

provided to grid companies to alleviate the financing pressure arising from the fact that costs incurred in grid expansion may not be recouped until power is sold to the end-user. ☺

Many Options For Solar Developers In California

by Laura Norin, Heather Mehta and David Howarth with MRW & Associates, LLC in Oakland, California

Installed capacity of grid-connected solar projects in California has grown from 360 to 1,120 megawatts since 2002, and many more projects representing thousands of megawatts are waiting in the wings.

Solar market pricing information is for the first time starting to emerge, and competitive pressures are starting to bear.

The dynamic situation presents great opportunity for solar businesses of all types. However, many important policy and program elements are still being debated, and upcoming legislative and regulatory decisions could have significant effects both on the demand for solar power and the viability of some of the state's solar markets.

Solar Power Expansion

The renewable energy industry in California is driven by requirements for utilities to supply a certain percentage of their electricity from renewable sources. California has had a renewable portfolio standard since 2002. The RPS currently requires utilities to supply 20% of retail sales from renewable energy in 2010. An executive order issued by Governor Schwarzenegger in November 2008 (S-14-08) extended the RPS goal to 33% by 2020 and expanded the jurisdiction to include municipal utilities that were exempted from the initial legislation. Legislation to codify the 33% by 2020 goal is pending in the state legislature.

California's three largest investor-owned utilities – PG&E, SCE and SDG&E – served just over 15% of their combined load with renewable energy in 2009. The California Public Utilities Commission expects that the three utilities will reach 18% in 2010 and achieve the initial 20% RPS goal in 2011. Because the RPS has flexible compliance mechanisms, / continued page 16

IN OTHER NEWS

American steelworkers their jobs.

Virgin Galactic, a company formed by Richard Branson to engage in commercial space travel, sold 32% of the company to Aabar Investments in Abu Dhabi for \$280 million in July 2009, subject to regulatory approvals. Late in 2009, the company agreed to withdraw and resubmit its application to give CFIUS more time to review it. The government is reportedly concerned about possible spread of missile-based weapons delivery systems. The company plans to build a spaceport in New Mexico. More than 340 people have paid deposits of \$20,000 a piece toward tickets costing \$200,000 each. A company spaceship is expected to make its maiden voyage in two to three years.

CAPITAL GAINS may be hard to claim on sales of projects, including in tax equity transactions.

The IRS said in a technical advice memorandum, or ruling by the national office to settle a dispute stemming from an audit, that a company that is a specialty retailer of consumer electronics and home office products cannot treat its gains and losses from sales of its stores in sale-leaseback transactions to raise financing as capital in nature. They are ordinary income, the IRS said.

Individuals pay lower taxes on their capital gains. Corporations pay taxes on capital gains at the same rate as on ordinary income, but need capital gains to offset any unused capital losses they are carrying forward. Capital losses are hard to use.

All income from asset sales is considered capital unless it falls into one of eight categories in section 1221 of the US tax code. One of those categories that produces ordinary income is if the store or other property is considered inventory — “property held by the taxpayer primarily for sale to customers in the ordinary course of his trade or business.”

The taxpayer in this / continued page 17

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the utilities will not be penalized for not achieving the 20% RPS this year.

Prior to the establishment of the RPS in 2002, large-scale solar power in California consisted of nine solar thermal power projects with a total capacity of 360 megawatts and one large-scale solar PV array with a capacity of just over three megawatts. Solar power was not a focus of early RPS procurement efforts, given its price premium over other forms of renewable energy. As such, only a small number of utility-scale

project pipeline: in August 2010, the California Energy Commission was conducting environmental reviews on 4,800 megawatts of solar thermal projects. In all, more than 8,000 megawatts of solar thermal capacity and 9,000 megawatts of medium-to-large scale PV capacity are reportedly in various stages of permitting, planning and development. While it is unlikely that all of this capacity will ultimately be built, the addition of just one third of this capacity would represent more than a ten-fold increase in California solar generation.

Solar developers have a number of options for selling output in California, ranging from annual solicitations for long-term utility contracts to residential rooftop programs. The

details of each utility program differ, as does the ease of participation. The programs can be roughly divided by generator size, though generators of certain sizes are eligible for multiple programs.

