there is no gridlock in Washington and something will actually get done. What do you think?

MR. MENEZES: I think that is right, but keep in mind the following. When I served on Capitol Hill, there was a unified government, but you still had to operate within the rules and even if you put together a bill in the House, it remains subject to points of order, and it takes a lot of cooperation to get the bill through the full House.

Then it goes to the Senate where, absent a budget reconciliation process, you have to get 60 votes to move the bill.

The Republican caucus is not a unified caucus. It is never an easy process, even with one party in control.

All of that said, this is the best chance in more than a decade for new legislation to move.

California: A Shifting Market for Solar

by Laura Norin and Naina Gupta, with MRW & Associates, LLC in Oakland, California

The California Public Utilities Commission is in the process of changing two key constructs that are central to the economics of solar in California.

The two are net energy metering that allows customers to sell extra electricity generated from rooftop solar panels to the local utility at the full retail rate and time-of-use pricing that values solar energy at a premium based on the time of day of solar output.

The changes will create new challenges for the solar industry in California, both for rooftop solar companies and utility-scale solar developers.

However, they should be seen as market corrections in response to the overwhelming success of solar in the state and not as an indication of the state's attitude toward solar development. In the long term, opportunities for new solar development in California continue to be strong. Near term prospects are somewhat more limited, especially at the wholesale level. However, opportunities are still available, particularly when solar is paired with energy storage or otherwise structured to maximize value to the grid or to meet specific needs.

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The court also said there is no going concern value to which part of the purchase price has to be allocated. It said a power plant that is not yet operating has none.

However, the court said there is "turn-key value." A power plant is worth more at the end of construction because it is "ready to use." It said this premium goes into basis in the power plant itself as opposed to an intangible.

The court said the government failed to prove there were any peculiar circumstances that cast doubt on whether the prices paid by the tax equity investors in the sale-leaseback transactions are not arm's-length prices. "[T]he Court should disregard the purchase price as basis only if the evidence shows that peculiar circumstances have highly inflated the purchase price," it said. A sale-leaseback transaction is not automatically peculiar, it said.

The evidence of market value was better in this case than most, the court said, because the price was established in an auction.

Terra-Gen prepaid part of the rent under the lease back of each project. The court declined to view the real purchase price paid by each lessor as the net purchase price after subtracting the rent prepayment each lessor was immediately repaid at closing. "[T]here is simply no evidence that these prepayments inflated the purchase price in any way," it said.

Of the remaining two cases, the government largely won one and the other was a draw.

One involved a biomass power plant. The government believes such a plant must be split between the parts that produce steam and electricity. A grant – and, by extension, an investment tax credit — can only be claimed on the part that generates electricity.

GUSC Energy completed a new power plant in November 2013 at an industrial park in Rome, New York, that uses wood chips to produce steam and electricity. The plant ran for only one winter in late 2013 and early 2014 and has been largely shut down since then due to low natural gas prices. During the one */ continued page 15*

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Background

Net metering allows customers with rooftop solar panels to manage the timing differences between their solar energy production and their need for power. In California, net-metering customers can sell surplus power back to the utility at the full retail rate, allowing a customer essentially to exchange power purchased from the utility during the night with surplus power the customer produces during the day. The retail price that net-metering customers receive is far above the price that wholesale generators would typically be paid for their power. However, sales from a net-metering customer in excess of the amount of power that the customer purchases from the utility over the course of a year are valued at a price that more closely reflects wholesale power prices.

A time-of-use rate structure prices electricity differently at different times of the day and year. For instance, prices could be lower during the night than in mid-afternoon and higher in summer than in winter. This type of rate structure is supposed to encourage customers to reduce electricity consumption during periods of peak demand when prices are high and shift electricity usage to other times when demand and prices are lower. Ideally, the rates in each time-of-use period are aligned with the cost to produce electricity during that period.

