CALIFORNIA ENERGY MARKETS®

NewsData LLC, Seattle & San Francisco: August 2, 2019 • No. 1550

BILLBOARD

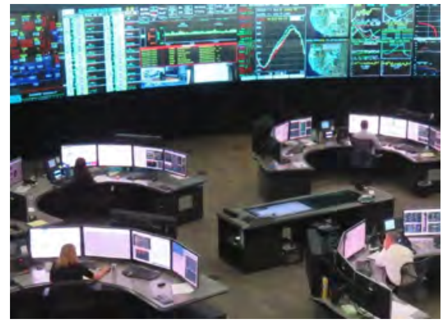
PRICE REPORT

Western Energy Prices, Demand Soften *Details on Page 4.*

ENERGY JOBS PORTAL

THE WEEK IN SUMMARY

[1] A 'New Reality': California Prepares for Public-Safety Power Shut-Offs



CAISO is preparing for impacts to the grid from public-safety power shut-offs. *Photo: Jason Fordney*

California's elected officials, utilities, grid operators and emergency responders are ramping up new efforts to combat utility-caused wildfires and preparing for public-safety power shut-offs. The California Independent System Operator said it might have to do additional load shedding in certain situations to maintain bulk electric system reliability. ***At [14], utilities and system users adapt to a new age of severe wildfire risk.***

[2] PG&E Disputes News Media Allegation of Past Transmission-System Work Delays

Pacific Gas & Electric attorneys in a July 31 filing disputed a news media report that the utility had delayed work on its transmission system despite knowing it could spark wildfires. In the filing, submitted to U.S. District Judge William Alsup in response to his order to explain the report, the company said it has not ignored investing in its infrastructure. Separately, utility representatives faced criticism at a Santa Rosa hearing on its 2020 general rate case application. ***At [15], PG&E mounts a vigorous defense of transmission work.***

[3] CPUC Tweaks Energy-Efficiency Funding

The California Public Utilities Commission at its Aug. 1 meeting approved a series of modifications to the "three-prong test" used to evaluate whether fuel-substitution programs can access energy-efficiency funding. Environmental groups argued in a 2017 motion that the test should be re-examined because of the state's changing energy landscape. But other groups are concerned that the changes lay the groundwork for electrifying buildings without considering associated costs. ***At [9], removing a "long-standing barrier."***

[4] Arizona Regulators, Stakeholders Explore Electric Restructuring in Workshop

Participants in Arizona's energy industry joined regulators for a two-day discussion of the pros and cons of restructuring in Arizona. The idea enjoys strong support, but Arizona Corporation Commission legal staff advised commissioners that establishing new rules might require workarounds not needed elsewhere, and incumbent utilities are encouraging a slow approach. ***At [18], Arizona regulators revisit restructuring.***

[5] Senate Transport Bill Funds Electric-Vehicle Charging Infrastructure

The Senate Environment and Public Works committee on July 30 unanimously reported out a five-year, $287-billion transportation bill that would authorize $1 billion in competitive grants for charging and fueling infrastructure for electric, hydrogen and natural gas-fueled motor vehicles. Meanwhile, the Senate Commerce, Science, and Transportation Committee reported out a bill requiring the federal pipeline agency to finalize within 90 days proposed safety regulations for gas gathering lines. ***Bill to speed permitting of renewables on federal lands draws broad support, at [20].***

NEWS IN BRIEF

[6] CCAs Pooling Resources to Create Integrated Resource Plans

Six California community choice aggregators issued a joint request for proposals seeking technical consulting services for creation of their next integrated resource plans.

The RFP was issued by Clean Power Alliance, East Bay Community Energy, Monterey Bay Community Power, Peninsula Clean Energy, San Jose Clean Energy and Silicon Valley Clean Energy "to obtain economies of scale and to coordinate and optimize resource planning efforts," the CCAs said.

> 'It gives us all a common set of assumptions.'

Under the proposal, the aggregators want a consultant to create one overarching joint CCA IRP, which will then be used to create individual plans. The process requires assessing state environmental and reliability requirements, EBCE CEO Nick Chaset said, and allows the CCAs to benefit from applying economies of scale to joint planning.

The primary rationale for undertaking combined resource planning, Chaset said, is for the CCAs to proactively address "some of the concerns we have heard in the Legislature and CPUC." One is that a "central buyer" is needed because CCAs are disaggregated and unable to plan adequately.

Procurement is not addressed in the document, but Chaset said a joint IRP "helps as we continue to look at joint procurement . . . It gives us all a common set of assumptions."

CCAs, along with investor-owned utilities and electric service providers, filed their first IRPs with the California Public Utilities Commission in August 2018. Of those, 20 IRPs were approved or certified in April; nine were deemed exempt; and another 19 "did not provide the required information about criteria pollutants associated with the resources serving their load," according to an April 25 proposed decision from CPUC Administrative Law Judge Julie Fitch.

The latter category included 17 CCAs, which were due to file advice letters containing the missing information before June 14 to have their IRPs approved.

The CPUC said that because some of the IRPs are vague in differentiating between contracted services and desired future procurement choices, load-serving entities must submit informal information on each of the contracts and the development of each source in their portfolios by Aug. 16. This will be a requirement in the 2020 IRPs, as the commission said it was "unable to distinguish between resources that represented existing contractual obligations and generic aspirational choices made by LSEs to round out their portfolios" (see CEM No. 1537 [11]).

Chaset said planning jointly will introduce some uniformity to the process when or if some IRP requirement parameters are unclear or open to interpretation, helping both the CCAs in preparation of documents and the commission in their review. It also "goes hand in hand with local control" as the IRP merely outlines the planning needs, leaving procurement decisions to individual CCAs' discretion.

"We expect to have the same amount of local control we currently have," Chaset said.

The deadline to respond to the RFP is Aug. 12. The fast-tracking is due to the deadline for 2020 IRPs, which are due in May 2020. Chaset said more CCAs are welcome to join, but they initially "wanted to get a critical mass of CCAs to get this RFP out." Those participating represent 69 percent of state CCAs' overall load.

A contract for the technical consulting service is expected to be awarded Aug. 28. ***–L. D. P.***

[6.1] APS Plans to Purchase 400 MW of New Solar and Wind Resources

Arizona Public Service plans to add a combined 400 MW of solar and wind resources to bring its renewable-energy portfolio to 2.5 GW by 2022.

The Phoenix-based utility, Arizona's largest, in a press release issued July 29 said it plans to issue two requests for proposals by Sept. 15. The first RFP will be for up to 150 MW of APS-owned solar resources to be sited in Arizona and designed with the option to add energy storage in the future. No further details regarding location or connection have been made available, APS spokeswoman Jenna Rowell said in an email.

A second RFP will seek up to 250 MW of wind at a location yet to be determined. APS wants to put the wind resources into service "as soon as possible" and not later than 2022, according to the release.

A third-party, independent monitor will review the entire procurement process for each RFP, and the company will release more specifics about its solicitations in the coming weeks, the company said. ***–A. S.***

BOTTOM LINES

[7] California's Rural Hydro Owners Fight to Avoid Buying Unneeded Solar Power

Large hydroelectric facilities currently don't count toward the state's renewables portfolio standard, rankling rural utilities that say they will have to spend hundreds of millions of dollars for renewables they don't need in coming years.

The Turlock Irrigation District and other rural public utilities are hopeful that legislation will pass next year that will permit them to count large hydro resources toward the renewables goals set out in SB 100. But they face a tough fight in a highly politicized and volatile California energy environment.

Legislation that failed to pass this session but could be revived next year, SB 386, introduced by Sen. Anna Caballero (D-Salinas), would have allowed TID and Modesto Irrigation District to count the output from the 203-MW Don Pedro hydroelectric project toward the 2030 renewables portion of the state's RPS (see CEM No. 1539 [10]). Opponents of the legislation see it as a slippery slope affecting California's climate goals.

Support for SB 386 faltered near the end of the session, as the architects of SB 100 and labor unions fought the bill, partially on the grounds that it would stifle development of renewables in the state. Existing hydroelectric facilities larger than 30 MW count toward the state's 100 percent zero-carbon resources by 2045 goal, but not the 60-percent-by-2030 RPS requirement.

"The argument that this would dramatically impact the state's climate goals—it's just not factual," TID spokesman Josh Weimer said of the bill. He questioned why the state was taking incremental steps toward 100 percent renewable/zero-carbon energy and said the 2030 date is "random." The amount of generation that comes from Don Pedro is a tiny fraction of its resource mix, which includes wind, solar and natural gas, he said.

TID is over-procured, and now must go out and purchase 200 MW of RPS-eligible power, which is estimated to represent a $300-million commitment to meet the RPS, Weimer said. Even if Don Pedro is counted, the utility will have to procure renewables it doesn't need, he said.

TID provides irrigation water to a 307-square-mile service area that incorporates 150,000 acres of Central Valley farmland, and has a customer base of 100,000 residential, farm, commercial, industrial and municipal accounts in a 662-square-mile service area.

The utility supports SB 386 because the current structure of SB 100 forces it to purchase energy its customers don't need. But the utility did not propose the legislation, rather coming on board after it was introduced, Weimer said.

"We believe in renewable energy—that is the direction that TID is moving," he said. "We are in no way trying to get out of that." The bill would delay purchases of unneeded energy and give time for technology to help with hydro balancing, he argued.

Don Pedro Dam and powerhouse. ***Photo: Turlock Irrigation District***

"The risks associated with these capital expenditures are borne directly by ratepayers in a region consistently recognized as economically distressed," a briefing by Caballero on SB 386 says.

"These are not new arguments," RL Miller, political director of Climate Hawks Vote, a super PAC that pushed for SB 100, said in a phone interview. She added that the same arguments were considered during deliberation of SB 100 and "explicitly rejected." The intent of the new renewables law was to create conditions where the market for wind and solar would grow, she said.

"The general idea is, by not allowing the competing arguably clean sources of energy to count, it creates conditions where solar and wind become the default," Miller said. "They end up as substantially less expensive than anything else."

Miller said the renewables-development argument is just one facet of the debate. Hydroelectric generation fluctuates based on seasonal rainfall, she said, and when hydro is at reduced levels, natural gas generation often makes up the difference. With SB 100 and renewables, "the intent here is to grow or create unstoppable market momentum," Miller said.

But when asked if the actual impact to renewable-energy development from SB 386 had ever been quantified, Miller said she didn't know.

In any event, the momentum toward 100 percent renewables is well underway in California—with some possible pitfalls along the way, such as the bankruptcy of Pacific Gas & Electric, which holds tens of billions of dollars in power-purchase agreements to meet SB 100.

Whether the pursuit of renewables is overzealous is in the eye of the beholder, as is the scope of the sacrifice that should be made, and in what time frame. But adjustments to the trajectory of SB 100 might be in order if the "affordable" part of the California energy equation has any hope of persisting, especially with so many other uncertainties facing energy consumers. ***–Jason Fordney***

WESTERN PRICE SURVEY

[8] Western Energy Prices, Demand Soften

Western energy prices decreased through the trading week on lower electricity demand.

After peaking at 42,195 MW July 26, California Independent System Operator demand dropped by roughly 4,700 MW by July 30. Demand stayed below 39,000 MW over the next two days, a trend expected to continue until Aug. 5, when demand is forecast to reach 42,000 MW.

Western daytime power prices dropped the value gained in the previous trading week, with hubs losing between $12.50 and as much as $22.50 in July 25 to Aug. 1 trading. Palo Verde lost the most, down $22.50 to $35/MWh—a 39-percent drop.

Western off-peak prices dropped between $3 and $5 in trading. Pacific Northwest hubs fell 21 percent by week's end. Nighttime power values ranged from $20.75/MWh at Mid-Columbia to $28.55/MWh at both North and South of Path 15 by Aug. 1.

Total renewables on the CAISO grid reached 15,935 MW July 29, meeting roughly 40 percent of demand. Thermal generation sources fulfilled 20,567 MW, or slightly more than 52 percent, of demand July 25.

Most Western natural gas prices fell by between 6 cents and 78 cents in July 25 to Aug. 1 trading. El Paso-Permian natural gas dropped the most, tumbling 78 cents to 34 cents/MMBtu. Alberta gas was the exception, climbing 68 cents to $1.04/MMBtu.