Project Viability Calculator

The progress by investor-owned utilities in meeting the RPS requirements has been slower than anticipated, in part because of contract cancellations and project delays. As of August 2010, the investor-owned utilities had terminated 574 megawatts of RPS contracts, and an additional 789 megawatts of contracted RPS power had not come on line even though the contracted delivery dates had passed (in many cases by more than a year). The CPUC has attempted to address this issue by developing a standard method for evaluating the viability of renewable projects that are bid into RFOs. Projects are assigned a viability score of between zero and 10, and this score is used as a screening tool in comparing project bids. The scores are established based on metrics in the following categories:

- Company or development team: Project development experience and ownership and operating experience
- Technology: Technical feasibility and manufacturing supply chain constraints
- Development milestones: Site control, permitting status, project financing status, interconnection progress, transmission requirements, and reasonableness of project's commercial online date

The precise metrics, weightings and scoring guidelines are all provided in advance. This system provides developers a framework for increasing their project viability scores.

solar projects have become operational since 2002. However, the installed solar capacity in California has more than tripled during this period, primarily driven by homeowners and businesses that have installed 700 megawatts of small-to-medium size grid-connected rooftop PV systems.

Over the next 10 years, the utility-driven market for medium- and large-scale solar systems likely will predominate, even as the consumer market continues to expand. The size of the utility-driven market can be appreciated by looking at the

of contracts that result from competitive procurement.

Bids into the RFO are benchmarked to the market price referent or "MPR." The MPR is intended to be a proxy for the long-term market price of electricity as established by the CPUC. By statute the MPR must reflect the long-term ownership, operating, and fixed-price fuel costs associated with a new gas-fired combined cycle turbine. For a 10-year contract with a 2010 start date, the MPR adopted in 2009 set the price at \$84.48 per MWh.

case argued that its business was the sale of consumer electronics goods. However, the IRS said it sold and leased back enough stores during the year that such sales were part of its business model. The business model freed up capital that could be redeployed in building other stores. The stores were held primarily for sale to customers, the IRS said.

The ruling is Technical Advice Memorandum 201027045. The agency released it in late July.

The ruling has broader implications for wind, solar and other renewable energy developers who use “partnership flip” and sale-leaseback transactions to raise capital for their projects. In many partnership flip transactions, the developer is treated for tax purposes as selling an undivided interest in the projects directly (rather than selling a partnership interest). The ruling could also affect developers who regularly sell projects to utilities that are unwilling to enter into long-term power contracts to buy the output.

A DISGUISED SALE led to a huge tax bill for a paper company. The company is in bankruptcy.

The US Tax Court found in August that the company failed to report a gain of \$524.5 million in 1999 on which it owed \$183 million in taxes plus another \$36.7 million as a penalty for substantially understating its taxes. The company paid PricewaterhouseCoopers a flat fee of \$800,000 for a “should”-level tax opinion that the transaction in 1999 would not trigger taxes, but it was only able to produce a draft of the opinion at trial that the court said was poorly reasoned, “littered with typographical errors, disorganized and incomplete.” The court said the company lacked good faith in relying on the opinion. The company reported the \$524 million gain, but not until two years later when the transaction unraveled.

Chesapeake Corporation — now called Canal Corporation — decided to sell its principal subsidiary that made paper napkins, toilet paper, facial tissue and / *continued page 19*

The MPR is both a cost containment tool and a benchmark of reasonableness for RPS contracts. Any contract that has a levelized price that is below the MPR established by the CPUC after the close of bidding is deemed per se reasonable, while contracts for renewable power executed by the utilities with prices above the MPR must be approved by the CPUC.

Each utility has an overall limit on the amount of above-MPR costs that it can incur. Once the above-MPR funds have been fully allocated, the utility is no longer under an obligation to procure renewable energy at prices above the MPR. As of the end of 2009, each of the three major investor-owned utilities had allocated all of its above-market funds to RPS contracts signed at prices above the MPR. However, the utilities are still under regulatory pressure to procure renewable power, and they continue to procure renewable energy at a range of price points.

Prices in RFOs

The RFO market provides very little price revelation. All RFO bids are sealed. Losing bids are never unsealed, while winning bids are unsealed three years from the project start date.