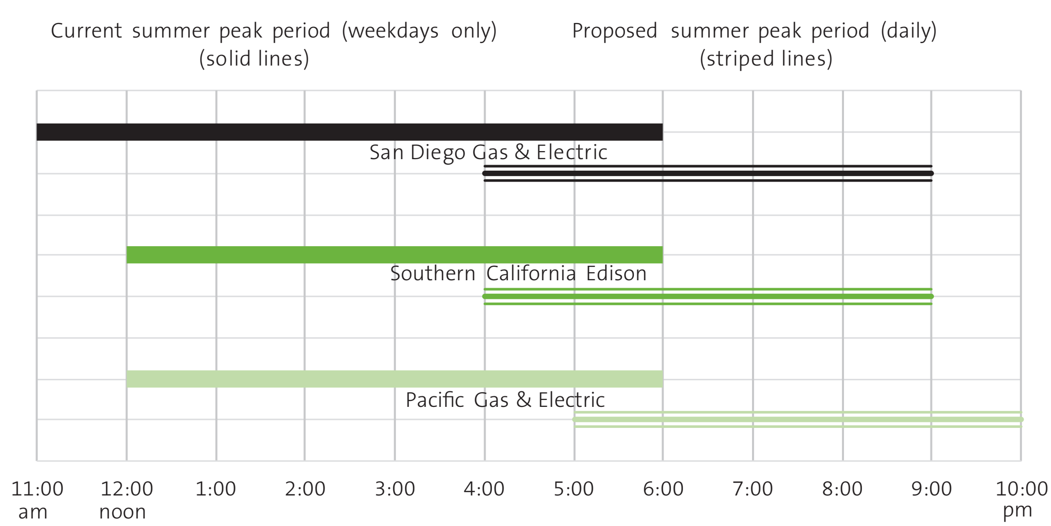
With few exceptions, non-residential customers of the three large investor-owned utilities in California are required to take service under time-of-use rates. These rates are currently optional for residential customers. Residential customers will be moved automatically to time-of-use rates beginning in 2019, unless they opt to remain under the old rate structure.

Net metering and time-of-use rates have contributed to the success of distributed solar in California. Net metering allows customers to size their solar systems to cover a large share of their electricity usage without concern for timing mismatches between solar generation and electricity need. Time-of-use rates have made net metering more valuable because the highest cost period under most rate schedules falls during summer weekday afternoons when air conditioning demand drives high electricity consumption and when solar panels are at peak output.

By installing solar, customers are able to avoid paying the utility for electricity use during high-cost hours and, through net metering, to sell their extra solar electricity to the utility at the high-cost rate. The ability to sell electricity at peak hours and rates has been a key driver of distributed solar economics in California for non-residential customers and for some residential customers.

Time-of-use pricing has also been of benefit to larger-scale projects bidding into utility power solicitations. The utilities apply time-of-delivery factors that place a higher value on power that is generated during times of higher system cost when evaluating bids. The overlap between the high-cost hours and the high solar hours means the utilities assign a higher value to mid-day solar generation than to power generated during the early morning hours or power generated evenly throughout the day.

Figure 1: Current and Proposed Summer Weekday Peak Periods for the IOUs



Expected Changes

The California Public Utilities Commission approved a new framework for the net-metering tariff — commonly known as NEM 2.0 — in January 2016.

NEM 2.0 will require net-metering customers to take service under a time-of-use rate and will increase their costs.

Their costs will increase because of a new interconnection fee of up to $150 to connect rooftop solar to the grid, plus an extension of public purpose charges and certain other utility charges to all electricity purchased from the grid, even electricity that is offset at a different time of day by self-generated power.

The additional charges will have the effect of reducing the value of power sold back to the grid to less than the full retail price of power.

The NEM 2.0 tariff will apply to customers that interconnect a new solar system after July 1, 2017 or after a utility reaches a previously set cap on new solar installations that are eligible for net metering, whichever happens first.

The cap has already been reached for San Diego Gas & Electric and is expected to be reached by the end of 2016 for Pacific Gas & Electric.