Notably, SoCal CityGate natural gas remained above the $3 mark despite losing 50 cents in trading. It ended at $3.03/MMBtu Aug. 1.

Several transmission lines in the area of the Tucker Fire were de-energized July 28 and 29 for fire crews' safety, according to CAISO, which issued both transmission emergency notices and grid warnings. Several 500-kV transmission lines as well as two lines of COI/Path 66 were forced out of service July 28. The warning for the latter became a transmission emergency, which ended July 30.

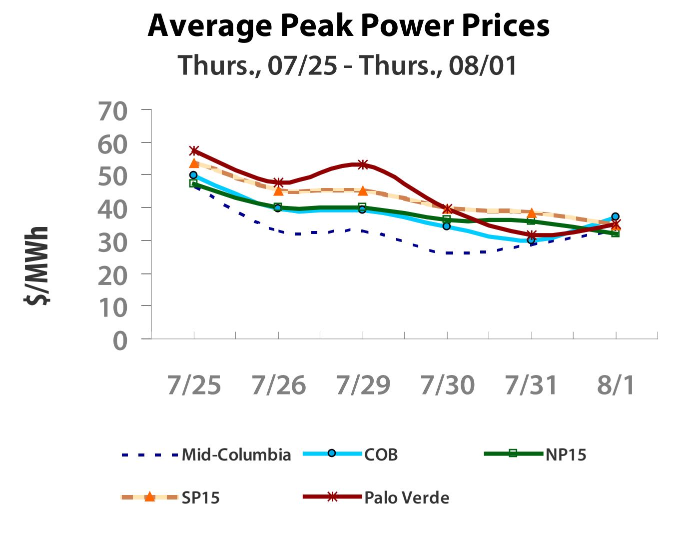
The Modoc County fire has burned 14,217 acres and is 74 percent contained as of Aug. 2, according to the InciWeb incident information system.

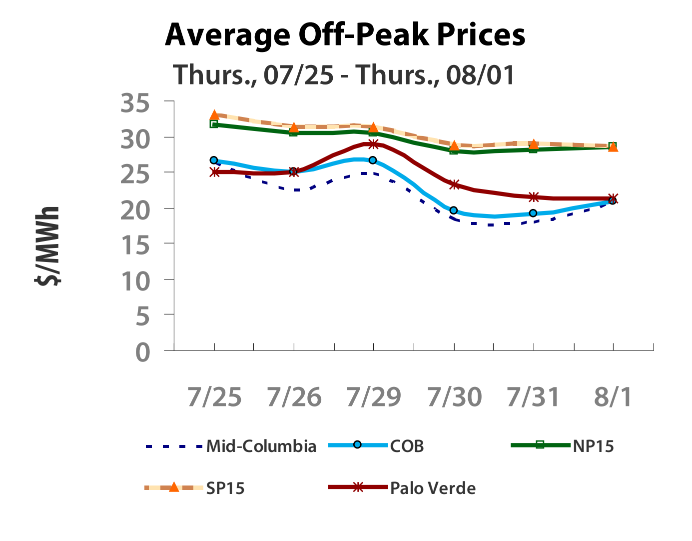
Energy prices in July were significantly lower than they were a year ago, when searing heat hit the region.

In July, the average high peak price at Henry Hub was $2.49/MMBtu, 41 cents lower than in 2018 (see "Price Trends," next page).

Western natural gas hub prices in July generally dropped between 32 cents and as much as $7.90 compared with the previous year, save for PG&E CityGate, which was 12 cents higher at $3.29/MMBtu. SoCal Border natural gas reached $2.92/MMBtu, which was $7.09 lower than in 2018.

Average Western power prices were between $172.85 and as much as $321.75 lower in July. SP15 fell the most year over year, down $321.75 to $55.55/MWh. ***–Linda Dailey Paulson***



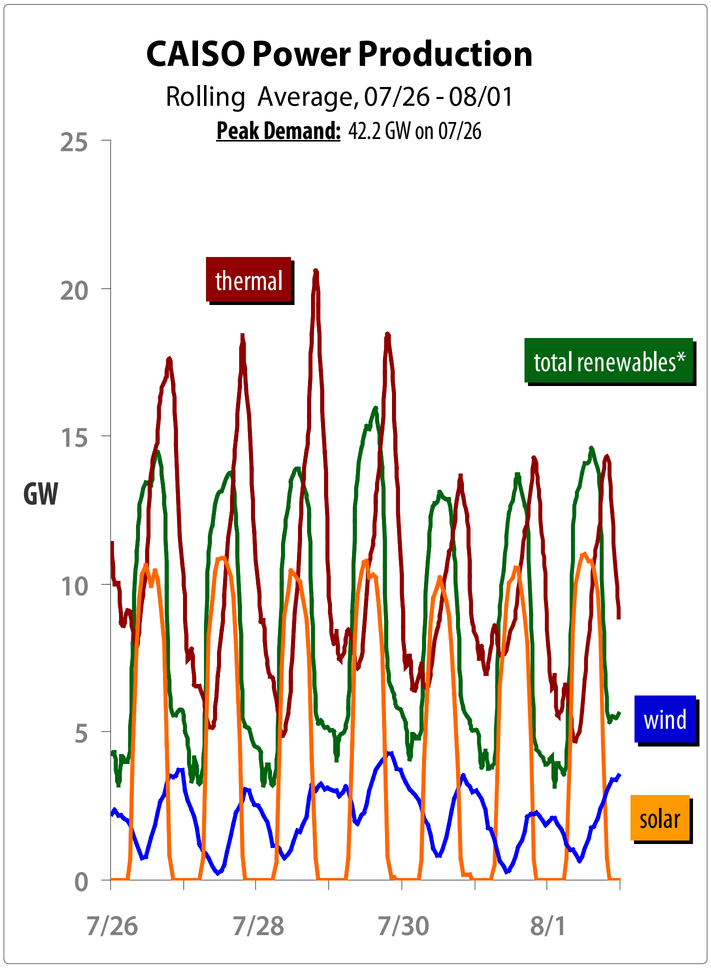


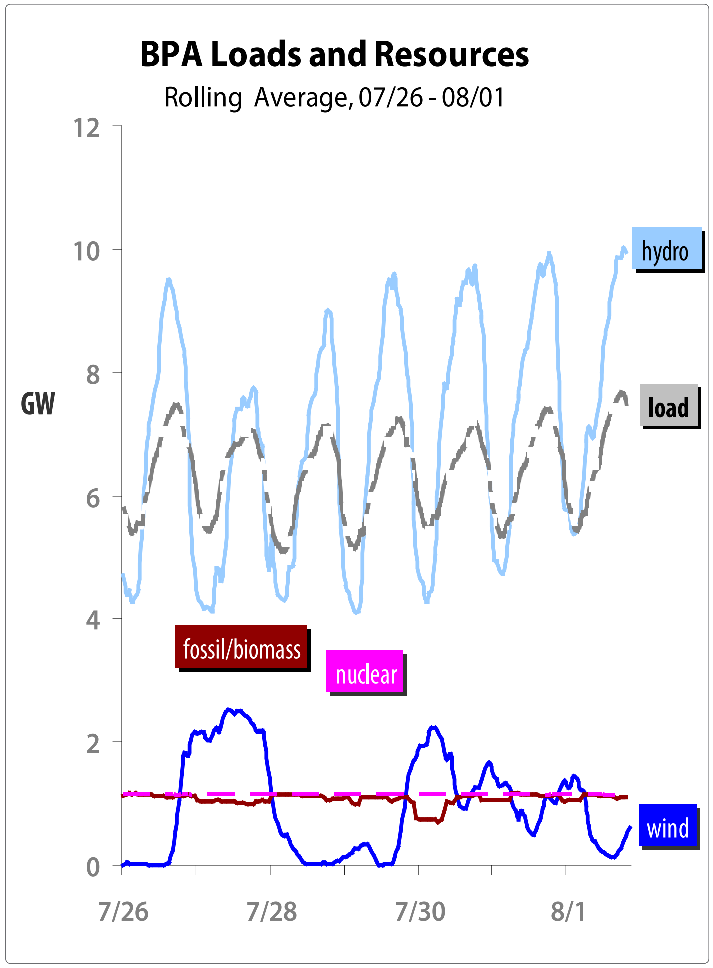
Average Natural Gas Prices ($/MMBtu)

	Th., 07/25	Tue., 07/30	Th., 08/01
Henry Hub	2.22	2.16	2.35
Sumas	2.11	2.06	2.02
Alberta	0.36	1.42	1.04
Malin	2.13	2.05	2.07
Opal/Kern	2.08	2.01	2.02
Stanfield	2.09	2.06	2.00
PG&E CityGate	2.74	2.68	2.64
SoCal Border	3.15	2.57	2.50
SoCal CityGate	3.53	3.00	3.03
EP-Permian	1.12	0.12	0.34
EP-San Juan	1.98	1.74	1.87

Power/gas prices courtesy Enerfax

POWER GAUGE

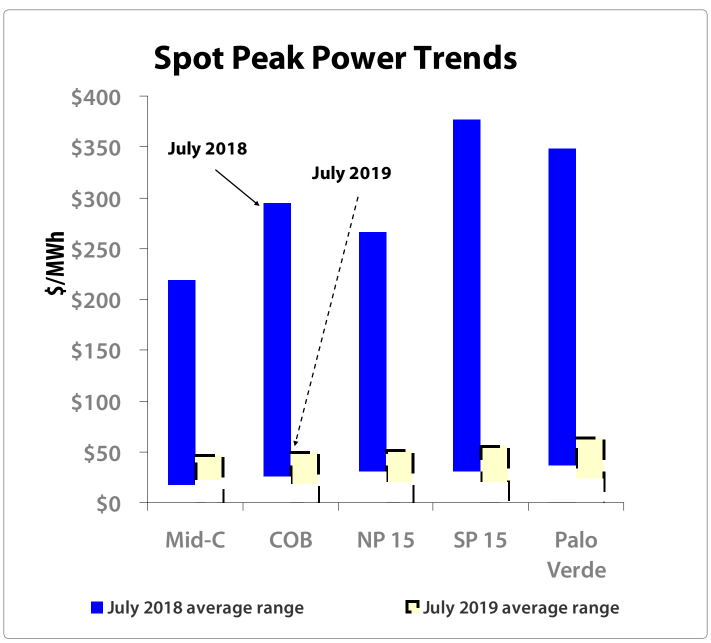


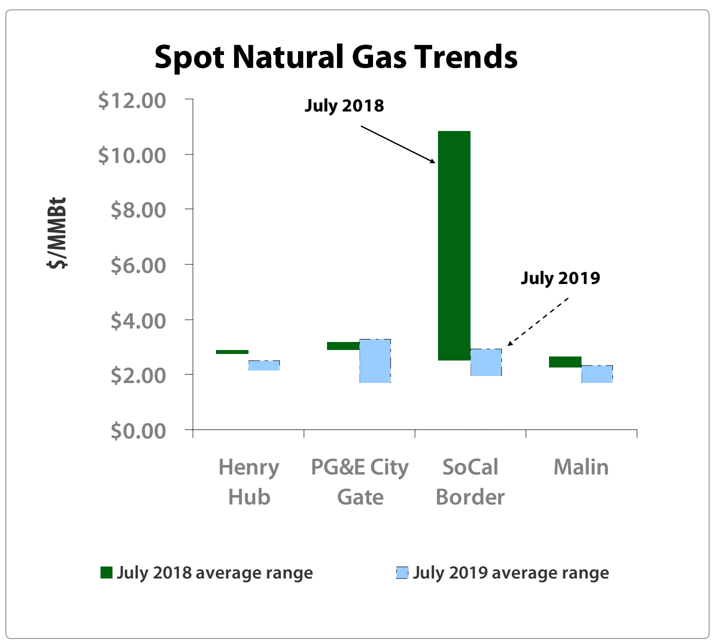


Source: BPA & CAISO

* includes small hydro (<30 MW)

PRICE TRENDS





Source: Enerfax

REGULATION STATUS

[9] CPUC Modifies Energy-Efficiency Test

(from [3])

The California Public Utilities Commission at its Aug. 1 meeting approved a series of modifications to the "three-prong test" used to evaluate whether fuel-substitution programs can access energy-efficiency funding *[R13-11-005, D19-08-009]*.