Beginning in 2010, a small amount of bid information has become unsealed; however, this information is associated with contracts from the 2002-2006 period, some of which have already expired (see Table 1). In general, the data reflect the low prices attributable to the low-hanging fruit that was available in the early days of the RPS program: more than half of the contracts were for existing projects, and the eight new projects were biogas or wind facilities. Thus, these data probably do not reflect the current market price for renewable power.

Table 1: RPS Contracts with Pre-2007 In-Service Dates

Project Vintage	Project Statistics	Average Price of Contracts with Fixed Prices, \$/mWh
Existing	17 projects, 677 mws	\$51.34
New	8 projects, 228 mws	\$51.19
Repower	6 projects, 93 mws	\$51.99

One approach for estimating the current market price for renewable power is to use the MPR as a rough benchmark. When a utility seeks approval of a renewable power contract, it reveals whether the price is above or below / *continued page 18*

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the MPR. During the first five years of the RPS, all approved RPS contracts were priced below the MPR. However, a number of these contracts have since been renegotiated and reapproved at higher prices, and many more recent MPR bids have come in above the MPR.

In 2007 the CPUC began to approve contracts priced above the MPR, and the CPUC has since approved at least 21 above-the-MPR contracts. Given these approvals, the MPR clearly does not represent a price ceiling for RFO bids. On the contrary, contracts that provide specific benefits, such as being able to reliably come on line quickly, may be approved at prices well above the MPR. However, the MPR remains a powerful benchmark, and some developers continue to bid into utility RFOs at below-MPR prices.

New price data for renewable resources recently became available in Nevada, where the public utility commission required NV Energy to disclose pricing data for its current renewable procurement plans. The prices ranged from \$81 per mWh for a landfill gas recovery plant to more than \$130 per mWh for solar thermal and solar photovoltaic facilities. These prices are generally similar to the prices used in California policy planning discussions, except for solar prices, which appear to be higher in California.

Tradable RECs

Renewable power in some parts of the country is less expensive than the prices observed in California and Nevada.

However, much of the low-cost power cannot be delivered to California given current transmission constraints.

A recent CPUC decision would allow the investor-owned utilities to use the renewable attribute of power that is not delivered to California (in the form of a tradable renewable energy credit or REC) to meet up to 25% of their annual RPS compliance obligations. Implementation of the decision has been stayed pending petitions for rehearing. As this article went to press, the CPUC issued a proposed decision that would lift the stay and increase the allowable use of tradable RECs to 40% of the annual compliance obligation.

If the tradable REC decision is implemented, this policy could lead to new opportunities for renewable energy developers located in the western United States, but lacking transmission access to a California delivery point, to sell RECs to the

Table 2: Utility PV Program Information

	SCE	PG&E	SDG&E
Total installations (50% utility-owned/ 50% PPA)	500 mws (DC)	610 mws (DC) 500 mws (AC)	52 mws (DC)
Size eligibility	1-20 mws 1-2 mws preferred	1-20 mws	1-2 mws only
Capital cost for utility-owned projects (2010\$)	\$3.96 per watt (DC)	\$4.32 per watt (DC) +\$0.29 per watt (DC) for land acquisition	\$3.96 per watt (DC)
PPA cost cap	\$260 per mWh	\$246 per mWh	\$235 per mWh
Focus for utility-owned generation	Commercial rooftops	Ground-mounted	Not specified, but likely rooftops
Competitive solicitations	RFO for IPP power: 50 mws (DC) per year for five years	RFOs for IPP power (61 mws (DC) per year for five years) and RFO for PV modules and contractors for utility facilities	RFO for PPAs and for turnkey projects
Other IPP solicitation information	Must begin providing power within 18 months of contract; prior to solicitation utility will identify preferred locations; winners will sign standard contracts with 20-year terms		
Status	Program implemented; first solicitation underway; results to be released in October	Program structure approved; awaiting ruling on application for rehearing and awaiting resolution approving implementation plans	Proposed decision approving program structure issued on July 13, 2010. Vote on whether to approve the proposed decision delayed until at least September 2

California market.