In addition to NEM 2.0, the California Public Utilities Commission has four regulatory proceedings underway to re-evaluate the structure of time-of-use periods for the three large investor-owned utilities and to reassess which hours during the summer peak period should have the highest rates.

In particular, the success of solar in California is driving a push to shift the highest rates to the evening when there is little or no solar electricity generation.

Electricity use remains high during summer afternoons, but the large amount of solar generation during these hours has reduced the need for relatively high-cost generation that used to be needed when customers turned on their air conditioning. There can sometimes be an oversupply of electricity in the afternoon hours, particularly during the spring months when air conditioning use is minimal and solar and hydroelectric generation are plentiful. Wholesale market prices tend to be relatively low during the afternoon hours due to the influence of solar. Energy use remains high in the evening, but the supply of solar power ebbs as sunlight fades, leading to higher wholesale market prices. Consequently, there is a push to move the summer peak-period, which is currently from around noon to 6 p.m., out to 4 to 9 p.m. or later (see Figure 1).

Figure 1 shows what the investor-owned utilities are proposing for their new peak hours.

The utilities' new peak hour definitions would reduce the value of solar electricity during weekdays because the hours when solar is at peak output would no longer be peak pricing hours. The impact on solar on weekends is less clear because weekends are currently considered / continued page 16

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season it operated, it supplied 46.7% of the steam heating needs of the industrial park but only 2.8% of the electricity.

The owner applied for a grant of $5,469,028, but was paid only $316,609 (after a 7.2% haircut due to budget sequestration).

GUSC Energy argued that the entire project is used to generate electricity. The court disagreed. It also disagreed with how the Treasury decided the share of the project cost that was for generating electricity. Treasury treated only 6.6% of the cost as eligible because only 6.6% of the steam was converted into electricity.

The government witness said this approach was flawed. The court was not happy with his approach either, but had nothing else to fall back on. He suggested dividing the electricity the plant generated by the electricity that a plant using fuel with the same energy content would generate if all the energy went to electricity generation. This led to 15.24%.

The court applied this fraction to give the plant owner an additional grant of $456,860. The Treasury had removed costs related to site cleanup, landscaping, ornamental iron work and paving. The court put them back into the basis used to calculate the grant.

The case is *GUSC Energy v. United States*. The court released its decision in early November.

Finally, the Treasury ended up with a draw in a case involving a solar company in Dallas called RCIAC that two individuals formed to install LED lighting and capacitor banks for businesses. They shifted to solar at the urging of their electrical materials supplier.

The company installed 18 solar panel systems in 2010 and 2011. The two individuals asked Treasury a number of questions. They got back answers that might have been useful to a tax lawyer, but not to an electrical contractor with a high school education. RCIAC was led to believe from the answers that it could claim a basis in the solar systems of $10.50 a watt. The Treasury paid a grant at that / continued page 17

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entirely off peak, while under the proposed new time-of-use periods, weekends would also include higher cost periods, allowing some share of weekend solar output to fetch higher prices than at present, but with the remaining generation valued at off-peak prices that may be lower than at present.

The net change in value would depend on what share of solar hours are included in the high-cost weekend period over the course of the year and how great the pricing differentials are between the different time-of-use periods. These issues remain subject to debate along with other critical details, including when the new time-of-use periods will be implemented and what protections will be afforded to customers with existing solar installations. However, the overall impact is expected to be somewhat negative.

Each utility's proposal is being considered in a separate proceeding at the CPUC. Decisions in these proceedings are expected over the next year or so, with SDG&E's proposal likely to be addressed first, possibly as early as late spring 2017. The commission is widely expected to approve shifts to the peak hours that are similar to the utility proposals, though details may vary.

For residential customers of PG&E and Southern California Edison, the high-cost hours have already been shifted somewhat later in the day in the standard optional time-of-use schedules, and the Figure 1 proposals would not be implemented immediately. The current PG&E "Schedule E-TOU" has high-cost hours from 3 to 8 p.m. or, optionally, from 4 to 9 p.m. The current Southern California Edison "Schedule TOU-D" has high-cost hours from 2 to 8 p.m.