"The proposed decision removes a long-standing barrier to allowing energy-efficiency incentives to be used for energy-saving fuel-substitution measures, and provides a pathway for customers interested in electrification of their appliances," Commissioner Liane Randolph said.

The three-prong test was established in 1992, as the state was experiencing a large-scale shift from electric equipment to natural gas-fueled equipment in buildings. Under the framework, projects that switched from natural gas to electricity, or vice versa, would only receive funding if they met three criteria: they should not increase energy consumption; they should meet certain cost-effectiveness standards; and they should not adversely impact the environment. For the third prong of the test, any party wishing to implement a fuel-substitution program would need to compare the environmental costs of the switch with values for residual emissions adopted in 2004.

However, in a June 2017 motion filed with the commission, environmental groups including the Natural Resources Defense Council and Sierra Club argued that the test requires review and modification given the changing energy landscape in the state—specifically, the role of fuel substitution in reducing greenhouse gas emissions.

Given California's clean-energy and energy-efficiency progress, the test now presents "a barrier to California's progress on climate and energy goals," according to the motion. The groups noted that the state needs to reduce emissions from buildings to meet its ambitious climate goals, which would in turn require electrifying building appliances and powering them with clean energy sources, as well as using "decarbonized" fuels—like biogas—to replace fossil fuels.

"The current structure and lack of clear guidance for the test make it difficult to access energy-efficiency funding available through California's efficiency programs for projects that involve fuel substitution—even when these projects use highly efficient technologies and reduce climate pollution," the motion said.

Among the changes the CPUC made to the test is the omission of the cost-effectiveness prong. The framework will now be known as the "fuel-substitution test."

The new version of the fuel-substitution test, outlined in the Aug. 1 decision, will require fuel-substitution measures to prevent increased energy use, as well as adverse environmental impacts. Specifically, they must not increase carbon dioxide-equivalent emissions above what is forecast.

The original version of the test requires any fuel-substitution program to have a 1-to-0 cost-benefit ratio or higher. But in comments, multiple parties, including NRDC and Southern California Edison, recommended that the standards be applied at the portfolio level rather than to individual projects.

The commission acknowledged that applying the cost-effectiveness threshold to each measure presents a barrier, since other energy-efficiency programs don't require the same standard.

"We do not wish to continue to erect a cost-effectiveness barrier for fuel substitution measures that represents a higher hurdle than for any other measure included in the energy efficiency portfolio. Therefore, we will not require that a fuel substitution measure pass a cost-effectiveness threshold at the individual measure level," the decision stated.

However, energy-efficiency program administrators still must propose overall cost-effective portfolios.

Environmental groups hailed the decision, saying that the state's billion-dollar energy-efficiency budget will now be available for technologies that transition customers from natural gas to electricity usage.

> **'We do not wish to continue to erect a cost-effectiveness barrier for fuel substitution measures.'**

"Now program administrators need to develop and propose a new set of programs, or integrate new measures into existing programs, so that funds can start flowing to the most promising technologies that save energy, cut pollution, and ultimately provide economic and environmental benefits to all Californians," Merrian Borgeson, a senior scientist with NRDC, wrote in an Aug. 1 blog post.

The decision, however, received criticism from other groups. De'Andre Valencia, advocacy director with the Los Angeles County Business Federation, said at the meeting that the decision lays the groundwork for the electrification of all buildings in California regardless of cost or impact to communities.

"While this regulation does not explicitly mandate electrification of all buildings, it is clear that this is the intent," he said.

Commissioners also passed a decision modifying the Self-Generation Incentive Program, which provides incentives to customer-side distributed energy systems, including wind turbines, waste heat-to-power technologies and advanced energy storage systems *[R12-11-005, D19-08-001]*.

A key concern for the CPUC has been ensuring that the program does not lead to a cumulative increase in greenhouse gas emissions. Analyses of the program conducted in 2016 and 2017 found that SGIP commercial storage projects had contributed net annual GHG emissions of 726 metric tons of CO_2 and 1,436 metric tons of CO_2, respectively. In 2017, residential storage systems also led to GHG increases.

SB 700, legislation passed last year, required the commission to implement regulations requiring SGIP storage systems to reduce emissions instead.

The decision requires, among other things, that the program's administrators provide a digital GHG signal to help developers and customers align their storage systems' schedules with low- and high-carbon emissions periods.

"These new rules will govern how energy storage systems are operated, to ensure that new systems reduce GHG emissions—which is a clear statutory requirement," Commissioner Clifford Rechtschaffen said.

Additionally, commissioners acted on the following items at the Aug. 1 meeting:

- Fined Liberty Power Holdings $431,014 and Gexa Energy $1.7 million for not complying with renewables portfolio standard program requirements *[R18-07-003, D19-08-007]*.
- Approved a $24-million budget for the California Energy Commission's natural gas research and development program for 2019-2020 *[Res G-3555]*.

–Kavya Balaraman

[10] Federal Appeals Court Rules Against California's PURPA-Related Program

California's treatment of "qualifying facilities" within a program meant to spur renewables development violates federal law, a U.S. appeals court ruled.

The U.S. Court of Appeals for the 9th Circuit on July 29 upheld a lower court ruling that the California Public Utilities Commission's Renewable Market Adjusting Tariff, or ReMAT, program violates federal law. The ReMAT program, enacted in 2012, violates provisions of the Public Utility Regulatory Policies Act, the three-judge panel unanimously found. PURPA, passed in 1978, was meant to promote nonutility energy resources such as renewables by requiring utilities to buy power from alternative generators known as qualifying facilities. The appeal was filed by Winding Creek Solar, developer of a 1-MW solar plant in California.

PURPA requires utilities to buy all the power from qualifying facilities and to pay the same rate they would have if they obtained power from a source other than the QF, known as an "avoided cost" rate. ReMAT violates PURPA's requirements because the state program capped the amount of energy utilities were required to purchase from QFs and because it set a market-based rate, rather than one based on the utilities' avoided cost, according to the decision, penned by Judge Margaret McKeown. California did not offer a PURPA-compliant alternative, and PURPA pre-empts the CPUC program, the decision says.

The pricing scheme violates PURPA because, while state agencies can take a number of factors into account when figuring avoided cost, the ReMAT price is "arbitrarily" adjusted every two months according to the QF's willingness to supply energy at the predefined price. The pricing scheme "strays too far afield from a utility's but-for costs to satisfy PURPA," the decision says.

Under the ReMAT program, the amount of energy a utility must buy is capped, and investor-owned utilities are only required to purchase 750 MW through ReMAT statewide. That amount is divided among utilities according to their customers' share of peak electricity demand, and utilities are permitted to subtract from their share any generation they are required to purchase under other CPUC programs.

As a result, Pacific Gas & Electric, which serves the area in which the Winding Creek plant would be located, is obligated to purchase only about 150 MW under ReMAT, according to the decision. That obligation is also divided among baseload, nonpeaking and peaking generation—which includes Winding Creek.

Winding Creek was accepted into the ReMAT program, but because it was not near the top of the acceptance queue, it did not receive an offer at the initial $89.23/MWh price. By the time it received a contract offer in March 2014, the price had dropped to $77.23/MWh—too low to develop the facility.

Winding Creek had previously challenged the ReMAT program at the Federal Energy Regulatory Commission, which issued various orders and intents not to act. The developer appealed in district court, and won there, but did not receive the $89.23/MWh price, as the lower court declined to rule on that, and so appealed to the federal court.

Although Winding Creek was victorious in the new 9th Circuit decision, the developer still did not receive its preferred remedy: a contract with PG&E at the $89.23/MWh price that would make the project viable.

"The district court did not abuse its broad discretion to fashion equitable relief by declining to grant Winding Creek a contract with PG&E at the initial $89.23/MWh price," the July 29 decision says.

The CPUC had argued that ReMAT's compliance with PURPA doesn't matter because QFs may instead sell energy to utilities through a standard contract. But the court found that the standard contract provides only one formula for calculating avoided cost, and that formula relies on variables that are unknown at the time of contracting.

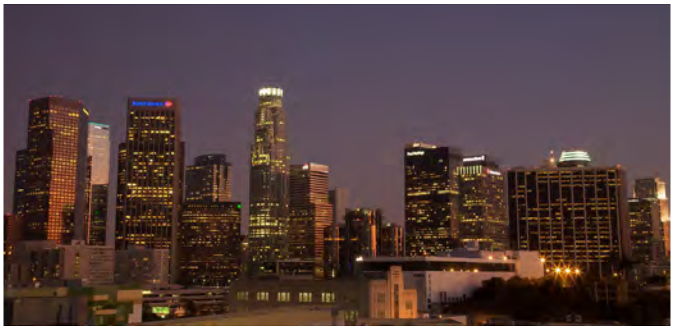
"The standard contract violates PURPA because it fails to give QFs the option to calculate avoided cost at the time of contracting," the decision says.

–Jason Fordney

[11] State Agencies Outline Building-Decarbonization Proposals

California regulators are crafting the outlines of two programs that will move the state toward its larger goal of addressing emissions from buildings.

The programs, outlined in a July 16 joint draft proposal by the California Public Utilities Commission and California Energy Commission, will focus on reducing the carbon footprint of residential and commercial buildings, which currently produce a quarter of statewide emissions. The Building Initiative for Low-Emissions Development, or BUILD, program would provide incentives to promote near-zero emissions technologies in new residential and low-income



The CPUC and CEC outlined proposals for two programs that would help reduce emissions from buildings. *Photo: Kevin Stanchfield/Flickr*

buildings. And the Technology and Equipment for Clean Heating, or TECH, program focuses on deploying high-efficiency electric heating systems in existing homes, to help customers reduce their utility bills.

Comments on the proposal, which was discussed at a July 30 workshop, are due on Aug. 13.

The BUILD and TECH programs stem from SB 1477, legislation passed in September 2018. The bill requires the CPUC and CEC to develop two programs aimed at reducing building emissions. In February, the CPUC launched a proceeding to implement both programs and to craft a larger policy framework around building decarbonization *[R19-01-011]* (see CEM No. 1525 [9]). The proceeding will also look into ways widespread electrification could impact the grid.

The two programs will collectively receive an annual budget of $50 million, drawn from revenue incurred by gas corporations under California's cap-and-trade program. Both programs would include "clean heating technologies" like heat pumps and solar-thermal systems, according to the proposal, and would be evaluated based on greenhouse gas reductions, cost-effectiveness and bill savings for customers, among other things.

Under the BUILD program, regulators would offer incentives to new building designs that incorporate emissions-reducing technologies. The incentives would only go to all-electric new residential construction and would vary based on the volume of GHG reduction, with more flexibility provided to buildings that house lower-income residents.

The TECH program would focus on large-scale deployment of electric space- and water-heating technologies in existing homes. As per the proposal, the CPUC would open a request-for-proposals process for third parties to pitch ideas and designs for the program. The selected party would roll out incentives for electric heating technology and conduct workforce development to ensure there are contractors, builders, plumbers and electricians to install the systems, among other responsibilities.

Rory Cox, an analyst with the CPUC, kicked off the discussion of the program with an anecdote about his sister, who lives in a 100-year-old home in Portland, Oregon, and reduced her electricity bills by installing a heat-pump water heater in her kitchen. This provides a model for how the TECH program could benefit customers, he said—reducing costs and helping people access contractors who can upgrade their systems.

"This has all been done before and I think that sort of story is a good example of what we mean when we talk about market transformation," he said.

Martha Brook, energy policy advisor at the CEC, said regulators want to ensure the programs are streamlined and simple from a regulatory perspective, as well as push for significant market transformation.

The CPUC's proceeding is intended to look into any alternatives that reduce GHG emissions and bring California closer to its goal of becoming carbon-neutral by 2045. But the role of natural gas has become a point of contention. Under the proposal, incentives would be available to replace natural gas systems with more efficient electric systems. However, the proposal would exclude the installation of more efficient gas systems, noting that this would fall under the scope of the CPUC's energy-efficiency program. The proposal also encourages parties to look into deploying the TECH program in areas that currently have gas-system problems, such as Southern California.

