a decrease in emissions to achieve the required GHG reductions,” according to CARB.

Concept 3 also forgoes cap and trade but focuses more intensely on the transportation sector, calling for 5.5 million to 6.5 million zero-emission and plug-in hybrid light-duty electric vehicles by 2050, for example, and more-ambitious targets for the LCFS.

“As this strategy would focus on transportation and fuels, staff would explore additional measures to promote technology with GHG emissions reductions from heavy-duty vehicles, public transit systems, and freight,” the paper notes. “Industrial sector GHG emissions would be addressed through the traditional regulatory approach for addressing criteria pollutants at stationary sources.”

Unique to Concept 4 is the inclusion of a carbon tax, in lieu of cap and trade. The tax, which would require legislative approval, would place a fixed cost on each metric ton of carbon dioxide-equivalent emitted. The price could be predetermined through economic modeling, according to CARB, or by using the U.S. Environmental Protection Agency’s social cost of carbon, which has a range of $11 to $105 in 2015.

CARB plans to release a draft 2030 target scoping plan in the fall. The agency is accepting comments on the concept paper until July 8.

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[16] Pinnacle West, Berkshire Propose Line for Wyoming Wind Power (from [6])

TransCanyon, a joint venture of Pinnacle West Capital and Berkshire Hathaway Energy, is proposing a 213-mile, 500 kV transmission line to link California to Wyoming wind resources.

The Cross-Tie Transmission Line would connect the 500 kV Robinson Summit Substation west of Ely, Nev., with the proposed Clover 345/138 kV substation near Mona, Utah. The $667 million Cross-Tie project would be completed by year-end 2024.

TransCanyon filed an application for Cross-Tie with the Public Utilities Commission of Nevada under the Utility Environmental Protection Act on June 14 and a right-of-way application with the U.S. Bureau of Land Management on June 15.

Cross-Tie is the second large transmission project proposed to connect Wyoming wind to California, but the other project is well ahead of Cross-Tie. BLM is expected to issue a decision this fall on the proposed TransWest Express Transmission Project, a $5 billion, 730-mile, 600 kV direct-current line proposed by TransWest Express LLC, a subsidiary of Anschutz Corp.
Cross-Tie meanwhile, could help deliver Wyoming wind power throughout the West by connecting PacifiCorp’s eastern system to the Desert Southwest and California, according to the developer.

To reach Southern California, Cross-Tie would rely on the One Nevada Line, a 231-mile, 500 kV line that runs from Robinson Summit Substation west of Ely to the Harry Allen Substation in Las Vegas. One Nevada is owned by LS Power and Berkshire subsidiary NV Energy, with NV Energy controlling rights to the line’s current 1,000 MW capacity.

At Harry Allen, Cross-Tie transmission customers would switch to the planned Harry Allen-to-Eldorado line. This 60-mile, 500 kV line would end at the Eldorado Substation on the California border near the southern tip of Nevada.

CAISO in January selected LS Power’s DesertLink subsidiary to develop, build and own the Harry Allen-Eldorado line. DesertLink is scheduled to complete the 60-mile line in 2020 under a CAISO cost cap of $147 million.

Another LS Power project, the 500 kV Southwest Intertie Project-North, which would run 275 miles from Robinson Peak to the Midpoint Substation near Twin Falls, Idaho, would increase the available capacity of One Nevada by another 1,000 MW.

LS Power has approval under the National Environmental Policy Act for SWIP North, but the company hasn’t set a target on-line date for the project.

Cross-Tie also is expected to provide access to Idaho through connection to the Gateway West and Gateway South transmission projects.

In addition, Cross-Tie’s 640 MW capacity rating would be boosted to 1,500 MW if Gateway West and Gateway South are complete by 2024 when Cross-Tie is expected to go into service, according to TransCanyon.

PacifiCorp’s 500 kV Gateway South line would stretch 400 miles. Gateway South would start at the planned Aeolus Substation in southeastern Wyoming, cross northwestern Colorado, and end at the planned Clover Substation, which also is the eastern end of the Cross-Tie line.

The 500 kV/235 kV Gateway West, a project of PacifiCorp and Idaho Power, would run 1,000 miles from the Windstar Substation near Glenrock, Wyo., to the Hemingway Substation near Melba, Idaho. BLM in March released revisions of route segments in Idaho where Gateway West is proposed to connect to the Midpoint Substation, where SWIP North will interconnect.  

[16.1] **Green Banks, Energy Districts Recommended to Lawmakers**

The Nevada Legislative Committee on Energy is considering recommendations for energy-efficiency and renewable-energy financing through a “green bank” and through Energy Improvement Districts, but also reviewed the proposed termination of incentives for solar water heaters.

The energy committee is expected to meet in early August and select up to 10 energy bills that would be submitted to the Legislature for its next regular session starting in February 2017.

At a June 17 meeting, the committee considered legislation to permit local governments to create Energy Improvement Districts. Residential and commercial property owners could use the districts to obtain long-term loans for rooftop solar systems and energy-efficiency improvements.

Under another proposal, Nevada could establish a green bank to finance energy-efficiency projects. A green bank could also offer financing to upgrade commercial buildings, add rooftop solar-photovoltaic systems with energy storage, and help Nevada motorists transition to plug-in electric vehicles.

Gov. Brian Sandoval already has the authority to establish a green bank. However, new legislation could create a simpler structure for a funding a green bank through a nonprofit organization, Jeffrey Schub, executive director of the Coalition for Green Capital, told the energy committee.

The Nevada Legislature in 2015 enacted SB 360, which authorized a study on prospects for establishing a Green Bank in Nevada. At the energy committee meeting, the Coalition for Green Capital gave lawmakers a preview of the study prior to its release on June 30.

Schub identified seven states with green banks, including California, and said five states are exploring the concept. However, green banks have a variety of structures and products designed to suit local needs.

Green banks can enhance the creditworthiness of loans for a network of private lenders; seek private loans to leverage government financing; or package a portfolio of clean-energy loans that would be sold to a private lender.

In addition, a Nevada green bank could help private employers create programs similar to Nevada's Direct Energy Assistance Loan program for energy-efficiency improvements in state workers’ homes.

Under the Nevada DEAL program, each state employee can borrow up to $6,000 in interest-free

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loans for five years. Loan payments are deducted from the employee’s paycheck.

In establishing a green bank, Nevada may need to use a loophole around the state’s constitutional prohibition on direct lending or investment of public money in private businesses.

The Legislature could sidestep the prohibition by establishing the green bank as a nonprofit organization before giving the bank a state grant, Schub said.

Also, a green bank could use demand-side management funds from electric utilities, obtain a federal grant, or get authority to issue its own bonds, Schub said.

Schub suggested a green bank would boost Nevada clean-energy programs, which have been hurt by an $11 million reduction in Nevada Power’s demand-side management budget in December 2015, continuing reductions in incentives for rooftop solar, and a net-energy metering rate increase in January 2016.

**Energy Improvement Districts**

Separately, Timothy Farkas, director of finance for Ameresco, an energy service provider, outlined planned legislation to let cities and counties create Energy Improvement Districts under a Property Assessed Clean Energy program.

Homeowners and commercial-building owners could use the districts to obtain long-term loans for energy-efficiency and distributed-generation projects.

Farkas said 16 states have active PACE programs.

The local government could issue a bond for the Energy Improvement District, but would take no responsibility for bond repayment.

The PACE bond would be repaid solely by commercial-property owners and homeowners with PACE-financed energy efficiency and distributed generation, Farkas said.

The proposed legislation would make the PACE lien superior to a home’s mortgage. The debt would be transferred to the new owner if the property was sold.

A nonprofit, such as a green bank, could administer the PACE program, Farkas said.

The Nevada New Industry Energy Task Force in May recommended Gov. Sandoval submit a bill for the PACE program.

In 2013, the Nevada Senate voted 21-0 to pass SB 250, which would have authorized Energy Improvement Districts, but the bill died in the Nevada Assembly.

**Solar Water Heaters**

Also during the meeting, Anne-Marie Cuneo, director of the staff at the Public Utilities Commission of Nevada, recommended the Legislature eliminate the Nevada solar water-heater program.

Since 2010, the program has resulted in 595 solar water-heater installations for Southwest Gas and 18 for gas customers of Sierra Pacific Power, Cuneo said.

The two utilities have spent a combined total of $2.9 million on the solar water-heater program since 2010.

Current solar water-heater rebates cover up to 30 percent of costs or $3,000. –J. E.

**[16.2] PUCN Lawyer Resigns After Alleged Tweets Against Rooftop Solar**

The Public Utilities Commission of Nevada confirmed that General Counsel Carolyn Tanner resigned on June 16. The commission did not comment on reasons for her resignation, but it came one day after Tanner was accused of using the fictitious name “Dixie Rae Sparx” on Twitter to criticize rooftop-solar companies and rooftop-solar customers while a PUCN case on net-energy metering rates was pending.

Fred Voltz, a frequent commenter at PUCN meetings, also said Sparx praised NV Energy in Twitter comments under a picture of a woman aiming a Western-style revolver over her arm. Voltz said he found the same picture on Tanner’s Facebook page.

Voltz contended that the Nevada Code of Judicial Conduct and the Nevada Administrative Act prohibit commission employees from communicating with persons on pending cases. –J. E.

**[17] BLM Fracking-Rule Strike-Down Cheers Producers (from [7])**

Congressional Republicans and oil and natural gas producers cheered a federal court’s June 21 decision striking down the Bureau of Land Management’s hydraulic-fracturing regulations.

Sen. James Inhofe (R-Okla.), chairman of the Senate Environment and Public Works Committee, called the voided rules a “power grab” and added that states are the “appropriate regulators” of the well-stimulation practice.

“We’re overjoyed with the ruling,” said Kathleen Sgamma, the Western Energy Alliance’s vice president for regulatory and government affairs. The alliance is a trade group of Western oil and gas producers.

Judge Scott Skavdahl of the U.S. District Court of Wyoming said BLM overstepped its authority under mineral-leasing and federal land-use planning laws in adopting the regulations, which would have applied to federal and Indian lands. He also found that exemption of non-diesel hydraulic fracturing from Environmental Protection Agency regulation under the Safe Drinking Water Act spoke to congressional intent.

“If agency regulation is prohibited by a statute specifically directed at a particular activity, it cannot reasonably be concluded that Congress intended regulation of the same activity would be authorized under a more general statute administered by a different agency,” Skavdahl wrote.

Skavdahl last year blocked implementation of the regulations, which had been scheduled to take effect June 24, 2015.

The rules would have required producers to disclose fracturing chemicals on the FracFocus.org database; comply with technical requirements covering well casing and cementing; set minimum standards for blowout prevention; and specify methods for storing recovered fracturing fluids.
Interior Secretary Sally Jewell has argued the rule is necessary to replace outdated federal regulations and to ensure baseline regulation of fracking of oil and gas wells on federal lands.

**Obama Signs Pipeline-Safety Legislation**

President Barack Obama on June 22 signed into law pipeline-safety legislation (S. 2276) requiring federal safety rules for natural gas storage facilities.

In addition, the bipartisan legislation will codify a task force to report on the causes of the four-month-long Aliso Canyon leak in Southern California, study its impact on electricity prices, and make recommendations for leak prevention.

Among the sweeping bill’s provisions are directives to the Pipeline and Hazardous Materials Safety Administration to complete safety standards and reports mandated in 2011 legislation, and to provide pipeline operators written findings within 90 days of an inspection, “to the extent practicable.”

**White House Announces Storage Commitments**

The White House on June 17 announced executive actions and 33 state and private projects to expand energy storage by 1.3 GW over the next five years, including the Bonneville Power Administration and Portland General Electric’s project to demonstrate demand response with 600 water heaters.

BPA spokesman Joel Scruggs said the project would provide data for a future market-transformation project. According to a BPA brief, if every new water heater in the Northwest was fitted with demand-response controls, “1,800 MW and 16,000 MWh of controllable power and storage” would be available over 20 years. That would defer a need to develop natural gas-fired peaking plants and avoid a maximum economic potential of 15 trillion Btu per year of power-plant gas consumption.

The project is designed to demonstrate demand-response shifting of power consumption to nighttime shaped loads and use of water heaters to absorb or curtail day-ahead and hour-ahead errors in wind forecasts, according to BPA.

Other announced projects include San Diego Gas & Electric’s plan to install 3,500 electric-vehicle charging stations; a Southern California Edison commitment to procure 580 MW of energy storage by 2020; and Pacific Gas & Electric’s proposal for five projects to integrate distributed generation into grid operations.

The Los Angeles Department of Water & Power plans 24 MW of storage this year, increasing to 178 MW by 2021, the announcement said.

Other actions the administration announced include plans for a grid-scale battery of up to 100 MW at Naval Weapons Station Seal Beach, and a 7 MW photovoltaic system with 6 MW of battery storage at Naval Base Ventura County.

**Report Spotlights Grid-Management Benefits**

Grid-management services designed to integrate high levels of variable renewables will create increasing demand for energy-storage and demand-response technologies, the White House Council of Economic Advisers said in a report released June 16.

The report said the technologies would enable grid operators to avoid costs of quickly ramping up dispatchable generation and bringing on ancillary services to meet steep increases in “net load,” during periods of the day when load rises and variable generation diminishes.

The White House quoted a recent Lawrence Berkeley National Laboratory study projecting 6 GW of demand response will be available in California by 2025 at an annual levelized cost of $200 per kW.

**Cantwell Prods FERC on California Price Gouging**

Sen. Maria Cantwell (D-Wash.) on June 21 asked FERC to prevent price gouging tied to limited gas storage at the capped Aliso Canyon natural gas storage field in Southern California.

In a letter to FERC Chairman Norman Bay, Cantwell urged FERC to ensure “electric generators and energy marketers do not take advantage” of the limited gas supply “to artificially raise Western electricity and natural gas prices.”

Referencing the West Coast energy crisis of 2000-2001, Cantwell said nearly 10,000 MW of capacity could be subject to supply disruptions resulting from the low gas storage at Aliso, which she said totals 15 Bcf.

Cantwell also noted the long-range weather outlook for a hotter-than-normal summer “is likely to exacerbate the problem.”

**Report Makes Case for Upping Coal Royalties**

The White House Council of Economic Advisers said June 22 there is “strong economic support” for increasing royalties on coal produced from federal lands.

In a report, the council said boosting royalties based on final delivered prices, with adjustments for heat content, quality and location, would help federal coal leases provide a “fair return to the taxpayer.”

Because federal coal is “so much less expensive on average to extract than other coal on the market,” higher royalties would result in only a “modest” reduction in coal production, the report said.

The council’s report quoted one study calculating an “effective royalty rate” of 4.9 percent, after factoring in final delivered price. The statutory minimum rate is 12.5 percent. Another study the report spotlighted estimated 42 percent of federal coal produced in Wyoming in 2012 was sold in “captive” transactions between parent and affiliate companies.

The Interior Department has suspended new coal leases while it studies the leasing program.

House Natural Resources Committee Chairman Rob Bishop (R-Utah) dismissed the report as “propaganda.”

**House Leaders Open to Energy Bill Conference**

Leaders of two House committees signaled willingness to hash out a compromise energy bill in a conference with the Senate.

Reps. Fred Upton (R-Mich.), chairman of the Energy and Commerce Committee, and Rob Bishop (R-Utah), head of the Natural Resources Committee,
said “our goal is to get something to the president that he will sign into law.”

Upton and Bishop said they “remain committed to working in a bicameral, bipartisan manner.”

The House on May 26 approved going to conference with the Senate, following its passage of an amended version of the Senate energy bill, S. 2012. Speaker Paul Ryan (R-Wisc.) named 41 conferees, but the Senate has held back. House and Senate Democrats have criticized the House version of the bill, which faces a White House veto threat.

Key differences between the House bill and Senate legislation include hydropower-licensing reforms and the House bill’s prohibition of Department of Energy technical assistance for energy building codes with paybacks greater than 10 years.

**BLM Planning Rule Draws Flak**

BLM’s proposed rule to streamline land-use planning drew fire at a June 21 Senate hearing from states and oil and natural gas producers, who argued it could push the agency away from multiple-use management of federal lands.

The proposal would convert BLM’s guiding statute—the Federal Land Policy and Management Act—“away from the principles of multiple use and sustained yield to preservation only,” Kathleen Sgamma, vice president for government and public affairs at the Western Energy Alliance, a group of oil and gas producers, told the Senate Energy and Natural Resources Committee’s public-lands panel.

James Ogsbury, director of the Western Governors’ Association, raised concerns that the proposal would ignore scientific information provided by states.

BLM Director Neil Kornze said current BLM land-use planning takes too long, driving up costs and sparking legal challenges. Kornze said the proposal would shorten planning by providing more information and public involvement opportunities up front.

**CPP Incentive Proposal Draws Fire**

EPA’s release of details of a proposed Clean Power Plan incentive program June 16 drew critics who argued that EPA is ignoring the Supreme Court’s stay of the rule limiting fossil-fueled generation CO2 emissions.

Sen. James Inhofe (R-Okla.), chairman of the Environment and Public Works Committee, said states and tribes should ignore EPA’s proposal.

Under the proposal, participating states and tribes could earn up to 500 million tons of emissions allowances for developing eligible renewables during 2020 and 2021 under mass-based emissions-reduction programs. For rate-based programs, up to 375 million in credits tied to megawatt-hours generated by eligible technologies would be available.

Hydropower and geothermal would join solar and wind as eligible technologies under the proposal.

**Agency Adjusts Duties on Chinese PV**

The International Trade Administration (ITA) on June 20 adjusted anti-dumping import duties on Chinese solar-photovoltaic products in an annual review, upping proposed duties on two Chinese PV manufacturing groups.

In a final determination capping the second review of 2012 duties, the Commerce Department agency set the duty at 12.19 percent for the Yingli Group and 6.12 percent for the Trina Group, a slight increase for both from rates proposed last Dec. 28.

The trade agency finalized proposed rates of 8.52 percent for 15 other companies and 238.95 percent for all China-based PV manufacturers without a separate rate.

The duties are designed to offset what ITA has determined are the manufacturers’ sales of PV products in the U.S. market at below-market rates. The duties apply to crystalline-silicon PV cells, modules, laminates and panels, whether made in China or by non-Chinese manufacturers sourcing the materials from China, ITA said. –Jim DiPeso
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[1] Sweeping CPUC Reform Proposal Advances With Assembly Vote

A sweeping CPUC reform package advanced this week after the June 27 agreement was announced by Gov. Jerry Brown; Assm. Mike Gatto, whose proposal to restructure the commission had made its way through the Assembly; and Sens. Jerry Hill and Mark Leno. The package would transfer certain ride-sharing and other transportation-related functions away from the commission, authorize the California Attorney General to prosecute any CPUC decision-maker or employee for violations of ex parte rules, tighten ex parte and public-access rules, and enhance oversight and safety. The reform package comes as a state audit finds the commission has mismanaged business practices. [At [12], a new day for the CPUC?]

[2] SSJID Votes in Favor of Eminent-Domain Takeover of PG&E System

The South San Joaquin Irrigation District has decided to attempt a hostile takeover of Pacific Gas & Electric’s distribution assets located within the SSJID service territory through eminent domain. Acquiring the assets is a make-or-break component of the district’s plan to supplant PG&E as the electric service provider for about 40,000 customers in Escalon, Manteca, Ripon, and adjacent unincorporated areas. PG&E asserts the district lacks the experience needed to ensure safe, reliable service. [Headed for the courts at [15].]


Before adjourning for summer recess until August, California lawmakers moved a host of climate and energy bills critical to the state’s overarching effort to drastically decarbonize its energy system. But slashing short-lived methane emissions stole the show in Sacramento ahead of a July 1 deadline for bills to pass policy committees. More than a dozen bills directly or indirectly related to Southern California Gas Co.’s massive methane leak at Aliso Canyon remain in play. [At [17], supporters hope amendments do not gut bills’ intent.]


Pacific Gas & Electric’s proposal to retire its Diablo Canyon nuclear power plant when current licenses expire in 2024 and 2025 cleared an initial hurdle June 28 with a unanimous vote by the three-member State Lands Commission to approve a new, limited-term lease for the submerged lands offshore of the facility that contain water intake and discharge structures. The commission will not require an environmental impact report on the new lease. [Also at [13], earthquake concerns.]
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CAISO’s Department of Market Monitoring has suggested abolishing a congestion revenue rights auction that reaps about $100 million a year for power marketers, and would instead give the money directly to load-serving entities. [Also at [18], new CRR rules, and update on regional transition]

[6] Latinos Walk Out of CEC Meeting on Calpine Plant

The CEC’s June 28 environmental scoping meeting and informational hearing on Calpine Corp.’s proposed Mission Rock Energy Center dissolved in chaos in the largely Latino agricultural community of Santa Paula as more than 100 disgruntled attendees spontaneously walked out after complaining about what they called an inadequate translation. [Lost in translation at [14]].


A proposed constitutional initiative to enable open access in Nevada that is backed by billionaire casino executive Sheldon Adelson is expected to qualify for the November ballot. But a SolarCity-backed referendum on net-energy metering rates must still overcome a legal challenge before it can be placed on the ballot. [At [20], interpreting definitions].

[8] Interior Finalizes Fossil-Fuels Valuation Rule

The Interior Department this week finalized a rule overhauling valuation of fossil fuels produced on federal lands, setting gross proceeds from arms-length transactions as benchmarks for calculating royalties. [At [21], “market-driven mechanism” replaces “difficult-to-use” benchmarks].

[9] California Announces $1 Billion Settlement With Volkswagen

Volkswagen will pay California $1.2 billion to remedy harm caused by the German automaker’s emissions-cheating scheme, the California Air Resources Board and Attorney General Kamala Harris jointly announced June 28.

The settlement deal includes about $380 million for incentivizing clean, heavy-duty vehicles and equipment in disadvantaged communities, and $800 million to advance investments in the state’s zero-emission vehicle program.

“This is a good deal for California’s environment and for California consumers,” CARB Chair Mary Nichols said in a statement. “It will bring over a billion dollars of projects to California to supercharge our expanding zero-emission vehicle market, and fully mitigate the environmental harm to our air as a result of VW’s cheating.”

VW has admitted to installing “defeat devices” in several models of clean-diesel cars, model years 2009-2015—an illegal practice under the Clean Air Act. The device amounts to a sophisticated algorithm that allows the vehicles to detect when the car is undergoing emissions testing, according to CARB, triggering full emissions controls only during testing (see CEM No. 1353 [16]).

The settlement deal with California is part of a broader $14.7 billion national settlement, which includes up to $10.5 billion for buybacks and lease terminations for nearly 500,000 vehicles; for emissions modifications that are approved by CARB and the U.S. Environmental Protection Agency; and/or to compensate consumers for harm caused by VW’s deceptive advertising.

The company had specifically targeted green-minded consumers when marketing clean-diesel vehicles, noting their “amazing fuel efficiency” compared to gasoline-fueled counterparts, and lower carbon emissions. [L. B. V]

NEWS IN BRIEF

[9.1] Sacramento Municipal Utility District Announces Tiny-House Competition

The Sacramento Municipal Utility District announced June 22 it is sponsoring a “tiny house competition” in the Sacramento region, challenging collegiate teams to design and build net-zero-energy solar houses with a footprint of 400 square feet or less.

The event is modeled after the U.S. Department of Energy’s Solar Decathlon, but the houses will be less than half the typical square footage of a home built for the decathlon, SMUD said.

“The homes will feature smart appliances, green building materials and techniques, renewable energy technologies and innovative designs scaled for small living,” the district noted.

Homes will be judged on criteria divided into four categories—architecture, energy efficiency, home life and communications. Winning teams will receive trophies and monetary awards.

The competition will be held Oct. 10-15 at Cosumnes River College in Sacramento. Teams representing the following schools are scheduled to compete: California State University, Chico; California State University, Fresno; Cosumnes River College; College of the Sequoias; Laney College; Sacramento State University; San Jose City College; Santa Clara University; University of California, Berkeley; and University of California, Santa Cruz, partnering with Cabrillo College.

The teams, which applied for the competition in late 2014, began working on their houses last year, according to SMUD. [L. B. V]
Wind and Solar Are a Bargain

It didn’t used to be the case that renewables were cheap, especially solar. In years past, CPUC commissioners grumbled about some relatively high-priced utility-scale solar contracts, though they nearly always approved them.

In the past few years, however, utility-scale solar prices have taken a steep dive, with utilities in California and the Southwest signing contracts below $50/MWh. Procurement has also gotten wiser: Gone are the days of supersized projects in the desert that cause permitting and regulatory headaches. Many of the recent low-priced contracts, in fact, that have come in below $50/MWh are in the 50 MW to 150 MW range, as studies have shown there are no economies of scale in building super-sized projects.

“Smaller projects (e.g., in the 20-50 MW range) feature PPA prices that are just as competitive as larger projects,” according to a 2014 report from Lawrence Berkeley National Laboratory, “Utility Scale Solar.”

The levelized prices of course factor in a 30 percent investment tax credit, and do not apply to distributed solar such as rooftop PV. But even without the ITC, both solar and wind are cheap after considering their benefits.

Both solar and wind produce natural gas savings that are worth 1.3 cents to 3.7 cents/kWh, according to a previous Berkeley Lab study, “A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards.”

There are also benefits for reducing pollution, which LBNL researchers quantified in a June 2016 study, “The Environmental and Public Health Benefits of Achieving High Penetrations of Solar Energy in the United States.”

Authors of that study looked at what would happen if the United States achieved the Department of Energy’s SunShot Vision, which entails solar-electricity penetrations of 14 percent of annual U.S. electricity demand by 2030 and 27 percent by 2050.

Achieving that scenario reduces lifecycle GHG emissions in the power sector by 13 percent in 2030 and 18 percent in 2050. “These reductions produce global benefits of $259 billion in the form of lower future climate change damages when applying a central value for the social cost of carbon (SCC), which is equivalent to a levelized benefit of solar of 2.2 cents/kWh–solar,” the authors state.

The SCC measure reflects, among other elements, monetary damages from the impacts of climate change on agricultural productivity, human health, property, and ecosystems.

Under an alternative method, when considering solar as a way to meet future carbon-reduction requirements, present-value benefits of achieving the SunShot Vision scenario range from $60 billion to $92 billion (0.5 cents to 0.8 cents/kWh–solar) when only considering Environmental Protection Agency Clean Power Plan estimates.

Benefits range from $142 billion to $347 billion (1.2 cents to 3.0 cents/kWh–solar) when considering longer-term carbon-reduction policy possibilities.

Reducing GHG emissions, however, is not the only benefit. Achieving the SunShot Vision also reduces sulfur dioxide (SO2), nitrogen oxides (NOx), and fine particulate matter (PM2.5) emissions. Total monetary benefits of these reductions from 2015 to 2050 reach $167 billion, and equate to 0.7 cents/kWh to 2.6 cents/kWh, the report says, with the average benefit at 1.4 cents/kWh.

