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Renewable Energy Policy Changes Lead to Damages Claims

by Rachel Thorn, in New York

Wind and solar companies and investors backing their projects have filed a large number of claims against the governments of Spain and the Czech Republic after the governments scaled back feed-in tariffs and other subsidies for renewable energy. Italy is also facing arbitration after making similar changes to its regulatory policies.

All of the companies relied on the subsidies and feed-in tariffs to build projects that are now either uneconomic or less profitable than expected after changes in government policy.

A US renewable energy company with two solar thermal plants in Spain filed the latest case in late May.

The companies charge that the policy changes breach various investment protections and amount to illegal expropriation of their projects under a multilateral treaty called the Energy Charter Treaty and under various bilateral investment treaties.

The Energy Charter Treaty establishes a legal framework for energy trade and investment. The treaty came into force in 1991 to promote cooperation in the energy sector after the end of the Cold War and is intended to encourage and protect */ continued page 2*

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STATE-MANDATED POWER CONTRACTS remain under a cloud after a US appeals court said in early June that Maryland cannot force utilities to sign long-term power contracts at different prices than the wholesale power prices in PJM, the regional wholesale power market.

The decision was in a case called *PPL EnergyPlus, LLC v. Nazarian*.

A federal district court reached the same conclusion last fall about a similar capacity auction in New Jersey. The New Jersey decision has been appealed to a different US appeals court than the one that heard the Maryland case.

According to the courts, the state actions violate the supremacy clause of the US constitution because they effectively establish a price for electricity sold at wholesale. The Federal Energy Regulatory */ continued page 3*

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energy-related investments, trade, the environment and energy efficiency.

Bilateral investment treaties are treaties between two countries that provide certain protections to investors from one country from actions (or inactions) by the country hosting the investment, with the goal of fostering foreign investment by helping to manage sovereign risk.

There are now at least 16 treaty arbitrations pending against Spain and the Czech Republic and at least one arbitration pending against Italy.

Bulgaria and Germany may be next.

Treaty Protections

The Energy Charter Treaty and most bilateral investment treaties provide protection against unlawful expropriation and require countries to give "fair and equitable treatment" to foreign investors, meaning countries must be transparent, reasonable and respect investors' legitimate expectations.

Both sets of treaties are notable because they not only establish substantive protections for foreign investors against a country, but also give qualified investors the right to bring international arbitration claims directly against the country hosting the investment. These claims may be brought under the arbitration rules of certain institutions, such as the International Centre for Investment Disputes — known as "ICSID" — or ad hoc arbitration tribunals governed by arbitration rules chosen by the parties, such as the United Nations Commission on International Trade Law Arbitration Rules — known as the UNCITRAL rules.

In 2007, Spain offered subsidies and feed-in tariffs as an incentive for developers to build wind and solar projects. However, in 2010, in the wake of the global recession, Spain imposed an annual cap on the number of hours of electricity such projects could sell at the feed-in tariff. Since then, Spain has rolled back incentives further, including additional curtailments of feed-in tariffs and a 7% tax on power generators' revenues in what are essentially retroactive cuts in operating revenues, and a reduction in subsidies for renewable energy producers, all set to go into effect this year.

Spain also plans to make producers of solar energy pay a fee for electricity they generate and use, a measure opponents have characterized as a "sun tax."

Similarly, since 2010 the Czech Republic has taken steps to reduce the incentives it put in place to attract foreign investment in the renewable energy sector. These include the repeal of a guarantee that feed-in tariffs could not decline by more than 5% from year-to-year, legislative changes that provide projects coming on line after January 1, 2013 will not receive the same benefits provided to similar plants before that date, and the introduction of a retroactive tax on revenues generated by certain solar photovoltaic plants that was later declared unlawful by the Czech constitutional court.

Investors are asking several European countries for damages after subsidies were cut for existing renewables projects.

In 2013, the Czech Republic adopted additional measures, including the end of feed-in tariff support for all types of renewable energy effective January 2014 and the imposition of a retroactive tax on certain solar PV plants.

Italy has followed the same pattern.

As a result of these changes, foreign investors in Spain, the Czech Republic and Italy lost subsidies and feed-in tariffs that had been guaranteed for almost a decade. In response, they have begun to file arbitration claims against the governments of these countries alleging the changes to the renewables regimes violate their rights and protections under one or both of the Energy Charter Treaty and various bilateral investment treaties. The investors filing claims include investment funds, banks, and renewable energy companies that have invested in solar and wind projects. To date, at least 17 arbitrations are pending.

In a rare event, 14 different groups of foreign investors (reportedly totaling 88 claimants) filed a collective action against Spain on November 17, 2011 in an UNICTRAL proceeding arising out of the Spain's revocation of subsidies for solar PV plants.

Since 2013, five additional foreign investors have filed claims against Spain before ICSID and at least three more have filed before the Stockholm Chamber of Commerce. These investors allege they relied on incentives when making their investments and that the subsequent changes in the tariff regime are in breach of the Energy Charter Treaty, amounting to an unlawful expropriation of their investments.

While a group of foreign investors failed in its attempt to bring a collective action against the Czech Republic earlier this year, separately at least seven individual investors have brought claims before UNCITRAL tribunals under the Energy Charter Treaty and bilateral investment treaties between the Czech Republic and the Netherlands, Germany, Cyprus, Luxembourg and the United Kingdom.

Although Spain and the Czech Republic bear the brunt of renewable energy claims, one claim was filed earlier this year against Italy before ICSID. In that case, three investors argue that cuts to feed-in tariffs are a breach of an earlier promise by Italy of long-term price support. The claim is not yet public, and it is unknown whether the investors are bringing their claim under the Energy Charter Treaty or one of Italy's many bilateral investment treaties.

Outlook

The number of claims against Spain, the Czech Republic and Italy is expected to grow as the full effect of the changes in regulatory and fiscal policy takes hold. As other countries reevaluate their renewables policies, these types of claims are unlikely to be limited to these countries.

Earlier this year, for instance, Bulgaria imposed a new fee on wind and solar energy producers and limited the amount of renewable energy that can be purchased at feed-in tariff levels. Further cutbacks are expected.

Meanwhile, Germany recently proposed measures that will scale back renewables subsidies and limit the expansion of onshore wind and solar capacity. The German government also intends to apply a surcharge to consumers who use renewable energy to cover the costs of feed-in tariffs.

Arbitrations of this kind usually take two to three years to reach a resolution. The oldest renewable / continued page 4

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Commission has exclusive jurisdiction to regulate the prices for such electricity.

A decision in the New Jersey appeal is expected imminently. The issue could end up before the US Supreme Court, although the court has discretion whether to hear appeals.

The cases are significant beyond Maryland and New Jersey because they may raise questions about the enforceability of other state programs that require utilities to sign long-term power contracts to the extent they affect the price at which utilities must buy wholesale power. The issue is whether any such effects on pricing are so great as to require federal preemption.

TAX CREDITS for renewable energy remain in limbo in Congress.

Senator Harry Reid (D-Nevada), the Senate majority leader, suggested at a press conference in early June that the Senate is unlikely to take up a bill before late November at the earliest to extend the deadline to start construction of new wind, geothermal, biomass, landfill gas and ocean energy projects by another two years through December 2015 to qualify for federal tax credits. Such projects had to be under construction by December 2013 to qualify. The Senate tax-writing committee voted on April 3 to allow another two years through 2015 to start construction. However, Republicans blocked the bill from being taken up by the full Senate after Reid prevented Republicans from offering an amendment to repeal an excise tax on medical devices that is part of the funding for Obamacare.

The construction-start language is part of a broader tax extenders bill that would extend more than 50 tax benefits that expired in 2013 or are scheduled to expire this year.

It is possible Congress will find a way to deal with the issues in a "lame duck" session after the November elections. It is also possible, if the November elections give the Republicans control over both houses of Congress, that Republicans will want to push unfinished business into the new Congress that starts in January 2015 when they will be in control. / continued page 5

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energy case against Spain or the Czech Republic has been pending for two and a half years.

Since a government cannot be ordered to reinstate subsidies for foreign investors that it has eliminated for all renewable energy companies, the potential outcome, if a treaty violation is found, is a damages award.

The number of claims filed under investment treaties has grown exponentially in recent years. In 2013, at least 57 known investment arbitration cases were brought under investment treaties, almost half of which were filed against European countries. Notably, the number of claims filed under the Energy Charter Treaty has almost doubled in the last three years. Damages awards in favor of a injured investors are common, and because the awards are binding under international law and there are reputational risks to failure to honor them, governments have generally paid.