Darren Hanway, who manages energy-efficiency programs at Southern California Gas Co., said the proposal takes a narrow interpretation of SB 1477, which is essentially an effort to reduce emissions.

"I think that is a tremendous missed opportunity," he said, adding that there are several efficient gas technologies that could reduce GHG emissions, as well as be more cost-effective. ***–Kavya Balaraman***

[12] Emerging Utility Rate Designs Could Erode DER Integration, Report Says

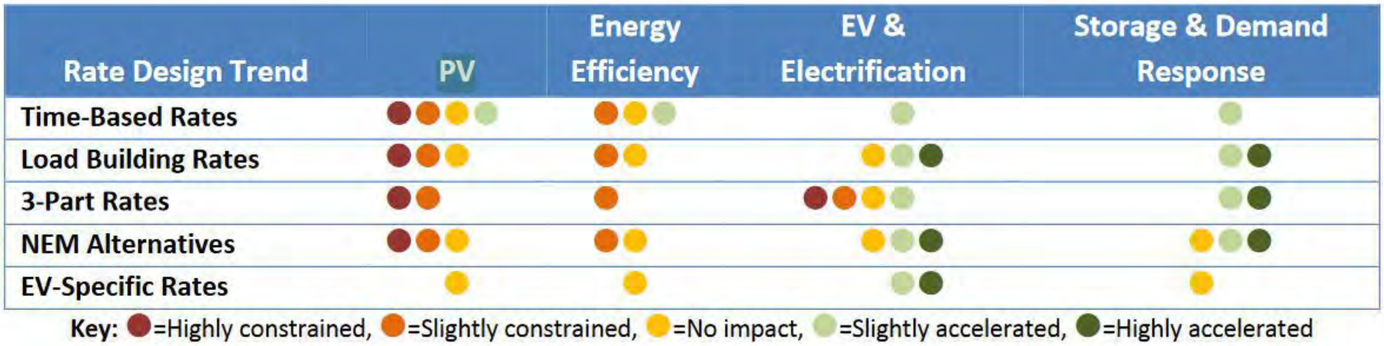
Emerging utility rate designs could constrain the growth of distributed energy resources, the Lawrence Berkeley National Laboratory said in a new report that included an analysis of the situation in California.

The findings in the July report come at a time when state agencies such as the California Energy Commission and California Public Utilities Commission are moving to increase the amount of DERs on the grid.

"Regulators engaged in retail rate reform efforts may wish to consider explicitly how new rate designs may impact deployment trends among different types of DERs, weighing those impacts against the many other considerations and stakeholder perspectives that regulators must balance in establishing utility rate structures," the report says.

An increase in variable energy resources such as solar power on California's grid exacerbates the duck curve, which refers to the state's power demand curve, leading to new approaches such as microgrids (see CEM No. 1549 [10]). As the demand curve has changed, regulators and utilities have also tried to design rates to mitigate the duck curve's highs and lows.

Each of the five rate designs analyzed in the report either constrain or accelerate adoption of DERs and solar, according to the report. The rate designs that were studied include time-based rates; mid-day load-building rates; three-part residential rates (for demand, volumetric energy charges and fixed customer charges); net-energy-metering tariffs; and electric vehicle-specific rates.



Potential rate-reform impacts on different types of DERs. *Source: Lawrence Berkeley National Laboratory*

Most of the emerging rate trends tend to support greater deployment of flexible DERs such as storage and demand response, while often constraining adoption of less-flexible resources such as photovoltaic solar and energy efficiency, the report found.

Though only one of the rate designs specifically tries to build load at midday, most other emerging rate designs also do so, the report said. So the emerging rate designs generally constrain growth of DERs that reduce consumption of grid-supplied electricity, according to LBNL's report—particularly in the case of DERs such as photovoltaic solar and energy efficiency.

'How well technologies fit users' needs can make or break DER integration.'

DERs can be constrained by two kinds of rate design: attribute unbundling and temporal granularity, the report said. Attribute bundling means shifting from fully bundled pricing to rate structures that break apart energy, capacity, ancillary services and other components. Temporal granularity means shifting from flat or block rates to time-based rates.

If a time-based rate offers extremes in prices—for example, if electricity at noon costs close to nothing and electricity in the evening is highly expensive—then DERs could become less appealing to customers, who might shift their electricity usage to the times when it is extremely cheap, rather than use a solar-plus-storage system.

Utilities have tried to increase electricity consumption during off-peak times through time-of-use rates, the report said. Load building is also a natural response on the part of utilities to declining sales growth and revenue erosion from energy efficiency and PV, according to the report.

To see if the time-based rates were working, the IOUs from 2016 to 2018 ran a pricing pilot program with about 50,000 households. The pilot found that customers increased their loads by a modest 1.6 percent during super-off-peak summer weekday times and by 2.1 percent during super-off-peak winter weekday times. The average study participant saw a bill reduction that ranged from 0.3 percent to 1.6 percent.

"Though perhaps somewhat obvious, it cannot be overstated how important are the specifics of any particular rate design in assessing the potential impacts on DER deployment," the report says.

Separately, at a July 25 workshop, the CEC took comment on its DER Research Roadmap, developed by Navigant Consulting and Gridworks. The commission created the roadmap to prioritize funding for technology projects that will improve DER integration through research in batteries, electric vehicles and smart inverters.

However, some industry experts say focusing only on technology might not solve all of the challenges associated with integrating DERs. Loren Lutzenhiser and Mithra Moezzi with QQForward said upcoming DER research funded by the CEC should focus not only on devices and energy flows, but also on patterns of use and social processes, such as habits, cultures, employment and travel, child-rearing, codes, regulations and supply chains.

There is a distinct possibility of designing a DER hardware system that is elegant, efficient, and optimized but will fail to integrate with the larger, complex and dynamic social systems of energy use in California homes, Lutzenhiser said.

"Failing to bring human factors into DER integration research puts the benefits of even the best hardware research and design at risk," Lutzenhiser wrote. "How well technologies fit users' needs can make or break DER integration, no matter how sophisticated the devices and networks envisioned."*–David Krause*

California Energy Markets® is a weekly report to clients of NewsData LLC, covering public utility and energy policy development, markets, litigation and resource development in California, Nevada, Arizona and New Mexico. ISSN 1044-2022. Report text section Copyright © 2019, NewsData LLC. NewsData LLC is a subsidiary of Pioneer Utility Services. All rights reserved; no reprinting without permission, no electronic storage or transmission without written license agreement. For newsletter subscription information, contact John Malinowski (206) 285-4848, ext. 203, johnm@newsdata.com. **Editorial Offices**: San Francisco: mail and express delivery: 425 Divisadero St., Ste. 303, 94117. Voice: (415) 963-4439, email: cem@newsdata.com. Seattle: mail and express: 4241 21st Ave. W, Ste. 306, 98199. Voice: (206) 285-4848; fax: (206) 216-4116. Website: www.newsdata.com. **Management and Staff:** Publisher & Editor-in-Chief, Mark Ohrenschall · Director of Information Systems, Daniel Sackett · Client Services Director, John Malinowski · Billing & Accounts Receivable, Jennifer West McCarthy · Editor, Jason Fordney · Staff Writers, Kavya Balaraman and David Krause · Contributing Writers, Rick Adair, Dan Catchpole, Jim DiPeso, Steve Ernst, Linda Dailey Paulson, Abigail Sawyer and Bill Virgin · Production Coordinator & CEM Production Editor, Amber Schwanke · NewsData Founder: Cyrus Noë (1929-2017)

[13] State Regulators Voice Concerns About Uptick in Diesel Generator Sales

California regulators on July 30 expressed concerns about potential increases in diesel generator sales due to utility power shut-offs planned for this wildfire season.

California Energy Commission Vice Chair Janea Scott said people who lose power during a shut-off might not have an alternative power-generation source, and therefore could end up using backup power that runs off fossil fuels, such as diesel.

"I've been reading about how people were going to buy diesel backup generators, and that is so much the opposite of where we're trying to go," Scott said. "I'm intrigued about how we get storage factored into small quantities or community-scale. What can we do to get that into place as we juggle our way through where we are right now?"

Aaron Jagdfeld, CEO of generator manufacturer Generac, said the company has seen a 600-percent increase in requests for generators by California customers over the past year. Likewise, Liesl Ramsay, CEO of Leete Generators in Santa Rosa, said the company has seen a significant increase in requests about backup power systems.

The workshop on July 30 highlighted problems accessing energy storage technology within California's disadvantaged and low-income communities. California Public Utility Commission member Clifford Rechtschaffen said the CPUC is trying "some new approaches" to incentivize storage solutions in disadvantaged and low-income communities, especially with power shut-offs imminent.

"There are dozens of tribal communities, lots of other vulnerable communities, and several hundred thousand medically vulnerable customers who are potentially affected by de-energization," Rechtschaffen said at the workshop. "I think it's a larger conversation that the state needs to have . . . the question of who bears the cost of mitigating the risk of de-energization."

The CPUC currently funds the Self-Generation Incentive Program, which provides rebates for distributed energy systems installed on the customer side of the utility meter. Qualifying technologies include wind turbines, waste heat-to-power technologies, pressure-reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells and advanced energy storage systems, according to the CPUC.

The CPUC created an "SGIP Equity Budget" as part of the program. The equity budget allocates 25 percent of the program's funds to nonprofits, small businesses, educational institutions and governments, along with disadvantaged and low-income communities. However, Rechtschaffen said "the program hasn't worked. Clearly, we need to do something different. We heard from a lot of parties that we need to raise the incentive levels because they don't work in disadvantaged communities."

The CPUC currently plans to add up to 500 MW of additional storage at the distribution level, with priority given to systems for the public sector and low-income customers.

Pacific Gas & Electric forecasts that some areas in the state could face power outages 15 times a year, and expects to provide a two-day notice to customers before a power shut-off (see CEM No. 1539 [14]).

The CPUC said reaching vulnerable communities to warn them of power shut-offs and talk about backup energy generation has been difficult. In a May 30 decision, the CPUC proposed to identify vulnerable communities based on the number of people enrolled in medical baseline *[D19-05-042]*. The CPUC said investor-owned utilities should increase outreach to vulnerable populations to talk about power shut-offs and backup power options. Southern California Edison disagreed with the CPUC's recommendation, stating that it should not be forced to use additional notification streams to reach communities disproportionately affected by de-energization.

As for next steps, Rechtschaffen said the CPUC plans to issue a new decision on the SGIP in the "next couple of weeks." ***–David Krause***

REGIONAL ROUNDUP

[14] State Expands Wildfire Effort; CAISO Discusses Load Shedding *(from [1])*

California's utilities and elected officials are mobilizing a new approach to electricity and wildfire planning to deal with what Gov. Gavin Newsom called "a new reality," including public-safety power shut-offs.

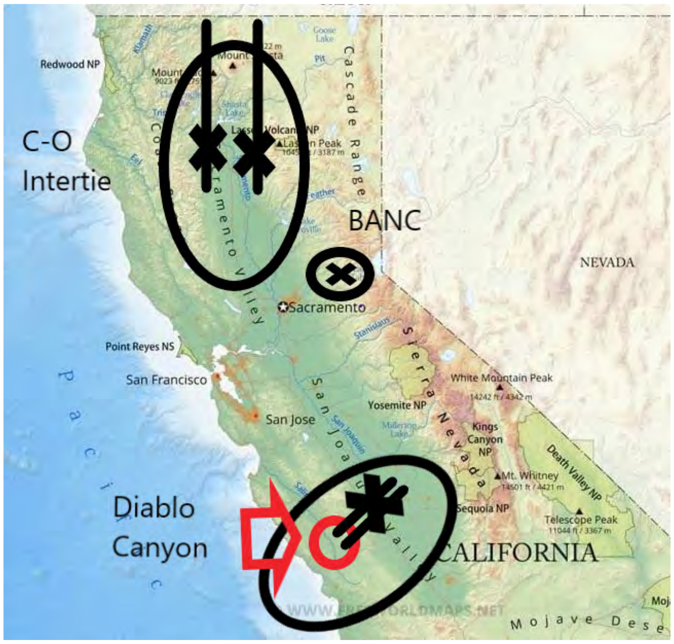
Newsom on July 31 spoke in Colfax, saying the state has funded an additional 400 seasonal firefighters and 13 new fire engines and has included $1 billion for disaster and emergency planning in the state budget.