The market impact of the tradable REC decision is not yet clear. In addition to limiting the use of tradable RECs to only 25% of the annual RPS compliance, the CPUC determined that the 25% cap applies not only to transactions that are entered into in the future, but also to any transactions that emanate from existing contracts, if such transactions meet the CPUC definition of a tradable REC. According to an analysis by a ratepayer advocacy group, SDG&E's existing contracts would easily exceed the 25% cap, meaning SDG&E could sign no new contracts for tradable RECs. The 25% cap is set to expire at the end of 2011, but this date could be pushed back to account for the delay in implementation.

The tradable REC decision imposed a cost cap of \$50 per tradable REC (where one REC equals one mWh of renewable power) if the utility intends to use the tradable REC for RPS

compliance. The cost cap should also sunset at the end of 2011 but may be pushed back. The \$50 cap is equivalent to the existing penalty for noncompliance with RPS procurement obligations.

SCE Standard Contract

Southern California Edison offers a standardized contracting process for renewable resources with capacities of 20 megawatts or less located within the CAISO-controlled grid. SCE expanded an older contracting program that targeted only biomass projects to include all eligible renewable resources so long as the facilities meet certain other criteria, including capacity and location.

SCE first offered the expanded renewables standard contracts program in 2009, leading to 13 power purchase agreements with a combined capacity of 200 megawatts. (SCE had sought up to 250 megawatts.)

The price paid for energy under the standard contract was equal to the MPR multiplied by time-of-delivery factors. SCE offered two different contracts depending on the size of the generating facility: one contract for generators with capacities of up to five megawatts and one contract for generators with capacities of up to 20 megawatts. SCE signed agreements with biogas, solar PV and wind projects.

In 2010 SCE again is offering standard power purchase agreements with terms of 10, 15 or 20 years. However, SCE is not offering an energy price at the MPR, but instead will follow a competitive RFO process for awarding contracts.

Small- and Mid-Size Solar PV

The California RPS does not include a specific solar set-aside. However, the CPUC has effectively carved out a distributed solar PV set-aside by establishing separate PV procurement programs for each of the state's large investor-owned utilities.

While the program details vary by utility, each of the programs is a 50-50 hybrid of utility ownership and power purchase agreements with independent power producers. The programs are designed to spur the development of small and mid-size PV within the utility service areas, even at a premium above the cost of large-scale renewable development.

These programs are in their earliest stages, with one underway and the other two nearing final stages of approval. As such, information on actual program costs is for the most part not yet available. However, in approving these programs, the CPUC set caps for the power purchase

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similar products. The problem was that it had a low tax basis in the stock. The company retained Salomon Smith Barney and PricewaterhouseCoopers to advise on the sale. Georgia-Pacific was interested in combining the business with its own. The advisers recommended a leveraged partnership structure where the Chesapeake subsidiary contributed its assets to a partnership with Georgia-Pacific. The Chesapeake subsidiary took back a 5% interest in the partnership plus received a "special cash distribution" of \$755.2 million, which was 97% of the agreed value of the asset it contributed.

Georgia-Pacific contributed its own tissue business to the partnership with an agreed value of \$376.4 million for a 95% interest in the partnership.

The partnership borrowed the \$755.2 million that it used to make the special cash distribution to Chesapeake from Bank of America. Georgia-Pacific guaranteed repayment of the loan, but the Chesapeake subsidiary then promised to repay Georgia-Pacific if it had to repay the loan.

US tax rules have a presumption that if one partner contributes assets to a partnership and is distributed cash within two years, the partner really sold the assets to the partnership.

However, there are a number of exceptions where there is no presumed sale.

One exception is if the partner receiving the cash distribution can put the debt in his "outside basis" in his partnership interest. He can if he is the one ultimately exposed on the debt.