There are some signs this may be changing. Outside of Europe, several countries are moving to withdraw from investment treaties, reportedly as a result of either claims decided against them or the risk of future claims. For example, since 2013, both South Africa and Indonesia announced that they would not renew their bilateral investment treaties with the Netherlands and suggested that they intend to terminate all their remaining investment treaties. Similarly in 2008, Venezuela terminated its bilateral investment treaty with the Netherlands and eventually withdrew entirely from ICSID in the face of a series of investment claims. In each case, the actions are prospective and do not affect claims that are brought before the "sunset" provisions in the treaties expire.

So far, there is no indication that European countries will follow suit, although the European Union has expressed concern over including investment dispute settlement provisions in future economic unions such as the proposed transatlantic trade and investment partnership with the United States. ◎

The Power Industry in Transition

The power industry business model in the United States is under stress. Demand for electricity nationwide is growing at roughly a 0.9% annual rate. Rooftop solar, fuel cell and other distributed generators are taking customers and revenue from the regulated electric utilities. The tension had led to disputes between the utilities and distributed generators over whether customers who generate most of their own electricity should pay monthly back-up charges to the utilities and over the prices at which the utilities should credit any spare electricity these customers feed back into the grid through "net metering."

Independent generators with utility-scale power plants are also affected, since the more growth in electricity demand that is taken up by distributed generation, the less need there is for new central station power plants.

Most discussions about these issues at industry conferences are among utilities or independent generators. However, the most important players in the debate may be the state public utility commissions that regulate the utilities. What do they think?

Members of public utility commissions in five states talked about the pressures on the existing utility business model at an Infocast conference on "transformative energy" in San Francisco in late April. The panelists are Susan Bitter Smith, a member of the Arizona Corporation Commission, Jeffrey Goltz, former chairman and currently a member of the Washington Utilities and Transportation Commission, Anne Hoskins, a member of the Maryland Public Service Commission, Hermina Morita, chairwoman of the Hawaii Public Utilities Commission, and Eric Callisto, former chairman and currently a member of the Wisconsin Public Service Commission. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Let's set the stage first by laying out a few basic facts about each of your states. Do utilities in your state merely transmit and distribute electricity, or do they also own power plants, starting with Susan Bitter Smith from Arizona.

MS. BITTER SMITH: Arizona has vertically-integrated utilities, so they are also generators as well as distributors. We are an elected body, so you have five politicians who are commissioners. We are also constitutionally created in Arizona, so we have strict constitutional dictates about what the commission can and cannot do and that may color some of the conversation about regulatory decisions and the challenges that we have.

MR. GOLTZ: Washington has vertically-integrated utilities. We dodged the deregulatory movement a couple decades ago, and we are an appointed commission, thank goodness. [Laughter.]

MS. HOSKINS: Maryland has restructured; it is a deregulated state. We have transmission and distribution regulated companies, but some companies, such as Exelon, have unregulated subsidiaries that are generators.

MS. MORITA: Our utilities remain vertically integrated. The Hawaii Electric Companies are on five islands, and the Kauai Island Utility Cooperative is on Kauai. Most of the base-load and peaking units are owned by the utilities, but we also have a number of independent power plants.

MR. CALLISTO: We are a little of both in Wisconsin. We have municipal utilities and four major investor-owned utilities. They all divested their transmission assets a decade ago. Those are all owned by American Transmission Company. Xcel Energy and our major coop wholesaler are vertically integrated.

MR. MARTIN: Do you allow consumers to choose their retail electricity suppliers, or does the local utility have a monopoly on retail sales, starting with Eric Callisto.

MR. CALLISTO: We do not in Wisconsin.

MS. MORITA: No in Hawaii.

MS. HOSKINS: Yes in Maryland.

MR. GOLTZ: No in Washington state, but we do not have strict service territory boundaries, so it is possible for some customers to opt for different utilities. It is not technically retail choice as we know that term.

MS. BITTER SMITH: We just had the conversation in Arizona. In addition to being the first state in the country to deal with net metering, we also had an open docket on retail competition. The decision of the commission was that retail choice is not allowed under the state constitution, so we do not have retail choice.

RPS Targets and Load Growth

MR. MARTIN: Does your state have a renewable portfolio standard requiring utilities to deliver a certain percentage of electricity from renewable sources and, if so, what is the target, and where are you in relation to that target?

MS. BITTER SMITH: Arizona does. The renewable standard is 15% by 2025. Most of our utilities are ahead of where they need to be and will probably exceed that limit well before the deadline. / continued page 6

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Meanwhile, the Internal Revenue Service is expected to release additional guidance in July on how much work had to be done in 2013 for a project to be considered under construction under the "physical work test." The guidance is being drafted by the US Treasury and is currently expected to take the form of questions and answers.

There were two ways to start construction of projects in 2013. One was by incurring at least 5% of the project cost. The other was by starting physical work of a significant nature.

The tax equity market has largely shut down for projects that relied on physical work while the market waits for the new guidance.

Meanwhile, the IRS has decided not to issue any private letter rulings on construction-start issues after accepting a number of ruling requests and then deciding that they were all too factual.

TREASURY CASH GRANT LITIGATION is moving closer to resolution.

There are 20 pending lawsuits against the US Treasury Department by companies that put new renewable energy facilities in service after 2008 and chose to be paid 30% of the "basis" the companies had in the facilities in cash rather than claim tax credits. All of the companies received smaller cash payments than they applied for. The Treasury was authorized to make the payments under section 1603 of the American Recovery and Reinvestment Tax Act. Many renewable energy projects are financed in a way that lets the owner use the fair market value as his basis for calculating tax benefits (and, by extension, section 1603 payments in lieu of tax credits) rather than the cost to build the project. This has led to many disputes with Treasury about how to determine the value.

The government filed motions for summary judgment in eight of the pending cases in late May. A summary judgment motion is a request for the court to decide the cases based on legal briefs from both parties. The / continued page 7

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MR. GOLTZ: Washington has an RPS of 3% by 2012, 9% by 2016 and 15% by 2020. People in California say that is pretty wimpy, but keep in mind that more than 60% of our electricity comes from hydro, and hydro does not count as renewable energy for reaching these goals. If you add the 15% by 2020 to the amount of hydroelectricity we use, then it is really an aggressive standard. We are past the 2016 goal and are very close to the 2020 goal, so I expect all of our utilities to make it.

MS. HOSKINS: Maryland has an RPS goal of 20% by 2022. We have a small solar set aside and, in a few years assuming the regulations come into play, we will also have an offshore wind set aside.

MS. MORITA: The targets for Hawaii are 15% by 2015, 25% by 2020 and 40% by 2030. The consolidated level for the Hawaii Electric Companies is around 34% today. If you look at where we are today island by island, Oahu is around 19%, Maui a little over 30%, the big island of Hawaii at 40% and Kauai is around 18%, so we have exceeded our 2015 targets and are well on our way toward reaching our 2020 targets.

MR. CALLISTO: Wisconsin has not only the lowest RPS among my colleagues here, we also have the lowest RPS in the Midwest. Our goal is 10% by 2015, and we are already essentially in compliance with that. It has been in place for a couple years. We also may be one of the only states — perhaps with Minnesota as the exception — that counts Canadian hydroelectricity as a renewable. [Laughter.]

The Canadian hydro piece is for new dams built in the future, so it is not part of our current RPS compliance, but our utilities are signing contracts with Manitoba Hydro in part to meet the requirements.

MR. MARTIN: Let's move to load growth. How rapidly is demand for electricity growing in each of your states?

MR. CALLISTO: Load growth is what the person asking wants it to be. If you are a utility asking for a rate increase, then load growth is down. Looking through the murky haze, the most recent data suggests that demand for electricity in Wisconsin is growing at 0.5% to a little more than 1% a year on self-reported data. Electricity demand in the Midwest as a whole is essentially flat with a slight increase in industrial demand.

MS. MORITA: There has been no load growth for our utilities because of rooftop solar and aggressive efficiency programs. Hawaii has an energy efficiency portfolio standard whose goal is a 30% reduction by 2030.

MS. HOSKINS: Maryland expects a 1.2% compound annual growth rate. We also have a very aggressive energy efficiency target, but the estimate takes this into account.

MR. GOLTZ: We have three investor-owned utilities, but the majority of the load is served by municipal utilities. For the three IOUs, it depends on where you are. They are expecting 2% annual load growth over the next 15 years in the western part of the state. Projected load growth in eastern Washington is less than 0% to 1%.

MS. BITTER SMITH: I am glad Eric Callisto went first because his answer is also true for Arizona. It depends whether there is a rate case pending and what the utility wants you to think. That being said, load growth in Arizona is flat. New housing starts are down in Arizona, and more and more homeowners are installing rooftop solar, which reduces utility load growth.

The basic power industry business model is under stress.

Effects of Rooftop Solar

MR. MARTIN: Is there a way to quantify the effect of rooftop solar?