"Climate change has created a new reality in California with catastrophic fires, and there is nothing more critical for my administration than to ensure we are investing in resources that can help our firefighters and communities prepare and respond to fires and other natural disasters," Newsom said in a written statement.

The planned shut-offs by utilities are requiring swift adaptation by grid operators. In a July 30 informational call, the California Independent System Operator provided more details on additional load shedding it might have to conduct if utilities shut off significant load because of wildfire risk.

The utilities' PSPS plans encompass all voltage levels on the system, including on the distribution system at up to 500 kV, and possibly larger transmission lines also. Depending on the extent of the shutdown, the effect on system operations will vary, CAISO said.

The ISO presented one scenario in which Pacific Gas & Electric sheds 200 MW of load at the



CAISO presented a scenario in which the California-Oregon Intertie and lines connected to the Diablo Canyon nuclear plant go down, which together with other factors requires further load shedding. *Graphic by CEM from CAISO presentation*

distribution level, and there is no impact on the system because transmission and energy are not significantly affected.

But in a second hypothetical scenario and string of events, PG&E de-energizes 2,000 MW of distribution lines and lines that interconnect into the Diablo Canyon nuclear plant are also de-energized as part of a PSPS. At the same time, another 3,200 MW of transmission capacity is lost at the California-Oregon Intertie, preventing imports.

In this hypothetical scenario, demand would be greater than energy capacity. Short on capacity, the ISO would shed 2,500 MW of load to balance the system, and the adjacent Balancing Authority of Northern California would lose 900 MW of imports because of the reduced capacity. CAISO would then order another 400 MW of load shedding from PG&E to provide energy to BANC, preventing the need for BANC to shed 400 MW of load.

In May, the California Public Utilities Commission approved a series of guidelines for utilities to proactively shut off power to portions of the grid during times of high fire risk *[R18-12-005, D19-05-042]*. The decision includes communication and notification guidelines for utilities to follow when shutting off power—such as engaging with first responders, customers and vulnerable communities—and requires the investor-owned utilities to craft protocols around de-energizing transmission lines (see CEM Nos. 1537 [11.1] and 1541 [9]).

The CPUC has reviewed the IOUs' plans, according to CAISO. Utilities will decide when shut-offs occur, with PG&E mentioning factors such as red-flag fire condition warnings from the National Weather Service; humidity levels of 20 percent or lower; forecasts for sustained winds generally above 25 mph; and wind gusts in excess of about 45 mph, depending on site-specific conditions such as temperature, terrain and local climate. Utilities will also monitor moisture content of dry fuel on the ground and live vegetation.

IOUs are responsible for direct load-management—which happens when the circuit feeding the load is de-energized—actions which are independent of CAISO's responsibilities.

CAISO will process the shut-off plans submitted by the utilities and will identify system impacts and possible mitigation to the utilities, if sufficient notice is given before a shut-off. CAISO might have to take additional steps on the transmission system, but said it will do its best to confine impacts to the utility area and to the CAISO balancing area.

Prior to being re-energized, circuits must be inspected, which is conducted by the utilities, and complete restoration might take several days, CAISO said.

Utilities and the ISO have issued public announcements to consumers on how to prepare for shut-offs, which disproportionately affect vulnerable populations such as the sick, disabled and elderly.

The shut-offs are also quickly leading to alternative solutions, signaling a shift to more distributed energy resources and microgrids as an alternative to traditional transmission and distribution infrastructure (see CEM No. 1539 [14]).

Customers in high-fire-risk areas are most likely to be affected, but any of PG&E's 5 million customers could be impacted, the utility said. PG&E said it would issue notifications 48 hours before shut-off, 24 hours before, and just before the power is turned off, communicated by phone, text and social media.

And the loss of the California-Oregon Intertie is not just hypothetical—CAISO called a transmission emergency on July 29 because two of three lines on COI/Path 66 were forced out of service due to fire, with the remaining line under threat of open-loop. The notice was lifted the next day. On July 28, the Malin-Round Mountain No. 1 and No. 2 500-kV lines were forced out |of service and there were threats to the Captain Jack-Olina 500-kV line due to fire, another transmission emergency that was lifted after about four hours. ***–Jason Fordney***

[15] PG&E Defends Transmission System Work in Court Filing *(from [2])*

Attorneys representing Pacific Gas & Electric disputed news media reports that the utility delayed work on its transmission system despite knowing that its infrastructure could spark wildfires, telling a district judge in a July 31 court filing that PG&E welcomes the public attention on "the acute problem of aging transmission infrastructure."

The filing came in response to a July 10 order in which U.S. District Judge William Alsup ordered the utility to explain a report in The Wall Street Journal that it had been aware of problems with its transmission lines but delayed the necessary work. PG&E attorneys said the company has been applying to the Federal Energy Regulatory Commission for transmission service rates that would allow it to gradually upgrade its aging infrastructure.

PG&E is pushing back against a report that it delayed repairs to its transmission system despite knowing of their wildfire risk. *Photo: PG&E*

The filing states that the delayed maintenance mentioned in the report refers to a recommendation from the North American Electric Reliability Corporation to ensure clearance between transmission-line conductors, as well as between the conductors and the ground. The work did not involve repairing portions of the transmission system—such as a damaged hook on the tower that sparked the Camp Fire—according to PG&E. Moreover, the attorneys said the scope of the work did not include the transmission tower in question.

"PG&E denies the generalized assertion that it repeatedly failed to perform the necessary upgrades to prevent failures on its transmission lines. The suggestion that PG&E has ignored investment in its transmission lines is inaccurate," the company said.

The Wall Street Journal article and Alsup's order were also cited in a July 24 letter penned by San Francisco Mayor London Breed and City Attorney Dennis Herrera to Gov. Gavin Newsom, providing an update on the city's efforts to purchase PG&E's infrastructure. The city believes it can make an "attractive" offer to PG&E "in the near future," according to the letter.

In its court filing, PG&E pushed back against the notion that it has failed to invest in its transmission infrastructure, noting that capital expenditure on the system grew from $655 million in 2008 to around $1.29 billion in 2018, while routine maintenance amounted to between $140 million and $294 million in that same period.

The utility acknowledged the WSJ article's assertion that an internal company presentation in 2017 estimated that its transmission towers were 68 years old on average, when their mean life expectancy is 65 years. However, company lawyers said life expectancy does not indicate the "complete failure of a structure," but an average of individual components like wires and foundations.

"PG&E adheres to a maintenance program under which it determines repair and replacement priorities for transmission assets based on a variety of factors," such as safety, customer impact and operational issues, the filing says.

In the July 10 decision, Alsup also ordered PG&E to detail the contributions it has made to political candidates since January 2017 (see CEM No. 1547 [15.1]).

In a separate filing, PG&E said it had spent $5.3 million between January 2017 and December 2018 on contributions to political candidates and parties, political action committees and ballot-measure committees. The payments came from shareholder funds and employee contributions, but did not include any customer funds, according to PG&E. The company has not made any contributions in 2019 to date.

The company does not prioritize political contributions over utility operations, the attorneys said, but does participate in the political process to represent its customers, employees and shareholders in legislative and regulatory circles.

"Policy decisions made by lawmakers and regulators at all levels significantly affect the environment in which PG&E operates, especially because its core utility business is highly regulated," they added.

The filings come as PG&E faces mounting criticism over its wildfire-prevention strategies, as well as requested rate increases to fund them. In December, the company filed its 2020 general rate case application to the California Public Utilities Commission, requesting a $1.1-billion increase in its 2020 base revenue requirement (see CEM No. 1519 [10]). It has been holding a series of public-participation hearings around California to hear from customers about the increase.

At a July 31 hearing in Santa Rosa, PG&E Corp. Executive Vice President John Simon briefed the crowd on the application, echoing points made by CEO and President Bill Johnson at a similar hearing in San Francisco (see CEM No. 1547 [9]). But attendees at the hearing were deeply skeptical of the requested rate increase, as well as legislative and regulatory efforts perceived as a "bailout" for the utility.

Joseph Onate, a Santa Rosa resident, criticized the passage of AB 1054, which creates a fund to help cover utility wildfire liabilities.

"PG&E is an ex-con. I think they're in violation of their parole, and yet you're entertaining them as if they were a special guest, which in my view makes you complicit in PG&E's endeavors," he told CPUC representatives at the hearing.

PG&E is simultaneously facing a CPUC investigation into its role in sparking the 2017 North Bay wildfires. The commission is reviewing allegations from its Safety and Enforcement Division that the utility's operations and vegetation-management activities fell short of required standards (see CEM No. 1545 [10]). On July 31, PG&E responded to the investigation in a lengthy filing, pushing back against the SED's claims. The utility said it could not accept the allegations since it had not had the opportunity to fully review the physical evidence connected with the fires, and raised objections regarding specific instances that investigators had suggested constituted violations.

"PG&E believes that the full evidentiary record in this proceeding will show that its patrol and inspection program and vegetation management policies and practices were consistent with, and at times exceeded, accepted good practices," the filing said.
–Kavya Balaraman

[15.1] PG&E Renegotiates Power-Purchase Contracts for Renewables, Storage

Pacific Gas & Electric has renegotiated three power-purchase agreements and two energy storage agreements, according to a July 31 filing to the court overseeing the company's bankruptcy proceeding.

The utility's motion seeks the bankruptcy court's approval to move ahead with the revised contracts. According to PG&E, the discounts negotiated with its counterparties will provide collective savings of $20 million over the life of the agreements.

The contracts include three solar PPAs inked with Recurrent Energy in 2017. Both parties have agreed to apply a 10-percent discount for the power purchased under the agreements, and to extend the project deadlines by up to two years.

In addition, PG&E sought court approval of two reworked energy storage agreements—one it signed in June 2018 with mNOC AERS LLC for a 10-MW lithium-ion battery-based project, and another with Hummingbird Energy Storage LLC for a 75-MW lithium-ion battery project. These agreements were part of a larger 567-MW energy storage package announced by PG&E in June 2018 (see CEM No. 1495 [9]).

PG&E and mNOC agreed to an 11-percent discount on the contract price as well as a 15-month delay of the project, while the Hummingbird contract would be discounted by 10 percent and delayed by a year.

Hummingbird owner esVolta in March had asked the court for safe-harbor protection over its contract with PG&E (see CEM No. 1532 [13]). PG&E and mNOC also had previously requested authority to terminate that contract, which U.S. Bankruptcy Judge Dennis Montali granted on May 13 (see CEM No. 1539 [13]). ***–K. B.***

[16] Aiming for Resilience, Calistoga Fast-Tracks Microgrid Development

The City of Calistoga is moving forward with developing a microgrid, but rather than designing it for disaster response, as many California communities plan to do, it will be used for citywide resilience.

The Clean Coalition on July 29 announced it had signed a consulting agreement to conduct a feasibility assessment for the city's microgrid.

Public-safety power shut-offs planned by utilities to mitigate wildfire risk are the main concern, and city leaders and consultants want to design a project that provides area residents with resilience in light of possible distribution-line de-energizing during fire season.

"Our fundamental concern is the uncertainty with the PSPSes and the overall impact to the community," Calistoga City Manager Michael Kirn said. Both residents and commercial entities need reassurance that their service is not going to be disrupted. The area's economy is largely dependent on tourism.

Kirn said it is unclear how the system will interface with the existing Pacific Gas & Electric distribution system and an anticipated "resilience zone." The concept had been for the microgrid to be located in a designated PG&E resilience zone with a grid interconnection that would enable a section of the grid to be islanded from the larger grid, enabling critical facilities to stay on line.

But PG&E told California Energy Markets that Calistoga is not a candidate for one of its resilience zones. The pilot program is currently only in Angwin, which is in Napa County as Calistoga is, according to PG&E spokesman Jeff Smith. It is not clear how that discrepancy will play out or affect the project.

The Calistoga microgrid project is still in the early planning stages, according to the Clean Coalition, which says stakeholder outreach to determine critical facilities and community needs is the next step.

Frank Wasko, managing director for the Clean Coalition, says the project is on a "fast track." Within the next few weeks, the group will be conducting a technical analysis, which will include working with PG&E, local geothermal contacts and community choice aggregator MCE as well as the city "to understand where they want us to focus."