“These benefits derive, in large measure, from a reduction in premature mortality from sulfate particles from SO2 emissions—achieving the SunShot Vision scenario reduces premature mortalities by 25,000-59,000 based on methods developed at EPA,” the report says.

When adding up all the benefits—natural gas savings, the social cost of carbon, and reduction of air pollutants—it’s possible that wind and solar are producing more benefits for society than what the power actually costs.

It’s possible that wind and solar are producing more benefits for society than what the power actually costs.
Natural Gas Prices Move Higher With Holiday

Western natural gas prices saw a lift heading into the July Fourth holiday weekend. Warmer weather has bolstered gas prices in recent weeks, a trend that continued this week.

Working natural gas in storage was 3,140 Bcf as of June 24, according to U.S. Energy Information Administration estimates. This is a net change of 37 Bcf compared to the previous week. Storage levels are now 22.8 percent greater than a year ago and 25.4 percent greater than the five-year average.

Working gas in storage within the Pacific region was adjusted lower by roughly 5 Bcf during the report week as part of a “non-flow-related adjustment,” according to the EIA. The report did not indicate the specific reason for the change.

Henry Hub gas spot values added 22 cents in Thursday-to-Thursday trading, ending at $2.90/MMBtu June 30.

Western natural gas values gained between 11 cents and as much as 51 cents in trading. PG&E CityGate posted the greatest gains, adding 51 cents to end at $3.26/MMBtu Thursday.

The calendar toyed with power trades. South of Path 15 was the only hub to post peak trades each day of the June 27 to July 1 trading period. Trades made June 29 were earmarked for July 2 delivery, while those posted June 30 and July 1 were earmarked for July 5 delivery.

Average peak power prices lost between $8.15 and as much as $11.45 in June 24 to July 1 trading. California-Oregon Border fell $11.45 to $29.40/MWh.

Nighttime power prices varied, with Pacific Northwest hubs up roughly 65 cents on average, while SP15 off-peak prices fell $5.45 in trading.

Demand peaked on the CAISO grid at 43,239 MW June 27, which was the high for the week. Total renewables production on the CAISO grid reached 12,691 MW June 24 and total solar production reached 7,794 MW that same day. Thermal generation peaked June 27 at 21,560 MW.

In June, average natural gas prices were on par with the same month last year. The average high price at Henry Hub was precisely the same at $2.93/MMBtu.

Average Western power prices in June were significantly less when compared with the same month last year. Prices last month were generally between $5 and as much as $60/MWh less than the same month in 2015, thanks to extreme heat last year.

-Linda Dailey Paulson
**CAISO Power Production**
Rolling Average, 06/24 - 06/30

**Peak Demand:** 43.2 GW on 06/27

- Green: total renewables
- Red: thermal
- Orange: total solar
- Blue: wind
- Light blue: imports

Source: BPA & CAISO

**BPA Loads and Resources**
Rolling Average, 06/24 - 06/30

- Blue: hydro
- Red: load
- Green: wind

Source: BPA & CAISO

**Spot Peak Power Trends**

- Mid-C
- COB
- NP 15
- SP 15
- Palo Verde

$/MWh

- June 2015 average range
- June 2016 average range

Source: www.theice.com

**Spot Natural Gas Trends**

- Henry Hub
- PG&E City Gate
- SoCal Border
- Malin

$/MMBtu

- June 2015 average range
- June 2016 average range

Source: www.theice.com

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A sweeping CPUC reform package advanced this week after the June 27 agreement was announced by Gov. Jerry Brown; Assm. Mike Gatto, whose proposal to restructure the commission had made its way through the Assembly; and Sens. Jerry Hill and Mark Leno, who have long been involved in legislative efforts to revamp the agency.

The reform package would transfer certain ride-sharing and other transportation-related functions to the California Department of Motor Vehicles and the California Highway Patrol; prohibit former utility executives from serving on the commission for two years; allow any state agency to participate in CPUC proceedings without official party status; and authorize the California Attorney General to prosecute any CPUC decision-maker or employee for violations of ex parte rules.

The package—much of which is enshrined in SB 215, initially introduced in February by Gatto (D-Los Angeles) and Sen. Ben Hueso (D-Chula Vista)—also includes transparency provisions that tighten ex parte rules, and oversight and safety provisions that include creating an ethics-ombudsman position and codifying the creation of a deputy director for safety, something the commission has advocated for.

SB 215 passed the Assembly Utilities and Commerce Committee June 29 on a unanimous vote of 14-0, and headed back to the Assembly Appropriations Committee.

Gov. Brown, lawmakers, and the commission itself hailed the measures.

The package represents “a massive realignment of values at the CPUC,” Gatto said in a press conference announcing the reform agreement. “It will enable them to be more specialized, more focused . . . basically they have the ability to make safety a priority, utility rates a priority.”

The measures come as the CPUC has been under fire over what lawmakers have called lax oversight that contributed to the deadly San Bruno natural gas pipeline explosion in 2010, as well as the long-running, massive gas leak at the Aliso Canyon storage facility, which spewed more than 94,000 tons of methane into the atmosphere over four months before it was sealed.

By tightening ex parte requirements and making changes to access rules for public documents, lawmakers hope to avoid another situation like the one that unfolded around the San Onofre Nuclear Generating Station settlement, which is now being re-litigated after it came out that the settlement framework was crafted between former CPUC President Michael Peevey and a Southern California Edison executive at a secret meeting during a conference in Poland.

“The principles are a blueprint for a CPUC that is focused, efficient, working in the public interest, and most notably, transparent and accountable,” Sen. Leno said in an announcement from the Governor’s Office. “The changes agreed to by the commission and the governor in SB 215 apply enhanced ex parte communication rules targeting the abuses of the past and ensure independent prosecution and stiff penalties for those who would violate the public trust.”

Governance provisions of the package include the transfer of responsibility for implementation and enforcement of certain transportation functions—including licensing, registration, evidence of insurance and select investigations—to the DMV, and enforcement and select investigations to the California Highway Patrol; using the Governor’s Reorganization Process. Another provision would require the CPUC to assess state telecommunications governance by Jan. 1, 2018. The package also requires the commission to set up cross-agency secondments, which would allow commission employees to work temporarily with agencies such as the Department of Conservation’s Division of Oil, Gas & Geothermal Resources and CARB, to facilitate better coordination of activities and communication.

It would authorize the CPUC to hire and locate employees in Los Angeles and Sacramento in addition to San Francisco; require voting meetings to be held in various regions around the state; and allow the governor in SB 215 apply enhanced ex parte provision to hold two meetings a year in Sacramento; allow for consideration of reports from state, federal, and academic sources; and allow a commissioner to issue an alternate opinion at any time before a CPUC vote rather than only with the issuance of a presiding judge's proposed decision, as currently allowed.

“The reform initiatives announced today represent the start of a new chapter for the CPUC that will allow the focus to return to the work of our dedicated staff in providing for a safe and productive California,” the commission said in a prepared statement. “The reform initiatives warrant our support, and we remain committed to an outcome that will provide enhanced accountability and transparency, and allow us to concentrate on core regulatory functions that protect Californians.”

The package gives the commission latitude to enact stricter ex parte rules in ratesetting or quasi-legislative proceedings, and requires commissioners and any interested parties to promptly log and make public the content of ex parte communications in ratesetting proceedings. Failure to comply with this provision would result in penalties from either the CPUC itself or the attorney general.

Other reforms would subject the commission to judicial review under the California Public Records Act; would require documents distributed to a proceeding’s service list to be docketed; would allow
commissioners to deliberate on ratesetting proceedings if no hearing has been held; would make the administrative record more open in quasi-legislative proceedings by not applying the formal rules of evidence; and, among other things, would give the commission authority to conclude proceedings that have exceeded established thresholds for timeliness.

On oversight and safety, the package would allow for the creation of an ethics ombudsman who could respond to any CPUC employee or member of the public; the ombudsman would also be responsible for overseeing staff ethics training. The package codifies a new deputy director position at the commission who would advocate for safety. The reforms also would task the commission with working with the U.S. Nuclear Regulatory Commission to expedite the relocation of spent nuclear fuel to an independent storage facility. The package also would enhance current safety laws related to pipe dig-ins.

The legislation codifies some reform initiatives already underway at the commission, said President Picker, speaking after a June 28 rate-design forum in Oakland. One of the things the package does is give the commission itself more flexibility in the way commissioners can communicate with each other, he said.

DGS Audit Finds Issues With CPUC Business Management

A new Department of General Services audit of the CPUC’s business-management functions found that several of the commission’s policies and procedures do not comply with state requirements.

The June 29 audit made several recommendations to better align commission practices with state requirements in areas such as contracting, purchasing, fleet management and invoicing.

The audit also identified other matters that DGS discussed with the commission, but that were not included in the report, according to a June 29 letter from Rick Gillam, chief, Office of Audit Services, to CPUC Executive Director Tim Sullivan.

“Overall, we concluded that CPUC’s policies and procedures are not sufficient to provide reasonable assurance of compliance with requirements governing the state’s various business management programs,” Gillam’s letter said. “However, it should be noted that we are pleased with CPUC’s commitment shown to improve compliance with state requirements.”

The CPUC agreed with each of the recommendations made in the audit. Sullivan, in a June 27 letter to Gillam included in the audit report, explained work that is already underway to boost compliance in several areas, and laid out actions the commission will be implementing.

SoCal Gas Makes Slow Progress on Testing Aliso Canyon Wells

Since a massive, four-month natural gas and methane leak at the Aliso Canyon gas storage facility in Southern California was permanently sealed in February, just four wells have been fully tested, remediated, inspected and been made available for gas withdrawal.

That slow pace—an average of one well a month to date—may exacerbate the ongoing reliability risk in the region.

A June 28 CPUC report looking at the working gas inventory, production capacity, injection capacity, and well availability at Aliso Canyon found that with the current amount of gas stored in the field—15 Bcf—and the 21 wells that are available for gas withdrawal, operator Southern California Gas Co. may not have the withdrawal capacity to meet needs under certain scenarios.

Findings in the report are based on the Aliso Canyon Risk Assessment Technical Report, which was prepared by staff at CAISO, the CEC, the Los Angeles Department of Water & Power, and SoCal Gas, and released in April. The joint report assessed different scenarios, and ultimately concluded that without gas from Aliso Canyon, there was significant risk of gas curtailment to nonresidential customers that could lead to blackouts on 14 days over the summer.

The Aliso Canyon leak, discovered in October, is considered the worst natural gas leak in U.S. history; more than 94,000 tons of methane poured into the atmosphere before the leak was plugged. Aliso Canyon, situated in the Santa Susana Mountains north of Los Angeles, is considered a critical part of SoCal Gas’ natural gas system; gas from the field bolsters supplies when the utility does not receive enough gas flowing through its transmission-pipeline network. In the summer gas from Aliso, the largest of SoCal Gas’ four storage fields, is used to support summer hourly peak demand, and in the winter gas from Aliso supports higher residential demand for gas for heating and cooking.

Under SB 380, a bill from Sen. Fran Pavley (D-Agoura Hills) signed by Gov. Jerry Brown in May, there is a continuing moratorium on gas injections into the field, which has a capacity of 86 Bcf, until all of the field’s 114 wells undergo a comprehensive testing and safety-inspection regime. The safety review will be considered complete when all wells have passed inspection, have been temporarily isolated from the reservoir, or have been plugged and abandoned. The new law also limits gas production (withdrawal) and injection to only a well’s interior metal tubing. Operators previously have injected and produced gas through the tubing as well as the annulus, or space between the tubing and well casing, as a way to increase injection or withdrawal capacity. Using only the tubing lowers both withdrawal and injection capacity.

The CPUC report was required under SB 380 as well. In addition to the four fully tested wells that are available for gas withdrawals. Five other wells have completed all safety testing and review, but are not available for gas withdrawals.
yet operational, and another 17 wells have completed Phase 1 testing and can be used for production if needed for reliability, under guidelines sent to the company in mid-June by the CPUC and the Division of Oil, Gas & Geothermal Resources. Twenty-three wells are still undergoing comprehensive testing.

Under the curtailment scenarios energy agencies considered in their Aliso assessment earlier this year, which looked at situations where potential outages and high heat days could lead to higher demand and less supply, the risks or curtailments were lessened if SoCal Gas could withdraw 252 MMcfd to 1,119 MMcfd from Aliso.

But based on the number of wells currently available for gas withdrawal and the lower withdrawal capacity due to the tubing limitation, the CPUC estimates that only 500 MMcfd can be withdrawn currently, which is not enough to meet needs under some of the scenarios studied.

“In each of these (four) scenarios, if enough gas were available for withdrawal from Aliso Canyon, the risks of gas curtailment and associated electricity outages could be reduced, if not eliminated,” the report states. The analysis also concluded it is critical for there to be at least 420 MMcfd of withdrawal capacity to meet the needs expected under two of the scenarios.

The commission in mid-June ordered SoCal Gas to submit a plan to increase withdrawal capacity by July 1 to the 420 MMcfd level.

**[12.3] Small, Hard-to-Find Leak Dogs PG&E’s McDonald Island Gas Field**

Pacific Gas & Electric is monitoring a small, unidentified gas leak at its McDonald Island natural gas storage facility, the largest of its three owned and operated storage fields.

The utility discovered the leak June 16 when workers conducting daily leak inspections mandated earlier this year by the Division of Oil, Gas & Geothermal Resources noticed bubbles near one of the 87 wellheads in the remote field. The utility to date has been unable to pinpoint the leak’s source.

PG&E has been fully engaged with DOGGR in monitoring and trying to find the leak, said PG&E spokesperson Nick Stimmel, and has notified the CPUC and the California Office of Emergency Services. There is “no safety, health, or environmental risk at this point,” Stimmel said.

A **June 30 letter** from DOGGR to PG&E noted that 10 wells with detectable levels of emissions have been identified at the facility, and two of those wells have been isolated from the rest of the reservoir. Flyovers commissioned by the CEC and again by PG&E showed what DOGGR characterized as a very low release, ranging from 236 kg per hour to 763 kg/hr, according to DOGGR. In comparison, emissions from the recent, massive leak at Aliso Canyon peaked at a high of more than 60,000 kg/hr.

“Just because it’s small doesn’t mean we’re not taking it seriously,” Stimmel said. The utility is using traditional leak-detection technology as well as an infrared camera and the flyovers to monitor the leak.

McDonald Island, a manmade island in the San Joaquin-Sacramento Delta, holds the 2,000-acre facility, which has a total capacity of about 81 Bcf. PG&E acquired the former oil field in the late 1950s, and the field was the site of a gas-well fire in 1974 that burned uncontrolled for more than two weeks. Currently the field is host to a PG&E pilot program to test the ability to monitor for methane.

**[13] Diablo Canyon Closure Proposal Moves Ahead With Vote on Land Lease (from [4])**

In 2010, Pacific Gas & Electric said that if it continued operating its Diablo Canyon nuclear power plant for 20 years beyond its current licenses, customers would save between $3.5 billion and $16.3 billion compared with shuttering the facility and replacing it with alternate generation resources.

That analysis, laid out in the utility’s January 2010 application at the CPUC to recover $85 million in costs related to renewing the 2,200 MW plant’s operating licenses, assumed a 90 percent capacity factor for Diablo Canyon going forward, and examined replacing the plant with a portfolio of gas-fired generation, energy efficiency, renewables, and coal-fueled integrated gasification plants with carbon capture and storage.

**Fast-forward six years,** and the energy landscape in California has changed dramatically:

- The cost of renewables, especially solar, has dropped sharply.
- SB 350, a 2015 law, increased the state renewables portfolio standard to 50 percent and requires a doubling of energy efficiency, both by 2030.
- A 2013 law, AB 2514, requires investor-owned utilities to procure 1.3 GW of energy storage by 2020.
- SCS Energy, the only developer seeking to build an integrated gasification combined-cycle plant with carbon capture and storage in California, earlier this year dropped its plans.
- Growing amounts of energy efficiency, distributed generation, community choice aggregation, and direct access are expected to reduce PG&E’s load by 3 to 21 TWh below current levels by 2021, according to an economic analysis done for PG&E by M.J. Bradley & Associates. PG&E’s total load in 2010 was 72 TWh. The utility expects that by 2025 Diablo Canyon will run at a capacity factor closer to 40 percent to 50 percent.

Those drivers, coupled with a potential price tag of billions of dollars to comply with California’s once-through-cooling policy, led the utility to craft a joint proposal with environmental and labor groups governing the closure of Diablo when its federal operating licenses expire in 2024 and 2025, and replace needed power with greenhouse-gas-free resources including renewables, energy efficiency and storage.

The utility expects the replacement resources, coupled with a $350 million retention and retraining program for Diablo Canyon’s 1,500 employees and payments to the county to cover the loss of property tax revenue, will cost less than relicensing the plant and operating it for another 20 years (see CEM No. 1391 [12]).
The proposal cleared an initial hurdle June 28 with a unanimous vote by the three-member State Lands Commission to approve a new, limited-term lease for the submerged lands offshore of the facility that contain water intake and discharge structures, and other plant infrastructure.

**The commission voted** 3-0 in favor of granting the leases without an environmental impact report, despite dozens of people who, while voicing support at the meeting for the closure proposal, urged the commission to require an EIR before approving the new lease.

“There is no particular joy in being the skunk at the picnic,” said John Geesman, at attorney for the Alliance for Nuclear Responsibility, at the meeting. “Everybody agrees that PG&E would have a more legally defensible new lease at Diablo Canyon if it were preceded by an EIR. I continue to be mystified by PG&E’s approach to risk and them wanting you to indemnify them from risk.”

The Alliance is a party to the proposal, which states that the Alliance reserves the right to request the Lands Commission conduct a discretionary EIR, but if the commission approves the leases without requiring an EIR, than the Alliance waives its right to appeal the decision.

Under the California Environmental Quality Act, existing facilities are generally categorically exempt from EIRs, unless there is a “reasonable possibility” that the activity—in this case the nine-year lease—will result in some significant impact on the environment. The Lands Commission agreed with staff’s recommendation that the lease be exempt from CEQA.

Geisha Williams, president of PG&E’s electric division, said the proposal, which brings together groups with diverse points of view, is a powerful statement “for what we believe is the best and most responsible path forward for Diablo Canyon.”

“All we’re asking for is a short extension,” Williams said. “License renewal is off the table. We believe that an EIR is not legally required or necessary.”

Having enough time to plan for an orderly transition is essential, said Lt. Gov. Gavin Newsom, a commissioner, adding that an EIR will “never go as fast as you think.”

He compared Diablo Canyon to the unexpected closure of the San Onofre Nuclear Generating Station. The early retirement of SONGS, after leaks were found in nearly new steam-generator tubes, led state agencies to scramble to ensure reliable replacement power.

“Let us not fail to plan,” he said.

**PG&E, which called the vote** a critical first step toward realizing the transition plan, will be required under the new lease to file by Aug. 26, 2020, a site-restoration plan, including an application for a lease covering the duration of decommissioning activities (which could last decades). PG&E expects the State Lands Commission review of the restoration plan will require an EIR.

Current leases for the land expire in 2018; with the approval, the current leases will be truncated, and the new leases will run concurrently with the U.S. Nuclear Regulatory Commission’s nuclear operating licenses. The new leases, which require annual payments of $279,000, include liability insurance of $10 million per occurrence, plus a $1 million surety bond.

PG&E has committed to withdrawing its application at the NRC to renew the operating licenses for Diablo’s two reactors, but would only do so once it receives CPUC approval of the closure proposal. It expects to file its CPUC application by the end of July, and will ask the commission to make a decision by the end of 2017.

The CPUC application will include PG&E’s forecast of costs to operate Diablo Canyon for another 20 years, according to PG&E spokesman Blair Jones. According to conditions of the State Lands Commission lease, if PG&E has not withdrawn its application at the NRC by Aug. 27, 2018, or filed a new lease application with the Lands Commission, the leases will terminate. –Mavis Scanlon

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### Parties to the Joint Proposal to Retire Diablo Canyon

- Pacific Gas & Electric Co.
- Friends of the Earth
- Natural Resources Defense Council
- Environment California
- Alliance for Nuclear Responsibility
- International Brotherhood of Electrical Workers Local 1245
- Coalition of California Utility Employees

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### Earthquakes Still Major Concern for Locals

Many people who spoke at a June 28 State Lands Commission meeting were concerned about the safety of Pacific Gas & Electric’s Diablo Canyon nuclear plant if a major earthquake hits.

The plant, which sits atop a bluff near Avila Beach, near several fault lines, could withstand a magnitude 7.5 earthquake, according to PG&E and Geisha Williams, president of PG&E electric, reiterated at the meeting that the plant is seismically safe.

Williams noted that an independent review panel, the U.S. Nuclear Regulatory Commission’s Senior Seismic Hazard Analysis Committee, has concurred with the utility’s technical analysis conducted as part of an NRC-required seismic hazard re-evaluation in the wake of the 2011 Fukushima earthquake and tsunami.
That concurrence approved PG&E to move on the next step in the process, with additional seismic analyses to be submitted to the NRC next year, PG&E spokesman Blair Jones said.

"Based on how the plant is built we do not anticipate the need to make any changes," Jones said.

A separate review panel convened by the CPUC to review studies mandated by the state under 2006’s AB 1632, the Independent Peer Review Panel, has raised some concerns about advanced seismic studies PG&E conducted as part of the overall seismic hazard assessment.

In general, the Independent Peer Review Panel agreed with studies sponsored by PG&E determining that uncertainties over the seismic hazard were reduced by studying the slip rates of the nearby Shoreline and Hosgri faults, said Chris Wills, a geologist with the California Geological Survey and chair of the IPRP.

But the panel did not agree with some of the studies that looked at the Irish Hills underlying the plant, Wills said. In a December report, the panel said there was not enough data to support conclusions by the utility on how amplification of seismic waves are considered. The details of how those waves are considered can have a significant effect on the analysis, Wills said.

The panel was skeptical of PG&E’s approach because the utility used the very few earthquakes at the plant in its study, Wills said. Using the more common approach to looking at wave amplification would result in a much higher ground motion, he said, adding that the panel would have liked for the utility to consider more than just one approach to this study.

“We raised questions about the approaches they were using and asked for further ways of showing this was the correct way to do it," Wills said.

Still, with more data, the panel felt this would be the right way to go in the future, Wills added, noting that PG&E is on the cutting edge of seismic hazard research in general. –M. S.

[13.2] New Members Join Diablo Canyon Independent Safety Committee

Dr. Michael Peck, the former U.S. Nuclear Regulatory Commission senior resident inspector who raised seismic safety concerns about Pacific Gas & Electric’s Diablo Canyon nuclear power plant, is among a trio of new members appointed to the Diablo Canyon Independent Safety Committee.

The CPUC at its June 23 business meeting ratified President Michael Picker’s selection of Peck, Captain Neil “Buzz” Carns, and Judge Alex Carlin for appointment to the safety committee from a slate of five candidates. The candidates were appointed by California Attorney General Kamala Harris, who makes the appointments on a rotating basis with the California governor and chair of the CEC. The commission also ratified the reappointment of long-serving incumbent member Dr. Robert Budnitz to the committee.

The Independent Safety Committee was established by the CPUC almost three decades ago to monitor and review the safety of PG&E’s operation of Diablo Canyon. The committee publishes an annual report each year covering committee activities and its review of operations for the previous fiscal year.

Dr. Peck was an NRC senior resident inspector for 12 years, spending five of those years as senior resident inspector at Diablo Canyon. Peck raised concerns about nuclear safety issues at Diablo within the NRC, using the agency’s non-concurrence and differing professional opinion processes, which provide ways for employees to raise issues or make recommendations that are different from those issued by the agency.

Peck was concerned that the agency was not following its own inspection practices related to how it enforces design-basis requirements at reactors, according to an account he penned about the situation in The Sacramento Bee in September 2014. Peck’s differing professional opinion, or DPO, as it is called, “asserted that PG&E continues to operate the Diablo Canyon reactors outside the bounds of the facility design basis as defined by the NRC Operating License,” Peck wrote. “Any operation outside of the design basis challenges plant safety due to erosion of regulatory margins.”

The CPUC invited members of the public to comment on the candidates, and received comments supporting and opposing each candidate; several PG&E employees at Diablo Canyon wrote the CPUC opposing Peck’s appointment.

In addition to his years as senior resident inspector, Peck was a senior U.S. Department of Energy facility representative, working on-site at the Hanford nuclear site in Washington and at Pacific Northwest National Laboratory. He also provided power-reactor operational and engineering support over a 6.5-year period, and has led research teams at the Nuclear Science and Engineering Institute.

Captain Carns is a former president, CEO and chairman of the Wolf Creek Nuclear Operating Co. who served at a number of plants and nuclear organizations.

Judge Karlin is a nuclear, energy and environmental attorney and consultant, as well as a former administrative judge with the NRC’s Atomic Safety and Licensing Board. From 2010 to 2014, Karlin was chair of the three-judge licensing board committee handling Diablo Canyon’s relicensing application. In his capacity as licensing board chair, Karlin also helped oversee cases including an amendment to the San Onofre Nuclear Generating Station license, the proposed high-level radioactive waste repository at Yucca Mountain, a license-renewal application for the Vermont Yankee nuclear plant, construction of a new nuclear plant in Levy County, Fla., the licensing of a uranium mine in Wyoming, and the siting of a new nuclear plant in North Anna, Va.

Committee members will serve three-year terms, starting July 1. –M. S.
It was over almost before it began. The CEC’s June 28 environmental scoping meeting and informational hearing on Calpine Corp.’s Mission Rock Energy Center dissolved in chaos at a Boys and Girls Club in Santa Paula, in Ventura County, as more than 100 disgruntled attendees staged a spontaneous walkout over what they called an inadequate translation, truncating the event.

The meeting, which followed a field trip to the nearby site of the proposed 255 MW natural gas-fired power plant, was only minutes underway when several attendees began to complain about the accuracy of the event’s Spanish interpreter.

Susan Cochran, the CEC hearing officer for the Mission Rock proceeding, halted her opening presentation to discuss the matter with Commissioner Karen Douglas, the presiding member in the proceeding, and other CEC staff. Former Santa Paula Mayor Gabino Aguirre then seized the microphone, blasting meeting organizers for being in “culture shock” and unprepared to communicate in Spanish.

The self-proclaimed “Citrus Capital of the World,” Santa Paula is an agricultural community in the Santa Clara River Valley whose population of around 30,000 is largely Latino.

“We are walking out,” Aguirre announced. Most of the attendees followed his “Vámonos” call.

Commissioners then informed those who remained that the planned presentations from Calpine and staff would be rescheduled with another interpreter. They still allowed public comment. But those who spoke did so only to oppose the plant and express outrage over the CEC meeting, which one attendee called “completely disrespectful” and another called “a travesty.”

“More than half of the people are outside rallying now. We are really offended,” Santa Paula Mayor Martin Hernandez said. “This hole is getting deeper and deeper for the applicant.”