MS. BITTER SMITH: I think most of you are familiar that the majority of the Arizona Corporation Commission decided to let Arizona utilities impose a charge of about $5 a month for the average customer with rooftop solar. We are now monitoring what is happening with rooftop solar deployment as result of that decision. The number of new rooftop customers was down in January as one might expect because we had grandfathered anyone who installed rooftop solar by the end of 2013, so December was a boom month for new solar installations and January was not such a great month. New installations were back up again in February. We are just getting the March numbers, so it remains to be seen whether the monthly charge will have a huge impact. My guess is that there will not be.

MR. GOLTZ: There is no way to quantify the effect of rooftop solar in Washington state. I might add as an aside to Susan's point that our family went to watch spring training baseball games in Arizona a couple weeks ago.

MS. BITTER SMITH: We appreciate that.

MR. GOLTZ: We had dinner with some old friends who have solar panels and they are really ticked about the $5 fee. I just want to let you know that. [Laughter.] Totally unfair, they said. It was a case of having only a couple hours for dinner, so there was not time to explain the whole scenario. [Laughter.]

MS. BITTER SMITH: I'm getting the phone numbers after this. [Laughter.]

MR. GOLTZ: We are watching what is happening in other states and are trying to get ahead of the issue. We have an open docket on this topic. It is pretty clear to me that the way to address the issues is not through a contested case or adjudication. We saw the Arizona case was front-page news in the *Wall Street Journal* and *New York Times*. Idaho had a big controversial proceeding that was acrimonious. We are trying to tackle the issues in a more deliberate way. We do not have much distributed generation at this point, although I have to say that if you were to move to eastern Washington, the sun really does shine there an awful lot.

MS. HOSKINS: We are not seeing the rooftop solar debates in Maryland at this time. Our state policy encourages net metering, and we are prohibited by a state statute from allowing differential assessments. We may see these issues arise in utility rate cases in the future.

I am very interested in this topic. It is one of the issues I worked on when I was a senior research fellow at Princeton before joining the Maryland commission. I am watching with interest what Minnesota has done, which is a value-of-solar proceeding where cost and benefit information is carefully collected and analyzed. To understand the actual impact of increased amounts of distributed generation, we need to look in detail at the potential effects on the */ continued page 8*

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procedure is used in cases where the facts are not in dispute.

It should lead to decisions in at least some of the cases this year.

The oldest case has been pending since July 2012. All of the cases have been filed in the US Court of Federal Claims. One case filed earlier than July 2012 was withdrawn by the solar company that filed it after the government accused the company of fraud.

The remaining cases raise five significant issues.

Many of the suits challenge the Treasury's cost-up approach to determining value. The Treasury has appeared to base some grant payments on what a project cost to build and then adding a profit margin that it considers reasonable.

At least two suits challenge whether part of what was paid for a utility-scale power project must be allocated to the power purchase agreement with a utility. Any amount allocated to the power contract would not qualify for a grant. The IRS ruled privately in 2012 that a power purchase agreement that can only be performed by supplying electricity from a specific project has no value separate from the project on the theory that the contract is like a tenant lease of a building. No one buying a building would allocate part of the purchase price to the tenant lease. The entire purchase price is treated as basis in the building. The IRS quickly thought better of applying the analogy to power contracts and withdrew the ruling.

The issue in at least one suit is whether the Treasury is required by law to accept what outside appraisers say is the fair market value of a project. Other suits involving projects that were sold to bank leasing companies and leased back raise the issue whether part of what the bank leasing companies paid must be treated as purchase price for an intangible asset like going concern value rather than the power plant. Grants are not paid on intangible assets.

Finally, the latest suit, ***/ continued page 9***

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network as well as the potential benefits to the network. At times, it seems like advocates are heading to their corners without offering the details that regulators need to make informed decisions.

MS. MORITA: Rooftop solar has seen exponential growth in Hawaii since 2010 due to two factors. One is the generous state tax credit, and the other is leasing programs. Putting the growth into context, at least 10% of customers have rooftop solar. I understand there is a waiting list of about 6,000 applications. Another way to look at this is the system peak for Oahu is about 1,300 megawatts, and there are about 235 megawatts of rooftop solar installed currently.

The regulated utilities are losing customers and revenue to solar rooftop companies.

MR. CALLISTO: We have little residential rooftop solar in Wisconsin, but a little more commercial rooftop. The state is in a grey area on third-party ownership. Most utilities believe that third-party ownership is illegal. A bill was introduced in our state legislature to try to rectify that, but I think that it has no chance of getting through.

Let me speak for myself and not for the rest of my colleagues on the Wisconsin commission. I think there is a need for every state that does not have an open docket or an already established policy to have a discussion about distributed generation. I have not been able to get such a docket open to date in our state, so I dissent on a fair number of issues related to this topic.

State Reactions

MR. MARTIN: Does your state encourage distributed generation, discourage it, or take a neutral position, starting with Eric Callisto.

MR. CALLISTO: Certainly we are not in place of encouragement. The majority's position is that any issues should be handled on a case-by-case basis in rate cases. We have seen a retraction of net metering.

MR. MARTIN: Mina Morita, as a public policy matter, should the Hawaii commission encourage, discourage or take no position on distributed generation?

MS. MORITA: We are actively looking at this subject. There are not only circuit issues, but also now system issues. We are seeing potential cross-subsidization issues raised by rooftop solar. We are trying to take a holistic approach by looking at both the technical and economic aspects and believing as a general matter that customers should have a choice.

MR. MARTIN: So far the story is that Wisconsin is not encouraging distributed generation and Hawaii is trying to deal with the technical fallout. Anne Hoskins from Maryland, should public utility commissions encourage or discourage distributed generation?

MS. HOSKINS: Public utility commissions are wrestling with a range of issues. They include what to do about carbon emissions, how to ensure grid resiliency and reliability, how to replace capacity as power plants shut down due to age or environmental regulations, and how to adjust to greater reliance on natural gas. Public utility commissions have an obligation to make sure that we have a reliable network. Rooftop solar and other types of distributed generation are an important part of the picture. The question is how all the pieces fit together.

I don't think that means commissions should take a predetermined position for or against solar. That would be inappropriate under most commission administrative procedure rules. But regulators need to understand how distributed generation fits into the network and ensure that the utilities who operate the distribution networks are doing it in a way that will enable connection fairly and efficiently when it makes sense to do so.

I agree with Eric Callisto and Jeff Goltz that it would be productive to approach this challenge in a comprehensive way where we can look at all of these pieces together rather than react incrementally as rate cases come to us.

MR. GOLTZ: We take our cues in Washington state from the legislature. The state statutes are pretty pro-distributed generation. Distributed generation counts double in our RPS, for example. We were asked three years ago by the House energy committee to assist it with a study to assess the barriers to distributed generation and help remove them in order to encourage distributed generation. We reported in the fall 2011 and have taken some actions since then to remove some barriers. We have amended our interconnection rules to try to make them easier for owners of distributed generation to interconnect with the utility.

MR. MARTIN: Susan Bitter Smith, it sounds like Arizona is trying to accommodate distributed generation.

MS. BITTER SMITH: It is, despite the fact that Jeff Goltz's friends are mad at us. We had one utility ask the commission for authority to charge customers with rooftop solar a $50 monthly backup charge. We ended up approving an average monthly charge of $5 after accepting a compromise suggested by a consortium of solar companies. We have an open docket to look at the value.

While I agree with my fellow commissioners that looking into these issues in a more deliberate manner free from outside pressure would ideal, it is not always an option. It was never our intention to make the front pages of the *New York Times* and *Wall Street Journal*. Every morning, there were stories or ads in the *Arizona Republic*, a steady drumbeat and campaign-oriented push. We had never seen anything like it in Arizona on an issue before the commission. Be forewarned. We are seeing ads starting to run in other states and issues starting to appear on election ballots. You, too, may see bodyguards for witnesses and extra security details added for the commission offices. We had thousands of emails, phone calls and robo calls coming into our offices.

MR. MARTIN: It is not an easy debate in which to be caught in the middle.

MS. BITTER SMITH: It is a complicated issue, and the danger for commissioners is that it gets distilled into a 30-second ad or a one-minute radio spot or a three second "push this button and e-mail your commissioner what you think." I am still getting emails. There are a lot of people who don't know we made a decision or who think it is coming on the November ballot. Jeff Goltz's friends are grandfathered if they already have solar panels, so they don't even understand they are not going to have to pay the $5 charge. It is confusion, which is not good for any of us in this room because there is no / *continued page 10*

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filed in mid-May, involved a 17.6-megawatt wind farm near the Anchorage, Alaska airport whose developer, Fire Island Wind, LLC, spent $5.3 million to dismantle an old navigational system and buy the air traffic controllers a new Doppler radar so that the developer could get clearance from the Federal Aviation Administration to put up its wind turbines. The developer treated the $5.3 million as a cost of the wind turbines. The Treasury would not let the amount be included in basis for calculating the cash grant on the project.