"That will help tighten up our scoping process so that we can proceed with the system sizing and design," Wasko said.

The Clean Coalition, based in Menlo Park, works to design and stage community microgrids in partnership with developers that are responsible for installing the microgrids. It is currently working on a microgrid in the Montecito community (see CEM No. 1529 [16]).

'Our fundamental concern is the uncertainty with the [public-safety power shut-offs].'

Much like the Montecito project, there will be a phased implementation in Calistoga starting with critical facilities. The assessment will initially identify candidate locations for five different microgrids. Some of these might include one or two of the nearby water-treatment plants, public schools, or the fire department. These facilities' microgrids could potentially be connected into a full community microgrid serving the Calistoga Substation grid area as originally envisioned.

Electric-grid resilience is a key issue for communities and cities in areas where wildfires are a near and ever-present danger, but plans to shut down power lines during high-wind, high-fire-danger conditions are a concern. Even a single power shut-off could result in communities being without power for days, or even a week or more, during the fire season, Gov. Gavin Newsom said earlier this year. PG&E forecast that some areas—including Calistoga—could face outages 15 times a year.

This possibility is propelling local-government officials to investigate how microgrids can keep critical facilities operational. Fire stations, hospitals, water districts and other local facilities could be left without power, and a diesel backup generator might not be adequate.

The City of Calistoga had two PSPS warnings last fall, with one resulting in a shutoff. In May, a month of PG&E maintenance work necessitated the installation of diesel generators in the city as backup power. Another warning was issued to the city June 7, according to documents filed with the California Public Utilities Commission.

Wasko said the potential loss of business revenues from outages might require classifying tourist destinations, such as three large resorts in the area, as potential critical facilities. The assessment will also identify the at-risk population. The area has a lot of older residents who need uninterrupted power to address their ongoing health needs, Wasko said.

The Clean Coalition will also identify commercial-scale solar siting potential in Calistoga. Program engineer Malini Kannan said the organization might look at both solar plus storage and geothermal energy for use in the microgrids. As of 2015, the Calistoga area had 2.5 MW of distributed solar, she said. Half of that is residential installations and the other half nonresidential.

"This is unique," said Wasko of the process. "We do plan to leave the door open for a community microgrid, to provide at least a framework for it to be connected with the existing distribution grid if the city wants that." The focus now is "an immediate and prompt solution for the city and constituents who want to move forward quickly."
–Linda Dailey Paulson

[17] Glendale Keeps Natural Gas Plant On, Adds Renewables to Power Mix

The Glendale City Council on July 23 approved a plan to keep an aging natural gas plant partially operational while incorporating a hefty amount of additional renewable energy resources into the city's energy supply.

Glendale Water & Power will add a 75-MW battery storage system and 50 MW of distributed energy resources to its power profile, which currently includes the 173-MW-capacity, gas-fired Grayson Power Plant.

City officials originally proposed to increase the gas plant's capacity from 173 MW to 262 MW, but after pushback from opponents concerned about pollution, they reduced the capacity to 93 MW.

"As Glendale residents and businesses are already overburdened by pollution, extending the life of Grayson and expanding it would be detrimental to their health, safety, and climate," the Sierra Club said.

The group last week said it supported the city's revised decision, because although the plant will stay active, it will operate at a lower capacity.

"Today's decision is the beginning of a major transition toward putting the power back in the hands of local communities," Sierra Club Senior Campaign Representative Luis Amezcua said. "It is critical that we continue to push for locally led decisions like these that end our reliance on fossil fuels, promote clean air and invest in energy solutions that work for our current and future communities."

"This is just the end of the beginning," Glendale Mayor Ara Najarian said. "We want to express appreciation to our residents, community groups, and

New site plan for Grayson Power Plant. ***Source: Glendale Water & Power***

A corroding natural gas pressure sensing line inside Grayson Power Plant reads 0 psig. ***Photo: Glendale Water & Power***

environmental-advocacy proponents for working collaboratively in finding a solution that will meet Glendale's energy needs."

The Grayson plant had been experiencing an increasing number of unplanned and forced outages, the city said, which threatened local reliability and prevented the utility from using biogas from a renewable natural gas supplier in Scholl Canyon.

The plant's current power-generation units are well beyond their useful life: Most are 40 to 70 years old, have high maintenance costs, and are not expected to continue running much longer. If GWP did not repower the Grayson plant at all, GWP sources of supply would be limited to about 287 MW, well short of GWP's peak load of 350 MW.

"I think an upgrade to the Grayson Power Plant is essential," Glendale City Councilmember Frank Quintero said. "We control our own destiny with our own power plant. The idea of revamping the plant, modernizing it, makes a lot of sense so that we are one of the key components in this Western grid."

"The men and women who work [at Grayson] take a lot of pride and ownership in the work that they do," GWP Superintendent Brian Brown said. "It's been passed down from generation to generation—the people who work on these power lines, in the power plant."

GWP said it would make every effort to purchase additional power generated by sources other than its natural gas plant, but added that its options for alternative power are limited.

For example, eliminating the gas plant entirely and utilizing solar power alone would require a significantly large battery storage system that could store enough energy to meet the city's electricity needs at other times. That type of project would be more expensive than keeping some of the city's natural gas generation on, according to GWP.

City officials also said the approved project will help the utility meet California's renewables portfolio standard requirements. GWP started its RPS program in 2004 and revised its goals in 2011, requiring at least 33 percent of the city's power from renewable sources by Dec. 31, 2020.

In 2017, the city had met this goal: 37 percent of its power came from renewable sources, along with 27 percent from natural gas, 13 percent from hydroelectric, and 6 percent from coal.

SB 350, signed in October 2015, requires retail sellers and publicly owned utilities, such as GWP, to procure 50 percent of their electricity from eligible renewable energy resources by 2030.

"Our residents have been active and engaged in GWP's plans to pursue a cleaner alternative to the Grayson repowering project. This greener portfolio will allow GWP to provide its customers with reliable and environmentally sustainable power, and will enable us to transition to a 100-percent clean-energy future," GWP General Manager Steve Zurn said.

City representatives directed staff to continue to research the ways in which Glendale could further reduce its reliance on fossil fuels. *–David Krause*

SOUTHWEST

[18] Arizona Regulators, Stakeholders Explore Electric Restructuring *(from [4])*

Arizona regulators on July 30 and 31 participated in a thorough discussion of retail electric competition with stakeholders from within the state and around the country at the first of several likely workshops at the Arizona Corporation Commission in Phoenix.

Community choice aggregators from California and others listed the benefits electricity choice could provide Arizona, but an ACC staff director and utilities are less enthusiastic.

"If I had to answer today," Elijah Abinah, director of the ACC's utilities division, said at the workshop, "I don't think opening retail choice to residential customers would be in the public interest." Abinah encouraged commissioners and stakeholders to bring every possible issue up for consideration. Abinah's goal, he said, is to develop recommendations for rules that could withstand any legal challenge.

Initial proposed rules, drafted by the ACC's utility staff, guided the conversation *[RE-00000A-18-0405]*. While the only consensus to emerge from the initial workshop was that the commission should proceed with caution, stakeholders—with the notable exception of utilities—were largely supportive of pursuing a competitive electricity market in the state.

Commissioners spoke about the potential of a competitive electricity market to draw large employers to the state, but questioned whether residential ratepayers would benefit from retail choice.

Maureen Scott of the ACC's legal division provided background on retail electric competition in the state. The 2004 Phelps Dodge decision effectively ended Arizona's early efforts with retail choice when an appellate court determined that many of the state's original rules governing retail electric competition were unconstitutional. The court, according to Scott's summary, ruled that creation of an independent system operator or regional transmission organization was not reasonably related to ratemaking and thus not within the ACC's power to require.

Other states with retail competition are dependent on their RTOs, Scott said, adding that it would not be legally impossible to create one in Arizona. "It would require some creative thinking" and a lot of careful thought to proceed with RTO formation in light of the Phelps Dodge decision, she said.

Other findings in the 2004 decision included the unconstitutionality of the ACC imposing market rates on customers and requiring incumbent utilities to divest of generation resources.

> **'There are ways that the commission can deal with these restrictions.'**

"While there are important restrictions that the court imposed [in the Phelps Dodge decision], there are ways that the commission can deal with these restrictions," Scott said. A benefit of not being the first to do this is the opportunity to study other states as models, she said.

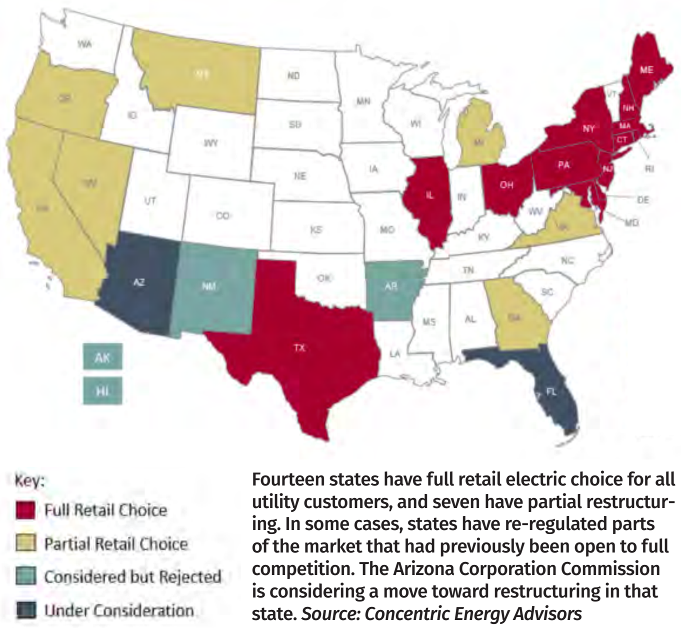
More than a dozen stakeholders, including trade associations, utilities and cooperatives, private energy and consulting firms and others, made presentations to the commission offering perspectives on potential pros and cons of electric restructuring. Consultants with a deep perspective on the effects of restructuring in the mostly Northeastern states advised the commission on best practices to have emerged from those markets amid great change in the energy sector.

Many states with a market for retail competition restrict that marketplace to nonresidential customers, Phil Metzger of the ACC utility division told the commission. Texas, pointed to by many presenters as a restructuring success story, is a notable exception. With the exception of some municipal carve-outs, participation in retail electric choice is mandatory for all Texas electric customers, whether residential or commercial.

The utility division's proposed rules—merely a starting point for discussion, staff stressed—suggest nonresidential customers with loads above 400 kW be the first allowed to participate in a competitive electric market. A provision would allow smaller nonresidential customers to aggregate their loads to a minimum of 5 MW in order to qualify for participation. Municipalities procuring on behalf of businesses and municipal operations would also be eligible for the aggregation provision, Metzger said.

Data from several states indicate that residential customers often pay more to retail providers than they would have paid an incumbent utility, according to Concentric Energy Advisors and others at the

Status of Restructuring by State



Fourteen states have full retail electric choice for all utility customers, and seven have partial restructuring. In some cases, states have re-regulated parts of the market that had previously been open to full competition. The Arizona Corporation Commission is considering a move toward restructuring in that state. *Source: Concentric Energy Advisors*

workshop. Several stakeholders also spoke of predatory business practices and inadequate protection for residential customers in restructured states.

Cathy DeFalco, a California Community Choice Association board member and general manager of the California Choice Energy Authority in Lancaster, explained the structure, benefits and her own experience with community choice aggregation to an enthusiastic commission. ACC Chairman Bob Burns was one of several regulators suggesting that community choice aggregation in Arizona could provide an opportunity for residential customers to participate in the benefits of a more open marketplace without taking on undue risk.

CCAs in California are exclusively government entities or "joint-power authorities" consisting of multiple government entities such as municipalities or counties. Local leadership determines the CCA structure, DeFalco explained, by focusing on the priorities of the communities they serve. These priorities range from low rates to increasing renewable generation and access to battery storage. The programs often provide benefits that extend beyond electricity access into the community and the grid itself, DeFalco said. These include distributed resource aggregation and investment in renewable-energy projects that have bolstered economic development.