In an emailed statement, the CEC apologized “for the lack of adequate translation services,” and said it “strongly encourages and welcomes public participation” in its programs and proceedings.

“As we explained that night, we are committed to an open process,” the statement continued. The commission plans to schedule another hearing soon in Santa Paula, and said it will work with community leaders to secure a better venue and ensure that there are effective translation services.

In an issues-identification report released on June 21, CEC staff noted six potential major issues with the proposed plant. These included the visual impact of the facility in an agricultural greenbelt, and impacts on biological and cultural resources and soils.

“Staff is concerned that building in a floodplain can be complicated, if not risky,” according to the report.

Mission Rock Energy Center LLC, a project-development subsidiary of Calpine, filed its application for certification in December. The simple-cycle power plant includes five turbine generators and would connect to Southern California Edison’s existing Santa Clara Substation via a 6.6-mile-long, 230 kV overhead transmission line. It also would feature 20 lithium-ion battery units, providing an additional 25 MW of storage capacity for up to four hours.

A proposed schedule for the analysis calls for a preliminary staff assessment to be completed in November and a final staff assessment to be released in January.

Santa Paula is about 20 miles inland from Oxnard, a larger Latino agricultural community where local opposition to NRG Energy’s proposed 262 MW Puente Power Project reached a crescendo in June when the Oxnard City Council imposed a ban on large-scale power generation on the coast.

Oxnard’s prohibition takes effect on July 7. Under state law, however, the CEC is the only licensing authority for thermal power plants of 50 MW or more. The commission, which has authority to make override findings of local laws and regulations, on June 17 released a PSA of the gas-fired Puente plant that recommends a license.

NRG Oxnard Energy Center LLC, a wholly owned subsidiary of the New Jersey-based power-generation giant, filed its application for certification in April 2015. The project would replace two 1950s-era once-through-cooling gas-fired generators, totaling about 430 MW of generating capacity, at NRG’s existing Mandalay Generating Station. A third 170 MW unit at the existing facility, built in 1970, will continue to operate.

The favorable staff assessment calls for a series of license conditions aimed at mitigating significant impacts to the environment, public health, and the transmission system.

The report came after the Oxnard City Council on June 7 voted 5-0 to approve an amendment to the city’s general plan that bans power-generation facilities greater than 50 MW in areas prone to coastal hazards, which includes the Puente site.

CEC staff will address any inconsistencies related to the prohibition in its final assessment, according to the PSA. Two days of workshops on the preliminary assessment in Oxnard are scheduled for July 21-22. The CEC said it would accept comments on the PSA until Aug. 4, after which staff will prepare a final assessment prior to evidentiary hearings and the commission’s proposed decision.

Attorneys for the city, however, called for an extension of the public review period on the PSA to Sept. 19, noting that the 1,200-page document “is not translated into Spanish,” and saying additional time was needed for review of the “complex environmental documents.”
SSJID to Move Ahead With Eminent-Domain Takeover of PG&E System  
(from [2])

The South San Joaquin Irrigation District has a green light to pursue a hostile takeover of Pacific Gas & Electric’s distribution assets through eminent domain. If the district is successful, it would be the largest eminent-domain overthrow of a utility in California in decades.

After listening to nearly five hours of testimony from district staff, consultants, PG&E, and members of the public, the SSJID Board of Directors on June 29 voted 5-0 to adopt a resolution of necessity in support of the takeover bid. The board directed SSJID attorneys to file an eminent-domain lawsuit to acquire PG&E’s distribution assets located within the district’s service territory.

“The board is keenly aware of the seriousness associated with exercising the right to provide retail electric service and does not take the condemnation actions lightly,” SSJID noted in a statement.

Securing ownership of the distribution assets is a make-or-break component of the district’s plan to supplant PG&E as the electric service provider for about 40,000 customers in Escalon, Manteca, Ripon, and adjacent unincorporated areas of San Joaquin County.

SSJID was established in 1909 to provide irrigation water service.

In May, SSJID offered to purchase PG&E’s distribution system for about $116 million. That price was based on an appraisal completed for the district by Nancy Heller Hughes of NewGen Strategies & Solutions. PG&E rejected the offer, noting it “looks forward to many more years as the area’s service provider” (see CEM No. 1589 [17]).

The takeover plan focuses on the entirety of PG&E’s assets in SSJID’s 112-square-mile service territory. The appraisal includes two substations, underground and overhead feeders, transformers, low-voltage circuits, utility poles and associated land, easements, and severance costs.

The provision of electric service is contingent upon being able to do so at rates 15 percent below PG&E’s, and on water customers not being adversely impacted.

PG&E asserted in a statement that SSJID based its takeover plans “on unrealistic financial projections that we believe would ultimately result in increased electric rates and risks to customers.”

The district “has significantly undervalued PG&E’s electric transmission and distribution assets and not adequately considered severance costs,” the company said.

SSJID’s eminent-domain authority is found within the California Water Code, according to a report by district staff.

Any district, the code notes, “may purchase or lease electric power from any agency or entity, public or private, and may provide for the acquisition, operation, leasing, and control of plants for the generation, transmission, distribution, sale, and lease of electric power, including sale to municipalities, public utility districts, or persons.”

Under the state’s Code of Civil Procedures, the district must make findings of public necessity to justify an eminent-domain takeover, including that its electric service plan would provide “a more necessary public use” of the infrastructure, staff said.

“SSJID’s project is a more necessary public use than PG&E’s existing use because of the significant benefits that SSJID’s ownership and operation of the distribution system will provide customers,” staff said. “These are public benefits that PG&E cannot provide.”

While SSJID is a public agency, “PG&E is a subsidiary of PG&E Corporation, owned by its shareholders, or investors, and managed as a private enterprise,” the staff report notes. “SSJID’s project will enable its customers to participate in the decision making process for service and the setting of rates.”

The district also asserts there will be economic benefits if the takeover succeeds. “Customer savings on electricity rates will result in increased consumer spending in the region positively impacting local jobs, incomes, and business activity,” the staff report notes.

PG&E disagrees with the district’s position that it is best suited to provide electric service in the territory.

“Entering into the retail electric business is no small undertaking and SSJID has no experience in providing retail electric distribution service,” PG&E said. “We don’t believe that our customers would want us to simply stand back and allow an inexperienced entity to take responsibility for ensuring safe, reliable, clean and affordable power in this area through an eminent domain takeover.”

SSJID won a major victory in March when a San Joaquin County Superior Court judge dismissed a lawsuit filed by PG&E that attempted to invalidate the approval of the district’s electric service plan by the San Joaquin Local Agency Formation Commission in December 2014 (see CEM No. 1377 [13]).

PG&E subsequently attempted to appeal the decision by seeking a writ of mandate from the 3rd District Court of Appeal. The petition was denied.

The company “will continue to oppose the taking of its property as SSJID moves forward with its hostile takeover plans.”

The district anticipates the eminent-domain process will take a minimum of three years. Proceeds from the sale of hydropower from the Tri-Dam Project, jointly owned with Oakdale Irrigation District, will be used to support costs of the legal process.

—Leora Broydo Vestel
Silicon Valley Clean Energy Drafts CCA Implementation Plan

Silicon Valley Clean Energy is putting the finishing touches on a plan to launch a community choice aggregation program that will provide electric generation service to customers in 11 cities and unincorporated areas in Santa Clara County.

If all goes well, SVCE will initiate generation service in April 2017, according to a draft implementation plan released June 27. Incumbent utility Pacific Gas & Electric will continue to transmit and distribute electricity to CCA customers, and provide billing and metering services.

The program will be rolled out in phases. SVCE expects to serve about 57,000 accounts in the first phase, representing nearly 1,100 GWh in annual energy sales, the plan notes. In 2018, at full enrollment, SVCE expects to serve about 211,000 accounts, totaling about 3,438 GWh in retail sales.

Initial energy supplies for the program will be procured through one or more contracts “with experienced, financially stable energy suppliers,” the plan notes.

SVCE customers will have two energy-supply options to choose from: a default mix with renewable content that exceeds the amount required under the state’s renewables portfolio standard; and a voluntary 100 percent renewable option available at a premium.

As the SVCE program moves forward, incremental renewable energy supply additions will be made based on resource availability as well as economic goals,” the plan notes. Future supplies may come from “direct investment in new renewable generating resources, partnerships with experienced public power developers/operators and purchases from third party suppliers.”

The goal of the program is to offer rates that are competitive with, and preferably below, PG&E’s rates, as this “will be critical to attracting and retaining key customers,” according to the plan.

As for financing, SVCE estimates it will require $22.73 million to cover costs for staffing and contractors, deposits and reserves, and working capital, to be recovered through generation rates in the first few years of operation. Participating jurisdictions have covered about $2.9 million in capital needs.

The City of Mountain View, on behalf of the Silicon Valley Clean Energy Authority, recently issued a request for proposals seeking a credit facility of up to $20 million from a financial institution.

The SVCEA Board of Directors will consider the implementation plan at a July 13 meeting. The plan also requires certification by the CPUC.

[17] Gas Reform and Climate Bills Advance Ahead of Summer Break (from [3])

Before adjourning for a month-long summer recess, California lawmakers advanced a host of climate and energy bills critical to the state’s overarching effort to drastically decarbonize its energy systems. But slashing short-lived methane emissions stole the show in Sacramento ahead of a July 1 deadline for bills to pass policy committees.

In a session largely defined by the Legislature’s reaction to one of the worst natural gas leaks in U.S. history—at Southern California Gas Co.’s Aliso Canyon storage facility—more than a dozen bills focused on reducing methane emissions or tightening regulation of California’s natural gas infrastructure remained in play.

Sen. Fran Pavley (D-Agoura Hills)—whose legislative district includes Aliso Canyon—is approaching the problem from a long-term policy perspective and delving into the devilish regulatory details.

Her SB 887 belongs to the latter category. The measure, which the Senate approved on June 1 and the Assembly Natural Resources Committee passed on June 27, updates safety standards for all 14 natural gas storage facilities in California by establishing new minimum standards for the operation, inspection, and monitoring of some 400 gas wells regulated by the Department of Conservation’s Division of Oil, Gas & Geothermal Resources.

Passage in the Assembly committee came with several key amendments aimed at addressing concerns expressed by independent gas storage-facility operators and industry groups opposed to the bill. As amended on June 30, SB 887’s requirements distinguish between “low-risk natural gas storage wells” and all others. Such “low-risk” wells are defined as newer facilities in non-urban areas with a demonstrated track record of regulatory compliance and mechanical integrity.

All wells, except those defined as low-risk, must include subsurface safety valves and must conduct injection and production through well tubing only by July 1, 2018. Low-risk wells have an extra year to comply.

Many wells in the state currently rely on the area outside of the inner tubing, called the annulus, which is being probed as a possible contributing factor in the Aliso Canyon leak. Operators of independent gas-storage facilities, however, have argued that they designed their facilities—which are newer than the ones operated by large investor-owned utilities—to use that area.

While independent facility operators noted Pavley’s efforts to work with them, they remained opposed to the bill. The amendments neutralized opposition from other industry groups, however, including the California Natural Gas Producers Association.

Some industry groups voiced outright support.

“We support the bill. We think the precautionary approach is the right approach,” said Barry Broad, representing the Utility Workers Union of America. He cautioned, however, that there remained disagreement over “where and when to use valves” because many have proven ineffective. “I hope you will take that under advisement,” he added.

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The head of DOGGR, for instance, testified that such safety valves have a failure rate of 35 percent (see CEM No. 1383 [12]). Amid the amendments to which Sen. Pavley has agreed, and the calls for additional concessions, some supporters expressed concerns. Matt Pakucko, a resident of Porter Ranch, the community north of Los Angeles most immediately affected by the Aliso Canyon leak, asked lawmakers to “make sure they do not gut the intent of the bill.”

The bill is on track for an August vote in the Assembly floor that could send the bill to Gov. Jerry Brown.

Another key methane measure approved by policy committees before the July 1 deadline was AB 2756, from Assm. Tony Thurmond (D-Richmond). It boosts fines for violations of state oil and gas well regulations (see CEM No. 1586 [12]).

SB 1441, from Sen. Mark Leno (D-San Francisco), seeks to reduce methane emissions 40 percent below 2012 levels by 2025 by prohibiting utilities from charging ratepayers for their lost, “fugitive” gas.

Emissions-Reduction Targets

On the longer-term policy front, Sen. Pavley’s SB 32, which the Assembly Natural Resources Committee passed on June 27, would extend the state’s greenhouse-gas emissions-reduction goal to 40 percent below 1990 levels by 2050—codifying language from Gov. Brown’s 2015 executive order setting the same goal.

Both build on an existing 2020 target created by AB 32, the state’s landmark Global Warming Solutions Act of 2006, to slash emissions of carbon dioxide, methane, hydrofluorocarbons, soot and other climate pollutants.

Since passing the Senate last year, Pavley’s bill has been amended to delete a separate 2050 target—also in line with Gov. Brown’s executive order—to reach an 80 percent reduction in GHG emissions after industry groups opposed the provision.

Speaking in the Assembly committee, Pavley addressed the importance of extending targets at least beyond 2020 to provide certainty for investors. The lack of such certainty, she suggested, played a role in the recent poor performance of CARB’s cap-and-trade auction in May.

Market participants, she said, “want a clear signal” and “are waiting to see what [the] Legislature will do.”

As amended on June 30, SB 32 only becomes law if AB 197 from Assm. Eduardo Garcia (D-Coachella) also is enacted. The co-joined bill, which passed the Senate Environmental Quality Committee on June 29, contains equity and transparency provisions severed from SB 32.

The measure directs CARB to adopt measures to help achieve the GHG-reduction targets and creates a joint legislative committee “to ascertain facts and make recommendations to Legislature” about the state’s climate-change policies and programs.

King Coal Dethroned

Two bills from Sen. Loni Hancock (D-Berkeley) targeting coal export in California also moved toward Assembly floor votes on lawmakers’ concerns that burning coal—whether in California or China—poses risks to the state’s climate policies.

SB 1277 requires a supplemental environmental report for a bulk shipping facility under construction near the Port of Oakland that aims to become the largest coal-export terminal on the West Coast, while SB 1279 bans state transportation funding for any new coal-export project located near a disadvantaged community.

Both measures passed the Senate in early June (see CEM No. 1388 [11.2]).

Sen. Hancock, speaking in the Assembly Transportation Committee on June 27, cited the state’s consistent legislative and regulatory efforts “to phase out our use of coal energy.” SB 1279 was necessary, she said, because “the people of California deserve to be assured that their taxes will not contribute to the transport and export of a fossil fuel.”

Amendments on June 20 clarified that the funding prohibition applies only to new export terminals and not to upgrades at existing ones. —Garrett Hering

[171] Brown Inks Budget Bill, but Energy Trailer Sidetracked

With little time left on the legislative clock, Gov. Jerry Brown on June 27 inked a suite of bills securing the bulk of the state’s record $171 billion budget for the 2016-2017 fiscal year, which kicked off July 1. But lawmakers left some important budget business on energy and environmental programs until they return from summer recess in August.

The state’s enacted budget for the Natural Resource and Environmental Protection agencies—which together house many of the state’s main energy and environmental boards and commissions—totaled approximately $8.5 billion. That was almost 10 percent less in state funds approved for the two agencies in last year’s budget.

Including federal funds, however, the combined agency budgets for the new fiscal year were only 5 percent below last year’s levels. The Resource Agency’s budget for this year totals $9.2 billion, compared to $8.8 billion in the last fiscal year, while CalEPA’s budget dropped to $3.7 billion from $4.8 billion.

In response to the massive methane leak at Southern California Gas Co.’s Aliso Canyon storage facility, the budget included nearly $14 million in spending increases for a variety of existing programs and departments. This included an additional $4.2 million for the Department of Conservation, which regulates underground gas storage facilities through its Division of Oil, Gas and Geothermal Resources.

The CEC’s 2016-2017 budget of nearly $460 million also included a modest Aliso Canyon-related funding boost—$1.7 million—to monitor and analyze the role of gas in electric-system reliability. The CPUC also received an extra $1.5 million for natural gas storage regulation in its $1.68 billion budget.

Proposed budgets for several programs, however, were delayed in trailer bills that failed to reach the governor’s desk before lawmakers left for summer break. Among them was AB 1612.
The energy trailer bill would make funds available for the New Solar Homes Partnership Program, should the CPUC order a continuation of it. It would also double annual funds for the CPUC’s Self-Generation Incentive Program to $160 million, to boost investment in energy storage.

When the Senate Budget and Fiscal Review Committee heard the bill on June 27, however, committee members on both sides of the aisle blasted the fact that the SGIP funding boost and an additional item expanding net metering of fuel cells were added at the last minute and had not been vetted by policy committees.

“Frankly, this is government as its very worst,” said Sen. Jim Nielsen (R-Gerber). “It is an embarrassment. Good policy it is not,” he added.

Sen. Mark Leno (D-San Francisco), who chairs the committee, also expressed “disappointment” over the sudden appearance of the items that “could have been in the January budget, the May revision or dropped into conference.”

The committee declined to vote on the trailer until after the recess.

Budgetary uncertainty also surrounds programs funded by auction revenues from CARB’s cap-and-trade program, which came under fire from the Legislative Analyst’s Office and lawmakers during the session (see CEM No. 1382 [13]). Demand for carbon allowances also crashed in CARB’s May auction (see CEM No. 1387 [8]). Thus, cap-and-trade spending was only partially reflected in the budget.

“The administration will work with the Legislature to appropriate additional cap and trade funding later in the legislative session,” according to a budget summary.

[17.2] California Coastal Commission Reform Bills Advance

A Senate bill seeking to ban ex parte communications—private, off-the-record exchanges—with commissioners at the California Coastal Commission passed the Assembly Natural Resources Committee June 27 on a 6-3 vote.

Sen. Hannah-Beth Jackson (D-Santa Barbara) introduced SB 1190 in February in response to the controversial, closed-door firing of the commission’s executive director, Charles Lester, amid allegations he influenced a staff report based on such communications with an applicant.

Lester is not the only member of the commission alleged to have engaged in improper private exchanges with applicants, however. Another member of the commission—Mark Vargas, who voted against Lester’s firing—visited U2 guitarist David “The Edge” Evans in Ireland last year shortly before the commission approved construction of his Malibu mansion.

Among its functions, the Coastal Commission participates in licensing proceedings at the CEC involving thermal electric power plants proposed on the coast. Every two years, the Coastal Commission also updates maps of areas of the California coast not suitable for new electric power plants.

“This bill will restore confidence by codifying the independence of the commission,” Sen. Jackson told committee members. “SB 1190 only gets the Coastal Commission to the same place the PUC has been prior to any of the reforms that were just signaled by the governor,” she added (see story at [12]).

A related bill from Asm. Mark Stone (D-Scotts Valley) would place the same requirements used to determine whether a person must register as a lobbyist before the Legislature on persons communicating with the Coastal Commission. AB 2002 passed the Senate Natural Resources and Water Committee on a 6-2 vote on June 28 and was referred to the Senate Appropriations Committee. It passed the Assembly floor in a 54-23 vote on June 2.

[18] Market Monitor Proposes Ending Auctions for Congestion Revenue Rights (from [5])

CAISO’s Department of Market Monitoring has proposed abolishing an auction that reaps about $100 million a year for power marketers, and would instead give the money directly to load-serving entities.

“We would like consideration of eliminating the [congestion revenue rights] auction and letting the ratepayers keep the congestion rents,” said Eric Hildebrandt, director of Market Monitoring, during a presentation of his annual report to the CAISO Board of Governors.

The CAISO board approved other changes to rules regarding congestion revenue rights (CRRs)—financial instruments used to offset market congestion costs in the day-ahead market—at the same June 28 meeting.

Congestion fees are intended—along with transmission access charges—to help load-serving entities meet their projected need.

But now the DMM finds that ratepayers are receiving far less revenue from the auction of these CRRs than the congestion revenues that accrue for those auctioned CRRs. The most drastic example was in 2014, when auction payments received by ratepayers were about $125 million, and the payments to auctioned CRR holders (many of them marketers) were almost $350 million.

Overall congestion-revenue-rights auction revenues between 2012 and 2015 averaged less than 50 percent of congestion payments, the DMM’s analysis found.
“The point here, if we look deeper, is that there seems to be limited use of CRRs for hedging,” said Hildebrandt. “Primarily the difference in the congestion and auction revenues is due to financial participants,” who play the market by making virtual bids in the day-ahead market and trading CRRs.

Hildebrandt noted that his group would further examine whether this gap between auction revenue to ratepayers and payments to CRRs was a nationwide trend, or a phenomenon of the CAISO market. “The auction is part of the FERC standard market design,” he said. “The theory was that if you have a competitive market then the price would in the long run approximately equal the auction costs. But it just hasn’t happened.”

Governors were incredulous at the “substantial amount of money” involved. “That is good work if you can get it,” one said. “It is really troubling.”

They suggested other alternatives, for instance having a floor on bids before a CRR may be entertained.

Mark Smith, a vice president at Calpine Corp., offered the idea of modifying auctions so that one side of the CRR must be linked to physical ownership. He said Calpine relies on its ability to hedge the price of energy.

New Changes to CRR Rules
The board also agreed to make some less controversial changes related to rules put in place in 2010 to prevent using so-called convergence or “virtual” bidding to artificially inflate CRR payments in the day-ahead markets.

Virtual bids are financial positions taken in the day-ahead market and liquidated in the real-time market. These bids sometimes alter congestion in the day-ahead markets and impact payments for a CRR.

To prevent gaming of this system, CAISO six years ago established a settlement rule. If modeled electrical flow caused by a virtual bid exceeded 10 percent of the transmission capacity of an internal path or intertie, then the bid was deemed complicit and the ISO’s settlement process rescinded the obtained CRR payment. Imports and exports reduced in the real-time market were also considered virtual awards and subject to this settlement rule. However, certain virtual bids (cleared at default load-aggregation points and trading hubs) were exempt.

Now CAISO governors agree that certain import and export reductions should not be subject to the CRR settlement for fear that this would limit the number of economical bids that participants are willing to submit to the real-time market. The new rules are an attempt to discern between true economic bids and the complicit bids.

EIM Marches On With New Governing Body
CAISO’s board also approved a new five-member governing body to provide delegated authority over rules for its young energy imbalance market.


EIM balances supply and demand for electricity every 15 minutes and dispatches the least-cost resource every five minutes. The market has generated $64.6 million in benefits since its inception, with PacifiCorp being the largest contributor.

A nominating committee worked closely with an executive search firm to select the slate of candidates. Members were appointed to serve staggered terms starting July 1, and their specific term assignments were selected by random drawing. They are as follows:

- Kristine Schmidt, who holds master’s degrees in public policy and international business, will serve a one-year term through 2017. President of Swan Consulting service, she was vice president of grid development at ITC Holdings.
- Doug Howe, a mathematician with three decades of experience in global utilities, will serve a two-year term through 2018. He was a state utility regulator in New Mexico, a utility executive, and a consultant.
- Carl Linvill, an economist, will serve a two-year term through 2018. He is a principal at the Regulatory Assistance Project in Montpelier, Vt., and previously served as a senior economist and a commissioner at the Public Utilities Commission of Nevada.
- Valerie Fong, a civil engineer with a power-industry career spanning 20 years, will serve a three-year term through 2019. She worked at Pacific Gas & Electric, was general manager of Alameda Power & Telecom, and recently retired as director of utilities at the City of Palo Alto.
- John Prescott, an electrical engineer with extensive experience in the technical workings of the grid, will serve a three-year term through 2019. He was for a decade the CEO of the Pacific Northwest Generating Cooperative.

Members will earn a $20,000 annual retainer, and will receive $750 for each day of participation at a noticed in-person meeting, and $500 for noticed teleconferences.

Regional Market Update
The board received updates on a goal under SB 350 to transform CAISO into a regional organization, as well as on PacifiCorp’s interest in becoming a participating transmission owner.

PacifiCorp and CAISO this month extended through the end of the year their memorandum of understanding to work on a transition agreement including discussion of transmission planning, generation interconnection, and CRRs.
But PacifiCorp may not join before the end of 2019, said Philip Pettingill, director of regional integration for CAISO.

The ISO is currently working on three policy initiatives that would be important to regional integration. These include making changes to the transmission access charge; regional resource-adequacy rules to ensure all parties bring sufficient resources to the system; and metering-enhancement rules that take advantage of new technologies to improve system flexibility.

Later this year, CAISO will look at a new stakeholder initiative to discuss how to handle greenhouse-gas allowances in a regional market.

CAISO’s regional integration effort is targeting July 8 as the publication date for a final report on a structure for the Western grid. [M. A. Hogarth Fogel]

[19] **FERC PURPA Conference Reviews**

**Must-Purchase, Avoided-Cost Issues**

The Federal Energy Regulatory Commission’s June 29 technical conference on implementation of the Public Utility Regulatory Policy Act featured two 10-member panels and the expected range of opinions on several controversial—but key—elements of the statute: the utility obligation to purchase power from small renewable qualifying facilities, and how best to set avoided costs included in the rates paid to those projects.

Without PURPA’s mandatory purchase obligation, “we would not have an independent power industry,” said Jerry Bloom of the California Cogeneration Council—a view echoed by other panel members—or the competitive markets that exist in many parts of the country.

And regardless of criticisms of the obligation that have been voiced in comments filed in a FERC proceeding, “No one has identified cogeneration as the problem,” he said, and “no one can be taking a position or should be taking a position that all of the QFs are similarly situated.”

**Combined heat and power** (CHP), especially, faces a different set of issues, Bloom added. “The commission is already aware that CHP as a distributed generation resource makes a significant contribution to reliability and emissions reduction … and is universally seen as a key component of our nation’s energy future.”

Over time, the implementation of PURPA “seems to have morphed into a tool for QFs” to sell their output to utilities without regard to actual needs, said Duke Energy’s Kendall Brown. Implementation “should return to its founding principles of energy conservation, just rates for customers and improving, not impairing, system reliability.” Contracts should be based on utility needs, not unconditional purchases, Brown said.

PURPA enabled competition, said Robert Kahn, executive director of the Northwest and Intermountain Power Producers Coalition (NIPPC). That’s why “investor-owned utilities have opposed it as long and vigorously as they have and [are] doing so today.”

Kahn also said the claim that the emerging Western energy imbalance market “somehow makes PURPA irrelevant is just nonsense.”

The thought that anyone would ever be drowning in PURPA power was the furthest thing from anyone’s mind when PURPA was developed, noted Commissioner Cheryl LaFleur.

“So for those of you who have spoken, and quite compellingly, about the need to continue PURPA as it has been, I’m interested in theoretically whether there’s ever such a thing as too much,” she told the panel.

**The issue isn’t how much** QF power, but how it’s managed, said California Cogen Council’s Bloom: “I think we have all the tools in place to manage this, and then we don’t have to decide who’s in and who’s out.”

When there are “true wholesale markets” for long-term power purchases that make projects financially viable, utilities can get a waiver from the obligation to purchase, the Natural Resources Defense Council’s Allison Clements pointed out.