The statute of limitations to file suit against the Treasury is six years from when a company is notified its grant has been approved for payment. If the government starts losing some of the cases, other suits can be expected.

In a separate development, the IRS said in early June that companies may not claim an investment tax credit to make up for haircuts in grant amounts due to sequestration. Grants approved for payment through September this year are subject to a 7.2% haircut as part of a Congressional budget deal in 2012 to keep the federal government open. Sequestration will continue past September, but potentially at a different percentage. Some developers must have tried to claim tax credits for the shortfall. The IRS said this is not allowed. The tax basis the project owner uses to depreciate the project must be reduced by one half the grant. The IRS said the basis reduction is for half the actual grant paid — after sequestration. The IRS announcement is in Notice 2014-39.

REITS can own some solar equipment, the IRS said.

An IRS proposal in early May to make it easier for real estate investment trusts to invest in solar was disappointing, but may not be the last word. The IRS is collecting comments through August 12. The proposal would let REITs that own buildings also own solar panels on the building that are used to supply electricity / *continued page 11*

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opportunity to have an articulate and informed discussion about what is a serious issue.

MR. MARTIN: The lead utility analyst at Bernstein Research said, in a cover email to utility investors attaching a summary of a debate among three power company CEOs in late March, that "distributed solar generators enjoy a parasitic relationship with their host, relying on the utilities for grid access and backup power supplies while eroding utilities' power sales and revenues. As distributed generation grows, utilities will face ongoing pressure to raise rates to preserve revenues, only adding to the attractive of distributed solar and accelerating revenue losses."

Ann Hoskins, how do the two models — distributed solar and regulated utilities — co-exist? A battle has erupted about not only about back-up charges, but also net metering.

Value-Based Solar?

MS. HOSKINS: More than 40 states have net metering. However, apart from Arizona, California and a few other states, most states do not have large amounts of solar penetration. Net metering is a simple way to enable people to put solar on their roofs and have an outlet for the excess electricity; it is a good place to start. In most states, the cross-subsidization argument is overstated, but down the road as solar penetration increases, it could become an issue. That's when it may be useful to separate the value of solar from its impact on the grid and evaluate both aspects.

MR. MARTIN: What does it mean to "separate the value"?

MS. HOSKINS: Customers with rooftop solar are using part of the electricity they generate and basically storing the rest on the grid. In some places, they are paid the retail rate by the utility for the electricity and, in some places, they are paid the wholesale rate. As I understand it, what Austin, Texas and now Minnesota have done is to treat the customer like an independent generator and have her sell her entire output to the grid. The state would hold a proceeding to determine the fair value of what the customer is providing the grid. Is it the wholesale power rate or is there some other benefit? For example, is there a benefit through reduced transmission expense? Is there a benefit through greenhouse gas impact? On the other side of the ledger, the customer would continue to pay for the electricity he takes off the grid. That takes away the idea that customers are unfairly using the network or shifting a burden. The customer can be paid for what she generates, and she can pay for her use of the network.

MR. MARTIN: So no backup charge, but figure out the appropriate price for the electricity?

MS. HOSKINS: Yes. And just to be clear, this is not the policy of the state of Maryland. We have net metering, and net metering has worked fine for us so far, but we all need to be thinking ahead about potential approaches to deal with the challenges and opportunities that will accompany increasing amounts of distributed generation.

MS. BITTER SMITH: She makes a very good point. I have heard some people from the solar industry say at other conferences that net metering is an issue in four states — Arizona, Hawaii, California and New Jersey — and the rest of you guys don't need to worry about it. You should not be talking about it. I would tell you that Anne Hoskins is correct. Now is the time for states to deal with this because you may get the opportunity without ads, emails and robo calls to have an articulate discussion.

MS. HOSKINS: One other point about the Austin, Texas or Minnesota approach is it could raise questions about federal jurisdiction. Some might argue that solar customers would be selling their power into the wholesale power market over which the Federal Energy Regulatory Commission, rather than the states, has jurisdiction.

MS. MORITA: In Hawaii, we are not looking solely at net metering, but at the value of all distributed generation and the kind of characteristics that are

Utilities want to collect monthly back-up charges and pay less for electricity from homeowners with rooftop solar.

needed to stabilize the grid. Simply put, you pay for the services that you receive from the grid, and you are fairly compensated for services that you provide that help the grid. That is the direction in which we are moving.

MR. MARTIN: Does that mean that instead of utilities relying solely on electricity sales for revenue, they receive a fixed charge from everyone connected to the grid and they also pay the retail rate for net metered electricity?

MS. MORITA: We have decoupling in Hawaii. The sales are decoupled from the revenues of the utility. However, it has to be improved. When this approach was enacted in 2010, there were no performance standards. We are moving toward a service approach rather than rate base.

Crane Provocation

MR. MARTIN: Eric Callisto, at the Bernstein Research conference, David Crane, CEO of NRG Energy, said investing in centralized generation and distribution of electricity is futile. He said the day will come soon when people can buy the equipment they need to generate electricity at Home Depot. He believes a superior strategy for legacy power infrastructure owners — also known as utilities — is to shed cost to ensure that the sector remains viable as a backstop source of reliable power, allowing it to extend its decline over the course of decades. Do you see it this way?

MR. CALLISTO: Mr. Crane is a thoughtful guy. I have seen him speak at a couple conferences. He makes you think, and that is certainly a thought-provoking statement. [Laughter.]

Having said that, I do not think the utility central station model is a dinosaur yet. I am not sure it ever will be a dinosaur, but the point that should be taken away from Mr. Crane's statement is utilities need to think differently.

And the same goes for the solar companies. It is time for the solar companies to start wearing long pants. As my colleague said, at some point, if you want to act and talk like a generator, then you get paid like a generator. We need to move away from the net metering model and find something that really talks about value.

The utilities need to move away from a model that admittedly has served them well for 100 years where the utility earns 10% or 12% returns on its rate base year after year by putting steel in the ground and earning a return over 20 years. Utilities that are willing to innovate, in a regulatory model where regulators are willing to provide an incentive to change, will succeed. Those utilities that continue to put / continued page 12

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to the building occupants. It is not clear the proposal would allow REITs to own solar panels in other situations.

REITs are corporations or trusts that do not have to pay income taxes on their earnings to the extent the earnings are distributed each year to shareholders.

The renewable energy industry is interested in REITs potentially as a source of cheaper capital. Congress created REITs in 1960 as a way for small investors to invest in large-scale real estate projects. Small investors pool their investments in the REIT and are treated essentially as if they had invested in the real estate projects directly without a corporate-level tax being taken out along the way.

The challenge for renewable energy is that a REIT must hold at least 75% real property or interests in real property. Examples of such assets are land, site leases, buildings and mortgages secured by real property.

The IRS, with the active encouragement of the White House and Department of Energy, issued proposed regulations in May redefining what qualifies as "real property" for REIT purposes. Under the new definition, solar equipment qualifies as a "structural component" of a building if it performs a utility-like function for the building, such as providing electricity, and the electricity is part of what the building occupants get for their rent for the use of space. In addition, the REIT must own both the solar equipment and the building, and it must expect the solar equipment to remain permanently in place.

The IRS and US Treasury are still thinking about whether it makes a difference if some of the electricity is supplied to the local utility, for example, through net metering. However, in an example showing how the new definition works, the IRS said that a solar system mounted on the ground next to a building whose electricity it supplies is considered a structural component of the building, / continued page 13

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their heads in the ground will get gobbled up or disappear. Mr. Crane's point in that regard is well taken.

MR. MARTIN: Jeff Goltz, do you see the world the way David Crane does?

MR. GOLTZ: I think there will be a long-term role for the regulated utility and the grid. There will be some outposts in Hawaii where people go off the grid. I do not see that happening in the Pacific Northwest. I agree with my colleagues about how to compensate distributed generators. The fair compensation to the distributed generators may be higher than the retail rate or it may be lower than the retail rate. It depends on what your retail rate is. In California, the tail block rate is 30¢ per kilowatt hour. If you look at solar studies, the value tends to be in the 12¢ to 20¢ range. Rocky Mountain Institute did an assessment a couple years ago. In the state of Washington, if your tail block rate is 9¢ or 10¢ a kilowatt hour and the value of solar is 15¢, then the utilities are getting a pretty good deal if they are paying only the retail rate for distributed solar.

MR. MARTIN: How do you tell what the fair value is?