However, CCAs have created many issues in California, including a rapid disaggregation of utility procurement and planning that has drawn attention and conflict with state regulators in that state.

Arizona's largest state-regulated utilities, Arizona Public Service and Tucson Electric Power, along with the Grand Canyon State Electric Cooperative Association and AARP, were less confident about moving away from the regulated monopoly utility model.

Michael Patten, representing TEP, said the company's customers do not seem to be "clamoring for change." Patten pointed to TEP's relatively low and stable rates compared with those in restructured states, and said its J.D. Power Residential Utility Customer Satisfaction Survey scores have been on the rise in recent years. TEP has worked with the commission to offer choices in rate structure in recent years, he said, adding that Arizona's investor-owned utilities have been beating state renewables portfolio standard targets.

Brad Albert, vice president of resource management for APS, pointed to resource adequacy as a major concern in what he referred to in his presentation as a "deregulated" electricity marketplace. The consulting firm Concentric Energy Advisors validated those concerns with the acknowledgment, in their presentation, that restructured markets have been challenged in meeting reliability needs that are determined by market forces rather than regulation.

Reflecting on whether competition could benefit the utility arena in Arizona, Burns suggested that renewable resources and technologies call for revisions to the regulated monopoly structure. "Monopolies are created to serve a mission," Burns said in his closing remarks, "but as soon as they're created, the priority shifts from the mission to protecting the structure." ***–Abigail Sawyer***

[18.1] Arizona Coalition Asks Regulators for a 100-Percent Clean-Energy Plan

Western environmental organizations want Arizona to join its neighbors in adopting a plan that will bring the state to 100 percent clean energy in the coming decades.

Western Resource Advocates, on behalf of 25 groups representing consumer, faith, business, environmental, public health and tribal interests, on July 30 submitted to the omnibus rulemaking docket at the Arizona Corporation Commission a nine-page clean energy plan proposal *[RU-00000A-18-0284]*. The coalition had hoped the matter would be taken up by commissioners at a two-day stakeholder meeting and workshop July 30 and 31, but commission discussion and presentations on electricity restructuring took up the bulk of the time at that hearing (see story at [18]).

The coalition's plan calls for requiring utilities to provide 50 percent of their power from renewable resources by 2030 and 100 percent from clean energy resources by 2045. Such targets are in line with other Western states that have adopted goals and mandates through legislation rather than regulatory process in recent months (see table, next page). Under the groups' proposed rules, compliance with the emissions standard would be measured using a regulatory structure that focuses on carbon content in emissions rather than mandating specific technologies.

Arizona was among the first states to establish a renewable-energy standard, but that standard, 15 percent by 2025, has not been revised since its adoption by the ACC in 2006.

The coalition's plan would also require that 10 percent of total retail electricity sales come from distributed resources such as rooftop and community

Western Renewable-Energy Targets	
Colorado	90 percent GHG reductions by 2050*
Nevada	100 percent clean by 2050
New Mexico	100 percent clean by 2050
California	100 percent clean by 2045

*Colorado targets economywide reductions of all greenhouse gases to 90 percent below 2005 levels.

solar by 2030. A 35-percent-by-2030 energy-efficiency target is another aim of the plan.

WRA, Western Grid Group, Vote Solar and the Sierra Club, in addition to signing on to the proposed plan, filed comments in May responding to the commission's April 25 staff report (updated July 2) that the groups say moves the state's energy policy backward.

The report's recommendation that the state eliminate renewable-energy and energy-efficiency requirements is particularly concerning to the groups. The July 30 comments and plan recommend "extending and improving upon" the renewables and efficiency requirements that the groups say have provided benefits to ratepayers and the electricity system "rather than eliminating them and starting from scratch."

The coalition intends that its plan—which, in addition to emissions, efficiency and other goals, will outline a new integrated resource plan process—as an alternative to recommendations in the April 25 and July 2 ACC staff reports. IRPs submitted by Arizona Public Service and Tucson Electric Power in 2018 were deemed to rely too heavily on natural gas resources and were ultimately not acknowledged by the ACC.

The commission in March 2018 enacted a moratorium on utility construction of new natural gas facilities and in February extended it through July of this year (see CEM Nos. 1480 [19] and 1525 [17]). It expired Aug. 1, one day after Brad Albert, APS vice president of resource planning and procurement, argued before the commission at the stakeholder meeting that natural gas continues to have a place in resource planning because of wide swings in electricity demand throughout the year. The electric load in July and August is frequently more than twice what it is in March, Albert told the commission. At those times, he said, the utility relies on every generation resource in its portfolio to meet reliability.

Discussion of the proposed rule changes was continued to Aug. 7. *–A. S.*

[19] Colorado Agencies, Automakers Propose to Adopt California ZEV Standard

A group of Colorado agencies and automakers reached an agreement on a proposed zero-emission vehicle standard, which they are jointly submitting to the Colorado Air Quality Control Commission for its consideration.

The commission is scheduled to adopt a ZEV regulation at its August regular meeting.

The negotiations among the Colorado Department of Transportation, the Colorado Energy Office, the Alliance of Automobile Manufacturers and the Association of Global Automakers reportedly took more than six months, and they ultimately agreed to implement the California Zero Emission Vehicle standard. If approved, the groups say this would "accelerate availability of ZEV options for Colorado consumers beginning next January while also ensuring a smooth transition into the program for automakers."

A provision in the Clean Air Act allows other states to adopt California's standard, which requires manufacturers to produce and deliver for sale a specific number of zero-emission vehicles. These can include battery-powered, plug-in hybrid and hydrogen fuel-cell electric vehicles.

The Colorado proposal includes incentives the automakers say would "make more vehicles available to Coloradans sooner," while limits on usage of the credits would "ensure greater ZEV sales in Colorado." If approved, the package should provide more zero-emission cars in the state as early as January 2020. The two trade groups' members represent about 99 percent of light-duty vehicle sales in Colorado.

"Automakers are building more electric models while Colorado is investing in market conditions that encourage consumers to buy them, so we have developed a way to work together on our shared goal of getting more electric vehicles on Colorado roads," the Alliance of Automobile Manufacturers and the Association of Global Automakers said in a statement. "This regulator proposal addresses concerns with earlier proposals by providing the support Coloradans need to buy electric vehicles while allowing auto manufacturers to transition into Colorado's ZEV program, which would cover vehicle model years 2023-2025, with the ability of automakers to earn early credits in the 2021-2022 model years."

However, it is those early credits that concern Ellen Howard Kutzer, an attorney with Western Resource Advocates, which has submitted its own proposal with a coalition of environmental advocacy groups.

"We're definitely very happy the automakers are agreeing to advocate for some form of zero-emission vehicle standard, but the early-action credits to be used raises concerns," she said.

The credits provision seeks to proportionally lower the number of zero-emission vehicles brought into the state, Kutzer said. "It's not a done deal per se," she said, since the state agency must still take action. The environmental groups are encouraging the state to adopt a rule that will provide "the highest benefits" for Colorado.

The Environmental Defense Fund, the Natural Resources Defense Council, Western Resource Advocates, the Sierra Club and the Southwest Energy Efficiency Project filed a brief July 10 encouraging the air-quality control commission to adopt a different ZEV program developed by the Colorado Air Pollution Control Division, part of the state's health department.

The groups said that through 2050 the climate benefits associated with that proposal "are valued at $6 billion to $18 billion, net present value." Additionally, "Implementation of the ZEV program as part of the Colorado Advanced Clean Cars regulation would result in $452 million of annual statewide savings in 2030 under a conservative analysis, and $825 million under an analysis assuming a high cost of gasoline."

The environmental groups are pushing for 10 percent of all new cars sold in the state to be zero-emission vehicles. They say a total of 15,000 zero-emission cars have been sold in Colorado to date.

The organizations are still reviewing the automakers' proposal to determine how it differs from the full California standard, but Kutzer, the environmental attorney, is "optimistic there is a deal" and that "ZEV rulemaking is moving forward in some form."

Colorado passed economywide greenhouse gas-reduction goals this spring (see CEM No. 1538 [18]), as well as other laws to make EV ownership more appealing to consumers. These include extending tax credits for EV purchases through 2026 and offering the Colorado Energy Office greater flexibility in administering grants to cover operating and installation costs of EV charging stations at the local level.

Another new Colorado law allows investor-owned utilities to pursue cost recovery through rates for investing in charging ports from the Colorado Public Utilities Commission, which mirrors Arizona policy (see CEM No. 1549 [18]).

The ZEV rulemaking will be the key topic at the next monthly air-quality control commission meeting, scheduled for Aug. 13 through 16. The agency will take public comments in person at two sessions on Aug. 13 as well as telephonically. Written comments were due to the agency by July 30.

The air agency is expected to render its decision Aug. 16, but there is typically an administrative delay of two or three months before state agency decisions are officially published, Kutzer said.
–Linda Dailey Paulson

POTOMAC

[20] Senate Transport Bill Would Fund Electric-Vehicle Charging *(from [5])*

The Senate Environment and Public Works committee on July 30 unanimously reported out a five-year, $287-billion transportation bill that would authorize $1 billion in competitive grants for charging and fueling infrastructure for electric, hydrogen and natural gas-fueled motor vehicles.

Sen. Tom Carper (D-Del.), the panel's ranking Democrat, said the legislation, S. 2302, includes "the first-ever climate title, committing $10 billion to programs and policies that will reduce global warming pollution" from motor vehicles and improve resilience of roads and bridges to extreme weather.

The bill would authorize grants for charging and fueling infrastructure along designated corridors designated by a state or group of states, such as the Regional Electric Vehicle West Plan states of Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah and Wyoming.

States in the Western group signed an agreement in 2017 to develop policies supporting development of electric-vehicle charging facilities on Interstate Highways 10, 15, 25, 40, 70, 76, 80, 84, 90 and 94.

In addition, the bill would authorize $370 million in grants for projects to reduce idling at marine ports, including electrification projects.

The bill also would authorize research into direct-air capture of carbon dioxide and CO_2 utilization.

Bill Speeding Rules for Gathering Lines Advances

Legislation requiring the federal pipeline agency to finalize proposed safety regulations for nearly 100,000 miles of gas gathering lines 90 days after bill enactment passed July 31 out of the Senate Commerce, Science, and Transportation Committee.

The bill, S. 2299, would reauthorize the Transportation Department's Pipeline and Hazardous Materials Safety Administration.

The proposed PHMSA safety regulations for gathering lines were first proposed in 2016.

The committee accepted Sen. Tom Udall's (D-N.M.) amendment on the gathering-lines rules. Udall, however, voted against reporting out the underlying bill because it did not include his proposed amendment requiring pipeline companies to upgrade technology for detecting gas leaks and to capture gas when making repairs. Udall said his amendment was critical for reducing methane emissions.

The bill also would require PHMSA to report publicly every 30 days the status of safety and reporting rules mandated by pipeline legislation enacted in 2011 and 2016.

Lawmakers have complained that the agency is taking too long to finalize the rulemakings.

Renewable-Energy Bill Draws Broad Support

Legislation to speed permitting of renewable-energy projects on federal lands, share rent and royalty revenues with state and local governments, and fund conservation won broad support July 25 at a House subcommittee hearing.

The bill, HR 3794, also would authorize the Interior Department to adjust rental rates and capacity fees for renewable-energy projects if the agency determines they are not competitively priced with comparable charges on nonfederal lands.

HR 3794 has 33 co-sponsors from across the House political spectrum. The bill has drawn favorable reactions from a broad range of interest groups, including the Solar Energy Industries Association, the National Association of Counties, Trout Unlimited and The Wilderness Society.

"You can do things together," Rep. Paul Gosar (R-Ariz.), the bill's sponsor, said at a hearing of the House Natural Resources Committee's Energy and Mineral Resources Subcommittee. Gosar is the subcommittee's ranking Republican.

Gosar said the bill would establish a permitting coordinating office and require the Interior Department to identify high-priority Bureau of Land Management acreage for wind and geothermal development. Currently, the priority-lands requirement applies only to solar.

In addition, Gosar said, the bill would share out rental and royalty revenues from renewables projects, with 25 percent each for affected counties and states, and 25 percent for a fund to finance conservation and recreational access projects.

Abigail Ross Hopper, CEO of SEIA, said in written testimony that the bill's provision for adjusting rents and capacity fees would remove a barrier to solar development on federal lands.