These high-cost periods still include some peak solar hours, so they are less detrimental to solar customers than the proposed non-residential peak periods (Figure 1). Also, most residential customers continue to take service under non-time-of-use rates.

Changes will be more significant for residential customers who are considering installing solar since customers who are subject to NEM 2.0 will be required to take service under time-of-use rates. In addition, over time, the non-residential peak periods are likely to be applied to residential customers as well.

The changes to net metering and time-of-use periods on existing solar customers will have a somewhat muted effect due to grandfathering provisions.

In particular, customers who are already engaged in net metering will remain under the existing net-metering tariff for 20 years from when they first connected their solar systems to the grid. In addition, a proposed decision currently before the CPUC, if adopted, would allow existing solar customers to continue to take service under current time-of-use rate periods for five years from their date of solar interconnection. However, this is a hotly contested provision, and it may be adjusted upward or downward prior to adoption. It is also possible that other relief may be provided to existing solar customers along with, or in place of, a time-of-use grandfathering period, such as a special earlier on-peak period.

New solar customers will take service under the new time-of-use periods and the NEM 2.0 tariff. They will have less incentive to install solar than before. The impact for a given customer will depend on the customer's usage profile, solar generation profile and utility, as well as the size of the solar system relative to the customer's electricity use and the particulars of the time-of-use periods and rates that are adopted.

Table 1 shows the combined impacts for an illustrative small commercial customer in San Bernardino, California of the NEM 2.0 changes and the new time-of-use periods that Southern California Edison has proposed. For this illustrative customer, these two changes combined would increase the customer's annual electricity bill by 60%. Yet, even with this large increase in the customer's utility bill, the savings the customer would realize from installing solar would be only 10% less after the new rules go into effect than before. This result may not hold for all customers.

Table 1: Impact of NEM and Time-of-Use Period Changes for Illustrative Small Commercial Customer

	Annual Electric Bill	Savings from Solar
Without Solar	$1,765	N/A
With Solar: Before NEM/TOU Changes	$270	$1,495
With Solar: After NEM/TOU Changes	$430	$1,335
Impact of NEM and TOU Changes	+$160	-$160
Impact of NEM and TOU Changes (%)	~60%	~10%

Illustrative customer is located in San Bernardino, California. The customer has a 6.5 kW-DC distributed solar system that is sized to meet annual electricity needs of about 10,000 kWh, and the customer takes service under Southern California Edison Schedule TOU-GS-1.

chadbourne

Changes to the time-of-use period structures additionally introduce regulatory uncertainty for customers who are considering installing solar.

The proposed decision on time-of-use periods before the CPUC would guarantee net-metering customers a minimum of five years under whatever time-of-use periods they start. While this five-year commitment is helpful, the prospect of further time-of-use period shifts after five years creates added risk for solar systems that require more than a five-year payback period. The prospect of additional future net-metering changes is less of a concern because the CPUC has already guaranteed that NEM 2.0 customers may continue receiving service under that tariff for 20 years.

The new time-of-use periods the utilities are proposing would apply only to retail rates, but the same shift is underway in the time-of-delivery factors that are used to value wholesale solar generation that is sold to the utilities.

In many cases, these time-of-delivery factors have already been updated in recent years to shift the highest value hours to later in the day. For example, PG&E's time-of-delivery factors assign the highest value to power delivered from 4 to 10 p.m. The correlation between the peak periods used for retail rates (time-of-use periods) and for wholesale procurement (time-of-delivery factors) is still subject to discussion at the CPUC; however, they should move into general alignment over time. The shift to later peak periods will affect both distributed solar and utility-scale solar.

Solar Outlook

The NEM 2.0 and time-of-use period changes are a response to widespread adoption of solar in California. Solar remains a preferred resource in the state, and the California Public Utilities Commission wants to maintain a viable solar market, but it wants a regime that requires lower rate support, given regulators' desire to avoid unnecessary subsidies between customers and in light of lower underlying costs: between 2007 and 2015, median installed prices for utility-scale solar fell by nearly 60% nationwide, and further cost reductions are anticipated.