MR. GOLTZ: The Minnesota process was interesting. They had a legislative mandate that set some parameters that limited their flexibility to a degree. There were a lot of variables in the Minnesota process. You have avoided fuel cost, avoided transmission and distribution costs, depending on where you are, perhaps avoided capacity cost and avoided environmental costs. You have to figure out how to determine each of these. Whatever you do will not be perfect. It involves some exercise of judgment. There will be a range of values.

MR. MARTIN: Susan Bitter Smith, are there other tools to address the growing tension between distributed generators and utilities besides what we have heard already put on the table: monthly backup charges, the rates paid for electricity through net metering and value-based solar?

MS. BITTER SMITH: Presumably so, and that is the next conversation that all of us have to have. As Jeff Goltz points out, there are two very distinct points of view about the value of solar and other forms of distributed generation. Just go to the Arizona docket and you can find two completely opposite positions taken in filings about how the value should be calculated.

I see some parallels to what happened in the telecom industry to what is happening to the electric utilities. The traditional land-line telephone company had a hard time holding on to its traditional business model. Electric utilities across the country know they need to adapt to a new environment. The opportunities are there to have these conversations and to do so sooner rather than later.

Rated-Based Solar?

MR. MARTIN: Eric Callisto, does the traditional utility revenue model still work, where utilities grow by making rate base investments whose costs they recover through electricity sales, in an age of rooftop solar, energy efficiency gains and potential widespread adoption of batteries? If not, what takes its place?

MR. CALLISTO: We have all had different experiments in our states with giving utilities other opportunities to earn, and I think we need to continue to think about that. Certainly a provocative suggestion would be to allow utilities to become full players in the rooftop solar business. That has come up in conversations. I know that has the hairs standing up on the backs of the necks of many people in the audience.

MR. MARTIN: What does that mean to be a full player in the business?

MR. CALLISTO: Utilities would be allowed to provide rooftop solar for their customers and put the costs in rate base. I think we should talk about it. I do not have a view on it, but I think we would all admit in our most honest moments that the utilities are major players in most of our states. When a utility comes before a commission with a model that it has spent time developing and has talked about with the state legislature and the governor, and it suggests that it can raise capital

The utility regulators are looking at other approaches.

cheaply and it knows the customers and should be able to rate base solar, you had better worry if you are a developer because the utility proposal has political legs. Whether or not it is the right choice, it will have momentum.

MR. MARTIN: Anne Hoskins, does the traditional revenue model work? If not, what takes its place?

MR. HOSKINS: I used to work at a utility that owned solar and put it into rate base. This was an effective approach for building out solar. But now that I look at the issues from a regulator's vantage point, I realize that we need to make sure that the other players on the competitive side of the business have fair access and an opportunity to develop. I also look back on when I worked at a competitive wireless company and remember just how valuable competition was in terms of encouraging innovation and new technology development.

The utilities are good at many things, but maybe innovation is not at the top of the list, and right now we need a lot of innovation. We need innovation in storage and in reducing the costs of solar technology and installation. That is my concern as I think about this. We need to give utilities an incentive to play a significant role because they are important players, but their most important role may be in maintaining and integrating distributed generation with the network.

MS. MORITA: I want to qualify that these are just my comments and not the comments of the commission as a whole. As I mentioned before, we are decoupled. As I see it, this has insulated the utility from making needed changes. We are trying to move more toward performance-based rate making because an important element in transformation is a cultural change within the utility. I do not think we can get the efficiency needed, and the productivity and outcomes we want by retaining the cost-of-service model for setting rates. If we want the outcomes we desire, then we have to move more toward performance-based regulation.

MR. GOLTZ: You hear a lot of talk at this and other conferences about the rate base model and whether to scrap it. The statutory model under which we operate is very flexible. The statutory terms could not give more discretion to the utilities commission in our state and in other states. We have plenty of room to adapt. We adapted by adopting decoupling. That is not statutorily mandated; we did it administratively. We can have performance enhancements, positive and negative, on the rate of return under our existing statutes. We have lots of flexibility.

My views on this are evolving continually, but I have felt for

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even though the tenant transfers excess electricity "occasionally" to the local utility.

The IRS said in another example that the land, underground gathering lines, concrete base and metal racks that hold the solar panels in place at a utility-scale project qualify as real property, but the solar panels do not. The agency drew a line around what qualifies at a utility-scale project in the same place as the market already draws it under the existing definition.

Some renewable energy companies have been worried that any expansion of what is considered real property for REIT purposes could undermine other positions the industry has taken. The industry treats solar projects as equipment in order to claim Treasury cash grants, investment tax credits and five-year accelerated depreciation on the projects. These tax benefits can be claimed only on equipment and not also on real property. The US renewable energy sector has attracted a large amount of foreign investment, including by prominent European utilities. These investors are not subject to US capital gains taxes when they exit US projects unless the projects are considered real property.

The IRS said it is redefining real property solely for REIT purposes and said it does not necessarily follow that real property must be defined the same way for these other purposes. It asked for comments on the extent to which the various other uses of the term real property in the US tax code should be reconciled.

The new definition will apply after the IRS republishes it in final form. The agency has scheduled a public hearing on the new definition on September 18.

Any requirement to show that rooftop systems are expected to remain permanently in place would complicate the ability to finance rooftop systems in the tax equity market. A tax equity investor must be able to prove he is the tax owner of equipment to claim tax benefits on it. It is hard to prove tax ownership of equipment that is bolted permanently to the roof of someone else's house.

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some time that an investor-owned utility should be able to get into the distributed generation business, even as a part of its regulated business, with the caveat that you have to be careful about the effect on competition. I would like to see more competition in the provision of distributed generation services. That would benefit consumers. If a regulated utility gets into it, then it is still subject to our consumer protection jurisdiction. If the utility abuses its power, we can hammer it.

From my experience, it is daunting for a homeowner to figure out how to put solar panels on his or her roof. You have to find a contractor. You have to figure out the tax benefits. It would be nice to have a general contractor to help with that. The utility is already selling you electricity, in our state at least, so the utility is already helping you with conservation expenditures. It is not that big of a step to add the solar rooftop business to what the utility is already doing.

MS. HOSKINS: No matter what we do, the drive toward distributed energy is consumer driven. As commissions, we need to recognize that technology changes, and the changes may require more flexibility in our processes and regulations.

One discouraging experience for me as a commissioner has been the number of requests I have seen for back-up diesel generators. With solar energy, with the potential for storage, with other types of natural gas generators, I wonder whether there is a more sustainable way for customers to achieve the reliability they are seeking and whether commissions have a role to play in that process. Rather than narrowly reviewing petitions from applicants, can and should regulators play a role in enabling new technologies to take hold?

Biggest Challenge

MR. MARTIN: So here is my last question for each of you. What is your biggest current challenge as a regulator?

MS. BITTER SMITH: Our biggest challenge in Arizona is the continuing dialogue about the stresses on the grid. What will happen moving into this new energy model? Solar is huge in Arizona, in relative terms, and we have to acknowledge that, and we have to make sure that we are accommodating some kind of a new structure that ensures that we have healthy public utilities but also opportunities for consumers.

MR. GOLTZ: Regulation is supposedly a surrogate for competition. If you can hypothesize a world where there are multiple electricity suppliers, competing for customers who want clean, affordable and reliable energy, there would be a lot of innovation among those competitive suppliers. They would be coming up with storage, coming up with renewables, coming with all sorts of different things. Some of them would go out of business. Some would prosper. The technology would evolve, and innovation would happen. It is hard in our regulated system to make that happen. Our biggest challenge as regulators is how to enable regulated monopoly suppliers to take appropriate risks in innovative technologies.

MS. HOSKINS: One thing that will come into play as we get the repeated requests for rate increases is the issue of affordability. It is something that worries me. We have so many investments that need to be made both in our natural gas infrastructure and our electricity infrastructure, but we also have rules that do not allow us to charge people differently based on income. Will the limited rate at which general wage levels are increasing become a cap on what we are able to invest in, even though these investments produce an overall social benefit? The issue of balancing affordability with reliability is going to become a significant challenge for us.

MS. MORITA: The biggest challenge for Hawaii is getting a coherent business strategy from the utility and moving forward. Without being presented with such a strategy, we end up having to regulate with a heavy hand.

MR. CALLISTO: All of the subjects that my colleagues mentioned — reliability, economics, the regulatory model — will turn at the first point on communications. It is a much more complicated world today than it was when the current business model was developed. You have RTOs. You have companies that just do generation. You have companies that just do transmission. The commissions need to be able to communicate with the various stakeholders to make things move forward at a pace that keeps up with the changing technology. It is really challenging. Thinking about how we communicate on these topics is important. ◎

UK Rooftop Solar Moves into High Gear

by Gaurav Sharma, in London

The UK government released a solar strategy in April that sets an ambitious goal of reaching one million solar rooftop installations by the end of 2015.