Chesapeake argued that its agreement to indemnify Georgia-Pacific for any loan repayments made Chesapeake ultimately liable. The court said the indemnity was illusory. The indemnity had been set up so that it was unlikely ever to be invoked. The Chesapeake subsidiary had limited assets. If Georgia-Pacific collected, it would have to give Chesapeake a larger interest in the partnership commensurate with the payment. A Chesapeake executive told the rating agencies that */ continued page 21*

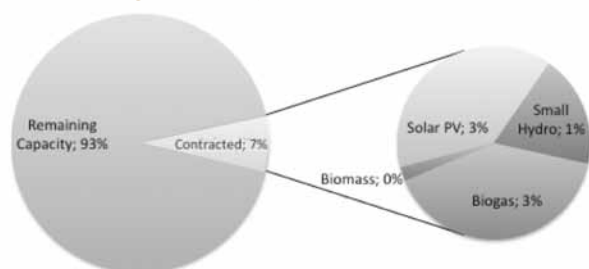
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agreement prices and set caps on the capital costs of the utility-owned generation. These prices range from \$235-\$260 per mWh (AC) for power purchase agreements and \$3.96-\$4.32 per watt (DC) for the capital costs of the utility-owned facilities.

The CPUC has expressed hope that actual power purchase

Table 3: Existing Feed-in Tariff Contracts and Remaining Capacity



agreement costs will be lower than the caps on account of competitive pressure. The CPUC has also recognized the potential overlap between these programs and an expanded feed-in tariff (discussed below) and indicated that the PV solicitations could be incorporated into the feed-in tariff auction mechanism, if that mechanism is adopted.

Additional information about the programs is provided in Table 2.

Feed-in Tariffs

Feed-in tariffs are standard contracts for power sales to a utility.

The California feed-in tariff program is designed to allow small renewable generators located within the service territory of an investor-owned utility to sell electricity to the utility without having to bid into an RFO.

Current regulations allow generators to sell up to 1.5 megawatts of renewable power to the utility for a price equal to the MPR for contract terms of 10, 15 or 20 years.

In turn, the customer is not eligible for net-metering or other ratepayer-funded incentives and must relinquish the RECs for energy sold to the utility. The utility must agree to the sale as long as the renewable facility meets eligibility requirements, the utility has not yet met its share of a

498.5-megawatt statewide cap and the interconnection does not pose safety or reliability concerns.

Through June 2010, the utilities had entered into feed-in tariff contracts for just 7% (34.5 megawatts) of the available capacity under the cap (see Table 3). Eighty-four percent of this capacity (28.9 megawatts) is in PG&E's service area, and nearly 40% is from biogas plants. An additional 39% of capacity represents contracts from a single solar PV developer entered into during the second half of 2009.

Prior to this, PV developers had said that the MPR was too low to attract solar development.

Legislation that became effective January 2010 authorized an expansion of the program to projects up to three megawatts and an increase in the feed-in tariff price to include the value of environmental compliance costs paid by the generators and possibly the value of additional power attributes, such as the time of power delivery. It also authorized an increase in the statewide cap to 750 megawatts.

However, prior to implementation of this expansion, the Federal Energy Regulatory Commission ruled that states do not have the authority to set wholesale rates, even for small-scale projects, unless the projects are "qualifying facilities" under the Public Utilities Regulatory Policies Act and the price does not exceed the utility's avoided cost.

The CPUC has not yet announced how it will revise the existing feed-in tariff program to comply with the FERC ruling.

Concurrently, the CPUC is also considering expanding the feed-in tariff program for the three large investor-owned utilities so that it applies to projects of up to 20 megawatts.

While this expansion is being considered under the rubric of a feed-in tariff, the CPUC staff recommendation is to price the power using an auction rather than a stated price. Under this proposal, contract terms and conditions and requirements for project viability, locational preferences and other parameters would be decided before the auction so that utilities would be able to rank projects on price alone. They would then sign all contracts that meet the pre-determined criteria up to a CPUC-authorized cap. The CPUC would publicly release the bid data (consolidated so that individual bids are masked), adding more transparency to the market.

Some parties to the proceeding oppose the auction proposal and have argued for a traditional feed-in tariff, at least for smaller systems. However, in the wake of the FERC ruling, the auction mechanism may be more viable since it does not require the CPUC to set the price of power.

The proceeding has been stalled since October 2009, but CPUC action on all of these feed-in tariff matters is expected during the third quarter of 2010. As the NewsWire went to press, the CPUC released a proposed decision that would establish a renewable auction mechanism for transactions up to 20 megawatts that use standardized contracts. (The commissioners will not take up this issue for a vote until the end of September at the earliest.)

Residential and Small Commercial Solar

In 2007, California embarked on a program to encourage Californians to install 3,000 megawatts of solar facilities on homes and businesses over a 10-year period.