California continues to encourage solar adoption. While the CPUC increased costs for net-metering customers, the NEM 2.0 changes are much less drastic than changes to net-metering programs that have been adopted or are under review in other states such as Nevada and Arizona. In addition, the CPUC rejected (for now) a request by the investor-owned / continued page 18

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level on the first system. The company then moved to install others.

Its actual cost to install was $4.79 a watt, but it claimed grants on a "retail" price that was 1.8 times higher. It expected a Treasury cash grant for 66% of the actual system cost and a rebate from the local utility, Oncor, for another 47% of the cost. (Oncor paid rebates to installers as a reward for installing solar.)

RCIAC never really collected the retail price from anyone. The systems were leased to customers, but the company was lax about collecting rent. The leases ran five years, after which the customers had options to buy the systems. At some point, RCIAC understood the IRS to say that the same company could not be both the installer and the owner, so it formed a separate company, LCM Energy, to own the systems.

The Treasury paid grants on a basis of $4.79 a watt plus 20%, for $5.70. The two contractors sued for the difference. The government then accused them of fraud and asked for the money back.

The US claims court said they were not sophisticated people trying to defraud the government, but were merely trying to understand the program based on what they thought they were told by Treasury. The Treasury contributed to the confusion by paying the first grant. The court let them keep what they were already paid, but declined to pay them more.

The case is *LCM Energy v. United States*. The decision was released in late October.

Treasury cash grants remain subject to budget sequestration, an effort by Congress to control the federal budget by cutting spending across the board. Grants approved for payment through September 30, 2017 will suffer a 6.9% haircut.

The new Congress that takes office in January could junk or revise the sequestration statute. Some Republicans want to eliminate sequestration for the defense budget. Democrats would resist without also dropping it for domestic spending. Any change / continued page 19

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utilities for demand charges for residential net-metering customers, and the CPUC is considering allowing net-metering customers to be grandfathered from changes in time-of-use rates period for five years.

A customer may be able to improve the economics of installing solar by combining solar with energy storage.

This would reduce the impact of the NEM 2.0 cost increases since less power would be sold back to the utility under the new net-metering tariff. The customer could also get the highest price for power solar back to the grid by storing the power until the high-cost hours. The CPUC has ruled that a solar system with storage is to be treated the same as a solar system without storage, so these uses are available without restriction.

Electric vehicles could also be used in combination with solar installations to increase the value of both systems. For example, for a system with excess solar power during the middle of the day, using the power to charge an electric vehicle may in some cases be more beneficial than selling the power back to the utility during hours that are outside of the high-cost period.

A less expensive option would be to orient solar systems toward the west (rather than south) to benefit from later-in-the-day sunlight. While this would not provide the same benefit as energy storage, it is a low-cost measure that could provide incremental value for some customers.

Table 2: California Investor-Owned Utility RPS Procurement Needs

	RPS Procurement Under Contract for 2020 (33% requirement)	Year New RPS Generation First Needed
PG&E	37.0%	2026
SCE	36.9%	2023
SDG&E	43.1%	2025

With these sorts of strategies and by passing along cost reductions, solar developers should continue to find a market for distributed solar in California, even though the market may not be as robust as in recent years.

Utility-scale solar is not affected by the changes to the net-metering tariff, but it is affected by the shift in time-of-delivery factors. It, too, can be helped by orientation of the solar system to follow the sun or to capture more sunlight from later in the day and can be combined with large-scale storage. The CPUC has directed the investor-owned utilities collectively to procure 1,325 megawatts of storage by 2020 and to implement this procured capacity by 2024. Storage installations that are linked with solar qualify under this storage requirement. In addition to aligning the hours of solar output with peak time-of-delivery periods to increase the value of the power generated, storage could also provide the opportunity to use solar as a flexible resource, further increasing its market value. For example, during the early evening when solar output falls while demand remains high, there is a need for a large amount of fast-ramping power. Storage facilities can quickly dispatch stored solar power to meet these ramping needs, providing a valuable grid service.