The focus is mainly on medium-size projects on the rooftops of commercial, industrial and larger public buildings.

The strategy paper is the first dedicated solar strategy released by any European government.

The United Kingdom has become an important player in the European market for solar PV despite notoriously fickle weather and the fact that most Britons flee to the Iberian peninsula and other points south when they want sunshine.

Size of Market

The domestic solar PV manufacturing base is relatively small, relying heavily on imports. However, in May 2013, the European Photovoltaic Industry Association reported that the UK has a 6% share of deployed solar capacity across Europe (in comparison to Germany with 44% and Italy with 20%). Although the UK has less sunshine and, therefore, lower load factors than other European countries, in southern England, where there are an estimated 250,000 hectares of south-facing commercial roofs, irradiation levels are comparable to that in Germany, where deployment of solar PV is considerably higher.

Last year was a record year for solar PV in the United Kingdom, with the industry continuing to press forward with significant levels of deployment after the realignment of financial incentives with market prices. Solar PV currently accounts for 12% of renewable electricity capacity in the UK. As of the end of June 2013, of the 2,400 megawatts of capacity installed, 1,700 megawatts were small-scale residential and commercial installations that benefited from feed-in tariffs paid by local utilities and other retail electricity suppliers and 200 megawatts were larger-scale installations that benefited from a "renewables obligation" that obligates the six UK electricity distribution companies to supply a certain percentage of their electricity from renewable sources. The percentage level of electricity to be generated from renewable sources was 10.4% in 2011 and is intended to rise up to 15.4% by 2015.

The sector has demonstrated the / *continued page 16*

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A PARTLY CONTINGENT PURCHASE PRICE creates tax complications.

Many developers sell projects that are still under development for cash at closing plus additional payments that are contingent on reaching various milestones.

The developer usually reports its gain under the installment method, meaning the gain is reported over time as payments are received.

IRS regulations require the gain be calculated each year by taking the maximum purchase price the developer might receive and subtracting his basis in the project to determine the fraction of the purchase price that would be gain. The developer then reports that fraction of each actual payment from the buyer as gain.

However, if the maximum purchase price is unclear by the end of the year in which the sale occurs, then the developer is supposed simply to spread its basis in the project ratably over the period that the purchase price will be paid. Thus, for example, if the purchase price might be paid over five years, the developer would subtract 20% of its basis in the project each year from what the buyer pays it that year.

One taxpayer who sold a company got the IRS to rule that it could use a different method for determining how much of each payment was gain. The ruling is Private Letter Ruling 201417006. The IRS made the ruling public in late April.

The buyer agreed to pay cash at closing, assume liabilities and make additional payments over the next seven years tied to growth in company revenues.

Since the ultimate purchase price the seller might pay was too uncertain, but the seller knew it might receive payments for up to seven years, it was required to spread its basis in the company shares it sold ratably over seven years. This would have led to a large gain in year one and a large loss in year seven based on projections the seller made assuming the company would continue to grow at the same rate it had in the past.

Instead, the IRS let the seller allocate part of its basis to each year over / *continued page 17*

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ability to deploy at all scales —- from residential and commercial buildings to large, utility-scale facilities, and growth has been seen across the spectrum. The government believes there is a potential deployment range of between 7,000 to 20,000 megawatts, with 20,000 megawatts being the maximum level of solar PV deployment by 2020.

Solar PV has been deployed currently on more than 500,000 buildings, so that the country is already more than half way to the 2015 target. The total installed capacity is expected to exceed 4,000 megawatts by the end of 2014, which would represent 67% growth in capacity in 18 months.

The UK solar PV market has already seen a significant reduction in costs in recent years. Installed costs have fallen by around 50% since 2009. Large-scale solar PV has a lower cost per installed megawatt than offshore wind, but it is still more expensive than onshore wind. The government is projecting a further reduction in levelized costs of domestic solar PV of around 20% by 2020. If this rate of cost reduction continues into the 2020s, solar PV could compete with other large-scale generation technologies such as combined-cycle gas turbines by 2025, assuming no further breakthroughs in gas turbine technology or major reductions in the cost of gas.

The UK Department of Energy and Climate Change will commission a solar PV strategy group in the next six months to report on opportunities for further reducing solar installed costs.

There are three main markets for solar PV in the UK currently: residential, building-mounted and ground-mounted installations. In addition to this, there is a small but growing market for building-integrated photovoltaics.

The UK wants to have a million solar rooftop installations by the end of 2015.

Financial Support

The UK government is planning to remove support for solar under the renewable obligation scheme for projects over five megawatts from April 2015, and generally the scheme will close to all other new generation at the end of March 2017.

The government said it proposed the changes because growth in the solar power sector had been faster than expected as developers have rushed to deploy large-scale solar to beat the deadline.

Solar facilities that are installed before the deadline will continue to benefit from the renewables obligation subject to the maximum 20 years of support and the 2037 end date. For the final 10 years of the renewables obligation regime (2028 through 2037), a "fixed ROC institution" will purchase the renewables obligation certificates from generators at a set price based on headroom plus 10%. A major advantage for generators of there being a government-backed institution that is compelled to pay a set price is that the risk of a renewables obligation certificates price crash in the twilight years of the scheme is removed. This chosen model ought therefore to

The government encourages solar currently through a feed-in tariff that is described below and the renewables obligation.

The ability to sustain such a high growth rate will depend on a number of factors.

A number of government initiatives place the obligation of financing energy policies on private companies. The cost is usually passed on to the consumer. To keep the cost affordable to consumers and ensure a secure energy supply, the government has set up a "levy control framework." This sets caps on levy-funded spending in each financial year to be funded by the government. Within the available budget, the government sets annual limits on the overall costs of the renewables obligation and the feed-in tariffs scheme, achieving further significant reductions in the cost of solar panels and inverters so that solar can compete with other low-carbon technologies and finding affordable ways to upgrade the electricity grid to accommodate more intermittent renewables.

promote greater financial certainty among investors and developers who are looking at the period 2028 through 2037 for existing or pipelined renewable obligation supported projects.

The falling cost of the technology has also contributed to widespread adoption.

By the end of April 2014, more than 325 solar PV farms of one megawatt or larger had been completed, and there are more than 60 projects with installed capacities of greater than 10 megawatts. Another 444 large-scale ground-mounted solar PV farms are currently at various stages of planning with 124 projects having had their planning applications approved.

The government now considers it necessary to control the costs of large-scale solar PV to ensure it remains affordable in the context of the renewables obligation. The government has proposed closing the renewables obligation scheme to new solar PV generating stations, both ground- and building-mounted, above five megawatts from April 1, 2015. Solar PV installations over five megawatts that applied to the scheme before the deadline will still be allowed to benefit from the renewables obligation as a form of transition relief for developers whose projects were already far along when the government announced its intention to withdraw the renewables obligation scheme from such projects.

From 2014 onwards, the primary financial support mechanism for new large-scale renewable generation will be contracts for differences. These are long-term contracts between the generator and an industrial customer who wants the electricity that pay the generator the difference between an estimated market price for electricity, called the "reference price," and the long-term price needed to cause the project to be built, called the "strike price." The actual electricity is sold into the grid. The industrial customer pays the generator a fixed strike price, and the generator turns over to the industrial customer the floating actual price he received from the grid for the electricity. The fixed strike price means that the generator is protected from wholesale price volatility and the cost of the electricity to the industrial customer is capped. The strike prices are set by Ofgem, the regulatory body that regulates the gas and electricity markets in the UK. The intention is to keep the strike prices consistent with the renewables obligation levels of support.

The feed-in tariffs scheme was introduced with the intention of encouraging deployment of small-scale (up to five megawatts), low-carbon electricity generation. The scheme has been a success with more than 450,000 */ continued page 18*

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the seven-year period in the same pattern as the seller expected to receive contingent payments.

IRS regulations allow the seller to use a different method for allocating basis if it can show that he will probably recover basis at least twice as fast under the alternative and the method is reasonable. The seller must receive IRS approval to use the method by asking for a private ruling.

CORPORATE INVERSIONS are becoming more common.

A corporate inversion is where a US corporation with substantial foreign operations reincorporates in a foreign country to reduce the amount of taxes it has to pay in the United States on its foreign earnings.

A wave of inversions early in the last decade led Congress to take steps in 2004 to discourage them. Now a new wave of inversions has led to new hand wringing on Capitol Hill, but the gridlock in Congress and the lack of consensus about what action to take make any further action unlikely, at least this year.

Forty one US multinational corporations have reincorporated in lower tax countries since 1982. Of that number, at least 13 moved since late September 2010, and another eight inversions were in the works as of late May. Of these 21 transactions, 11 involve reincorporation in Ireland, three in the United Kingdom, three in Holland and one each in Canada, Australia and Germany.