If power from PURPA projects is cheaper for ratepayers, “I’m not sure what the problem is,” NIPPC’s Kahn said. “Historically we’ve looked at it as a function of marginal costs, but on more than a few occasions, utilities will define avoiding a cost as the operating cost of the system.

“The truth of the matter is if we can beat them, we should be beating them, because it’s in ratepayer interests.”

The afternoon session focused on an increasingly problematic element of PURPA: how best to set a utility’s avoided cost, which is a key component of the rates charged to small QFs.

NorthWestern Energy’s Al Brogan, representing the Edison Electric Institute, got right to the point, noting that EEI has proposed specific changes to existing avoided-cost rules. “Determining the appropriate avoided cost has become increasingly controversial,” he told commissioners. “FERC identifies factors that should be considered, but various methods that states routinely use fail to reflect these factors. That forces utilities to enter long-term contracts at fixed prices, substantially above the market.”

Brogan recommended FERC allow states to consider the cost of transmission-system upgrades and network integration services in setting the rates paid in QF contracts.

Setting avoided costs is all about limiting costs and protecting ratepayers, said Todd Foley, senior VP of policy and government relations for the American Council on Renewable Energy. Methodologies need to be updated to capture the full value of new technologies and processes, including demand response, storage and automated metering infrastructure, that “enable a more flexible, modern and cleaner grid.”
States play the primary role in calculating avoided-cost rates, said National Association of Regulatory Utility Commissioners President Travis Kavulla—who pointed out that he is also a member of the CAISO energy imbalance market transitional committee. “So if it’s done poorly, it is our fault—and vice versa. Accurate calculation is a very hard thing to do, which is why flexibility is an essential element in the regulations.”

FERC has deferred avoided costs to the states, said FERC Chairman Norman Bay. “So to the extent there’s a problem with calculating avoided costs, is that a problem for us or is it really a problem we should defer to states to resolve? It’s one of the big questions I’m trying to grapple with.”

While FERC should always have an important backstop role, allowing states to set avoided costs is a reasonable approach, said Don Sipe of the American Forest and Paper Association. “Variability is good in how to do that, but be open to claims where there are avoided-cost calculations or other methods that clearly defeat the idea of encouraging QF development,” he said. “That’s sort of where the line is. It’s a judgment call.”

States clearly need guidance on methodologies, said John Hughes of the Electricity Consumers Resource Council. He pointed out that utility-built projects can also be grossly overpriced, with ratepayers bearing those costs. “It seems somewhat disingenuous that ratepayers shouldn’t have the risks of long-term deals regarding QFs, but bear all the risks of long-term obligations that utilities make, including for some very high-cost generating assets. You can’t do one one way and the other another way, and say ratepayers benefit.”

The power grid has undergone tremendous changes since PURPA’s enactment, and “we have more robust energy markets now,” said Commissioner Collette Honorable. “We’re at a place where we’re attempting to wed or coordinate what’s happening today with the original intent of Congress.” FERC needs to determine what “it should or can do to aid in successful implementation of PURPA.”

FERC “will caucus as to how to proceed as an agency,” FERC associate general counsel Lawrence Greenfield said in closing the conference. “Lots of issues have been raised, and we want to think about what we want to do next.”

[19.1] FERC OKs Suspension of Klamath Relicense

FERC agreed this month to suspend the relicensing proceeding for PacifiCorp’s 169 MW Klamath River hydroelectric project, pending submission of applications for transfer and surrender of the license pursuant to the revised Klamath Hydroelectric Settlement Agreement (KHSA).

“The order is welcomed and will allow PacificCorp and the other settlement parties to concentrate fully on implementing” the revised KHSA, said Bob Gravely, spokesman for PacifiCorp.

The original license expired in 2006; PacifiCorp filed to relicense the project in 2004. FERC issued a final environmental impact statement in 2007 calling for millions of dollars in upgrades to protect anadromous fish runs.

In 2010, a group of 47 federal, state, local, tribal and resource-group entities reached a pair of settlements to remove the project. But the settlements required passage of federal legislation which ultimately failed to materialize, triggering a dispute-resolution proceeding under the settlement that led to a revised deal signed April 6 of this year.

In May, PacifiCorp asked FERC to hold the relicensing in abeyance lest parties be forced to proceed simultaneously on two contradictory fronts—relicense and removal. It sought expedited treatment with the promise that PacifiCorp and the four-month-old Klamath River Renewal Corporation (KRRC) would file applications to transfer the license to an entity called Renewal Corp., which would simultaneously file to surrender the license.

Those papers were due to be filed “on or around” July 1. But PacifiCorp’s Gravely said that since KRRC is still getting up and running, the papers are more likely to be filed in mid-August. [Ben Tansey]

[20] SolarCity Rooftop-Solar Referendum Depends on Nevada Supreme Court
(from [7])

The odds are good that Nevada voters will get to vote on whether to allow retail power competition for all electric-utility customers in the state. But it’s still unclear whether voters will have the chance in November to consider overturning a rate increase for net-energy metering customers, as before the NEM referendum can advance, the Nevada Supreme Court must rule on an appeal in a court case on the measure.

The net-energy metering referendum and the Energy Choice Initiative each collected more than twice the 55,000 signatures needed to get their issues on the November general election ballot in Nevada. The NEM referendum submitted 120,000 signatures from around the state, and Energy Choice filed 122,000 signatures by the June 21 deadline. The referendum and initiative must have 13,800 valid signatures from voters in each of four Nevada Congressional districts to qualify for the ballot.

County officials face a July 11 deadline to tell the Nevada Secretary of State whether random sampling indicates the signatures are valid on the open-access initiative and NEM referendum.

SolarCity, the backer of the net-energy metering referendum, and Las Vegas Sands, the main backer of the open-access initiative, apparently were motivated by their displeasure with regulatory decisions by the Public Utilities Commission of Nevada.

Las Vegas Sands, which is controlled by billionaire Sheldon Adelson, in May 2015 applied to the PUCN under Nevada Revised Statute 704B, which allows customers with 1 MW or more of load to exit Nevada Power or Sierra Pacific Power.
The commission imposed a $23.9 million exit fee on the Sands to compensate remaining customers of Nevada Power, a charge the Sands contends was too high. In addition, the commission said the casino operator must pay its share of non-bypassable charges for shutting down the 557 MW, coal-fired Reid Gardner Generating Station; the eventual retirement of Nevada Power’s interest in the coal-fired Navajo Generating Station; and must-take, above-market renewable-energy power-purchase agreements.

The Sands is now proposing a constitutional amendment to open the Nevada retail power market to competition by July 2023. The amendment also would allow electric utility customers to produce electricity for themselves or in association with others.

The initiative would require that "economic and regulatory burdens be minimized" to promote competition and apparently to prevent the commission from charging exit fees.

The Sands has contributed $685,000 and MGM Resorts gave $10,000 to Nevadans for Affordable, Clean Energy Choices, the political action committee supporting the Energy Choice Initiative.

Voters must approve the Energy Choice Initiative in November and again in the 2018 general election before the Nevada Constitution would be amended to require open access.

MGM International and Wynn Las Vegas had also filed with the PUCN last year for open access. But rather than fight the exit charges the commission imposed, MGM agreed to pay $86.9 million and Wynn Las Vegas agreed to pay $15.7 million, plus undetermined non-bypassable charges.

The No Solar Tax net-energy metering referendum would become effective if approved solely in the upcoming election.

SolarCity contributed $1.95 million to the net-energy metering referendum. On the other side, Citizens for Solar and Energy Fairness, a political action committee backed mostly by NV Energy subsidiary Nevada Power, collected $1.5 million to oppose the NEM referendum.

CSEF has also challenged the net-energy metering referendum in a lawsuit filed with the First Judicial District in Carson City. District Judge James Russell on April 7 ruled the net-energy metering referendum petition was invalid.

Russell concluded the petition should have been filed as an initiative, rather than a referendum. He said the petition sought to amend a statute by deleting some words, and that referendums can only be used to repeal an entire statute.

The No Solar Tax PAC appealed the district-court decision to the Nevada Supreme Court, citing Article 19, Section 1, which states that a referendum may deal with a statute "or any part thereof."

“No court in the nation (save the district court in this case) has ever held that a referendum is invalid because it results in 'amending' the statute,” No Solar Tax said in a June 23 brief.

The Nevada Power PAC, however, quoted a different legal interpretation in the Nevada Secretary of State’s Initiative and Referendum Guide for 2016, which says a referendum can only approve or disapprove a statute.

The Nevada Supreme Court will hear oral arguments on the No Solar Tax appeal on July 29.

The Nevada Secretary of State’s Office on June 28 reported that it needed a Supreme Court decision on the net-energy metering referendum by Aug. 15. Otherwise, county election officials may be forced to operate ballot-printing equipment around the clock, resulting in overtime, outsourcing, and temporary staffing expenses.

---John Edwards---

[20.1] Rocky Mountain Power Packaging Renewables for Large Customers

With the help of legislation enacted in March, Rocky Mountain Power is seeking regulatory approval to obtain renewable energy to run one or more proposed Facebook data centers in Utah.

Facebook also is considering data-center sites in unspecified other states.

The utility wants Facebook to become the first of many large businesses it hopes will take advantage of an economic-development provision in Utah Senate Bill 115, an omnibus energy measure dubbed the Sustainable Transportation and Energy Act.

SB 115 allows the Utah Public Service Commission to authorize the utility to acquire renewables for customers who have an aggregated annual peak load of 5 MW or more—if the arrangement is in the public interest.

The bill also enables Rocky Mountain Power to offer potential business customers flexibility in the timing of acquiring renewables and in creating a customized rate design.

Rocky Mountain Power on June 17 proposed a tariff to implement the SB 115 provision.

RMP on June 21 filed an application to use the tariff, laid out in Electric Service Schedule 34, for Facebook data centers in Utah, but terms of the proposed Facebook contract were redacted.

Under Rocky Mountain Power’s proposal, it would provide energy to Facebook from its own resources when renewables facilities dedicated to Facebook are ramping up and when the contracted renewables are insufficient to meet Facebook’s needs.

Facebook would pay Rocky Mountain Power the utility’s avoided-cost rate plus an incremental charge for the difference between the cost to supply renewables and the utility’s avoided cost. RMP also would charge an administrative fee.

If Facebook locates a data center in Utah, Rocky Mountain Power will purchase renewables from new projects, rather than existing renewables facilities.
Rocky Mountain Power would enter into power-purchase agreements with renewables projects on behalf of Facebook, but Facebook would bear all financial obligations for the PPAs. SB 115 also allows large customers to own their own renewable-energy plants or to contract for power from renewable-energy generators owned by Rocky Mountain Power.

RMP asked the commission to approve the Facebook renewables tariff by the end of August.

The potential Facebook deal underscores growing corporate interest in using renewables. According to The Rocky Mountain Institute, a nonprofit energy research organization based in Boulder, Colo., publicly announced corporate renewable-energy deals in the United States and Mexico totaled 3.23 GW in 2015, up from 1.18 GW in 2014. The deals included corporate power-purchase agreements, green tariffs, and corporate-owned renewable generation.

The Renewable Energy Buyers Alliance has set a goal of helping corporations buy 60 GW of additional renewables in the U.S. by 2025, according to RMP.

Many large power users require renewables for expansions of existing facilities and for new plants, according to Rocky Mountain Power. In addition, most large power users want the renewables to come from new projects, not existing facilities, according to RMP.

While regulated utilities are starting to implement renewable-energy tariff options for large power users, most retail customer renewables transactions have happened in open-access markets, according to Gary Hoogeveen, chief commercial officer at Rocky Mountain Power. –J. E.

[20.2] **Palo Verde Nuclear Chief Taking New Arizona Public Service Post**

Randy Edington, the executive vice president and chief nuclear officer credited with resolving regulatory and operational deficiencies at the Palo Verde Nuclear Generating Station nine years ago, is taking a new job at Arizona Public Service.

On Oct. 31, Bob Bement, senior vice president of site operations at Palo Verde, will take over as executive vice president of nuclear and will report to Edington, who will become executive vice president and adviser to APS Chief Executive Officer Don Brandt.

“When Randy arrived, Palo Verde faced difficult regulatory and operational challenges,” Brandt said in a June 28 announcement.

Edington hired a new team, including Bement, and “restored confidence and operational excellence,” Brandt said.

When Edington arrived in 2007, the U.S. Nuclear Regulatory Commission ranked Palo Verde in Column Four, the bottom category for performance reflecting multiple and repetitive “degraded cornerstones.” Palo Verde now is in Column One, the top category for performance.

The succession of top managers “reinforces the culture of performance and operational excellence” at Palo Verde, APS spokesman Alan Bunnell said.

The 4,000 MW Palo Verde plant is owned by Southern California Edison, the Southern California Public Power Authority, the Los Angeles Department of Water & Power, APS, the Salt River Project, PNM, and El Paso Electric. –J. E.

[20.3] **Pattern Energy Sells Wind Power From New Mexico to Edison**

Pattern Energy Group of San Francisco on June 30 said it signed two 20-year power-purchase agreements with Southern California Edison for the 324 MW Broadview wind project north of Clovis, N.M. Terms of the PPAs were not disclosed.

Construction is starting on Broadview with commercial operations expected by early 2017, according to Pattern Energy. The Broadview facility will have 141 Siemens 2.35 MW wind turbines.

Pattern Energy said it will acquire an 84 percent interest in the cash flow from Broadview and a 99 percent ownership interest in the associated 35-mile, 345 kV Western Interconnection line.

Pattern Energy will pay Pattern Development, an affiliated limited partnership, $269 million for the wind project and line interests. Institutional investors agreed to buy the remaining 16 percent cash-flow interest in Broadview, according to Pattern Energy. –J. E.
and manipulation in organized wholesale electricity markets.

Authorizing “private rights of action” over sales of products in markets run by independent system operators and regional transmission organizations “could create uncertainty” and impair market operations, the committee leaders said in a letter to CFTC Chairman Timothy Massad.

The letter was sent by Chairman Fred Upton (R-Mich.) and the ranking Democrat, New Jersey’s Frank Pallone. They said electricity product sales in organized markets are subject to extensive FERC oversight and enforcement.

A divided CFTC on May 10 proposed amending a 2015 commodities regulation exemption for electric-energy products. The 2015 order exempted from Commodity Exchange Act requirements financial transmission rights, forward capacity transactions, and reserve and regulation transactions sold in organized markets and subject to a FERC- or state-approved tariff or rate schedule.

The 2013 order included an exception allowing the CFTC to enforce general anti-fraud and anti-manipulation regulations.

Massad said at the time that private rights of action can “deter bad actors,” but Commissioner J. Christopher Giancarlo said the proposal would create “legal uncertainty.”

CAISO Sees Transmission Planning Mismatches

Differences among Western Interconnection transmission-planning regions on determining project benefits could result in “unfair cost allocation” among the four regions, a CAISO official told FERC’s transmission-development technical conference.

FERC held the June 27-28 conference to examine competitive development cost and rates issues associated with the Order No. 1000 transmission-planning process.

Gary DeShazo, CAISO’s coordination director, said the differing methods used by the ISO, WestConnect, Northern Tier Transmission Group, and ColumbiaGrid “could result in inconsistencies” in estimating benefits of interregional transmission projects.

He said, however, that it’s too soon to draw conclusions on whether the Order No. 1000 process has helped or impeded identification of needed interregional projects. DeShazo said CAISO is “optimistic” that planning will “facilitate interregional transmission project development.”

Court Delays Schedule on New Power Plants Suit

A federal appeals court on June 24 suspended the briefing schedule for litigation challenging the Environmental Protection Agency’s rule limiting CO2 emissions from new, modified and rebuilt natural gas- and coal-fired power plants.

The court acted at the request of states and utility groups challenging the rule, finalized in 2015. Petitioners said the delay would enable them to file consolidated challenges to the rule and to EPA’s April 29 denial of their request for reconsideration of the rule.

For new gas-fired plants, the rule limits CO2 emissions to 1,000 pounds per MWh. For new coal plants, the limit is 1,400 pounds/MWh, which EPA said is achievable by super-critical pulverized-coal facilities capturing about 20 percent of their emissions.

Obama: Wires Key to Clean-Energy Blueprint

President Barack Obama said developing transmission will be key to generating 50 percent of North America’s power from “clean energy” by 2025, a goal announced by Obama and his Canadian and Mexican counterparts June 29.

Obama, joined by Canadian Prime Minister Justin Trudeau and Mexican President Enrique Peña Nieto for the “Three Amigos” summit in Ottawa, said “there may be some wonderful hydroelectric power that we’d like to get to the United States. The question is, are there enough transmission facilities for us to be able to buy at a competitive price.”

EIA: Tax Credits, Efficiency Regs Lower Demand

Long-term extensions of tax credits for renewable energy and energy-efficient equipment, as well as continuing updates in efficiency standards, would reduce energy consumption 4 percent through 2040, compared to a business-as-usual scenario, the Energy Information Administration said in an analysis released June 28.

Energy-related CO2 emissions would fall 2.4 percent through 2040, EIA also projected.

Building energy consumption would fall below its 2015 level between 2022 and 2034, with on-site distributed generation increasing to 249,000 GWh by 2040, nearly double the business-as-usual projection, EIA estimated.

By 2040, building energy consumption would fall 5.4 percent below business as usual, or 1.1 quad, with tighter energy-efficiency standards and building codes, EIA said.

BuRec Hands Out Efficiency Grants

The Bureau of Reclamation on June 23 awarded 53 energy- and water-efficiency grants totaling $25.6 million to Western water districts and agencies.

The Coachella Valley Water District and the Kern County Water Agency were among the California recipients of funds for reducing irrigation pumping loads.

Ostendorff Leaves NRC

William Ostendorff departed the Nuclear Regulatory Commission at the end of his term June 30, leaving the commission with three members, just enough for a quorum.

Ostendorff had served on the commission since 2010.

NRC Names New Regional Chief

NRC has named Kriss Kennedy, a 28-year agency veteran, as the new administrator of the Western region, the commission announced June 27.

Kennedy will oversee inspection and safety at 13 operating commercial nuclear power plants, including Columbia Generating Station in Washington, Diablo Canyon in California, and Palo Verde in Arizona.
CPUC Urged to Tear Up SONGS Settlement. Jump to [5].

Report: California Reaps Benefits From Doubling Renewables. Jump to [6].

**Southwest:** Utah Officials Want Right to Keep PacifiCorp Out of RTO. Jump to [7].

**Potomac:** Trump Vows to ‘Lift the Restrictions’ on Energy. Jump to [8].

SoCal Gas Wants to Annul Porter Ranch Cleaning Order. Jump to [9].

Prosecutors Wind Down Federal Case Against PG&E. Jump to [9.1].

**Bottom Lines:** Business Groups Stand Tall for PG&E. Jump to [10].

CEC Plans Smoother Mission Rock Meeting. Jump to [15.1].

Regulators Favor Energy Storage, Not More Gas, for APS. Jump to [19].

Another Nevada Casino Looks to Exit Utility Service. Jump to [19.1].

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**Western Energy Prices Soar Ahead of Heat Wave**

Details on Page 4.

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Go to www.EnergyJobsPortal.com for the latest in regional energy career opportunities.

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**CPUC Opens Penalty Consideration Phase in Long Beach Outage Case**

A year-long investigation at the California Public Utilities Commission identified multiple systemic failures by Southern California Edison that led to two lengthy outages in Long Beach last summer. The agency has opened a penalty-consideration case against the utility for the outages last July and August, which affected as many as 30,000 customers. Edison is facing fines and penalties of up to $50,000 per day, per violation. At [12], maintenance and management problems.

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**SDG&E to Establish Division for CCA-Related Marketing, Lobbying**

San Diego Gas & Electric would be the first investor-owned utility in the state to establish a division to engage in community choice aggregation-related marketing and lobbying activities under a controversial plan that is awaiting consideration by the California Public Utilities Commission. SDG&E says the division is needed to facilitate “healthy discussion” on CCA. Opponents say SDG&E’s true aim is to limit competition. At [14], information vacuum?

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**CAISO Proposes Smaller Role for California in Expansion**

Responding to criticism that its proposal for governance of a regional ISO is too California-centric, the California Independent System Operator eliminated the role of a California-dominated interim committee. In a revised set of principles for governance of the regional entity, CAISO also addressed preservation of state authority, and offered a kind of compromise on who can file new tariff amendments and when they can do it. Also at [17], greenhouse-gas tracking removed.

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**Imperial Irrigation District Green-Lights NEM Success Program**

The Imperial Irrigation District has approved a follow-on program to its state-mandated net-energy metering program, despite industry claims that the new initiative will kill the solar business in IID territory. The new “net billing” program will use bi-directional metering to measure energy consumption and generation, with billing and crediting taking place on a monthly basis. IID believes it will reduce subsidization by non-solar customers by 40 percent, or about $4 million, annually. NEM change at [16].
[5] **CPUC Urged to Tear Up SONGS Deal**

Southern California Edison wants to see the CPUC uphold a 2014 settlement allocating costs related to the premature closure of the San Onofre Nuclear Generating Station, but other parties in the case want the settlement thrown out after revelations that a preliminary outline of a deal was hammered out in secret meetings between former CPUC President Michael Peevey and Edison.  

At [13], would a better deal have been struck?  


A draft of the California Energy Commission’s 2016 Environmental Performance Report on California’s electrical generation system details the environmental impacts of the state’s many energy and climate-change policies, such as AB 32 and SB 1368.  

lower emissions and cleaner air.  

[7] **Utah Officials Want Right to Keep PacifiCorp Out of Regional Group**

A Utah legislative committee wants to draft a bill that would give lawmakers the right to block Rocky Mountain Power and ultimately all of PacifiCorp from joining California in a regional transmission organization.  

At [18], few details out yet.  


Republican presidential nominee Donald Trump on July 21 vowed to “lift the restrictions on the production of American energy.” Meanwhile, the White House rolled out guidance for allowing homes with PACE energy-efficiency upgrades and renewable-energy liens to receive FHA-insured mortgages.

Cantwell asks national academies to recommend grid-modernization policies, at [20].

**NEWS IN BRIEF**

[9] **SoCal Gas Petitions Court to Annul Porter Ranch Cleaning Directive**

Southern California Gas Co. said July 12 it has petitioned Los Angeles County Superior Court to annul a directive by the Los Angeles County Department of Public Health to provide comprehensive housecleaning services for homes in the Porter Ranch community.

The homes are located within a five-mile radius of the massive natural gas well leak that occurred at the Aliso Canyon Storage Facility, operated by SoCal Gas.

Under a directive issued by the department, SoCal Gas could be required to clean nearly 35,000 homes, virtually every home in Porter Ranch, according to the company.

SoCal Gas said it has cleaned about 1,700 homes to date.

“There has been no data provided to support this unnecessary demand from a health and safety perspective,” the gas utility said in a statement. “It will only cause additional disruption to a community that wants to get back to normal as soon as possible.”

In May, the county health department released the results of indoor environmental testing of homes located in Porter Ranch.

Testing and analysis of household surface dust revealed levels of metal contaminants such as aluminum, barium, cobalt, iron, and manganese that were higher in Porter Ranch homes than in the comparison group. The metal contaminants are consistent with those found in well-drilling fluid, according to the department, suggesting they originated at the gas-storage facility, and may have been facilitated by efforts to stop the leak.

“These metals do not pose long-term health risks, but can cause respiratory and skin irritation and could be contributing to symptoms reported by residents,” the department said.

SoCal Gas is seeking a writ of mandate from the court to halt the cleanings.

“The facts are clear,” the company said. “Public health officials, including Department of Public Health, have repeatedly stated that their data do not suggest that the conditions in the greater Porter Ranch area present a risk to public health, and that the community is safe.”  

L. B. V.

[9.1] **Prosecutors Winding Down Case Against PG&E**

Federal prosecutors called their last witness this week in a criminal trial against Pacific Gas & Electric. The utility is facing 12 counts of violating the Federal Pipeline Safety Act, and one count of obstructing a federal investigation. The charges all stem from the deadly 2010 natural gas transmission-line blast in San Bruno that killed eight people, injured dozens of others, and destroyed 38 homes.

A federal investigation by the National Transportation Safety Board into the blast found the probable cause of the accident was PG&E’s inadequate quality-assurance program when Line 132 was installed, and an inadequate integrity-management program, which failed to detect the defective pipeline segment.

Prosecutors have been barred from tying their case to the cause of the San Bruno explosion, although U.S. District Judge Thelton Henderson in a July 10 motion ruled that attorneys in the case could refer to San Bruno.

Ravindra “Ravi” Chhatre, the NTSB investigator who led the agency’s inquiry into the blast, testified at the trial that PG&E tried to hide its practice of overpressurizing gas transmission lines in densely populated areas. Doing so would allow the utility to avoid more intensive and expensive safety testing.

Chhatre also testified that he believed PG&E tried to hide its practice of overpressurizing gas transmission lines in densely populated areas. Doing so would allow the utility to avoid more intensive and expensive safety testing.

Chhatre also testified that he believed PG&E tried to intentionally mislead investigators.  

M. S.

[9.2] **Correction**

A story in CEM No. 1394, “Social-Media Comments Trigger Lawsuit Against Regulators, Utility,” incorrectly reported the date Carolyn Tanner resigned as general counsel of the Public Utilities Commission of Nevada. Tanner resigned June 16, not July 16.

We regret the error.  

–CEM
Business Groups Stand Tall for PG&E

As stakeholders in Pacific Gas & Electric’s 2017 general rate-case proceeding at the CPUC continue efforts to hash out a settlement, business groups are speaking up at public hearings on the case in support of PG&E’s $2.25 billion rate-hike request.

PG&E filed the rate application back in September; the added revenue would support investments in infrastructure, reliability, and technology. Average customer bills would go up about 3 percent, or $4 a month.

“It appears to us to be a very modest expense,” said Jay Hoyer, chief executive of the Walnut Creek Chamber of Commerce, at a July 19 public hearing in Oakland. “Every business that exists needs to prepare for the future—it seems that’s what PG&E is doing.”

About three dozen people spoke at the Oakland hearing—one of 19 hearings in 11 cities throughout PG&E’s service territory that the CPUC is facilitating to get public input on the rate case—and only one, a retired woman living on a fixed income, objected to the proposed increase.

CPUC Administrative Law Judge Stephen Roscow, who is the judge assigned to the rate case and who oversaw the hearing for the CPUC, said the commission has heard similar objections from people in Bakersfield, Fresno and Stockton.

I wasn’t too surprised to hear the outpouring of support for PG&E from the business community—after all, PG&E gives financial support in the form of dues or donations to many, if not all, of the groups represented at the Oakland meeting. If PG&E’s revenue requirement for administrative and general expenses is drastically cut, the utility may have to be more selective in the amounts it dispenses.

PG&E shelled out $14 million in dues payments last year, and another $33.5 million in donations, according to the utility’s most recent GO-77 report, filed annually with the CPUC. (PG&E’s total dues payments included about $900,000 in employee dues covered by the company, as well as a few large dues payments to industry organizations, like the $919,000 payment PG&E made to the Nuclear Energy Institute, and the $1.9 million that went to the Edison Electric Institute.)