The program has three components.

First, a “New Solar Homes Partnership” aims to add 360 megawatts of solar systems on new homes in PG&E, SCE and SDG&E service areas. The program provides financial incentives to builders and developers who install PV systems on highly efficient residential buildings.

Second, the “California Solar Initiative” is providing rebates to customers of PG&E, SCE, and SDG&E who install solar panels, with a program goal of adding 1,940 megawatts. Rebate levels are established based on the expected or actual performance of the panels, and incentive payments decline as more systems are installed. Current incentive payments are \$0.65-\$1.55 per watt for residential customers (depending on the utility) and \$0.35-\$0.65 per watt for commercial customers. Customers with operating solar systems are also eligible for a further incentive, called net energy metering. Net energy metering allows customers to sell their solar power to the grid at the full retail value of the electricity and then to buy back this same power at other times of the day or times of the year when their load exceeds their self-generation.

Finally, a third component aims to add 700 megawatts of solar systems in the service areas of municipal utilities. Incentives at municipal utilities vary widely, with some utilities providing extremely attractive incentives.

Through July 2010, 670 megawatts of PV have been installed under these programs at an average price of \$9.21 per watt for systems smaller than 10 kilowatts and \$7.66 per watt for larger systems. The California Energy Commission has certified more than 1,900 solar PV installers and retailers for this program, though fewer than 20 firms have more than half the market share of installations to-date. The largest players in terms of overall megawatts of installations

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the company’s only real risk in the transaction was tax risk associated with its effort to defer taxes.

Chesapeake reported the transaction as a sale of the tissue business for book purposes. The rating agencies treated it as a sale. Within a month after closing, the partnership refinanced most of the loan from Bank of America by replacing it with a loan to the partnership from Georgia-Pacific.

Two years later in 2001, Georgia-Pacific had to sell its interest in the partnership for antitrust reasons so that it could make another acquisition. The Swedish paper company to whom it sold was not interested in buying unless it could buy the whole partnership. Therefore, Georgia-Pacific bought the remaining 5% interest from Chesapeake and paid the company an additional \$196 million to compensate it for the loss of tax deferral on the original transaction.

The case is Canal Corp. v. Commissioner. The lesson is to be careful of highly structured transactions that purport to produce tax results that are at odds with the underlying substance of the transaction.

INDIA is taxing foreign law firms on their fees for legal advice to Indian clients, even if the work is done outside the country.

Linklaters, a UK firm, lost a case in the Mumbai Income Tax Appellate Tribunal in mid-July. The firm did work in 1995 and 1996 from London and also had lawyers visit India during work for clients with operations or projects in India. The firm said that it was not subject to income tax on its fees for this work because it had no “permanent establishment” in India and, therefore, could not be taxed under the UK-India tax treaty.

The tax tribunal disagreed. It said that a May 2010 amendment to the Indian income tax laws clarified that fee income for technical services made by an Indian resident or used in India is taxable in India, regardless of whether the services are performed in / continued page 23

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are SunPower (10%), Chevron Energy Solutions (7%), SolarCity (6%), Team-Solar (5%) and REC Solar (5%).

These solar incentive programs provide commercial opportunities primarily for consumer-oriented companies rather than traditional project developers. Companies can compete by lowering upfront costs and risk for consumers, such as by leasing a solar system to a customer or owning a system on a customer's rooftop and selling the power to the customer. Companies can also compete on cost by providing a standard product or they can offer PV as part of integrated energy management services. SunPower, the company with the most market share in these programs, combines a number of these strategies, offering several financing and leasing options, a 25-year partial warranty and several options for monitoring panel performance.

Multiple Options

Given the number of programs in California to promote installation of solar facilities, in many cases developers have the opportunity to choose among several programs (see Table 4).