The attraction is not only a lower tax rate — the US corporate income tax rate is 35% compared to 12.5% in Ireland and 20% in the United Kingdom — but also the United States taxes US corporations on their worldwide earnings while the other countries impose limited or no taxes on offshore income. Another factor is the $1.95 trillion in earnings that US multinational corporations have parked in offshore holding companies and are unable to use in the United States */ continued page 19*

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installations (2,200 megawatts of capacity) registered under the scheme by June 2013. Of these, around 99% are solar PV installations.

FIT generators receive three financial benefits from the scheme: a payment at the tariff rate from the local utility for all electricity generated by the installation, an export tariff or additional payment from the local utility for surplus electricity exported to the local grid, and savings on their electricity bills from generation used on site. A comprehensive review of the tariff program in July 2012 has led to a new 'degression' mechanism under which tariff levels are being reduced as the level of solar deployment increases. The tariff rate for a particular solar PV installation project is fixed for 20 years on the date the project is put into service, but the tariff can rise in line with inflation.

Key Actions

Permitted development rights for micro-generation have facilitated the deployment of solar PV at smaller scale by removing the need for formal planning permission for many small installations. Some of this deployment has been on brownfield land or connected to existing commercial or industrial facilities. In addition, a significant proportion has been sited on greenfield sites where these have met planning policy requirements. With increasing solar PV deployment, it is likely that the larger proportion will be small-scale installations. The government is working on extending the automatic granting of permitted development rights in England for building-mounted solar PV to rooftop systems up to one megawatt.

The government is interested in promoting wider use of mid-scale solar on top of factories, supermarkets, warehouses, car parks and other commercial and industrial buildings. The government aims to work with developers to cut red tape and sweep away barriers to making use of industrial rooftops. The government will be using the public estate such as the Ministry of Defense and hospitals to target up to 1,000 megawatts of solar PV. Sites are currently being assessed for their suitability, and the expectation is that installation could start later in the summer, subject to gaining any necessary approvals.

The government has also targeted the 24,000 schools in England and Wales to install solar arrays. The government will identify the first 500 megawatts of deployment and seek private finance partners to incentivize installation later this year.

As the benefits of solar deployment on public buildings are realized, the government expects deployment across this sector to increase substantially.

The government will continue to encourage overseas investment in the manufacturing end of the sector through the Department for Business, Innovation and Skills and the Foreign Office.

Developers need to know they will be able to connect their projects to the electricity grid. Ofgem has put new regimes in place on standards of performance and penalties when agreed time frames and provision of service are not met by local utilities.

Residential Rooftop Market

An average of 2,000 new residential rooftop systems are now being installed each week in the UK.

Installing solar PV on housing, where systems typically are less than four kilowatts in size, is the largest sub-sector of the UK solar PV market currently, both in terms of number of installations and the total capacity installed. More than half a million homes now have solar panels. This is a remarkable achievement given that, as recently as 2010, that number stood at fewer than 15,000 installations.

The main drivers for the growth in the domestic sector have been the introduction of

An average of 2,000 new systems are being installed each week.

the feed-in tariffs in 2010, the dramatic reduction in installed costs, particularly the price of the panels themselves, and the increasing confidence and familiarity that consumers have with the technology and the benefits that it can bring. Most systems are owned by homeowners or small businesses, unlike in the United States where solar rooftop companies have made rapid inroads by retaining ownership and either leasing solar systems to homeowners or selling them the electricity under leases or power contracts with 20-year terms.

The average homeowner in the UK with solar on his roof recoups the cost of the system in approximately 10 years. As the cost of solar PV at a domestic scale continues to fall ultimately towards grid parity, recoupment should be faster.

The government is interested in seeing innovation in financing. The market is moving to various product choices such as lease financing, power purchase agreements, home equity solar loans or even small loans from the local utility.

Commercial and Industrial

Growth in the commercial and industrial market has been slower than in other European countries, but there is potential for very significant growth in the UK.

Some of the barriers to the wider uptake by potential commercial and industrial customers include inability to access capital, the transaction costs (management time), suitability of the building stock and split incentives, primarily landlord-tenant issues. These issues can be significant for companies of any size, but are likely to be particularly acute for small to medium enterprises.

In many other European countries, particularly Germany, more than half of solar PV deployment is in this sector, compared to 5% to 20% in the UK.

In Germany, for example, the legal ownership of mid-scale roof-mounted arrays is often simpler than in the UK because the array can be dismantled and moved elsewhere, for example if the business moves to new premises. Additionally, a higher proportion of commercial and industrial buildings are owner-occupied in Germany than in the UK, simplifying PV deployment and avoiding the contractual complications between landlord and tenant often experienced in the UK.

Property ownership is less common in the UK. Most commercial tenants lease their premises from landlords. The complexity of the relationship between landlords and tenants, particularly in the large retail sector, has an effect. Landlords incur the costs of the deployment and / continued page 20

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without triggering US income taxes. An inversion could make the earnings easier to redeploy.

Congress amended the tax code in 2004 to make it more painful for US companies to invert. In cases where the shareholders of the former US corporation continue to own at least 80% of new foreign parent company by vote or value, the foreign corporation is treated as a US company for tax purposes, so any benefit from inversion is eliminated. If the shareholders of the former US corporation retain at least 60% of the new foreign corporation, then a toll charge is collected on any appreciation in asset value when the company leaves the US tax net. The toll charge cannot be offset by using tax attributes such as net operating losses and foreign tax credits. In addition, some executives of the inverted company may have to pay an excise tax at a 20% rate on the value of their stock options and stock-based compensation when the company leaves the US tax net.

However, a US company can avoid the tax penalties if the affiliated group of companies headed by the new foreign parent company has substantial business activities in the new parent's home country. In that case, it is not considered to have inverted.

Given these rules, two types of inversions are still possible.

One is a "self inversion" where the US corporation simply reincorporates abroad and has substantial business activities in its new home country. Such inversions are rare. The IRS interpreted substantial business activities in 2012 to mean at least 25% of the affiliated group's sales, assets, income and employees must generally be in the country where the new foreign parent corporation is incorporated.

Most recent transactions involve mergers of a US and foreign corporation where the shareholders of the foreign corporation continue to own more than 20% of the combined entity. In the typical "acquisition inversion," the US company combines with a smaller foreign company. The combined / continued page 21

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take the feed-in tariff payments, but tenants benefit from reduced energy bills.

The government has set up a separate "finance task force" to focus on these barriers. Ministers will meet with senior representatives of the retail and finance sectors in the early summer to agree on a way forward, with a view to holding meetings in the future with other sectors facing similar problems.

The government is also considering the introduction of new permitted development rights that would assist in removing another barrier to deployment. Currently, rooftops with over 50 kilowatts in capacity require planning permission, which can add significantly to development timescales, increasing uncertainty and therefore risk. Solar PV developers and financiers have identified this as a barrier, and statistics show a marked fall in deployment of systems above 50 kilowatts which would seem to strengthen this claim. The government is working on a proposal to allow permitted development rights for solar rooftop panel systems up to one megawatt. The proposal is expected over the summer.

The amount of time that it can take to complete the application process for a feed-in tariff on installations above 50 kilowatts may be another source of delay and therefore risk. Ofgem has introduced a two-stage application checking process (as opposed to three stages) for straightforward applications to enable approval more swiftly. Ofgem is also producing two new guidance documents, designed to help applicants get their applications right the first time, that will be published later this year.

Building-Integrated Solar

The potential market for building-integrated photovoltaic solar is both new build and refurbishment of existing buildings. This is so-called "third generation" solar. Examples of BIPV products are putting solar inside the glass of skyscrapers and inside canopies that shield windows from the sun. Solar roof tiles integrated into building roof designs will also make solar PV less visible, while other products including louvres, glazed facades and atria offer other potential areas for BIPV integration. Some BIPV products can incorporate insulation, which can improve the energy efficiency of existing buildings.

The solar PV strategy group being set up by the government will focus on this as a potential growth market. ◎

Rooftop Solar Gets Traction in China

by Edwin Lee, in Beijing

Distributed solar has been receiving more attention and incentives from the Chinese central and local governments in the past 18 months. However, there are still obstacles that are preventing the market from reaching its full potential.

The National Energy Administration has set a goal of adding 8,000 megawatts in distributed solar capacity and 6,000 megawatts of new utility-scale solar during 2014. This would be a 72% increase over solar installed capacity at the end of 2013. Total installed capacity at the end of 2013 was 19,420 megawatts, of which 16,320 megawatts were utility scale and 3,100 megawatts were distributed solar. If the government were to realize its goals for 2014, the growth rate this year in distributed solar would be more than 250%.

However, scuttlebutt in the market is that this rate of growth will not be achieved.