Speaking for the National Association of Counties, San Bernardino County Supervisor Robert Lovingood said revenue sharing would help local governments pay for services and infrastructure to support renewable-energy projects.

EPA Proposes NSR Rule Change

The Environmental Protection Agency on Aug. 1 proposed a rule to change its calculation method for determining whether modifications at power plants and other industrial facilities would trigger New Source Review permitting requirements.

Under the change, EPA would take into account a plant's overall projected emissions increases and decreases in determining whether NSR permitting requiring emissions-control upgrades would be triggered.

EPA Administrator Andrew Wheeler said the proposed change would simplify permitting.

The Sierra Club said the proposal would open a "major loophole" by allowing facilities planning modifications "to claim that planned decreases in pollution will offset any immediate increases in pollution, thus escaping their obligation to install critically needed pollution-control technology."

The American Forest and Paper Association praised the proposal, arguing that the change would "exclude minor projects from a burdensome and inefficient permitting process."

The rule would codify a guidance memo issued in 2018 by then-Administrator Scott Pruitt. The memo was challenged in court by the Sierra Club, Environmental Defense Fund and the Natural Resources Defense Council.

EPA Proposes Coal-Ash Rule Changes

The Environmental Protection Agency on July 30 proposed changes in coal-ash regulations, in response to a 2018 court ruling remanding parts of the 2015 rule back to the agency.

EPA's proposal would drop a requirement that reusing 12,400 or more tons of unencapsulated coal ash for structural fill or other nonroad uses would trigger an environmental review.

The proposal would replace the numerical trigger with "location-based criteria," such as proposed placement of ash in a wetland or floodplain. Proponents of reusing coal ash for such nonroad purposes would have to show the reuse would not result in releases above health and environmental standards, under the agency's proposal.

EPA's proposal also would regulate coal-ash piles with one set of rules. Under current rules, different regulations apply to piles at power plant sites and piles storing ash for reuse.

The U.S. Court of Appeals for the D.C. Circuit in August 2018 agreed to EPA requests to remand rule sections addressing coal-residual piles exceeding 12,400 tons and regulation of materials that will be repurposed.

The court also sent back for rewriting the rule's provisions allowing unlined impoundments to continue receiving coal combustion residuals unless they leak, classifying clay-lined impoundments as lined, and exempting unlined impoundments at inactive power plants from regulation.

Wind Tower Imports Probed

The Commerce Department on July 30 kicked off investigations to determine whether wind tower imports from four countries are being sold in the U.S. at below-market prices. The four countries are Canada, Indonesia, South Korea and Vietnam.

In addition, Commerce is examining allegations that Canada, Indonesia and Vietnam are unfairly subsidizing towers exported to the U.S.

The International Trade Commission is conducting a separate investigation, launched July 15, to determine whether dumping and subsidies involving the four countries' wind towers are harming domestic manufacturers.

The probes could result in imposition of antidumping and countervailing duties.

Two domestic manufacturers, Arcosa Wind Towers of Dallas and Broadwind Towers Inc. of Manitowoc, Wisconsin, filed petitions requesting the investigations.

If the Commerce Department rules for the petitioners and if the trade commission determines alleged dumping and subsidies have resulted in economic harm, Commerce would impose duties equal to the dumping and subsidy amounts. The commission must make a preliminary finding by Aug. 23.

Commerce said final determinations would be made by Dec. 16 on its subsidies probe and by March 2 for the antidumping investigation.

Alleged dumping margins, according to Commerce, are 53.63 to 61.59 percent for Canadian towers; 26 to 47.19 percent for Indonesia's products; 280.69 to 331.26 percent for towers from South Korea; and 39.97 to 65.96 percent for Vietnamese towers.

Of the four countries, South Korea is the leading exporter of towers to the U.S., totaling 34,937 metric tons in 2018, up sharply from 2,796 metric tons in 2017, according to Commerce Department figures.

Trump Threatens More Tariffs on Chinese Goods

President Donald Trump on Aug. 1 threatened to impose tariffs on $300 billion worth of Chinese goods exported to the U.S. starting Sept. 1, which would expand charges to virtually all products consumers and businesses buy from China.

Tariffs have drawn fire from business groups, which say they drive up prices of goods purchased by Americans and create uncertainty.

Electrical machinery, including transformers, generators and motors, is among the top sets of goods the U.S. imports from China, according to the U.S. Chamber of Commerce.

The U.S. currently charges 25-percent tariffs on $250 billion worth of Chinese products. China has levied retaliatory tariffs on U.S. goods, including a 25-percent charge on liquefied natural gas that took effect June 1.

In 2017 and 2018, China was the destination for about 10 percent of U.S. LNG shipments, and tariffs are likely to dry up LNG trade between the two countries, according to Nikos Tsafos, an energy and national security researcher for the Center for Strategic and International Studies. In a May 14 commentary, however, Tsafos noted that Chinese buyers “have never been major customers for U.S. LNG.”

Chinese products currently subject to U.S. tariffs include solar inverters; AC generators up to 75 kVa in output and single-phase AC motors; tungsten halogen, mercury, sodium vapor and metal halide lamps; non-lithium-ion electric-vehicle batteries; vacuum cleaners and vacuum parts; electric ranges, ovens and parts; television sets; and various electrical products, including insulators, plugs, sockets and resistors.

Cantwell Introduces Energy R&D Bills

Sen. Maria Cantwell (D-Wash.) on July 31 introduced a package of bills aimed at modernizing the grid and strengthening cybersecurity.

Cantwell’s package includes:

- S. 2332, authorizing Department of Energy programs to demonstrate storage, microgrid, EV charging, and advanced distributed-generation technologies.
- S. 2333, creating DOE programs to identify and test supply-chain vulnerabilities and response capabilities among DOE, national laboratories and private industry.
- S. 2334, creating a DOE advisory board on developing skilled energy workforces.
- S. 2335, supporting research in emerging building technologies.

Senators Float Industrial Emissions Bill

A bipartisan group of senators and House members on July 25 introduced bills authorizing research into reducing greenhouse gas emissions from industrial sectors, including cement and steel production, chemicals and plastics.

Sponsors said about 30 percent of U.S. GHG emissions come from what they called “hard-to-reduce,” energy-intensive industrial sectors, along with shipping and aviation in the transportation sector.

“In the industrial sector, there remain many obstacles which demand additional research and resources to overcome,” Rep. Sean Casten (D-Ill.), sponsor of the House legislation, said.

Casten said the bill would coordinate research into low-carbon industrial technologies that DOE is carrying out.

A broad group of industry and environmental organizations support the legislation, including the National Association of Manufacturers, the American Chemistry Council, the Natural Resources Defense Council and Environmental Defense Fund.

Carbon Tax Bills Introduced

Bills to tax greenhouse gas emissions were introduced July 25 by lawmakers on both sides of the aisle.

Carbon tax legislation has little chance of enactment in the 116th Congress because of opposition from Senate leaders and Trump, but the bills could set a marker for the 117th Congress, especially if a new president takes office in 2021.

Legislation dropped into the hopper includes:

- S. 2284, introduced by Sens. Dianne Feinstein (D-Calif.) and Chris Coons (D-Del.). The bill would set an upstream fee on fossil-energy sources, starting at $15 per ton of CO_2-equivalent in 2020, and tie increases to future emissions levels. The fee would not apply to “non-emissive” uses, such as gas used as an industrial feedstock. A fee would be charged on fluorinated gases, priced at 20 percent of the carbon fee. Seventy percent of fee proceeds would be rebated to citizens and legal residents with household incomes up to $150,000 per year. A companion bill in the House is sponsored by Rep. Jimmy Panetta (D-Calif.).
- HR 3966, introduced by Reps. Dan Lipinski (D-Ill.) and Francis Rooney (R-Fla.). The bill would levy a fee starting at $40 per ton of CO_2 in 2020, rising 2.5 percent plus inflation every year that the U.S. does not meet emissions targets. Coal, oil and natural gas would be charged at the point they enter the U.S. economy.
- HR 4058, also introduced by Lipinski and Rooney, would charge fossil-energy producers and large industrial emitters $30 per metric ton, rising 5 percent plus inflation every year. Seventy percent of net revenues would be used to cut payroll taxes, 10 percent would go to Social Security beneficiaries, and 20 percent would go into a fund for research and energy-bill relief for low-income households.

Dems Introduce Energy ‘Victory Bonds’ Bills

Senate and House Democrats on July 25 introduced legislation authorizing the sale of up to $50 billion per year in “Clean Energy Victory Bonds.”

Bonds with denominations as low as $25 would be available for purchase under the legislation.

Proceeds of bond sales would supplement federal financing of energy-efficiency and renewable-energy deployment, including upgrades at federal facilities, state and local grants for energy projects, and research. Proceeds also could be used for grid upgrades and EV charging infrastructure.

The House bill is sponsored by Reps. Zoe Lofgren and Doris Matsui, both California Democrats. The Senate version was introduced by Sen. Tom Udall (D-N.M.).

DOE Considers Package A/C Standards

The Department of Energy on July 29 opened a comment period on whether energy-efficiency standards should be revised for evaporatively cooled and water-cooled commercial-package air conditioners.

Standards for the appliances were last updated in 2013 and 2014, except those for water-cooled packages with cooling capacity of less than 65,000 Btu per hour, which were last updated in 2003.

One of the issues on which DOE is seeking comment is whether to use the integrated energy-efficiency ratio as a metric for the energy consumption of evaporatively cooled and water-cooled packages.

Manchin Urges Trump to Fill FERC Seats

Sen. Joe Manchin (D-W.Va.) on July 31 urged Trump to name Republican and Democratic nominees to fill two Federal Energy Regulatory Commission seats.

Manchin, ranking Democrat on the Senate Energy and Natural Resources Committee, urged Trump to stick to the "precedent" of FERC operating "above the political fray."

FERC has been operating with four commissioners since Kevin McIntyre's death on Jan. 2. Another vacancy will open at the end of this month when Cheryl LaFleur steps down, leaving FERC with the minimum three commissioners needed for a quorum.

In a July 30 podcast, LaFleur said top issues facing FERC include pipeline reviews, including climate impacts, and review of Order No. 1000. "The onset of competitive transmission processes has been more trouble than anticipated," she said of Order 1000, the 2011 transmission planning and cost-allocation rule.

BLM Releases Plan for Reduced Bears Ears

No energy leasing is provided in the reduced Bears Ears National Monument, according to a proposed management plan and final environmental impact statement the Bureau of Land Management released July 27.

The proposed plan sets out management policies for the monument's Indian Creek and Shásh Jaa' units, which include the acreage left in monument status when Trump in 2017 issued a proclamation shrinking Bears Ears from 1.35 million to 201,000 acres.

Trump's proclamation has been challenged in court by tribes and environmental organizations.

"If we win the legal fight to restore Bears Ears National Monument, this plan will just be 800 pages of wasted effort," Heidi McIntosh, managing attorney of Earthjustice's Rocky Mountain Regional Office, said in a statement.

Release of the plan drew fire from Democrats on the House Natural Resources Committee. Rep. Raúl Grijalva (D-Ariz.), the committee's chairman, said, "I'm confident when the courts rule, these illegal actions will be overturned and Bears Ears National Monument will be restored."

NRC Eyes 'Greater Than Class C' Disposal Option

The Nuclear Regulatory Commission is considering disposal of "greater than Class C" radioactive waste in "near surface" facilities and is seeking public comments on a framework for adopting regulations.

A commission proposal estimated that 80 percent of the material could be disposed of in near-surface facilities, defined as within 30 meters of the surface.

Greater-than-Class-C waste is low-level waste containing radionuclides at levels exceeding Class C, considered the most hazardous of three categories of low-level waste.

Currently, such materials are stored at power plant sites and interim storage facilities. The NRC said they consist of plutonium-contaminated fuel-cycle wastes, activated metals from power plants, and waste generated in manufacturing of industrial and medical products.

The preferred alternative in a 2016 DOE environmental impact statement was sending the material to the Waste Isolation Pilot Plant in New Mexico or to "generic commercial facilities." The EIS estimated the current volume of activated metals from power plants at 880 cubic meters. ***–Jim DiPeso***