PG&E is a dues-paying member of virtually all of the chambers of commerce in its service territory, and even though its total dues payments last year were lower than the $15 million it paid in dues in 2014, in some cases the utility’s support goes well beyond basic membership fees.

Take the Pleasant Hill Chamber of Commerce, for example. Membership rates for small companies seem to be modest, topping out at about $650 a year for companies with up to 50 employees. Larger companies are encouraged to call the chamber to discuss a membership rate.

PG&E paid the chamber $10,000 in dues last year. I caught up with Steve Van Dorn, the president and CEO of the Pleasant Hill chamber, on Wednesday. Van Dorn had urged the CPUC to support PG&E’s rate increase at the Oakland meeting, saying the proposal would result in more reliable and safer energy; he was one of several folks from the Pleasant Hill/Walnut Creek area urging support of the rate increase.

Van Dorn explained to me that PG&E’s $10,000 payment gives the utility “community impact partner” status, a type of membership that gives larger businesses such as PG&E an opportunity to showcase their logos on all chamber messaging, as well as tickets and sponsorships for local events including the annual mayor’s breakfast and the annual Art, Jazz and Wine Festival.

In 2014, PG&E made a $52,000 donation to the Pleasant Hill Community Foundation, which I’m sure didn’t hurt the company’s efforts to drum up support, nor does it hurt that PG&E public-affairs and government-affairs veteran Tom Guarino is the chair-elect of the Pleasant Hill chamber.

I counted at least six speakers at the Oakland meeting from Pleasant Hill, including a few residents and local business owners, but not one person mentioned the financial ties the community has to PG&E, nor did Judge Roscow ask.

The CPUC is working hard to expand accountability and transparency throughout the agency and in all of its proceedings and activities. That effort should be expanded to also cover these public rate-case hearings. Speakers from organizations with financial ties to utilities should be required to disclose that relationship up front.

To be sure, much of what the speakers said was valid—there is a need to ensure reliability, invest in infrastructure and technology, and make sure energy is delivered safely. But there was little to no nuance in those supportive comments indicating whether the amounts PG&E is seeking are too much or too little. And no one, at least not at the Oakland hearing, tied PG&E’s current big push on safety to the underlying reason why the utility over the past several years has focused on this area—the deadly 2010 natural gas explosion in San Bruno.

Another public hearing on the rate case is coming up in San Bruno on July 26. It will be interesting to contrast the atmosphere at the hearing in that city, still recovering from the pipeline explosion, with the love-fest that took place in Oakland.

I am all for paying higher rates to ensure safety, to ensure there will never be another San Bruno. But I’d rather see PG&E shave some bucks from its ballooning revenue requirements than spend that money to get sponsorships and a few tables at a chamber’s annual gala. –Mavis Scanlon
Western Energy Prices Soar Ahead of Heat Wave

With temperatures across the West forecast to increase throughout the week ahead, Western peak power prices rose in anticipation of greater air-conditioning and fan use.

California’s Central Valley expects 100-plus-degree days between July 23 and July 28. Bakersfield, for example, should reach 109 °F by July 27, while Fresno expects to reach 104 °F that same day. Likewise, Palo Verde-area highs are expected to remain above the century mark, but could cool from 113 °F July 22 to 106 °F by July 27.

Demand peaked on the CAISO grid at 41,627 MW July 21, but the week's high demand was forecast to occur July 22, when use was expected to reach 42,178 MW. In the week ahead, demand should reach roughly 44,000 MW on July 25.

Average peak power prices soared between Thursday and Friday, with California-Oregon Border rocketing $38.50.

Peak power prices jumped between $9.55 and $45.25 in July 15 to July 22 trading. Prices July 22 ranged from $49.50/MWh at Palo Verde to $72.50/MWh at California-Oregon Border, which saw the greatest gains.

Likewise, average nighttime power prices leapt between $6.50 and as much as $17.20 in trading. California-Oregon Border prices were up $17.20 to $40.35/MWh.

Meanwhile, working natural gas in storage was 3,277 Bcf as of July 15, according to U.S. Energy Information Administration estimates. This is a net increase of 34 Bcf compared to the previous week. Storage levels are now 16.8 percent greater than a year ago and 20.6 percent greater than the five-year average.

Henry Hub gas spot values shed 8 cents in Thursday-to-Thursday trading, ending at $2.70/MMBtu July 21.

Western natural gas prices varied. Southern California Border posted the greatest gains, up 17 cents to end at $2.91/MMBtu July 21, while Malin values fell 5 cents to $2.64/MMBtu.

In its weekly report, the EIA noted the continued efforts Southern California Gas Co. is making to test the wells at its Aliso Canyon storage field in order to restore them to operation as soon as possible. The testing is being conducted under a protocol developed by California’s Division of Oil, Gas & Geothermal Resources and other experts.

Total renewables production on the CAISO grid reached 11,757 MW July 21. Thermal generation peaked that same day at 18,932 MW, while solar generation peaked at 7,964 MW July 15.

— Linda Dailey Paulson
Power Gauge

CAISO Power Production
Rolling Average, 07/15 - 07/21

BPA Loads and Resources
Rolling Average, 07/15 - 07/21

REGULATION STATUS

[12] CPUC Could Fine Edison for Outages
(from [1])

A year-long investigation at the CPUC identified multiple systemic failures by Southern California Edison that led to two lengthy outages in Long Beach last summer.

The agency said July 18 it has opened a penalty-consideration case against the utility for the outages last July and August, which affected as many as 30,000 customers, and which led to fires, explosions and other situations that put public safety at risk. No fatalities were reported as a result of the outages.

Staff in the CPUC’s Safety and Enforcement Division opened an investigation into the incidents last July, and found problems at Edison with maintenance and management of the utility’s electric system in Long Beach, as well as deficient emergency-response and communications capabilities.

“I support opening this penalty consideration case to examine the allegations of our staff that Edison improperly installed, configured, and maintained its network; inadequately maintained records and system knowledge; and had a poor emergency response plan that contributed to the multi-day electrical outage in Long Beach that left more than 30,000 customers without power,” said Commissioner Catherine Sandoval in the CPUC’s announcement.

Edison could be fined up to $50,000 per day, per violation, if the commission finds that statutory fines and penalties are warranted.

In an emailed statement, Edison said it is reviewing the commission’s order instituting investigation, and noted that at the time of the incidents, it “acknowledged the extraordinary nature of the outages and their impact on customers.” Edison provided all customers who lost power for more than 24 hours a $100 credit.

The outages—from July 15 to July 20, and from July 30 to Aug. 3—occurred during periods of high temperatures and high demand on Edison’s system. The two incidents primarily affected about 3,825
customers, but 30,000 customers were affected at the peak of the outages.

Although the size and duration of the outages is a big consideration, SED said the most significant fact is that the outages were not triggered by any external event such as wind, snow, rain, or heat storms.

“Rather, the 2015 Long Beach outages would have been completely avoidable with proper secondary network inspection, maintenance and operation protocols,” SED staff said in the investigation report.

A secondary network is one of two main types of electrical distribution systems, and includes “protectors” that are supposed to be set in an automatic position and should open or close based on conditions in the system, to protect conductors and primary feeders. (The other type is a radial system.) Edison's secondary system in Long Beach, built in the 1920s, serves more than 3,800 customers in the city's downtown area.

SED determined the precipitating event for the July 15 outage was insulation degradation and ignition of a lead cable splice on one of the system's 12V circuits, which damaged a nearby cable splice, leading their respective circuits to relay and lock out, which ultimately de-energized the circuits, reducing the number of protectors available to regulate and protect the network system. It also interrupted power to customers on the radial network in the city served by the same circuits. The investigation found one of the protectors had been set in a manually closed position, preventing if from working properly.

Efforts to repair the damage were complicated by the fact that Edison had inaccurate maps of the network system, according to SED.

“SED discovered serious neglect and deterioration of SCE’s Long Beach secondary network.”

SED discovered serious neglect and deterioration of SCE’s Long Beach secondary network, improperly configured protective devices, equipment installed without critical components, deteriorated cables, poorly constructed and failed cable splices, and improperly racked equipment,” the heavily redacted investigation report said. “SED’s investigation also revealed that SCE’s inadequate knowledge of the secondary network system contributed to longer restoration times.”

For the July 30 outage, SED determined that secondary conductors burned and failed on one of Edison's underground vaults; the fire damaged sections of two other primary feed circuits that were in the same vault. To limit the damage, the utility de-energized two substations, an action which also de-energized other primary and non-primary feed circuits out of those stations.

The entire sequence of events for the second outage is redacted from the investigation report, as is a large portion of the first. (The commission said in its order it believes Edison marked as confidential too much of its data responses to SED; the utility will have an opportunity to justify why those portions should remain confidential, according to the order.)

Edison said it has taken corrective actions since the incidents, based on recommendations in its own internal analysis as well as those made in an independent analysis of the incidents by Davies Consulting LLC, a utility risk-assessment and management consultant based in Maryland.

According to the Davies report, the root causes of the July 15 incident were: “SCE operated the Long Beach underground secondary network outside of its optimal design state; did not have processes in place to actively monitor and track equipment that was being operated abnormally; and made operating decisions that resulted in the network shut-down.”

The consultant also found that damage sustained during operation and restoration efforts for the July 15 incident led to the second outage. Davies made 35 recommendations across six areas: underground network operations, emergency planning and preparedness, incident response and management, communications, information technology, and corporate culture.

The CPUC’s formal investigation will look at whether Edison violated state requirements, including Public Utilities Code, commission rules, general orders, decisions, or other applicable laws and regulations, according to the order instituting investigation [116-07-007], which was not yet docketed at press time.

The commission voted to open the penalty phase in a closed session that followed the commission’s July 14 business meeting. —Mavis Scanlon

[13] Parties Urge CPUC to Rescind SONGS Settlement (from [5])

Women’s Energy Matters, an advocacy group, minced no words in its latest filing urging the CPUC to throw out a 2014 settlement that resolved cost-allocation issues related to the premature closure of the San Onofre Nuclear Generating Station.

The settlement, which stemmed from the early closure of the plant after leaks were found in its new steam generators, granted ratepayers refunds and credits of about $1.45 billion; called for Southern California Edison, the majority owner and operator of SONGS, and minority owner San Diego Gas & Electric to stop collecting in rates any monies related to a replacement steam-generator project at the plant; and called for the utilities to accept a 2.6 percent rate of return on other retired assets at the plant, substantially lower than the usual authorized return of 7.9 percent. It also called for shareholders and ratepayers to equally share any money recovered through an arbitration proceeding against Mitsubishi, the manufacturer of the steam generators. Even with the refunds and credits, under the settlement ratepayers would still shoulder some $3.3 billion in SONGS-related costs between 2012 and 2022, including costs for replacement power.

Women’s Energy Matters (WEM) and other parties to the settlement now say the settlement is unreasonable in light of the whole record. In early 2015,
months after the settlement was approved, Edison disclosed a secret meeting that took place in 2013 between former CPUC President Michael Peevey and Stephen Pickett, then an Edison senior executive. During the meeting, at the Hotel Bristol in Warsaw, Poland, Peevey and Pickett sketched out a settlement framework. Last August, a CPUC judge ruled Edison had committed 10 separate violations of ex parte and ethics rules; the utility was fined $16.7 million.

**In May of this year,** the commission took the unusual step of reopening the record in its SONGS investigation, and asked parties to submit briefs on whether the settlement was reasonable and met CPUC standards for approving settlements in light of the whole record, including whether $25 million allocated in the settlement to a greenhouse-gas program at the University of California is reasonable.

“WEM believes it is ratepayers, not shareholders, who must be made whole,” the group said in July 21 comments in the proceeding [I12-10-013].

“The SONGS case is atypical and extreme,” WEM said. “It involves a reckless management decision to use a new design for the replacement steam generators, and an imprudent, illegal management decision to purposely withhold information from the [U.S. Nuclear Regulatory Commission]” to avoid a federal review of the generator replacement as a license amendment, the group said. “Add to the mix the revelations of a crooked settlement, negotiated in secret by a CPUC president who once served as president of the very utility he was negotiating with.”

WEM reiterated its recommendation that the only costs ratepayers should be saddled with related to SONGS are costs paid for replacement power between Feb. 1, 2012, and when the plant was permanently shut down in June 2013.

**The Alliance for Nuclear Responsibility** also urged the CPUC to set aside the settlement, by using what it called the commission’s rescission authority to undo the settlement deal.

In a July 7 opening brief on the commission’s May 9 ruling to reopen the record in the case, the Alliance said it was astonished to learn late last year of additional unreported ex parte communications in the summer of 2014, this time between Edison regulatory executive Russell Worden and CPUC Administrative Law Judge Melanie Darling. Darling retired early this year, reportedly amid the controversy over the investigation.

“Conducting such discussions outside the presence of A4NR and the other I12-10-015 nonsettling parties was a textbook example of the unfairness which flows from one litigant’s preferential access to decision-makers,” the Alliance said.

The Alliance contends “the settlement was a product of SCE’s extrinsic fraud on the I12-10-013 non-utility parties and SCE’s fraud-by-concealment against SCE’s negotiating counter-parties.”

The Alliance wants to see the commission reinstate a November 2013 proposed decision in Phase 1 of the investigation that ordered a refund of $94 million for overcollection of SONGS-related costs in 2012. (This proposed decision was issued while Edison was still contemplating a restart plan for the plant.) It also recommended the commission prepare and issue a proposed decision for Phase 2 of the investigation—Phase 2 was to consider removing the plant from rate base—and convene a prehearing conference for a Phase 3 that would determine how the commission should proceed with the remainder of the investigation.

**In its opening brief,** The Utility Reform Network said the settlement should be set aside due to the “pervasive ex parte violations” involving Peevey and Edison executives.

If the settlement is set aside, TURN urged the CPUC to open to look at the reasonableness of costs related to the steam-generator replacement project.

If the settlement is not set aside, TURN would also like to see the Greenhouse Gas Research Fund contribution to the University of California eliminated, and the full $25 million refunded to ratepayers.

The extensive private communications between Peevey and the Edison executives “may have emboldened SCE and SDG&E to resist more significant concessions in the settlement process,” TURN said.

TURN said it agrees with a contention made by the Alliance for Nuclear Responsibility that had the ex parte communications been disclosed in a timely manner (rather than two years after they occurred), both TURN and the Office of Ratepayer Advocates “would likely have negotiated a better settlement.”

**Edison contends** the settlement should stand, and that it appropriately protects Edison customers from paying for the failed steam generators provided by Mitsubishi that prompted the closure in the first place.

The company notes that shareholders, not ratepayers, are paying for the faulty steam generators, adding that it reduced the amount customers pay related to past investments in the plant.

As of early June, Edison had already provided refunds and rate reductions of $1.6 billion under the settlement, a figure that does not include any recoveries from its arbitration with Mitsubishi or from nuclear fuel sales. —Mavis Scanlon
CPUC to Vote on SDG&E Plan for CCA-Related Marketing Division (from [2])

San Diego Gas & Electric would be the first investor-owned utility in the state to establish a division to engage in marketing and lobbying activities related to community choice aggregation under a controversial plan that is awaiting consideration by the California Public Utilities Commission.

The commission was set on July 14 to vote on a resolution approving the marketing plan, which has drawn opposition from CCA proponents, but the item was held. It is now scheduled to go before the commission Aug. 18.

Under the state’s CCA Code of Conduct, established by the CPUC in accordance with SB 790, IOUs can lobby against CCAs, but they have to do so through a “functionally and physically separate” division that is funded exclusively by shareholders, not ratepayers, and is staffed by employees who do not work for the utilities.

The code of conduct stipulates that a plan demonstrating there are adequate procedures in place that will preclude the sharing of information with the independent division must be submitted to the CPUC. SDG&E filed an 18-page compliance plan with the commission in November.

The independent marketing division, or IMD, will allow for “ongoing dialogue on issues key to the future of the energy industry and [the] San Diego region is able to benefit from a full range of expert input,” SDG&E said in the filing. It will be funded by Sempra Energy shareholders and located at Sempra headquarters.

The division “will be staffed by personnel who do not have access to non-public SDG&E information, whose day-to-day activities will not be managed by SDG&E management, whose labor and overhead expenses will be charged to accounts paid for by Sempra Corporation shareholders and who will be located at premises that are physically separate from SDG&E.”

The CPUC’s Energy Division in June issued the draft resolution supporting SDG&E’s plan.

“SDG&E has done everything required to demonstrate to the commission that there are adequate procedures in place to prevent the unlawful sharing of information, people, and resources with its IMD,” the resolution notes. “There is no reason to deny SDG&E the opportunity to market or lobby via its IMD.”

Several parties, including the Alliance for Retail Energy Markets, Climate Action Campaign, San Diego Energy District and Sierra Club, wrote to the CPUC opposing the resolution, asserting the separations between the utility and parent Sempra are inadequate, and questioning if there is a need for the division in the first place.

‘SDG&E appears to be launching this division to prevent competition rather than participate in competition.’

Aggregators Marin Clean Energy and Lancaster Choice Energy, in comments filed July 5, argue the draft resolution “falls short of requiring that SDG&E comply with the prohibitions on shared services and transfer of confidential information, omits provisions to ensure compliance with disclosure and reporting rules, and does not adequately consider how basic enforcement will occur.”

The aggregators requested “additional opportunities for all parties to seek information from SDG&E and contribute to the development of adequate procedures” that ensure compliance with SB 790 and the CCA Code of Conduct.

The aforementioned code provides for a number of restrictions on what utilities can say about CCAs, prohibiting, for example, untrue or misleading statements.

The restrictions have created an information vacuum for local governments and stakeholders “who are trying so hard to pursue the right path toward a greener energy future,” SDG&E said. “This vacuum is the product of the utility’s concern that it might be accused of advocating against CCA, as opposed to the utility simply participating in a healthy public discussion of the region’s efforts and progress toward a greener future.”

Currently there are four operational CCA programs in the state. None, as of yet, are in SDG&E territory, but both San Diego County and the City of San Diego are engaged in CCA exploration efforts.

MCE and LCE contend that SDG&E’s interest in more robust public dialogue on CCA “should be received with a healthy dose of skepticism.”

“Since there is not yet a competitive retail energy market in the San Diego area, SDG&E appears to be launching this division to prevent competition rather than participate in competition,” the aggregators said. “A more apt description is that SDG&E is launching an organization akin to a Political Action Committee where unlimited funds can be utilized in a campaign without oversight.”

SDG&E and the division will maintain separate accounting books and records, according to the utility, and make them available for open examination by the CPUC.

—Leora Broydo Vestel

Report: California Reaps Benefits From Doubling Renewables (from [6])

California’s many energy and climate-change policies are resulting in environmental payoffs such as greenhouse-gas emission reductions and air-quality improvements, according to a new draft report from the CEC.

The 2016 Environmental Performance Report (EPR) on California’s electrical generation system also describes areas for future focus.

The rapid expansion of renewable energy—as well as increases in energy efficiency and distributed resources, modernization of the natural gas fleet, and reduced purchases of coal-fired generation—have led to lower levels of pollution. Similarly, a move to use alternative water resources and cooling technologies is boosting water efficiency in power generation.
And the retirement of once-through cooling (OTC) plants is further spurring emission reductions, while providing new opportunities to build more-efficient generators that have the ability to aid in the integration of renewables.

The report—which follows on similar EPRs in 2005 and 2007—is part of the CEC's 2016 Integrated Energy Policy Report Update, which also provides information about natural gas, climate adaptation and resiliency, electricity demand forecasts, Southern California electric-infrastructure reliability, and nuclear energy.

One difference with this year's EPR is that it relied on existing publicly available data sets—from the CEC, CARB and the State Water Resources Control Board—rather than soliciting data from power producers, as was done in the past.

In particular, the draft report highlights the more-than-doubling of renewable generation—from 9,300 MW in 2005 to nearly 20,000 MW in 2015—as a “major success story.” Indeed, the increase in renewable generation is one factor tied to the dramatic reduction in carbon emissions coming from the electricity sector, a drop of 15 million metric tons between 2000 and 2013.

Still, the overall electricity sector accounts for just 20 percent of the state's GHG emissions. The big payoffs are expected down the road with the electrification of the transportation sector, which represents 37 percent of statewide greenhouse-gas emissions.

Another area of opportunity in fighting climate change will be reductions in methane emissions, as these are more efficient at trapping radiation than carbon dioxide. Natural gas is about 90 percent methane, and the danger is that natural gas leaks would result in higher GHG impacts compared to impacts from combustion. This problem was underscored by the now-sealed leak at Southern California Gas Co.'s Aliso Canyon storage facility.

In the area of air quality and public health, the report details statewide reductions in criteria pollutant emissions between 2000 and 2012. These improvements in the electricity sector are the product of both renewables expansion and the move to more modern power plants with the retirement of OTC plants.

Meanwhile, there will be a constant balancing act between maintaining electric reliability and air-quality standards. The tension between the two was underscored by the unexpected closure in 2012 of the San Onofre Nuclear Generating Station and its subsequent retirement in 2013, as well as the likely retirement of over 5,000 MW of OTC plants, and the moratorium on natural gas injection at Aliso Canyon. Local air districts are trying to accommodate power producers, for instance by opening up some normally unavailable emissions offsets.

In terms of water, the state's electricity system is becoming increasingly efficient—due to both the modernization of power plants and the use of renewables. There has been a push to use alternative water sources and cooling technologies driven by concerns about power-plant impacts to local water supplies. For instance, in 2014, 80 percent of power plants using steam and requiring steam condensing did so using recycled water or made use of dry cooling. These modern thermal power plants use significantly less fresh water than similar generators did in 2003, according to the report.

Renewable resources are also displacing fossil-fueled power plants, which made inefficient use of water. Similarly, there is now a greater call for low-water-use peaker plants, as well as fast-start plants that use significantly less water because they run less often. The renewable generators themselves—wind and solar photovoltaic—have fewer water requirements, although much water is used for soil grading during construction of certain utility-scale plants.

Finally, the report notes some changes that may come with the California drought, now in its fifth year. For instance, power plants using surface water for cooling may seek amendments with the CEC, as four projects have done over the last two years. And four power plants in Kern County may also face problems as they rely on supplies from the State Water Project, which has low reservoirs.

Additionally, the Sustainable Groundwater Management Act of 2014 now requires the formation of local agencies to evaluate supplies in local basins and to create sustainability plans for these water basins. This could be an issue for projects in the planning stage.

A chapter of the report is dedicated to emerging and transformative technologies, and highlight the big drop in costs of solar PV, as well as trends in wind power, geothermal, and offshore renewable-energy technologies.

The CEC scheduled an Aug. 4 workshop on the report, and called for written comments to be filed by Aug. 28. [M. A. Hogarth Fogel]
CEC Plans Smoother Mission Rock Meeting

CEC commissioners hope that a new interpreter and a translation system will help in community meetings like one planned July 28 in Santa Paula, Calif., to discuss the Mission Rock Energy Center.

A crowd of about 100 mainly Latino attendees walked out of the CEC's June environmental scoping meeting and informational hearing for Calpine Corp.'s proposed 275 MW natural gas-fired power plant after complaining about the accuracy of the event's Spanish interpreter (see CEM No. 1592 [14]).

Public adviser Alana Mathews apologized at the CEC's July business meeting, saying that things at the Mission Rock meeting were not "up to the usual standard that we have at the Energy Commission." She introduced RoseMary Avalos, formerly of the Hearing Adviser's Office, who would be joining her office. Avalos is bilingual in Spanish and English.

Imperial Irrigation District Approves NEM Success Program (from [4])

The Imperial Irrigation District has approved a follow-on program to its state-mandated net-energy metering program, despite industry claims that the new initiative will kill the solar business in IID territory.

District staff developed the new “net billing” program, approved July 19 by the IID Board of Directors, as a successor to NEM. The NEM program is fully subscribed as of April at 50.2 MW, representing 5 percent of the district’s peak load.

Under the new program, IID will use bi-directional metering to simultaneously measure energy consumption and generation—a process referred to as “instantaneous net generation” by industry—with billing and crediting taking place on a monthly basis. There is no annual true-up, as was the case with NEM, and no cap on participation.

More specifically, when a customer’s rooftop solar system is not entirely offsetting on-site load, the district will charge for the energy consumed at the regular retail rate. When a system is producing excess power, the customer will receive compensation from IID at a rate equal to what the district pays under its lowest-cost utility-scale solar contract. Right now that rate is about 6.8 cents/kWh.

Approximately 3,400 IID customers, out of a total of about 152,000, have rooftop solar systems. The new program aims to reduce cross-customer subsidization occurring under NEM.

Solar customers in the district’s NEM program do not pay their full share of fixed costs for things such as transmission, backup generation, and administration, according to the district, resulting in a $4.1 million annual cost shift to non-NEM ratepayers. The new net-billing program, IID asserts, should reduce subsidization by non-solar customers by 40 percent annually.

Mathews said that translation services would be on hand at the upcoming meeting, including when people spoke at the podium. She added that she had purchased translation-services equipment for the CEC to be used at future meetings.

Commissioners are also gearing up for community meetings as part of its SB 350 Barriers Report. The legislation requires the CEC to publish a study on barriers to the following: solar-photovoltaic energy generation, access to other renewable energy by low-income customers, contracting opportunities for small businesses in disadvantaged communities, and energy-efficiency and weatherization investments.

The first phase of the study is a review of the literature and the second is a series of workshops. These will be held Aug. 5 in Los Angeles, Aug. 5 in Fresno, Aug. 18 in Riverside, and Aug. 19 in Oakland.

"You've got 149,000 people out there that are subsidizing the 3,400," said board member Bruce Kuhn. "We have to do what's best for all the people."

The solar industry believes the new net-billing program fails to account for some of the benefits rooftop solar provides, such as avoided transmission charges, and that the compensation provided will greatly decrease the economic value of solar, increasing the payback profile.

"The vast majority of customers in IID territory who wish to put solar on their roof would no longer have the ability to do so," notes a July 11 letter sent to the district by the California Solar Energy Industries Association.

Jimmy Slembski, president of Draper, Utah-based Zing Solar, told the board the new program will "effectively eliminate rooftop solar in the area" due to the instantaneous nature of the billing, as well as the purchase rate for excess solar "being a moving target" given it can change if IID signs a lower-priced utility-scale solar contract.

"We know that we can’t have a program that’s bad for IID," Slembski said. "But this program, it’s going to effectively kill the rooftop solar industry.”

IID believes staff has worked in earnest to find a workable solution that responds to calls from the solar industry and customers to adopt a successor program, while also addressing subsidization by non-solar ratepayers.

"The only way we could have worked closer with the industry would have been to have you write the successor plan for us," said IID General Manager Kevin Kelley.

"Job one here," Kelley added, "is for the IID board to adopt a successor program that’s sustainable for IID and doesn’t put you out of business. If we find that’s not the case, we can always make an adjustment."