A bigger issue for utility-scale solar than the regulatory changes is the near-term glut of renewable power. While California has a very aggressive renewable portfolio standard, requiring 33% of procurement from RPS-eligible power by 2020 and 50% by 2030, the investor-owned utilities are not expected to need new RPS power until the early-to-mid 2020s (Table 2).

The California utilities will eventually be back in the market for renewable power. Table 3 shows the full renewable procurement needs of the three investor-owned utilities in 2030 compared to the amount of renewable power currently under contract.

Significant gaps remain, particularly for Southern California Edison. In addition, in a settlement agreement that is under CPUC review regarding closure of the Diablo Canyon nuclear power plant, PG&E has agreed to replace the nuclear power with

Table 3: California Investor-Owned Utility RPS Procurement 2030

	Total RPS Procurement Needed in 2030 (GWh)	RPS Procurement Under Contract for 2030 (compare to 50% RPS)	Additional RPS Procurement Needed for 2030 (GWh)
PG&E	21,427	40%	4,340
SCE	38,533	28%	16,847
SDG&E	7,478	40%	1,552

greenhouse gas-free resources, some of which is likely to be solar power, and also to increase its RPS target voluntarily to 55% of retail sales during the period 2031 to 2045. If this agreement is adopted, then PG&E's RPS requirement will increase by approximately 2,000 GWh per year above the amount shown in Table 3 for each of these years.

In the near term, utility-scale solar developers may do better to focus on municipal utilities and community choice aggregators, called CCAs. (For earlier coverage about CCAs, see "Huge Potential New Demand for Power" in the October 2016 *NewsWire* and "Another Potential Offtaker: Community Choice Aggregators" in the August 2016 *NewsWire*.)

CCAs are entities that procure power on behalf of investor-owned utility customers in their jurisdictions, with the local utility continuing to distribute the power. California has seen explosive interest in CCAs in recent years, and the projected growth in CCAs is contributing to utility RPS surpluses as the utilities shed customers to CCAs.

CCAs must meet the same RPS requirements as the utilities must meet, and many have even more aggressive renewable targets. For example, the Marin Clean Energy CCA currently operates with a resource mix of 51% renewable energy, and is committed to a longer-term goal of sourcing 80% of its electricity needs from renewable sources. In addition, many of the existing and planned CCAs have goals for the development of new, local renewable resources, which could include new solar projects.

The changes to time-of-use period (and the closely related time-of-delivery factors) that are being evaluated in California will continue to be reexamined as the power grid continues to evolve.

The introduction of larger amounts of storage and electric vehicles on the grid will shift the power supply and demand curves in ways that are not yet known. In addition, a process is currently underway to better integrate (and perhaps combine) the California grid with the grids of other western states. With this closer integration, a wider portfolio of resources is becoming available for dispatch, which is helping to even out the intermittency of renewable generation more efficiently and cost effectively. This, too, may shift the hourly makeup of supply that is available in California and may push the high-cost hours to other periods or lead to more consistent pricing throughout the day.

While future time-of-use period changes are uncertain, as costs for solar continue to trend downwards, the available subsidies and rate supports should be expected also to diminish.

The near term may be the most / continued page 20

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in the sequestration statute would affect grants paid after the effective date.

STATE PLANS to promote renewable energy and nuclear power are at risk in two widely watched lawsuits in New York and Connecticut.

Five independent generators, the Electric Power Supply Association and the Coalition for Competitive Electricity filed suit in federal district court in New York in October to block the state from awarding "zero emissions credits" worth $17.48 a megawatt hour in 2017 and 2018 to owners of up to four nuclear power plants.

The case tests whether a state can offer such credits as a supplement to wholesale power prices without running afoul of federal law. The Federal Energy Regulatory Commission supervises the wholesale power market.