Table 4: Eligibility of PV Facilities for California Incentive and Sales Programs

Program Name and Size Eligibility	Size of PV Facility	1 kw-1 mw	1-1.5 mws	1.5-2 mws	2-3 mws	3-20 mws	20+ mws
Programs Currently Active							
Rebates and Net-Metering	1 kW-1 mw	X					
Feed-in Tariff	0-1.5 mws	X	X				
SCE PV Program	1-20 mws		X	X	X	X	
SCE Standard Contracts	1.5-20 mws			X	X	X	
IOU RPS RFOs	1.5+ mws			X	X	X	X
Programs Awaiting Implementation							
Feed-in Tariff Expansion	1.5-3 mws			X	X		
PG&E PV Program	1-20 mws		X	X	X	X	
Programs Awaiting Approval							
SDG&E PV Program	1-2 mws		X	X			
Feed-in Tariff Expansion	3-20 mws					X	

For example, PV facilities of 1.5 to three megawatts located in the SCE service territory are eligible for the SCE distributed PV program, the SCE standard contract and any of the investor-owned utilities' annual RPS RFOs. They will also be eligible for the feed-in tariff once the program expansion is implemented.

Often the choice is straightforward: a developer of a two-megawatt PV facility in the SCE service territory would

probably have lower transaction costs and a higher probability of success bidding into the SCE PV program than the SCE RPS RFO. However, in other cases the choice can be more complex and can depend on such factors as expectations of future prices, amount of on-site load, and the developer's comfort with standard contract terms. Price revelation emerging from some of these programs can also help developers identify the programs in which they are likely to be most successful.

Market players would be wise to keep a close eye on the California legislature and regulatory bodies. Key decisions or legislative votes are expected in the coming months concerning the RPS requirement, the investor-owned utility PV programs, expansion of the feed-in-tariff and the status of tradable RECs. ☺

Potential Effects of US Financial Sector Reform

Five experts spoke a week after the United States enacted a massive financial sector reform bill in late July about the potential effects on the project finance market. They spoke on a conference call, hosted by Chadbourne, to which more than 1,100 people listened. The following is an edited transcript.

The five are John Eber, managing director of energy investments for JPMorgan Capital Corporation, Thomas Emmons, managing director and head of project finance lending at the New York branch of Rabobank, James Metcalfe, global head of power & utilities at UBS Investment Bank, Marshal Salant, managing director, Citigroup Global Markets, and John Shelk, president and CEO of the Electric Power Supply Association. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: The bill is a massive statute; by some estimates it is over 2,000 pages. I looked this morning at the official version that is on the banking committee website. That's 861 pages, but it is single spaced and densely worded and has small type. The table of contents alone is 12 pages.

Environmental Update

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industry for decades. However, advances in horizontal drilling and fracking methods are leading to new scrutiny from Congress and the Environmental Protection Agency.

Reps. Henry Waxman (D.-California) and Edward Markey (D.-Massachusetts) sent letters to eight oil and gas companies in February 2010 requesting information on the types and amounts of chemicals used in fracking, whether these chemicals are used near or below a source of drinking water and how the water from fracking operations are disposed of. There have also been several bills introduced in Congress to address fracking. H.R. 2766 and S. 1215, which were introduced in June 2009, propose repealing an exemption in the “Safe Drinking Water Act” for fracking and would require disclosure of the chemicals used in the fracking process. S. 3663, which was introduced in July 2010, would amend the Emergency Planning and Community Right-to-Know Act to require companies to disclose the chemicals used in the fracking process.

The Environmental Protection Agency is studying fracking and its potential effects on drinking water supplies. It asked for comments in August on pre-and post drilling site characteristics, chemical composition of fracking fluids and water quality, sources and amounts of water used in the process, well construction and integrity and operation and management practices.

The study could lead to voluntary short-term measures to minimize risk associated with the process. These measures could include the development by the government of best management practices addressing well construction, the chemical composition of fracking fluids and waste disposal.

After EPA announced the study, Russia

announced that it would curtail natural gas production by the state gas company, Gazprom, until the study has been completed. Russia is a major producer; it may be concerned about the future of the natural gas market if fracking leads to a dramatic increase in supplies.

Any restrictions the US imposes on fracking could have a significant effect on the natural gas market, according to a 2009 study commissioned by the American Petroleum Institute. The study said US regulation could lead to a 10% loss of natural gas production within five years and, if the regulation also leads to restrictions on the fluids used in fracking, it could cause a 22% reduction in natural gas production by 2014. ☺

— *contributed by Andrew Giaccia and Sue Cowell in Washington.*

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