Customers enrolled in the original NEM program are grandfathered in under the terms of their 20-year contracts.

‘We have to do what’s best for all the people.’
[17] CAISO Proposes Smaller Role for California in Expansion (from [3])

The California Independent System Operator published a set of revised principles on July 15 for the governance of a prospective West-wide or regional grid operator, following stakeholder criticism that it was too California-centric.

The revised proposal does away with a plan for a board dominated by California political appointees to oversee early steps in the formation of the regional operator, and would lead to the creation of a new ISO board to replace the existing ISO governance structure.

The latest governance document sets out revisions relating to the preservation of state authority; transmission-owner withdrawal; creation of a transition committee of stakeholders and state representatives; the transition period; the composition and selection of a regional ISO board; the establishment of a Western States Committee; and provisions for stakeholder processes and participation.

The principles, along with the results of studies on the environmental and economic impacts of ISO expansion, will be formally presented during a daylong workshop scheduled for July 26, before being subjected to another round of comment and submitted to the California governor for possible presentation to the state Legislature.

If the Legislature approves it, a transition committee of stakeholders and state representatives would be formed, CAISO said.

Charged with developing a regional governance design, the committee would include one representative from each state involved, a structure similar to CAISO’s energy imbalance market process. The committee would also include representatives from nine industry sectors. The existing ISO board would have authority to ensure industry-sector representatives are geographically diverse.

In addition to laying out a governance-design proposal, the transition committee would develop a two-step process that would allow a stakeholder-based nominating committee to submit candidates for the new ISO board. Candidates would have to be approved by another committee that includes members of another body to be known as the Western States Committee (WSC).

The separately incorporated, nonprofit WSC—previously referred to as the body of state regulators—would provide policy direction on “matters of collective state interest.” Proposed modifications include removing the requirement that representatives selected by each state must be state regulatory commissioners, and the addition of two new, non-voting positions—one to represent federal power marketers in the West, and one for consumer-owned utilities in the ISO footprint.

CAISO highlighted its decision to remove GHG tracking from its list of principles.

The WSC would have “primary authority” over specific policy initiatives to be determined by the transition committee, but “not necessarily” for administrative work such as budget decisions and staffing. The WSC would be required to have “some form of weighted voting based on load.”

To resolve the thorny issue of who would have authority to make Section 205 rate-setting filings with FERC, CAISO is proposing a provision that would allow the ISO to file tariff changes with FERC if the WSC takes no action after a certain amount of time.

The proposal includes new principles concerning when the final governance plan would become effective. It would have to be approved by each of the states’ representatives on the transition committee, and then be certified by the California governor as being “in the best interests of California and its ratepayers.”

New members of the ISO board would be seated within 18 months of the governance plan becoming effective.

Most comments submitted on the previous proposal supported the preservation of state authority, but wanted clarification, with investor-owned utilities and independent power producers warning against “an absolute ban on a centralized capacity market” and limits on the ISO board’s authority to manage unforeseeable developments.

To this end, the proposed modifications refine the general scope of state authority to be preserved, and clarify that unanimous approval from both the board and the Western States Committee would be needed to amend the bylaw on protecting state authority.

Other modifications define a process to determine when a proposed action would impair state authority; refine the restriction on capacity markets “to focus mainly on mandatory capacity markets that are connected to resource adequacy requirements”; and allow states or local regulators “to approve participation in other types of forward capacity markets.”

CAISO highlighted its decision to remove greenhouse-gas tracking from its list of principles “because it is not directly relevant to corporate governance.”

The ISO already has a mechanism to track and account for GHG emissions “across the new multi-state” balancing-authority area, and believes the proposed ISO can enhance the transparency of resources used to serve load while at the same time supporting each state’s distinct policies.

[18] Utah Officials Want Right to Keep PacifiCorp Out of Regional Group (from [7])

An interim energy committee in the Utah Legislature wants to draft a bill that would allow lawmakers to decide whether Rocky Mountain Power may join an 11-state regional transmission organization formed from the California Independent System Operator.

Critics at a July 13 committee meeting lambasted the proposed West-wide grid organization. CAISO has
since proposed revisions to its governance principles in an attempt to satisfy issues Utah officials and others had raised (see story at [17]).

The proposal for a regional ISO dates back to PacifiCorp's April 2015 agreement to work with CAISO to create a regional transmission group.

PacifiCorp is looking for ways to lower costs and retail rates, Cindy Crane, CEO of PacifiCorp’s Rocky Mountain Power division, told the Utah Legislature’s Public Utilities, Energy, and Technology Interim Committee at the meeting.

PacifiCorp won’t join the regional ISO unless all six states in its service territory approve, Crane said.

“We think [the regional ISO] has to be truly independent. We think the state authority has to be protected,” she said.

The Legislature legally could block Utah from joining the regional ISO, Thad LeVar, chairman of the Utah Public Service Commission, told the committee.

Utah officials raised concerns about governance of the regional transmission organization. In addition, speakers reiterated concerns that Utah must be able to preserve control over its own energy policy, energy resources, transmission and generation siting, and retail rate regulation.

Laura Nelson, director of the Utah Governor’s Office of Energy Development, said at the meeting she was skeptical about Utah joining a regional ISO.

Nelson acknowledged Utah could gain access to inexpensive solar power from California and could enjoy improved access for exporting energy to California. Also, utility peak-capacity needs could be reduced through participation in the regional ISO, she said.

However, Nelson said she feared the regional ISO might cause Utah to share in transmission costs needed to implement policies in other states. For example, Utah has a voluntary renewables portfolio goal of getting 20 percent of retail sales from renewables by 2025, rather than a mandatory renewables portfolio standard like other states.

To be acceptable, the regional ISO must be independent, not influenced by special interests, and provide for participating states to have equal influence over decisions, Nelson said.

Chris Parker, director of the Utah Division of Public Utilities, feared California might dominate or have veto power over decisions of the regional ISO. FERC would have ultimate control, Parker said.

“If FERC decides something is not allowed, it may not matter what is in these governance documents,” Parker said.

The revised governance principles allow participating transmission owners, such as PacifiCorp, to unilaterally withdraw from the ISO.

Michele Beck, director of the Utah Office of Consumer Services, said she hadn’t studied the revised principles in depth, but saw some improvements.

However, Beck told California Energy Markets she worried about leaving governance details to the proposed transitional committee. “I don’t have confidence that that process will work well,” she said.

Beck said she remains concerned about state sovereignty, which may be impossible to adequately resolve through governance design.

In addition, the regional ISO could directly or indirectly determine more than half of the costs that feed into Utah retail rates, Beck said, noting transmission access charges—a sticking point for Utah, since its fees are well below those of California—and grid-management fees. Also, procedures, including those related to transmission congestion, indirectly may drive up costs for energy in Utah, Beck said.

Jennifer Gardner, staff attorney with Western Resource Advocates, said the regional ISO could combine up to 58 balancing authorities, where utilities manage supply and demand from power customers.

“Things have been working, but they could be working a lot better,” Gardner said.

The majority of North American utilities already belong to regional transmission organizations like the proposed Western ISO, Gardner said.

Doug Hunter, CEO of the Utah Associated Municipal Power Systems, said Utah needs to ask seven California balancing authorities, including the Los Angeles Department of Water & Power, why they haven’t joined CAISO.

The Mountain West Transmission Group is proposing an alternative regional organization, Hunter said. Mountain West participants include the Western Area Power Administration; Xcel Energy; the Colorado Springs, Colo., utility; Tri-State Generation and Transmission Association; and Black Hills Energy.

—John Edwards


Arizona Public Service argued for increasing reliance on gas-fired peaking plants to back up intermittent wind and solar power during a review of its preliminary integrated resource plan. But advocacy groups and members of the Arizona Corporation Commission favored energy storage instead.

Commission Chairman Doug Little agreed with the Southwest Energy Efficiency Project that APS would create the risk of a spike in gas prices that could hurt ratepayers if it invests in too much gas-fired generation.

Jim Wilde, Arizona Public Service director of resource planning, favored increased use of gas-fired generation, noting low costs and the ability to serve customers when intermittent renewables aren’t available. APS gets 3,000 GWh from renewables today, up from 1,350 GWh in 2012.

Gas sells for $2.50/MMBtu and generates electricity from the 984 MW combined-cycle Redhawk power plant for less than $20/MWh. Also, the outlook is for lower and more stable gas prices, Wilde said.

APS said it is getting 26 percent of its energy from gas-fired generation, but intends to increase gas generation to 36 percent by 2031.
Little said he preferred that APS rely more on energy storage to meet peak demand and less on natural gas.

“We’re assuming a significant risk if natural gas prices return to the prices we’ve seen in the past,” Little said.

Commissioner Bob Burns agreed: “We’ve got to be careful and not put too many eggs in one basket.”

Jeff Schlegel, the Southwest Energy Efficiency Project Arizona representative, said APS was emphasizing solutions such as gas-fired generation that benefit the company, which earns a return on investments in power plants. APS should offer more customer-controlled programs, such as energy efficiency and demand response, to lower peak demand, Schlegel said.

**APS said it will stop** burning coal at Cholla power plant Units 1 and 3, which generate 387 MW, in 2025 and is evaluating whether to continue operating them. (APS closed the 260 MW Cholla Unit 2 last year.)

In 2019, APS intends to complete the modernization of the Ocotillo plant, which will remove two 110 MW steam units, retain two 55 MW combustion turbines, and add five 102 MW combustion turbines. The project will boost generating capacity to 620 MW, up from 330 MW previously.

APS expects microgrids for the Marine Corps Air Station in Yuma and the Aligned Data Center in Phoenix will add 33 MW of diesel generation by year-end 2016.

Also, the utility expects to join the CAISO-Pacific Corp energy imbalance market in October.

Tucson Electric Power proposed to continue operating the coal-fired Springerville Generating Station, but also outlined plans to increase its use of renewables, including the use of New Mexico wind power to offset diminishing solar power generation in late afternoon.

**TEP has set a non-binding goal of getting 30 percent of its retail power sales from renewables by 2030, twice the Arizona renewable-energy standard of 15 percent by 2025.**

Tucson Electric owns 192 MW of coal-fired Springerville Unit 1 and is awaiting FERC approval to buy the other 195 MW from co-owners Alterna Springerville LLC of Wilton, Conn., and LDVF1 of New York.

The utility will pay $85 million for the 195 MW interest and the sellers will pay TEP $12.5 million for past operating costs.

**TEP has a 170 MW interest in Unit 1 of the coal-fired San Juan Generating Station in New Mexico, but plans to end its involvement in San Juan in 2022. It also has an option to exit its 168 MW ownership interest in the coal-fired Navajo Generating Station in 2030 and its 110 MW ownership in the Four Corners plant in 2031.**

NextEra Energy Resources is scheduled to complete a 10 MW lithium-nickel-manganese-cobalt facility late in 2016 at the DeMoss Petrie Substation in Tucson near Interstate 10 and West Grant Road. E.ON Climate & Renewables by June 2017 will install a 10 MW lithium-titanate-oxide storage facility and accompanying 2 MW photovoltaic array at the University of Arizona Science and Technology Park southeast of Tucson. TEP will lease the two 10 MW battery-storage facilities.

Ken Wilson, an engineering fellow at Western Resource Advocates, recommended APS and TEP consider a large-scale battery-storage demonstration project for peaking power and to facilitate energy arbitrage. Wilson suggested 5 MW of battery storage that can operate continuously for four hours.

Wilson predicted that it will be advantageous for utilities and customers to rely on battery storage, rather than gas-fired peakers, to meet peak-demand needs. The demonstration project would give the utilities experience in energy storage.

Little liked Wilson’s proposal for a battery-storage demonstration project.

**Separately, APS and TEP both mentioned interest in small modular reactors, nuclear generators up to 300 MW. But neither utility is proposing to install these generators as part of its integrated resource plan.**

**TEP also is interested in natural gas reciprocating engines, because they are efficient and fast-responding generators.**

The ACC expects to vote on final integrated resource plans for APS and TEP in April 2017.

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**John Edwards**

[191] **Peppermill Casino Asks PUCN for Permission to Exit Electric Utility**

The Peppermill Resort Spa Casino in Reno on July 12 filed an open-access application to exit Sierra Pacific Power and buy energy from Cargill Power Markets.

Peppermill uses 55,000 MWh yearly, with an average load of 6 MW and peak load of 10 MW. The casino intends to obtain its power outside the Sierra Pacific service territory, but doesn’t intend to build a new power plant.

Under Nevada Revised Statute 704B, utility customers with an average load of 1 MW may apply to the Public Utilities Commission of Nevada to buy electricity from an alternative provider.

The Peppermill is the latest in a series of large power users to seek an opportunity to end their ties to utility subsidiaries of NV Energy.

MGM Resorts International, Wynn Las Vegas, and Las Vegas Sands in 2015 filed applications to replace Nevada Power as their electricity provider. MGM and Wynn are expected to exit Nevada Power in October. MGM agreed to pay $86.9 million in open-access fees, plus undetermined non-bypassable charges, and Wynn agreed to pay $15.7 million for open access, plus non-bypassable charges.

The Sands, owned by billionaire Sheldon Adelson, balked at $23.9 million in exit fees and additional non-bypassable charges. Adelson is backing a voter
initiative to amend the Nevada Constitution to allow all electric-power customers in Nevada to buy electricity from alternative providers.

Switch Ltd., a Las Vegas-based data-center operator, in 2015 was denied an opportunity to exit Nevada Power. Switch sued NV Energy and the commission in federal court on July 12, seeking $50 million in damages and the right to open access. –J. E.

POTOMAC

[20] Trump Vows to ‘Lift The Restrictions’ on Energy Production (from [8])

Republican presidential nominee Donald Trump on July 21 vowed to reform “energy rules” and “lift the restrictions on the production of American energy.”

In his acceptance speech to the Republican National Convention in Cleveland, Trump touched only briefly on energy, but his remarks followed themes of the platform the convention adopted July 18.

Trump said “excessive regulation is costing our country as much as $2 trillion a year, and we will end it very, very quickly.”

The party platform vows to “do away” with the Environmental Protection Agency’s Clean Power Plan and opposes a carbon tax, reiterating standard congressional-Republican energy talking points. It calls for “developing all forms of energy that are marketable without subsidies,” singling out fossil fuels, nuclear power and hydropower.

According to a Reuters report, Trump is considering naming Continental Resources CEO Harold Hamm to run the Department of Energy, should the New York businessman be elected the 45th president on Nov. 8. Continental is an independent oil producer active in Oklahoma and in North Dakota’s Bakken shale formation. Hamm, in a convention speech, called for increased domestic oil and gas production.

In addition, the platform proposed transferring unspecified federal lands to “willing states.” Rep. Ryan Zinke (R-Mont.) resigned as a convention delegate to protest the proposed transfer.

White House Rolls Out PACE Guidance

The White House on July 19 rolled out guidance for allowing single-family residential properties with energy-efficiency upgrades and renewable-energy liens to be eligible for Federal Housing Administration-insured mortgages under some conditions.

The announcement came as part of a broad “clean energy for all” initiative, which includes a goal of bringing 1 GW of solar energy to low- and moderate-income households by 2020.

Under the guidance, the purchase of homes that have Property Assessed Clean Energy (PACE) liens attached to them could be financed by FHA mortgages under five conditions, including collection of payments in the same way that special assessment payments are collected.

In addition, PACE liens do not have to be in the first lien position ahead of an FHA mortgage, the guidance said. When homes with PACE liens are sold, the liens stay with the properties.

The White House said more than 100,000 households nationwide have used PACE to finance $2 billion in home energy-efficiency upgrades.

Current rules bar the encumbrance of FHA-financed properties with other liens. The rules had been seen as an impediment to PACE loans, which finance efficiency upgrades and renewables projects at homes with repayment through property taxes.

President Barack Obama last year directed FHA to make the rules change.

Cantwell Seeks Grid Study From Academies

Sen. Maria Cantwell (D-Wash.) on July 15 asked the National Academies of Sciences and Engineering to recommend steps the federal government should take to accelerate modernization of the electric-power grid.

Cantwell, ranking Democrat on the Energy and Natural Resources Committee, asked the academies to report on “no-regrets” research and development the federal government should carry out and on policy “gaps,” such as “poorly designed incentives.”

In addition, Cantwell asked for recommendations on integrating cybersecurity into grid systems relying increasingly on digital communications.

In a letter to Marcia McNutt, head of the academies academy, and C.D. Mote Jr., the engineering academy’s president, Cantwell inquired how policymakers can “ensure that consumers don’t have to accept greater vulnerability as the price of greater connectivity.”

FERC Approves Voltage Ride-Through Rule

FERC on July 21 finalized a rule requiring small generators with capacity of 20 MW or less to be able to ride through frequency and voltage disturbances. The rule ends an exemption from ride-through requirements with which larger generators must comply.

In comments sent to the commission May 23, the Bonneville Power Administration said “sensible” ride-through requirements are necessary to ensure “small generators tripping off line do not cause disturbances to spill over into neighboring balancing authorities.”

BPA noted it has six interconnection requests from small generators in its queue, while balancing authorities to which it is linked in the Western Interconnection “are seeing dramatic growth in the amount of small generators coming on line, particularly in the Southwest.”

Pacific Gas & Electric said it also supported the proposed rule, but added that small generators should be able to disconnect from the grid to avoid islanding conditions. Southern California Edison said ride-through requirements applied to small generators would “promote fair and equitable treatment” for all generators.
FERC, Corps to Streamline Hydro Permitting

FERC and the U.S. Army Corps of Engineers have signed an agreement to streamline permitting of non-federal hydropower projects at Corps facilities, including preparation of one environmental impact document, FERC announced July 21.

The agreement updates a 2011 accord. Once the Corps has approved construction, FERC would also authorize construction, under the agreement.

Aliso Technical Conference Rescheduled

FERC on July 19 rescheduled its planned technical conference to explore CAISO measures to protect reliability in connection with limited Aliso Canyon natural gas storage.

The conference, due to begin at 7 a.m. Pacific time, will be webcast live.

DOE Awards $19 Million for Building Efficiency

The Energy Department on July 15 awarded $19 million for 18 projects to develop building-efficiency technologies.

The grants fund projects for sensors and controls, windows and building envelopes, HVAC, and modeling. Recipients include:

- Glint Photonics of Burlingame, Calif., for a rooftop-mounted daylighting system that uses internal optics and light guides to direct light into building interiors, reducing lighting load by up to 70 percent.
- Lawrence Berkley National Laboratory, for development of insulation that is an estimated two to four times as efficient as conventional materials.
- PARC in Menlo Park, Calif., to develop peel-and-stick sensor nodes for relaying data to building energy-management systems.

EIA Projects Record Gas-Fired Generation in 2016

Natural gas-fired generation is expected to hit record levels this year, the Energy Information Administration said July 14.

Energy from gas-fueled power plants is projected at 380,000 GWh this year, up 4 percent from the 2015 level, EIA said. In addition, gas will maintain its lead as the top U.S. power source at 34 percent, trailed by coal at 30 percent, nuclear with 19 percent, and renewables totaling 15 percent, EIA said.

Gas-fired generation, however, is expected to dip in response to projected increases in gas prices, but is then projected to start rising through the following two decades, according to EIA.

McConnell Backs Carbon-Capture Tax Credit Bill

Senate Majority Leader Mitch McConnell (R-Ky.) on July 14 agreed to cosponsor bipartisan legislation to extend a tax credit for carbon capture and sequestration.

The bill (S. 3179) also would extend from 10 to 12 years the period when plant owners could claim the credit, and lengthen from five to seven years the deadline for construction to begin to qualify for the credit.

The credit is due to expire when 75 million tons of carbon dioxide have been sequestered, and as of 2014, about half of those storage credits had been claimed, industry and environmental organizations said in an April 5 letter to Senate Finance Committee leaders.

The credit is $10 per ton for captured CO2 used for enhanced oil recovery and $20 per ton for CO2 sequestered in deep saline formations.

In addition to McConnell, S. 3179 is cosponsored by Sen. Jon Tester (D-Mont.) and seven others. The legislation was introduced July 13 by Sens. Heidi Heitkamp (D-N.D.) and Sheldon Whitehouse (D-R.I.).
[1] PG&E Convicted on Six Counts in Criminal Trial; Plans Motion to Acquit

A federal jury on Aug. 9 found Pacific Gas & Electric guilty on six of the most serious counts against it in a criminal trial stemming from the San Bruno pipeline explosion. The jury found PG&E guilty of one count of obstructing a federal probe into the blast and five counts of knowingly and willfully violating minimum safety standards under the Pipeline Safety Act. PG&E looks to toss out conviction and appeal at [14].

[2] California Delays Regional Grid Bill to 2017

California Gov. Jerry Brown has delayed to next year legislation required to transform the California Independent System Operator into a regional grid operator for the Western U.S. CAISO, PacifiCorp and other stakeholders welcomed the additional time to build consensus. At [15], delayed but not deterred.

[3] Mendocino County Board Votes to Join Sonoma Clean Power

Sonoma Clean Power has received a green light to expand its community choice aggregation service into neighboring Mendocino County. Service to the county's three CCA-eligible cities is also a possibility if they elect to join. Concerns remain, however, about the county's voting power on SCP's governing board. Expanding opportunity at [17].

[4] PG&E Files Diablo Canyon Closure Plan at CPUC

The $5.5 billion, 2,240 MW Diablo Canyon nuclear power plant is not needed. That is one of the conclusions owner and operator Pacific Gas & Electric reached in its Aug. 11 application at the CPUC to phase out its production of nuclear power by 2025 and replace it with a mix of energy efficiency, renewables and energy storage. Phasing out Diablo at [13].

BILLBOARD

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PRICE REPORT

Sun, Sun, Sun, Here It Comes Details on Page 4.

ENERGY JOBS PORTAL

Go to www.EnergyJobsPortal.com for the latest in regional energy career opportunities.
[5] **CEC Funds Incubators, Microgrids, Water-Energy Nexus Projects**

The California Energy Commission on Aug. 10 approved $14 million in grants for water- and energy-saving technologies, clean-energy entrepreneurs in Los Angeles, and a clean-energy microgrid in Santa Monica with electric-vehicle charging. Commissioners also approved funding for a documentary film on the prehistory of a Riverside County solar farm. [At [12], incubators, universities, disadvantaged communities, and prehistories.]


California can meet federal Clean Power Plan requirements with some simple updates to the state’s cap-and-trade and GHG emissions-reporting regulations, according to a new proposal issued by the California Air Resources Board. CARB expects that 38 GW of installed capacity will be subject to the Clean Power Plan, but that existing policies along with a few regulatory tweaks will meet CPP targets. Assured compliance at [16].

[7] **Arizona Delays Demand Charge Vote in UNS Electric Rate-Case Precedent**

The Arizona Corporation Commission completed the first half of a general rate case for UNS Electric but postponed action on demand charges, which could set precedents for net-energy metering rates at other utilities. Separately, the Nevada Supreme Court found SolarCity’s proposed NEM referendum was invalid. [At [18], Southwest solar wars.]

[8] **Clinton, Trump Highlight Competing Energy Plans**

Hillary Clinton called for a “more resilient power grid” to deliver renewable energy “to power every home in our country,” while Donald Trump vowed to boost coal, oil and natural gas production. Meanwhile, the Interior Department issued an unprecedented advisory warning states against accepting self-bonding for coal-mine reclamation requirements until at least 2021. [Also at [19], Western energy groups sue BLM over energy leases.]

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**NEWS IN BRIEF**

[9] **Approximately 14 Percent of Aliso Canyon Wells Clear All Tests**

Southern California Gas Co. has said it could start re-injecting gas in September for wells that have been cleared by the state Division of Oil, Gas & Geothermal Resources.

So far the number of cleared wells is 17, according to SoCalGas. Approximately 96 wells, meanwhile, are in the second phase of testing, the utility said in an Aug. 5 update.

The Aliso Canyon leak, discovered in October 2015, is considered the worst natural gas leak in U.S. history; more than 94,000 tons of methane poured into the atmosphere before the leak was plugged in February.

The Aliso storage facility, which has 114 wells and can store 86 Bcf of gas, is considered crucial to electric reliability in Southern California in the summer and winter, as it supplies natural gas to more than 9,000 MW of generation. –C. R.

**[9.1] Ivanpah Meets Production Marks**

Units 1 and 3 at the Ivanpah solar-thermal power plant have met their production requirements for the first six months specified in an agreement with Pacific Gas & Electric, according to plant owner NRG Energy. Earlier this year, PG&E agreed to give NRG a forbearance in meeting its energy-production goals through July at the Ivanpah units, which have a combined capacity of 248 MW and are under contract to PG&E for 25 years. The CPUC approved the agreement in March (Res E-4771) (see CEM No. 1377 [12]).

Under the forbearance agreement, PG&E agreed to refrain from taking certain actions (including declaring an event of default and invoking associated remedies) for an initial six-month period, NRG said in an Aug. 9 report filed with federal regulators. If the units met certain production requirements during that period, then the forbearance agreements provide for a six-month extension, NRG said. –C. R.
Housing, Transportation and Climate Change

How bad is the Bay Area housing market? A Palo Alto Planning and Transportation Commission member resigned her seat because she and her husband—a software engineer—could not afford a single-family home in Palo Alto.

In a resignation letter that has gone viral on the Internet, the commissioner, Kate Vershov Downing, said she currently rents a home with another couple for $6,200 a month. Buying the home would cost $2.7 million, or $146,127 per year for a mortgage and taxes.

“If professionals like me cannot raise a family here, then all of our teachers, first responders, and service workers are in dire straits,” she wrote. “We already see openings at our police department that we can’t fill and numerous teacher contracts that we can’t renew because the cost of housing is astronomical” around the Bay Area.

To some extent, professionals with children might have to adapt in the Bay Area housing market, perhaps raising their kids in apartments as many Europeans do. But even apartments are expensive. The average monthly rent for a two-bedroom apartment in San Francisco is $4,650; in Palo Alto it is $3,806. That excludes a wide variety of workers from even the rental market. The average salary for solar PV installer, for instance, is around $36,000 a year.

Of course, some professionals have left the Bay Area or else moved to cheaper areas to try to get by. But for those that flock to the exurbs, that raises a policy problem: transportation emissions.

“Development patterns influence greenhouse gas emissions expended in the transportation sector via the proximity and connectivity of jobs and housing,” explains the California Department of Housing and Community Development in a policy initiative. “Denser forms of development can increase the effectiveness of these relationships, while reducing travel time, travel costs, and the GHG emissions responsible for elevating the risks of climate change.”

Unfortunately, California doesn’t have the right smart-transportation policies in place. Most of the focus has been on electric-vehicle subsidies, but that effort has backfired. With gasoline prices so low, most consumers are not choosing EVs. Statistics in fact show that as gasoline prices fell, SUV sales increased and sales of electric vehicles dropped (see CEM No. 1391 [9]). When there’s extra money for consumers to burn, it doesn’t go in the greenest furnace but the biggest one.