The value of the credits will be reset after 2018. The program is expected to run 12 years.

At least three of the six New York nuclear plants are expected to receive the credits.

The credits were approved by the New York Public Service Commission in August as part of a plan to try to keep the nuclear power plants open. Nuclear power accounts for roughly 31% of total New York generating capacity. The state says the nuclear power plants are important to limiting carbon emissions.

The program is scheduled to take effect in March 2017.

The nuclear owners will sell the credits to the New York Research and Energy Development Authority, NYSERDA, at the price established by the New York Public Service Commission. NYSERDA then will resell them to New York utilities on a *pro rata* basis in proportion to each utility's share of total New York electricity load.

Low natural gas prices are forcing nuclear power plants across the country to shut down.

The credits represent a significant subsidy on top of what the nuclear plants are being paid currently for their electricity.

The generators, who compete with the nuclear plants for a share of / continued page 21

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challenging as customers adjust to the new time-of-use periods and new NEM 2.0 tariff, and as wholesale procurement is limited due to a glut of RPS power at the investor-owned utilities. Opportunities for wholesale contracting should open up again more widely in the early 2020s, and time-of-use periods (and time-of-delivery factors) may shift further during this period, possibly in a direction that would benefit solar economics. In the meantime, CCAs and municipal utilities may provide avenues for medium or large-scale solar projects, and opportunities remain available in the residential and commercial markets for systems that are competitively priced. ◎

Chile: Solar Outlook

by Brian Greene and Monica Borda, in Washington

Chile had 6.7 megawatts of installed solar capacity at the end of 2013. Three years later, the installed solar capacity in Chile is more than 1,200 megawatts, and there are more than another 1,600 megawatts under construction and more than 12,000 megawatts in development.

We decided to take a closer look at Chile to understand the reasons for this incredible growth and the prospects for the Chilean market going forward.

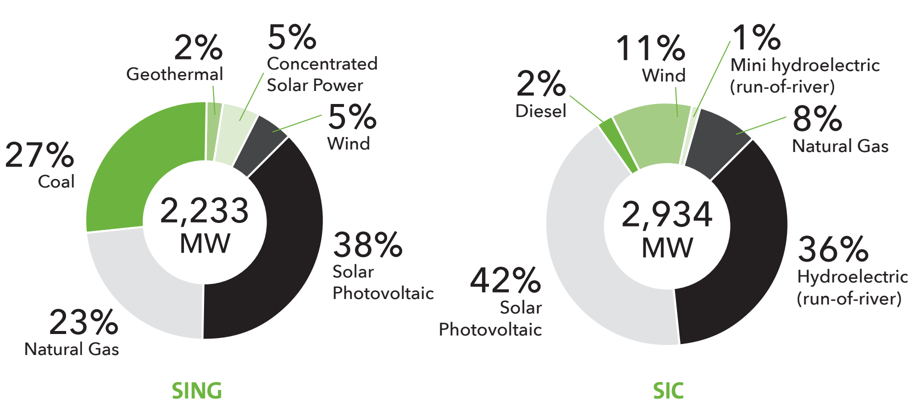
Catalysts

The reasons for the explosive growth are economic and political. The Atacama desert in the north of Chile provides for one of the best — if not the best — solar resource on earth. Chile also benefits from a stable economy and historically high energy prices due to a lack of domestic fossil fuel production.

In Chile, the term "non-conventional renewable energy" is used to refer to all types of renewable energy excluding hydro projects larger than 20 megawatts. The Chilean Ministry of Energy set a target in May 2014 of generating 20% of Chilean electricity from non-conventional renewable energy by 2025, with 45% of the electric generating capacity to be installed in the country from 2014 to 2025 to come from such non-conventional renewable sources. In September 2015, the 2050 Energy Advisory Committee — a public body established to develop a long-term energy policy — released an even more ambitious renewables forecast — its Energy Roadmap 2050: A Sustainable and Inclusive Strategy — in which the government targeted at least 70% penetration of non-conventional renewable energy in Chile's energy systems by 2050, with more than 20,000 megawatts of wind and solar generation. Solar energy was projected to meet 19% of this electricity demand. Thus, while Chile did not offer any tax credits or feed-in tariffs, the solar industry was greeted in Chile with enthusiasm and cooperation by the Chilean government.