Although a 2007 bill, SB 375, directed local governments to direct sustainable communities and transportation plans, nothing much has come of it. The Bay area is largely relying on the same transportation network.

The lack of a viable transportation and smart-growth policy could well undermine the state’s efforts to reduce greenhouse-gas emissions to 40 percent below 1990 levels by 2050. Much of the focus of GHG policy has been on the electric sector, but in-state generation accounts for just 13 percent of GHG emissions, and that number will surely decline given falling costs for solar and wind generation as well as the 50 percent-by-2030 renewables portfolio standard. Meanwhile, the transportation sector accounts for a whopping 40 percent of emissions.

To solve the transportation-emissions problem, the California Legislature needs to encourage high-density, affordable housing near public transportation corridors. Part of the package should include affordable housing, high-density market-rate housing with rent control, limiting speculation in real-estate markets, and providing incentives to build high-density residential developments, perhaps through revision to the property tax structure.

The usual objections to such a policy are likely to be heard. For instance, it’s frequently said that there’s simply “not enough land” to build housing in the San Francisco Bay Area. Baloney. The problem is that what has been built is primarily low-density industrial office parks, which will be empty if a tech bubble erupts, and high-density residential projects face numerous regulatory challenges.

There’s also the argument that going high-density would kill the area’s natural beauty and cultural allure. That’s another load of bull. If metropolitan Rome, which has a population of 2 million, can build high-density apartment buildings in some areas and still retain its beauty, then so can the 48-mile stretch between San Francisco and San Jose.

–Chris Raphael
Sun, Sun, Sun, Here It Comes

Bright, warm days in California are increasing power demand, some of which is being offset by record solar production.

Demand peaked on the CAISO grid at 38,322 MW Aug. 11, but the week’s high was forecast to occur Friday, when use was projected to reach 38,677 MW.

“Temperatures across the state are rising and we are expecting to see loads increase into the low 40,000 MW [range]” beginning Aug. 14, said CAISO spokesperson Steven Greenlee. Demand should reach 46,300 MW by Aug. 16.

The grid operator set a solar production record on Aug. 7, recording a new instantaneous solar peak of 8,352 MW. The previous peak of 8,310 MW was reached Aug. 5. Total renewables production on the CAISO grid reached 11,464 MW on Aug. 8 (see “Power Gauge” on next page).

In response to the expected heat, Western peak power prices jumped by $11 to $17/MWh over the trading week (see chart). California-Oregon Border posted the greatest gains, up $17.60 to $48.25/MWh.

Average nighttime power prices added between $3.50 and as much as $7.60/MWh in trading. Mid-Columbia posted the greatest increase, up $7.60 to $28/MWh.

Meanwhile, working natural gas in storage was 3,317 Bcf as of Aug. 5, according to U.S. Energy Information Administration estimates. This is a net increase of 29 Bcf compared to the previous week. Storage levels are now 12.2 percent greater than a year ago and 15.3 percent greater than the five-year average.

Henry Hub gas spot values dropped 22 cents in Thursday-to-Thursday trading, ending at $2.67/MMBtu Aug. 11.

Western natural gas prices followed suit, losing between 12 and 60 cents. Alberta natural gas posted the greatest loss, plunging 60 cents to $1.28/MMBtu by the end of trading.

Natural gas storage in Southern California has been relatively flat this summer, according to the EIA’s Aug. 9 “Today in Energy” report. The region has not injected inventory to meet demand for the upcoming winter as a result of the moratorium on injections at the Aliso Canyon gas-storage facility; currently storage there is limited to 15 Bcf. Other storage in the region is at 93 percent of capacity, or 46 Bcf, according to EIA estimates. Resumed natural gas injections at Aliso require regulatory approval; Southern California Gas Co. hopes to begin reinjection in September on wells that have passed safety tests (see story at [9]).

Linda Dailey Paulson
CEC Funds Clean-Energy Incubators, Microgrids, Water-Energy Nexus (from [5])

Money isn’t everything, as the old saying goes. But where would energy innovation be without it?

The CEC on Aug. 10 approved nearly $14 million in grants for water- and energy-saving technologies, clean-energy entrepreneurs in Los Angeles, and a Santa Monica microgrid to integrate renewable energy, energy storage and electric-vehicle charging.

$5 Million for Clean Energy Incubator

The Los Angeles Cleantech Incubator received the single largest grant, $5 million, to create the Los Angeles Regional Energy Innovation Cluster. The group will be a hub for clean-energy startup companies in the Los Angeles region, opening doors for clean-energy entrepreneurs by connecting them with local business and technical expertise to help commercialize their technologies.

“...program we are doing is an important part of our commercialization work,” CEC Chair Robert Weisenmiller said at a business meeting before the commission approved the Electric Program Investment Charge grant.

A CEC work-scope document for the grant does not name specific technologies to be commercialized through the Los Angeles incubator. It does, however, say that the technological advancements and “breakthroughs” should help to overcome barriers to state energy goals and greenhouse-gas emissions-reduction targets.

Specifically, the technologies should lead to “lowered customer energy usage intensity, increased electricity grid reliability, and grid safety”—in addition to slashing emissions. The recipient will collaborate with key energy stakeholders in four counties—Los Angeles, Orange, Santa Barbara, and Ventura—to identify regional energy needs.

It is the fourth such clean-energy cluster the CEC has supported, following previous grants for hubs in San Diego, the Bay Area, and the Central Valley.
**Santa Monica Microgrid**

The CEC also approved a $1.5 million EPIC grant for the City of Santa Monica to plan and design a microgrid integrating renewable energy, energy storage, electric-vehicle charging, and other distributed energy technologies in a local redevelopment area.

“This is a good example of what we are trying to do at the community level,” Weisenmiller said. The city intends to use the funds to design the so-called Santa Monica Advanced Energy District centered in an area known as the City Yards, which the city is planning to redevelop as part of a master plan. The microgrid will incorporate on-site energy systems at buildings in the district, including an arts center and a solar-powered mobile-home park.

Project designers will explore the use of various distributed energy resources such as photovoltaics, combined heat and power, energy storage, EV-to-grid technologies, and waste-to-energy systems.

The commission selected the Santa Monica microgrid project as part of a competitive solicitation—the EPIC Challenge—to advance microgrids across the state. In March, CEC staff recommended 13 projects, including the Santa Monica microgrid, to receive a total of $19 million, pending full commission approval.

**University-Based Research**

The University of California, Berkeley, received a $1.9 million EPIC grant to develop a system integrating advanced ceiling fans with intelligent thermostats. Fan speeds and the thermostats are able to adjust automatically. UC Berkeley will install the integrated system in low-income multifamily residential and small commercial buildings in disadvantaged communities throughout the state to evaluate their performance.

Five projects offering dual energy and water savings received EPIC grants totaling nearly $5 million. This included a $1 million research grant for UC Davis to assess cooling technologies to reduce overall water and energy use at dairies. The method showing the greatest promise will be pilot-tested at a dairy in Tulare.

Another recipient, Altex Technologies Corp., will develop and pilot-test a hybrid heat exchanger at an existing chiller system, while Kennedy/Jenks Consultants will pilot-test a novel membrane technology to increase water recovery and reduce energy demand at a wastewater-treatment plant. Two other companies—Lawrence Livermore National Security and Porifera Inc.—received grants to develop different energy-efficient approaches to treating water.

Each of the five projects addresses “the important nexus between water and energy in California,” said CEC Chair Weisenmiller, including several that “bring innovations from the energy space into the water space.”

A research foundation at California State University, Chico, received $75,000 to produce a documentary film about the prehistory of the Ford Dry Lake area in Riverside County. The area now is home to NextEra’s Genesis Solar Energy Project, a 250 MW solar-thermal power plant licensed by the CEC.

Construction of the facility turned up thousands of artifacts dating back more than 1,000 years. This discovery delayed project construction and required mitigation for impacts to cultural resources—the documentary film is part of that mitigation.

The 26-minute video production will explore ancient tribal lifestyles in an area prone to periodic flooding and drought. The project team will seek participation from the Mojave, Chemehuevi, and Cahuilla tribes. Weisenmiller said it was important to document the site’s prehistory “for posterity.”

**[12.1] Comments Due on PSA for AES’ Alamitos Gas Plant**

A CEC proceeding on AES Southland’s proposed 1,040 MW natural gas-fired power plant in Long Beach finally is reaching some critical milestones. After an Aug. 9 workshop on the CEC’s preliminary staff assessment of the proposed Alamitos Energy Center, stakeholder and public comments were due Aug. 12.

The largely favorable PSA, issued in July, found that the plant “would lead to a net reduction in [greenhouse-gas] emissions in California” and would not result in impacts “that are cumulatively significant.”

In addition, CEC staff found the plant “would provide flexible, dispatchable and fast ramping power in relatively small increments of capacity, which should improve the electric system reliability in a high-renewables, low-GHG system.”

The project would be built near AES’ existing 1,950 MW Alamitos Generating Station, which the company plans to decommission and demolish because of State Water Resources Control Board restrictions on the facility’s water-cooling system. The new facility would rely on air cooling.

The estimated $1.3 billion to $1.5 billion project would also feature up to 300 MW of battery-based energy storage, for which AES is seeking separate approval from the City of Long Beach.

The developer had hoped the CEC would approve the thermal-electric portion of the project by October. But CEC staff said that was not feasible. The commission expects to issue a revised schedule this month.

**[12.2] Tiff Erupts Over Gas Plant’s ‘Drought-Proofing’ Proceeding**

A fundamental disagreement over the scope of a proceeding to consider “drought-proofing” an existing 830 MW natural gas-fired power plant in Southern California broke out at an Aug. 11 status conference between the CEC and attorneys for the operator of the water-cooled facility.

“We obviously have some fundamental disconnects,” said Jeffery Harris, whose firm represents High Desert Power Project LLC, a subsidiary of Tenaska Inc., which operates the plant near Victorville.

“I am concerned about a lack of transparency,” Harris said, claiming that CEC staff was overreaching by revisiting issues related to the California Environmental Quality Act.
Since the CEC licensed the project in 2000, the facility owner has sought and received permission to expand its cooling-water options several times. Water use for plant cooling originally was restricted to State Water Project deliveries, but was expanded in 2009 to include local recycled wastewater. In 2014, the commission also allowed the temporary use of Mojave River Basin groundwater.

While High Desert’s temporary use of groundwater was set to expire at the end of September, the CEC in June granted a one-year extension to Sept. 30, 2017, and created a loading order that placed all other options ahead of groundwater (see CEM No. 1390 [10.1]).

The current proceeding addresses the plant operator’s petition, filed last fall, for permanent use of Mojave River Basin groundwater.

Commissioners Karen Douglas and Janea Scott, as well as CEC staff, vigorously defended their environmental concerns over the project’s water use.

A CEC issues report identified five topics of concern: recycled water, percolation of State Water Project water, groundwater, water quality, and reliability. The CEC, the California Department of Fish and Wildlife, the Mojave Water Agency, and the Victor Valley Water Reclamation Authority are working together to refine the scope of a water-balance study.

The study, which could take until next year to complete, will determine current inflows and outflows in the Mojave River Basin, “thereby informing the health of riparian habitat in the transition zone” affected by the project, according to an Aug. 8 CEC filing.

“This process may spur additional questions or topics appropriately addressed in this proceeding,” said CEC staff in the filing.

But in a written response to the commission’s issues report, Harris argued, “There is no need to further delay these proceedings with protracted regional modeling or processes.”

The attorney called for the committee to rely on evidence “that is already available” to expedite settlement discussions between the parties and a decision as early as the CEC’s next business meeting on Sept. 14.

Commissioner Douglas cautioned at the meeting, however, that such an ambitious schedule “is probably not happening.” The commission and applicants agreed to clarify their positions in future filings and meetings. It remained unclear, however, whether evidentiary hearings would be required, which would lengthen the proceeding.

PG&E Files Diablo Canyon Closure Plan at CPUC (from [4])

The $5.5 billion, 2,240 MW Diablo Canyon nuclear power plant is not needed. That is one of the conclusions owner and operator Pacific Gas & Electric reached in its Aug. 11 application at the CPUC to phase out its production of nuclear power by 2025 and replace it with a mix of energy efficiency, renewables and energy storage.

The application follows PG&E’s June 21 joint proposal with environmental and labor groups to close Diablo Canyon when its current operating licenses expire in 2024 and 2025. The proposal includes an unprecedented voluntary commitment by PG&E to a 55 percent renewable-energy target in 2031, higher than the state’s current 50 percent-by-2030 renewables portfolio standard target (see CEM Nos. 1391 [12] and 1392 [13]).

PG&E applied to recover close to $2 billion to cover the proposal, including $1.3 billion for an “early action” first tranche of 2,198 GWh of energy-efficiency resources that PG&E proposes to procure starting in 2018. And PG&E proposed new cost-allocation mechanisms to recoup costs for a second and third tranche of clean resources. The utility’s proposed revenue requirement does not include the estimated $1.8 billion the utility expects to recover in rates by 2025 for its investment in the plant, or the ballooning costs to decommission the facility once it is shut down (see CEM No. 1396 [19]).

But PG&E contends that operating the plant beyond its current licenses would cost far more. Utility forecasts indicate a substantial portion of Diablo Canyon’s output would not be needed beyond 2025, largely because California’s energy policies over the past decade have led to customer defections to community choice aggregators and direct-access providers, as well as higher procurement requirements for renewables, energy efficiency, and distributed generation.

“DCPP is a baseload power plant; therefore these changes have the effect of making DCPP a resource on the margin,” said Janice Frazier-Hampton, director of integrated resource planning in PG&E’s Energy Policy and Procurement group, in testimony on a Diablo Canyon needs analysis accompanying the application.

Frazier-Hampton said California’s clean-energy policy preferences for energy efficiency, renewables, combined heat and power, and other resources have displaced the need for much of the plant’s generation. Diablo Canyon currently generates about 18,000 GWh a year, and closer to 16,000 GWh when refueling outages are taken into consideration.

Also, as California continues to move closer to a clean energy future, a large non-dispatchable unit such as Diablo Canyon no longer ‘fits’ the needed generation profile of the changing energy landscape,” Frazier-Hampton said.

California is moving to an electric system with more reliance on flexible resources that can ramp up or down quickly, and this decreasing need for baseload generation is a challenge, Steven Malnight, senior vice president for regulatory affairs at PG&E, said in testimony.

Another challenge is ongoing costs to operate Diablo Canyon. The utility forecasts its annual revenue requirement to continue operating the plant beyond its current licenses would be close to $1.7 billion in

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[13] The application follows PG&E’s June 21 joint proposal with environmental and labor groups to close Diablo Canyon when its current operating licenses expire in 2024 and 2025. The proposal includes an unprecedented voluntary commitment by PG&E to a 55 percent renewable-energy target in 2031, higher than the state’s current 50 percent-by-2030 renewables portfolio standard target (see CEM Nos. 1391 [12] and 1392 [13]). PG&E applied to recover close to $2 billion to cover the proposal, including $1.3 billion for an “early action” first tranche of 2,198 GWh of energy-efficiency resources that PG&E proposes to procure starting in 2018. And PG&E proposed new cost-allocation mechanisms to recoup costs for a second and third tranche of clean resources. The utility’s proposed revenue requirement does not include the estimated $1.8 billion the utility expects to recover in rates by 2025 for its investment in the plant, or the ballooning costs to decommission the facility once it is shut down (see CEM No. 1396 [19]).

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2025, or $102/MWh, and more than $1.74 billion in 2030, according to the utility’s testimony. Those costs include cost recovery for existing book value of the facility, future capital expenditures, operations and maintenance, administrative and general expenses, and nuclear fuel expenses.

Ralph Cavanagh, co-director of the Natural Resources Defense Council’s energy program, said in a blog post the operating-cost estimate of more than 10 cents per kWh was among the “important new details” included in the proposal.

“NRDC continues to believe that substituting those zero-carbon resources for Diablo Canyon will save electricity users at least $1 billion,” Cavanagh said. NRDC helped negotiate the proposal and is a party to it.

Revenue requirements for the closure proposal, in contrast, total about $1.8 billion spread out over eight years starting in 2018. If approved as submitted, ratepayers would pay $64 million in 2018, about $251 million to $253 million a year between 2019 and 2024, and about $202 million in 2025.

In the application, PG&E seeks CPUC approval to implement four sections of the joint proposal:
- Procurement in three tranches of GHG-free resources to replace a portion of Diablo Canyon power.
- Employee retention and retraining programs totaling $363.4 million.
- Community-impact mitigation program totaling $49.5 million.
- A number of ratemaking and cost-recovery proposals.

PG&E estimated the first, 2,198 GWh tranche of procurement to replace Diablo Canyon power—consisting of energy-efficiency resources—would cost about $1.3 billion, to be recovered over seven years starting in 2019.

Tranche 2 costs, for contracts targeting another 2,099 GWh of GHG-free resources and/or energy efficiency starting when the first unit retires in 2024, would be recovered through the utility’s Energy Resource Recovery Account and a new Clean Energy Charge that would be assessed on all bundled customers as well as customers who departed the utility for community choice aggregation.

Tranche 3 contract costs, for RPS-eligible resources in a post-closure transition period, would also be recovered through the ERRA account and the Clean Energy Charge. In this third tranche, PG&E would procure renewable resources to bring its total RPS to 55 percent. Although PG&E estimates Tranche 3 procurement would total about 289 GWh, the exact amount would depend on PG&E’s bundled load at that time.

PG&E expects procurement under the three tranches to result in the addition of 4,586 GWh of GHG-free-generation equivalent energy in 2030.

While that is just 25 percent of Diablo Canyon's current output, PG&E and the other parties to the proposal say that is just a first step, and the tranches are not intended to procure everything that may be needed.

Todd Strauss, a senior director of energy policy, planning and analysis with PG&E, said in testimony that while the exact procurement costs for all three tranches won’t be known until procurement is completed, the utility expects an “upper bound” on costs of $105/MWh for 2025 and $113/MWh for 2030. Those figures represent levelized cost projections for renewables that might be expected to come online and a number of assumptions about the energy mix, transmission costs and tax credits, plus projected renewables integration costs.

Those non-bypassable charges appear to still be a sticking point. PG&E is still in talks with several parties, including CCA providers, the utility said in a news release announcing the application.

PG&E also proposed a so-called “self-provision option” for CCAs, through which a CCA provider could elect to self-provide GHG-free resources to reach a 55 percent RPS for 2031 through 2045. This would be in lieu of CCA customers paying the Clean Energy Charge component for Tranche 2 procurement.

Community choice aggregation provider MCE Energy did not return a call for comment by press time.

In addition to the revenue requirements, PG&E proposed implementation of a cost-recovery mechanism to fully recover its investment in the plant and bring its book value to zero by the end of 2024 for Unit 1 and by the end of 2025 for Unit 2. This cost, estimated at $1.8 billion, is already included in current generation rates, according to PG&E, but the utility proposed a new retirement balancing account so it can true up on an annual basis actual depreciation and capital spending on the plant.


Proposed resolutions up for CPUC consideration at an Aug. 18 business meeting would approve three long-term solar power-purchase contracts for Southern California Edison, and two energy storage contracts for San Diego Gas & Electric.

SDG&E entered the energy storage contracts with AES Energy Storage LLC to help deal with electric-system reliability risk in the Los Angeles Basin stemming from a continuing moratorium on natural gas injections and withdrawals at the Aliso Canyon gas-storage field.

A resolution the commission approved in May directed Edison to expedite in-front-of-the-meter storage deals that can be on line by year-end to deal with Aliso Canyon-related reliability issues. That resolution was modified to include SDG&E after comments recommending SDG&E leverage its 2016 Preferred Resources Local Capacity Requirement request for offers to seek projects that might be able to come on line in the same time frame, according to the resolution.

SDG&E is seeking approval of two storage engineering, procurement and construction contracts with AES. The first is a 30 MW/120 MWh lithium-ion battery storage project to be located at an SDG&E substation in Escondido, and the second is a 7.7 MW/30 MWh lithium-ion project in El Cajon. Both contracts state the projects will be on line by Jan. 17.

The Alliance for Retail Energy Markets and the Direct Access Customer Coalition protested the contracts.

Edison’s three 10-year contracts are with Luz III, IV, and V, for solar-thermal trough projects in Boron.
Each project would be 30 MW, and the projects are slated for commercial start dates of March 1, 2017, and Feb. 1, 2018. All of the projects are renewables portfolio standard-eligible and would count toward Edison’s RPS compliance in the 2017-2019 period.

Power-purchase costs for both the Edison and SDG&E contracts remain confidential at this time. Both sets of contracts are included on the consent calendar for the CPUC’s Aug. 18 business meeting.

COURTS

(from [1])

A federal jury on Aug. 9 found Pacific Gas & Electric guilty on six of the most serious counts against it in a criminal trial stemming from the September 2010 rupture of a gas transmission pipeline in San Bruno. The rupture and fire killed eight people, injured 58, and destroyed 38 homes.

The jury found PG&E guilty of one count of obstructing a federal probe into the blast—the National Transportation Safety Board’s investigation into the cause of the San Bruno incident—and five counts of knowingly and willfully violating minimum safety standards under the federal Pipeline Safety Act, relating to pipeline integrity management and identification of threats to a pipeline.

PG&E was found not guilty on six other counts, mainly related to recordkeeping for pipeline repairs and pressure testing.

PG&E plans to file a motion by Aug. 16 asking the court to acquit the guilty verdicts on the grounds that there is insufficient evidence to sustain a conviction. In criminal cases, such motions—filed under Rule 29 of the Federal Rules of Criminal Procedures—are often automatic or boilerplate, and must be done to preserve the right to appeal.

In this case, however, Steven Bauer, an attorney with Latham & Watkins LLP on PG&E’s defense team, asked Judge Thelton Henderson if the defense could file a 50-page brief, according to a transcript of the Aug. 9 proceeding, indicating that this will not be a boilerplate motion.

Sen. Jerry Hill (D-San Mateo), who has worked in the years since San Bruno to enact a number of pipeline-safety and CPUC reform bills, said that while he is very grateful the jury came in with this verdict, “the sad part is we now have a utility that is a convicted felon.”

The criminal conviction comes after previous federal and state investigations faulted PG&E for San Bruno. Several investigations at the CPUC into the disaster culminated in a record $1.6 billion penalty the commission levied last year against the utility. And in its 2011 final report on San Bruno, the NTSB determined the probable cause of the blast was PG&E’s inadequate quality assurance and quality control during the installation of a section of the ruptured line (Line 132). The section had a visible flaw in a seam weld, and NTSB determined PG&E’s pipeline integrity-management program failed to detect and repair the defect. The federal agency also found poor oversight at the CPUC was a contributing factor, as was an exemption of older, existing pipelines from regulatory requirements for pressure testing.

High Evidentiary Standard

A criminal conviction for Pipeline Safety Act violations is rare, in part because of the high standard prosecutors have to meet under the statute that a violation was made “knowingly and willfully,” said Rebecca Craven, program director with the Pipeline Safety Trust.

Earlier this year, during hearings on reauthorization of the Department of Transportation’s pipeline-safety program, Pipeline Safety Trust Executive Director Carl Weimer testified that the current statute sets the bar “unusually high for holding companies accountable for criminal behavior.” He advocated for aligning pipeline-safety rules with current rules for hazardous materials, which set a “willfully or recklessly” standard for criminal behavior.

During the criminal trial, PG&E had argued that all evidence and argument relating to San Bruno should be excluded, and throughout the case, attorneys for PG&E argued that no PG&E employees knowingly or willfully violated federal pipeline laws and that the incident was just a tragic accident.

Evidence at the trial, however, indicated PG&E willfully violated the federal law by failing to adequately gather, integrate, and assess information that would help it prioritize risks and threats to pipelines in high-consequence areas, or densely populated areas where a gas release poses a significant risk of injury or death.

PG&E knowingly relied on inaccurate information about Line 132, the prosecution contended, and failed to gather and integrate data about the pipeline that could be used to identify and evaluate potential threats, including the cause of 50 previous leaks on various segments of Line 132. Jurors also found the utility guilty of counts that it failed to identify and evaluate all potential threats to covered pipeline segments and failed to prioritize a covered pipeline segment as a high-risk segment.

Obstruction of Justice

On the obstruction charge, the prosecution proved beyond a reasonable doubt that PG&E intentionally endeavored by corrupt means to influence, obstruct or impede the NTSB proceeding. PG&E did so by sending the NTSB a letter dated April 6, 2011 regarding the utility’s policy on raising pressure on pipelines.

The letter stated that a utility policy of raising the pressure on several pipelines to their maximum allowable operating pressure—as a way to avoid
having to classify the lines as high-risk and subjecting them to additional testing—was a draft policy that had not been approved.

Under the PG&E policy, a line would be classified as high-risk only if pressure exceeded maximum operating pressure by 10 percent or more. The letter stated that this draft policy was never approved, without saying that the utility in fact followed this practice—in violation of the law—from 2009 to April 2011, according to the prosecution.

“The information from the NTSB investigation and the trial indicated very serious problems with PG&E management’s decision-making and their fundamental lack of knowledge about the pipe in the ground,” said Craven. “It is heartening to us that the Justice Department brought this case—it indicates the federal government takes pipeline safety seriously.”

Accountability and Trust

Nick Stimmel, a spokesperson for PG&E, did not respond to specific questions about whether any individual employee would be held accountable now that the guilty verdict was in.

“While we are very much focused on the future, we will never forget the lessons of the past,” PG&E said in a statement. “We have made unprecedented progress in the nearly six years since the tragic San Bruno accident and we are committed to maintaining our focus on safety. We want our customers and their families to know that we are committed to re-earning their trust by acting with integrity and working around the clock to provide them with energy that is safe, reliable, affordable and clean.”

Sen. Hill questioned how PG&E could be seeking to regain customers’ trust while still refusing to admit its guilt—and while seeking to overturn the guilty verdict. “To re-earn trust, first you have to admit you have a problem,” Hill said.

Mindy Spatt, a spokesperson for The Utility Reform Network, said TURN was not at all surprised by the verdict.

“PG&E gave safety short shrift and put profits ahead of safety,” she said, noting $5 million had been awarded to PG&E by the CPUC for work on the segment of Line 132 that ruptured, but the utility never spent the money on it. “The problem is not that the system was inherently unsafe, but that it was mis-managed,” she added.

A Small Fine

Each of the violations in the criminal conviction carries a maximum penalty of $500,000, meaning PG&E is facing a maximum penalty of $3 million, which is far less than 1 percent of the $206 million PG&E earned in the second quarter of this year.

PG&E said in a securities filing that its conviction “could harm its relationships with regulators, legislators, communities, business partners, or other constituencies” and make it more difficult to hire qualified employees and senior management. The utility may also face remedial measures in sentencing that it may not be able to recover in rates, it said, including a potential third-party monitor—something the City of San Bruno is advocating for.

After testimony in the trial wrapped up, prosecutors dropped their request to seek penalties of as much as $562 million under the Alternative Minimum Fines Act.