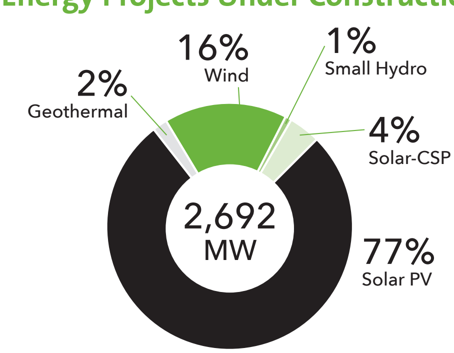
These conditions led to a flurry of large utility-scale solar projects being constructed and financed in a short period of time, including First Solar's Luz del Norte project (141 megawatts), SunEdison's Amanecer (100 megawatts), San Andres (50 megawatts) and Maria Elena (73 megawatts) projects and Total's Salvador project (70 megawatts).

Figure 1: Power Projects Under Construction



Source: Comisión Nacional de Energía, Reporte mensual sector energético, *Vol. No. 14, p. 5 y. 6 (April 2016)*

Figure 2: Non-Conventional Renewable Energy Projects Under Construction



Source: Centro Nacional para la Innovación y Fomento de las Energías Renovables Energías renovables en el mercado electrico Chileno, *p. 3 (April 2016)*

Environmental Update

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states in recent years, but future funding decisions will be made by the next administration and the next Congress. If the requirement for states to meet obligations under the Clean Power Plan and other regulations is rescinded, then that could create a divide between those states whose politicians favor such protections and those who do not.

What will industry do? Facing the prospect of a US retreat from climate action, there have been a number of private sector calls to support of the Paris Agreement. For example, 365 businesses and investors, including Fortune 500 companies such as DuPont, Hewlett Packard Enterprise, the Kellogg Company and Unilever, all called for continued engagement on climate change in a November 2016 statement. "Implementing the Paris Climate Agreement will enable and encourage businesses and investors to turn the billions of dollars in existing low-carbon investments into the trillions of dollars the world needs" to expand clean energy, the statement said. "Failure to build a low-carbon economy puts American prosperity at risk."

Nicholas Akins, CEO of American Electric Power, an Ohio-based electric utility that generates power in 11 states, told *The New York Times* after the election that his company is making investments in energy generation aimed at 20 to 40 years from now. He assumes that carbon pollution will be regulated in the long run, whether or not the Trump administration dismantles the Clean Power Plan. "We will not be building large coal facilities. We're not stopping what we're doing based on the new administration. We need to make long-term capital decisions. I don't think the course will change."

Will other nations step into our shoes on climate change? Chinese President Xi Jinping said China intends to continue with its plans to cut carbon emissions without regard to what Trump does. China pledged under the Paris agreement that its emissions will drop after 2030, and that China will put in place a national system next year to force companies to pay a fee for their carbon pollution. It will be ironic if China steps firmly into a leadership position on climate change as America backs away.

Naming Names

In early December, Trump's transition team took the peculiar step of asking the US Department of Energy to provide the names of all employees and contractors who attended climate change policy conferences. The questionnaire asked for "a list of all Department of Energy employees or contractors who have attended any Interagency Working Group meetings" to create a measurement known as the social cost of carbon, which has been used by the Obama administration to measure the economic consequences of greenhouse gas emissions and to justify the economic cost of climate regulations. Another request was for "a list of Department employees or contractors who attended any" United Nations climate change conference "in the last five years."

The Trump transition team distanced itself from the questionnaire after DOE declined to provide names. ◎

– contributed by Andrew Skroback in Washington

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