That development “was absolutely stunning,” Spatt said. “In our mind, the stronger the penalty the stronger the message,” she said. “The concern here is not only that PG&E be held accountable, but that it also send a message.”

Abraham Simmons, an assistant U.S. attorney and spokesperson for the U.S. Attorney’s Office, said his office could not comment on litigation strategy while a case is pending.

The case may remain pending for a while longer. Judge Henderson set an Oct. 11 hearing date for PG&E’s Rule 29 motion, with a sentencing hearing likely to follow. If PG&E decides to appeal, the case will linger even longer.

“There is always an opportunity to appeal, both the conviction and sentencing,” Simmons said. “So we are a long way from finality in this case.”

[Mavis Scanlon]

REGIONAL ROUNDPUP

[15] California Delays Regional Grid Bill to 2017 (from [2])

California Gov. Jerry Brown has delayed until early next year legislation required to transform CAISO into a regional grid operator for the Western U.S.

In Aug. 8 letters to leading California lawmakers and the governors of five Western states—Oregon, Washington, Idaho, Utah, and Wyoming—Brown cited “very significant progress” on the proposed regional-grid initiative but conceded “there remain some important unresolved questions that would be difficult to answer in the remainder of California’s current legislative session.”

CAISO had sought enactment of a bill this session to kick-start the formation of its proposed Western grid, which would combine the two largest transmission operators in the West—CAISO and PacifiCorp—by 2020 and expand to other balancing authorities in the Western Electricity Coordinating Council by 2030.

But with an Aug. 31 deadline fast approaching for lawmakers to pass bills in the final month of the two-year session, regional-grid legislation had not even been introduced as CAISO continued to revise its proposal for how a Western grid would be governed.

“I am confident that working collaboratively we can develop a strong proposal for the California Legislature and your regulatory authorities to consider...
in January,” Brown wrote in his letter to Western governors.

In July, CAISO circulated a governance proposal for stakeholder comments, along with a report on the impacts of regionalization on California. Western energy-market stakeholders, however, gave mixed reviews of both (see CEM No. 1397 [18.1]). Some California lawmakers also raised questions.

“If we do this, we need to make sure we do it right . . . Our climate leadership cannot be undermined,” Senate President Pro Tem Kevin de León (D-Los Angeles) told reporters during an Aug. 3 press conference.

The senator said he supported the initiative “in theory” as a way to “export our climate leadership to other states.” But he pointed to concerns over governance issues between California and other states, the complexity of the proposal, and its impacts on California.

Sen. De León’s SB 350, enacted last year, was the impetus for the regional-grid initiative. The law called for California utilities to derive 50 percent of their retail electric sales from renewable energy by 2030. It also directed CAISO to study the potential benefits of a regional grid and to develop a governance proposal to be submitted to the Governor’s Office by the end of 2017.

In separate letters to legislative leaders in Sacramento and Western governors, Gov. Brown said he directed his staff, the CEC, the CPUC, and CARB to continue working with the Legislature, CAISO, state and energy regulators, and other interested parties to refine the proposal.

The legislation would enable the creation of a transitional committee to develop a regional governance plan. PacifiCorp must then obtain regulatory approvals from its six state regulatory commissions to participate in the expanded regional grid.

PacifiCorp, a subsidiary of Warren Buffett’s Berkshire Hathaway Energy, was hoping to begin the process by late this year or early next. But that timeline appears delayed by several months at least, depending on when California’s Legislature actually passes the bill.

Delayed, Not Deterred

“We agree that more time is needed to work through remaining issues and that it’s better to get it right than get it fast,” PacifiCorp spokesman Bob Gravely told California Energy Markets.

“We appreciate that Gov. Brown is reaching out to leaders in the other states PacifiCorp serves and will continue working with everyone involved.”

CAISO echoed that sentiment.

“We look forward to working with stakeholders in California and throughout the western U.S. to further refine our governance proposal and any other remaining issues to ensure that all parties have ample time to fully evaluate the impacts of a western grid,” CAISO said in an Aug. 8 statement.

Pacific Gas & Electric’s Dede Hapner, vice president of FERC and ISO relations, said the utility, which has been supportive of the initiative, is “not at all disheartened” by the delay.

“The whole point of this is to make a lot of progress so legislation will be all ready to go,” she said. “The main thing is other states and the California Legislature have to feel comfortable enough to change the law. Taking a little more time getting more people comfortable makes sense.”

Bonneville Power Administrator Elliot Mainzer agreed.

“The ISO proposal is quite complex as Governor Brown has suggested,” Mainzer said in an email. “We support the decision to take more time given that complexity.”

Mainzer called “constructive, deliberate engagement” among the ISO and other interested parties on the proposal “absolutely necessary.”

As currently proposed, the Western grid would not include federal power-marketing agencies, but BPA would be involved in shaping it as a member of the Western States Committee.

CAISO currently is updating its process and timeline to allow for additional stakeholder input so it can launch legislation in January.

How a regional organization would be governed “remains the primary issue to work through before this can move forward,” said PacifiCorp’s Gravely. Other key issues are whether the expanded regional grid will include a method for tracking greenhouse-gas emissions and how transmission charges will be determined.

PacifiCorp believes any delay in finalizing the governance plan will “push back the schedule for the state filings,” Gravely added, as well as the actual go-live date for the expanded ISO.

‘Taking a little more time getting more people comfortable makes sense.’

Ben Tansey
**CARB Proposes Complying With Clean Power Plan Through Cap and Trade**
*(from [6])*

California can meet federal Clean Power Plan requirements with simple updates to the state’s cap-and-trade and mandatory reporting regulations, according to a [CPP compliance proposal](#) the California Air Resources Board issued Aug. 5.

The CCP establishes carbon-dioxide emissions performance rates for existing electric generating units, or EGUs. Proposed by the U.S. Environmental Protection Agency, implementation and enforcement of the rule was stayed earlier this year by the U.S. Supreme Court while litigation over the plan winds its way through the courts. Several states in addition to California continue planning efforts to meet requirements of the CPP.

CARB finds that a “state measures” approach would allow California to meet the greenhouse-gas emissions targets called for in the CPP, while ensuring smooth operation of California’s existing suite of climate programs.

“This approach maintains the efficient and effective” cap-and-trade program “without isolating affected EGUs in a CPP-only system,” the proposal notes.

Under California’s existing cap-and-trade program, new or existing electrical generating facilities are covered if annual emissions are at or above 25,000 metric tons of carbon dioxide-equivalent in a given year.

Covered entities must report and verify emissions in accordance with the mandatory reporting regulations, or MRR, which provides the core data used to implement cap-and-trade.

**EGUs affected by** the federal plan, according to CARB’s proposal, are defined as fossil-fueled units that began construction on or before Jan. 8, 2014; serve a generator connected to a utility power-distribution system with a nameplate capacity greater than 25 MW; and have a heat input rating greater than 250 MMBtu/hour, among other criteria.

A total of 249 generating units will be subject to the CPP, with a combined total of 38,015 MW of installed capacity, CARB determined.

Those 249 units are at 93 facilities, owned by 67 different companies.

The CPP’s implementation date is Jan. 1, 2022, with full reductions to be achieved by Dec. 31, 2031.

CARB staff calculated that the interim CPP target for the 2022-2029 period is about 423.9 million short tons of carbon dioxide-equivalent (CO₂-e), to be achieved over several interim compliance periods, and the final 2030-2031 target is about 100.6 million short tons of CO₂-e.

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**Even under a conservative scenario modeled as the base case, compliance with the CPP ‘is amply achieved.’**

The limit of 100.6 million represents the cumulative mass emissions allowed for the eight-year period of 2022-2029, or for the two-year period of 2030-2031, the proposal notes.

CARB has found, even under a conservative scenario modeled as the base case (under which California’s climate and energy laws and policies are not further tightened), that compliance with the CPP “is amply achieved.”

“An even more conservative stress case, which is designed to strain the system and emphasize conditions under which emissions from existing EGUs might increase, also achieves compliance,” the proposal notes. “In reality, California’s policy structure is likely to be substantially more stringently focused on reducing GHG emissions than either of the modeled scenarios, meaning that compliance with the CPP is assured, plausibly at emission levels well below those described in the modeled results.”

**CARB has already proposed** amendments to cap and trade that would allow the program to extend beyond 2020 in order to achieve a greenhouse-gas emissions-reduction target of 40 percent below 1990 levels by 2030, as established by executive order B-30-15.

A number of the amendments are geared toward the CPP, including aligning cap-and-trade compliance periods with those of the federal plan, and providing for a federally enforceable backstop set of emissions standards in the “extraordinarily unlikely” event that EGU emissions exceed federal targets (see CEM No. 1394 [15]).

CARB is also proposing amendments to “ensure congruent and appropriate” reporting of GHG emissions.

Staff plans to “carefully review any potential interactions” between the proposed CPP compliance plan and any amendments before finalizing the proposals. The plan and amendments are expected to go before the board for approval in the spring of 2017.

States’ initial CPP compliance plans were set to be due to EPA in September, with a possible extension of up to two years, although those deadlines fall under the Supreme Court stay.

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**Mendocino County Board Votes to Join Sonoma Clean Power** *(from [3])* Sonoma Clean Power has received a green light to expand its community choice aggregation service into neighboring Mendocino County.

The Mendocino County Board of Supervisors on Aug. 2 unanimously approved a CCA ordinance and a resolution requesting that SCP initiate generation service within unincorporated areas of the county.

Service to the county’s CCA-eligible cities—Fort Bragg, Point Arena and Willits—is also a possibility if they elect to join. The City of Ukiah has its own municipal utility and is thus off-limits to CCA service.

SCP went live in 2014 and serves all eligible areas of Sonoma County. Expanding to Mendocino County would increase SCP’s total load, currently about 2.3 million MWh, by about 19 percent, given service...
to unincorporated areas and the three cities, according to an analysis completed by staff.

In such an expanded CCA, greenhouse gas emissions would be reduced by about 19 percent, as SCP’s standard power supply has a higher percentage of renewables than that of incumbent utility Pacific Gas & Electric. There would be a minor impact on rates, either lowering or raising them by about 1 percent for all SCP customers over the next three years.

In exploring various CCA options, including launching a new program and contracting with a third-party service provider, the county ultimately found joining SCP is the most sensible way to achieve such goals as reducing electricity-related greenhouse-gas emissions, providing greener power at a competitive cost, and achieving long-term electricity stability.

“This is certainly the best available, and possibly the only available opportunity for us to put in place a CCA program for Mendocino County,” said Supervisor John McCowen.

The two counties have worked collaboratively to address water- and energy-related resource issues, through the North Coast Resource Partnership and other initiatives. Officials said joining forces on CCA will build on that relationship.

“When we were starting this program several years ago, the thought of expanding to other areas came up several times,” said Cordel Stillman, SCP consultant and deputy chief engineer at the Sonoma County Water Agency. “It was always felt that the best place to expand would be to the north.”

One outstanding sticking point is the representation Mendocino County and the cities will have on the SCP governing board, which makes key operational decisions. The board currently has nine members, one representing unincorporated areas of Sonoma County, and a director representing each participating city.

Under the conditions approved by the SCP board in July, Mendocino County would be entitled to two seats: one representing the county and a second collectively representing the cities if all three join (see CEM No. 1395 [15.1]).

In anticipation that one of the mayors may decide not to move ahead with CCA participation, Mendocino County supervisors expressed concern about having just one seat on the SCP board.

“I don’t think it’s a deal-breaker at this point, but I think it’s important to this board that we have two seats, assuming we have at least two cities,” stated Mendocino County Supervisor Dan Hamburg.

Supervisors also emphasized that outreach to elected officials and potential customers in the cities is critical for CCA acceptance.

“I would bet the penetration of understanding in this county of what a CCA is is probably 1 or 2 percent,” Hamburg said. “We have a big educational job ahead of us.”

The addition of Mendocino County would not materially change SCP’s negotiating position with power suppliers, according to staff.

“On the plus side, it would somewhat increase our volume purchases and make SCP slightly more attractive to energy sellers,” notes a July staff report from Sonoma Clean Power. “On the minus side, we have significantly filled SCP’s energy needs at favorable prices through 2020, and expanding the territory would require additional purchases that are likely to be at higher prices as the market probably moves upward.”

Under SCP’s current timeline, generation service would begin in Mendocino County in June 2017. The SCP board still needs to take a final vote in October to keep the ball rolling.

[171] LADWP Announces Retirement of General Manager Marcie Edwards

The Los Angeles Department of Water & Power announced Aug. 1 the retirement of Marcie Edwards, the public utility’s general manager of more than two years. LADWP’s chief operating officer, David Wright, will replace Edwards on an interim basis.

Edwards “guided and stabilized the utility through a critical moment in its history,” the announcement notes, effectively navigating LADWP through the botched implementation of a new customer billing system, building support for a rate-increase plan to enable critical infrastructure investments, and keeping the utility on track to eliminate coal-fired generation from its power supply.

“When I took office, LADWP was facing difficult challenges—we needed a visionary leader to put our utility back on track, and that’s exactly what Marcie Edwards has done,” Los Angeles Mayor Eric Garcetti said in a statement. “She has left an indelible mark on our city, and I am deeply grateful for her service.”

Wright joined LADWP in 2015 and focused on fixing the billing system and improving customer service. For nearly a decade, he served as general manager of Riverside Public Utilities.

“I will do everything I can to make LADWP a utility that not only focuses on infrastructure, reliability and sustainability, but that strongly focuses on improving service levels to our customers to significantly higher levels,” Wright said in a statement. “It’s important that LADWP makes it easy to do business with us by working better and more efficiently for our customers than ever before.”

Edwards officially steps down as GM on Aug. 16 and will continue to assist with the transition.

She will serve as special adviser to the mayor, the LADWP board, and Wright through Dec. 31.
Utility Net-Energy Metering Case Moves Closer to Final Vote (from [7])

In a potentially precedent-setting general rate case, the Arizona Corporation Commission on Aug. 11 moved a step closer to deciding whether to approve mandatory demand charges for UNS Electric’s residential net-energy metering customers.

In approving at an Aug. 11 meeting a number of decisions related to the first phase of UNS’ general rate case, the ACC adopted a schedule for ruling on demand charges for net-energy metering customers. The commission also decided many parts of UNS’ proposed general rate increase.

But before tackling NEM, the commission wants to get a report in October in a separate proceeding looking at the costs and benefits of rooftop solar. The ACC then will start the second phase of UNS’ rate case, where net-energy metering rates will be designed and submitted for a commission vote by March 2017.

UNS, an affiliate of Tucson Electric Power, serves mostly rural, low-income customers who live around Lake Havasu City and Nogales, Ariz.

Commissioner Bob Burns, the sole dissenter in the UNS rate case, said he was concerned with increasing rates for customers facing economic challenges.

While UNS no longer supports mandatory demand charges for non-solar residential customers, it hopes to persuade the commission next year to adopt mandatory demand charges for net-energy metering customers. The demand charges would be based on the highest one-hour kilowatt of use during peak periods.

According to UNS, residential customers with 7 kW of solar PV panels get a $642 yearly subsidy from other customers, but comprise only 2 percent of total residential customers.

“This commission gave solar more life,” Commissioner Bob Stump said after voting on the first half of the UNS Electric rate case.

“The big lie that the commission is anti-solar will continue,” but Stump said he was confident Arizonans “will reject criticism and cynicism.”

Solar advocates applauded the commission’s rejection of some of the UNS proposals.

“UNS Electric’s drastic proposals would bring rooftop solar growth to a halt,” Earthjustice attorney Michael Hiatt said in a statement. “The decision sends a powerful message to Arizona utilities that the commission will not simply rubberstamp their anti-solar agenda.”

And Court Rich, an attorney for The Alliance for Solar Choice, said NEM customers accounted for only 2 percent of utility cost shifts UNS alleges. Rich said 95 percent of low-usage bills have nothing to do with rooftop solar, but result from factors such as vacant homes and seasonal residents.

Stakeholders disagreed whether UNS residential customers understand demand charges, but agreed customers don’t have load-management systems for minimizing demand charges.

UNS expects to have smart meters, which can measure demand, installed for all of its residential customers by fall 2016.

Solar Rates So Far

While the demand-charge issue remains to be resolved, the commission’s decision in the first half of the rate case would increase residential rates by 14.5 percent, but large-commercial and industrial rates will increase only 5 percent.

As part of that decision, the commission approved a $1.58 monthly charge for providing new residential NEM customers with a second meter needed for rooftop solar. UNS Electric asked for a $6.95 monthly meter fee.

The commission also decided not to change the rates of the 1,800 UNS Electric residential customers with existing rooftop solar. Any customers who connect to the grid before the March rate-design decision also will qualify for current NEM rates.

For new residential customers with rooftop solar, UNS proposed to use a “renewable credit rate” to compensate NEM customers for excess rooftop-solar power fed into the grid, at about half of the current 11-cent retail energy rate used to pay for excess customer generation.

The renewable credit rate would be 5.84 cents/kWh, the same price Tucson Electric Power pays under its latest power-purchase agreement for photovoltaic energy.

NEM Customers Get Option

The commission, however, gave new net-energy metering customers an option to instead choose the so-called RPS Credit Option.

The proposed RPS Credit Option would give net-energy metering customers the opportunity to lock in excess-power credit rates over 20 years. It would start at 11 cents/kWh and ratchet down in nine steps to 5.5 cents, with the steps based on the amount of additional MW of rooftop solar installed in UNS’ service areas.

The RPS Credit Option is designed to complement Arizona’s renewables portfolio standard, which is called the Renewable Energy Standard and Tariff. The REST reaches 15 percent of retail power sales by 2025. The standard also requires utilities to obtain 50 percent of the REST annual minimum from distributed generation.

TOU Rate for Non-Solar Residents

For non-solar residential customers, time-of-use rates will be the default rate after a transition period of six months or more. Ratepayers will be allowed to opt out of TOU rates.
Peak times will be 3 p.m. to 7 p.m. in summer and 6 a.m. to 9 a.m. and 6 p.m. to 9 p.m. in winter.

The commission increased the residential basic service charge to $15 monthly, up $10 monthly currently. However, residents who use TOU rates will pay only a $12 monthly basic service charge.

As part of the UNS rate-case decision, the commission also adopted a proposal from Commissioner Andy Tobin to establish a system benefit charge for 10 years. The charge will be collected by levying a kWh charge against all customer classes.

The system benefit charge will be used to compensate new rooftop-solar customers at the value determined for solar DG based in the ACC’s pending value-of-solar case. If the commission determines solar DG is worth less than the retail rate, the funds would be used for other purposes.

Those purposes include developing energy efficiency, demand-reduction technology, and energy storage devices. Also, extra funds would be used to compensate utility shareholders for fixed charges and to reduce the purchased power and fuel adjustment-clause liabilities for utility customers.

[18.1] Nevada Supreme Court Says No to SolarCity’s No Solar Tax PAC

The Nevada Supreme Court has blocked SolarCity’s effort to ask voters to change the statute that led to increased net-energy metering rates for residential customers.

On Aug. 4, seven Nevada Supreme Court justices unanimously ruled that the referendum gave petition signers an unsatisfactory description of the purposes and consequences of passing the referendum. The referendum description was inaccurate, misleading and argumentative, according to the court.

The Supreme Court decision is a victory for Citizens for Solar and Energy Fairness, a political action committee that received most of its funding from Nevada Power, and a loss for No Solar Tax, a PAC funded by SolarCity.

The lawsuit revolved around the decision of the Public Utilities Commission of Nevada to increase rates for net-energy metering starting in January 2016.

No Solar Tax in January petitioned the Nevada Secretary of State to put a NEM referendum on the November ballot, allowing voters to revise Senate Bill 374.

SB 374, which became law in June 2015, directed the PUCN to determine if NEM rates should be raised.

No Solar Tax obtained 120,000 voter signatures on its petition, more than twice the 55,000 needed to get the referendum on the November general election ballot.

In February, the Citizens PAC filed a lawsuit in the First Judicial District Court in Carson City to stop the referendum. In April, District Judge James Russell ruled the No Solar Tax referendum was invalid, accepting Citizens’ argument that a referendum can only serve to approve or reject a statute.

No Solar Tax, Russell said, used a “piecemeal approach” to change various portions and words of the statute. As a result, he said, No Solar Tax should have filed the matter as an initiative rather than a referendum.

The Aug. 4 Supreme Court decision affirmed Russell’s decision for a different legal reason than the one Russell cited.

The state Supreme Court said the referendum sought to change SB 374. The description failed to mention that the referendum “would remove the PUCN’s power to set specific net metering rates altogether,” the high court said.

Also, the court said the referendum description used terms not in the statute, such as “green energy.” The description also contained “argumentative” language calling new NEM rates “unaffordable and cost-prohibitive,” the Supreme Court ruled.

The Supreme Court did not comment on the district-court ruling that No Solar Tax should have filed an initiative, rather than a referendum.

Bring Back Solar Alliance, which supports the No Solar Tax PAC, said it was disappointed with the Supreme Court decision.

Bring Back Solar intends to work with legislators, stakeholders, and solar supporters in Nevada to promote solar. “We look forward to crafting strong solar policies that give Nevadans the freedom to power their homes and communities with clean solar energy,” Erin McCann, Bring Back Solar campaign manager, said in a statement. –J. E.

[19] Clinton, Trump Highlight Competing Energy Plans (from [8])

Hillary Clinton called for a “more resilient power grid” to deliver renewable energy “to power every home in our country,” while Donald Trump vowed to boost coal, oil, and natural gas production.

Democratic nominee Clinton, speaking Aug. 11 in Warren, Mich., said the U.S. should aim to be the “clean energy superpower,” ahead of competitors Germany and China. “We invent the technology, we should make it and use it and export it, which will help to grow our economy,” she said.

The former secretary of state also called for increased technical education and skills training through increased apprenticeships.

Republican nominee Trump, in an Aug. 8 speech in Detroit, bashed Environmental Protection Agency regulations adopted by the Obama administration, and said he would “unleash an energy revolution that will bring vast new wealth to our country.”

The New York businessman quoted an Institute for Energy Research study saying that “lifting the restrictions on all sources of energy” would increase gross domestic product by $100 billion annually. Trump, however, did not specify what restrictions he would lift.

He also vowed to impose a freeze on new regulations upon taking office.
**Interior Warns Against Coal Self-Bonding**

An Interior Department agency warned states against accepting new self-bonds for coal-mining reclamation requirements until at least 2021, in an unprecedented advisory released Aug. 9.

Citing bankruptcy filings of major coal producers, Interior’s Office of Surface Mining Reclamation and Enforcement said the “projected significant further reduction in the market for coal raises serious questions” about allowing financially stressed coal producers to self-bond for meeting requirements of the Surface Mining Control and Reclamation Act of 1977.

Joe Pizarchik, the office’s director, said in a statement that the coal industry is under stress from “lack of global demand” and competition from low-cost natural gas.

The advisory—the first such document the office has issued—was sent to the 24 “primary” states, including six Western states, operating surface coal-mining regulations under Interior-approved state programs. Nineteen of the primary states accept self-bonding, which is allowed but not required. Earlier this year, Colorado stopped accepting self-bonds.

The advisory cautioned against new self-bonds until the coal market reaches “equilibrium,” which it said would likely not occur for another five years.

The document advised states to look into the financial health of companies that have self-bonded. In addition, it said, companies emerging from bankruptcy as reorganized firms should be in existence for at least five years before being eligible for self-bonding.

Congressional Democrats who have raised concerns about self-bonding praised the advisory. Rep. Raúl Grijalva (D-Ariz.), ranking Democrat on the House Natural Resources Committee, said states “following this guidance will save taxpayers money and make the coal industry more financially transparent.”

Grijalva and two other House Democrats said the guidance accepted many recommendations they made in a June 10 letter to Interior Secretary Sally Jewell. In the letter, they said self-bonds are not covering reclamation costs, noting that Arch Coal had $485 million in self-bonds in Wyoming when it filed for bankruptcy, while Peabody Energy, which also filed for bankruptcy, had $1.47 billion in self-bonds in five states, including Colorado, New Mexico and Wyoming.

**Western Energy Group Sues BLM Over Leases**

An oil and natural gas producers group on Aug. 11 filed suit in federal court alleging the Bureau of Land Management has failed to conduct quarterly lease sales required by federal law.

In a suit filed in U.S. District Court for the New Mexico District, the Western Energy Alliance said six BLM state offices, including five in the West, failed to carry out Mineral Leasing Act requirements to conduct quarterly lease sales in each state with eligible acreage.

The group’s law firm, Baker Hostetler, accused the Interior Department of carrying out “the politicized agenda of special interest groups and the environmental lobby’s ‘Keep It in the Ground’ campaign.”

**FERC Authorizes Apple Subsidiary to Sell Energy**

FERC on Aug. 4 authorized Apple Energy to sell solar energy, capacity, and ancillary services at market-based rates.

Apple Energy, a wholly owned subsidiary of the Cupertino, Calif.-based technology giant, has acquired 130 MW of capacity under a long-term power-purchase agreement with the California Flats LLC solar-photovoltaic plant in southeastern Monterey County.

In addition, Apple Energy owns the 50 MW Bonnybrook PV project, under construction south of Phoenix, and the 19.9 MW Fort Churchill PV plant in Nevada’s Lyon County.

**EPA Pushes Back on States’ CPP Argument**

EPA on Aug. 2 said states’ argument that an appeals court’s regional-haze ruling backs up their Clean Power Plan challenge doesn’t hold water.

In a letter sent to the U.S. Court of Appeals for the D.C. Circuit, Justice Department environmental attorney Eric Hostetler said the 5th Circuit Court of Appeals’ July 15 ruling “adds no support” to more than two dozen states’ argument that EPA failed to adequately assess the CPP’s potential impacts on grid reliability.

In a July 27 filing, the states pointed to the 5th Circuit’s overturning of EPA’s rejection of regional haze-control plans adopted by the states of Texas and Oklahoma.

EPA has cited the Clean Air Act’s Section 111(d) as authority for adopting the CPP, which calls for reducing power-plant CO₂ emissions 32 percent below 2005 levels by 2030, through enforceable state emissions-reduction plans.

**EPA: Emissions Down Since 2005, Up From 1990**

U.S. greenhouse-gas emissions have fallen 7 percent since 2005, but are up 7 percent over 1990 levels, EPA said in a climate-change trends report released Aug. 2.

While power generation holds the highest long-term share of emissions, at 51 percent of all emissions since 1990, the electricity sector’s CO₂ emissions fell 15 percent between 2005 and 2014, from 2.4 billion metric tons to 2.04 billion metric tons, EPA figures show.

The report noted that declines in snowpack feeding river flows have been measured in all 11 West Coast and Rocky Mountain states. “Decreases have been especially prominent in Washington, Oregon, and the northern Rockies,” the report noted.

Declines exceeding 80 percent have been measured at stations in north-central Montana, southeastern Oregon, and central Arizona, according to EPA’s report.