The market expectation is that 6,000 megawatts of distributed solar will be installed in 2014 and 8,000 megawatts in each of 2016 and 2017.

This will require annual investment of roughly RMB 70 billion (around US$11.2 billion) during each of the three years.

China will become the biggest PV market in the next five to 10 years. For now, the Chinese distributed solar market is still at a preliminary stage compared to the European Union, the United States, Korea and Japan.

Foreign investors are starting to consider entering the market. Investors should be aware of some basic facts and issues and take steps to minimize the risks.

Policies

The State Council formally encouraged installation of distributed solar in an opinion published in July 2013. An article about the opinion is available on the Chadbourne website at [http://www.chadbourne.com/files/Publication/842a2295-7b97-4ccf-942a-151e43cf918a/Presentation/PublicationAttachment/f7138ee2-c03e-4502-9c77-1e5c402662a9/ChinaTakesStepsSavePV_Lee_Jul13.pdf]. The basic principle is "generating for self consumption, connecting surplus to the grid, adjustment by the grid," which is basically a self-consumption model. The priority is to encourage industrial and commercial entities to install distributed solar on their rooftops. The State Council is also keen to see solar panels installed on the roofs of schools, hospitals, government buildings and homes. A hundred distributed solar generation model zones will be established, 18 of which were identified by the National Development and Reform Commission in August 2013.

The National Energy Administration issued a separate set of "interim measures" to encourage distributed solar on November 13, 2013. It ordered grid companies to build the necessary upgrades to accommodate distributed solar systems on the grid.

Anyone planning to install a rooftop system must make a filing with the local energy administration. The filed project must be completed within two years after the filing date or it will not qualify for a government grant. (The grant is described later in this article.)

The procedure for connecting to the grid is more straightforward than before. The grid company must let the customer or solar company know the plan for interconnection within 30 business days after accepting the application to interconnect.

In China, there are two major state-owned grid companies, China Southern Power Grid and State Grid. China Southern is the grid company in the provinces of Guangdong, Guangxi, Yunnan, Guizhou and Hainan. State Grid operates in the rest of China. Both companies have local branches or subsidiaries at provincial, city or county levels. For distributed solar projects at 35 KV or lower voltage, the grid company at the city or county level should be approached for grid connection. Larger projects should deal with the grid company at the provincial level.

Distributed projects are exempted from the need to hold a power generation license based on a National Energy Administration notice on April 9, 2014. Before April, such projects required a license that is complicated and time-consuming to obtain.

Grants and Subsidies

The central government provides grants of RMB 0.42 (US$0.07) per kilowatt hour of output. The grants run for 20 years. The grid company must pay for any surplus power the owner of the rooftop solar system feeds into the grid at the local benchmark price of coal-fired power, which is around RMB 0.50 (US$0.08) depending on the location of the project and the type of customer. Thus, the customer not only avoids having to pay something like RMB 0.50 per KWh by generating his own electricity, but he also receives RMB 0.42 from the / continued page 22

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company can choose a third country as its new tax home. The executive team usually remains in the United States.

The chairman of the Senate tax-writing committee, Ron Wyden (R-Oregon), said in an op-ed piece in the *Wall Street Journal* in early May that he plans to try to put a halt to inversions by merger by requiring the shareholders of the foreign corporation to own at least 50% of the combined entity. This would leave the door open only to mergers of equals or takeovers of US corporations by larger foreign corporations.

Chiquita Brands International is moving overseas in a merger with Irish rival Ffyfes PLC, which is based in Ireland. The combined company will be a tax resident of Ireland. Chiquita shareholders would own 50.7% of the combined company. The deal is not expected to close until later this year.

Neither Orrin Hatch (R-Utah), the ranking Republican on the Senate tax-writing committee, nor Dave Camp (R-Michigan), the chairman of the House tax-writing committee, joined Wyden in threatening action. Republicans say the only way to stop inversions is to reduce US corporate income taxes to bring them in line with lower taxes in other countries.

This is in contrast to 2002 when Senator Charles Grassley (R-Iowa), then ranking Republican on the Senate tax-writing committee, joined the committee chairman, Max Baucus (D-Montana), in a joint statement that Congress would act to shut down inversions effective the day of the statement: March 21, 2002. However, the final bill did not become law until 2004, by which time there was a new Congress. Thus, the final effective date slipped to a date early in the new Congress: March 4, 2003.

The Wyden proposal is similar to a proposal that the Obama administration made in its budget message to Congress in March. Senator Carl Levin (D-Michigan) and his brother, Congressman Sander Levin (D-Michigan), the ranking Democrat on the House tax-writing committee, intro- / continued page 23

Local Goals and Incentives by Province

Province	Goal for new PV installations in 2014 (in MWs)			Incentives
	Total	Distributed solar	Utility-scale	
National	14,050	8,000	6,050	Grant of RMB 0.42 per KWh
Hebei	1,000	600	400	For projects that commence production by the end of 2014 and 2015, the on-grid tariff is RMB 1.30 and RMB 1.20 per KWh respectively with some conditions. The on-grid tariff will last for three years.
Shandong	1,200	1,000	200	The on-grid tariff that connect to the grid in 2013 through 2015 is RMB 1.20 KWh (including the RMB 0.42 per KWh grant by the central government)
Shanghai	200	200	—	Industrial and commercial customers will receive an additional RMB 0.25 per KWh grant and individuals and schools will receive an additional RMB 0.40 per KWh. The incentive will last for five years and the grant for a project cannot exceed RMB 50 million (US$8,012,569) per year.
Jiangsu	1,200	1,000	200	If the projects commence generation in 2012 through 2015, do not receive a national grant of RMB 0.42 per KWh and involve ground, rooftop or building integrated PV, the on-grid tariff is RMB 1.30 in 2012, RMB 1.25 in 2013, RMB 1.20 in 2014 and RMB 1.15 in 2015 per KWh.
Zhejiang	1,200	1,000	200	An additional RMB 0.20 per KWh grant will be provided at the provincial level based on output. Some governments at city or county level will provide another RMB 0.10 to 0.30 per KWh. Investment subsidies are available in Tongxiang city.
Anhui	550	300	250	If all the modules and inverters are purchased locally in Hefei city, then an additional grant of RMB 0.25 per KWh will be paid. The operator of rooftop and building-integrated PV projects will also receive RMB 0.02 per KWh. The grants will last for 15 years. For the rooftop solar projects in rural areas, RMB 3.00 per watt subsidies will be provided (maximum 5,000 KW per house).
Guangxi	150	100	50	For distributed solar projects in Guilin city: besides the national grant RMB 0.42 per KWh, the surplus output will be purchased by the grid company at the coal-fired on-grid tariff of RMB 0.4552 per KWh.

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government to the extent he consumes the electricity he generates and RMB 0.92 (RMB 0.42 plus RMB 0.50) to the extent electricity is fed back into the grid.

Despite the grants, solar companies seem bewildered about how to profit from, secure land and rooftop leases for and finance distributed solar.

Local governments in nine provinces adopted incentive measures in May. The nine announced they will provide additional grants at the local level that should let solar companies and customers earn internal rates of return of 10% to 16% on the investment in the solar equipment. The additional incentives vary by province.

The term of most local grants and subsidies, except for Anhui and Jiangxi provinces, is three to five years, which is much shorter than the national grant term of 20 years.

Local governments that have not yet adopted local incentives are expected to do so as an inducement to solar companies and customers to reach local goals for new solar installations. Solar has become of major importance because it could help improve the air quality in China.

The National Energy Administration will consult with local governments later in 2014 about the goals to be set for next year. The new goals will be set in January of each year.

China wants 250% growth in rooftop solar in 2014.

Recent Uptick

The distributed solar market is still struggling to find a suitable commercial model for rooftop projects.

Since there is no mature commercial model in China, first quarter 2014 installations were already behind the goals that

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duced nearly identical bills in May to do the same thing. The bill would also continue to treat a re-domiciled company as a US company for tax purposes if it remains managed and controlled from the US and at least 25% of its employees, employee compensation or assets are located or derived in the United States.

Meanwhile, the IRS tightened the existing rules in late April by issuing a notice that said inversions would trigger US toll charges on US shareholders who receive shares in the combined new company as consideration for their shares in what was formerly treated as a "killer B" tax-exempt reorganization. The notice is Notice 2014-32.

The popularity of re-incorporations in Ireland is starting to worry the Irish government, as it could undermine Ireland's insistence that it is not a tax haven. Some companies that have set up tax residence in Ireland use a "double Irish" structure to shift profits from Ireland to Bermuda to reduce taxes even further.

CHILEAN PROJECTS are expected to face higher taxes.

A tax reform bill that Chilean President Michelle Bachelet submitted to the National Congress in April would increase the corporate income tax rate from 20% to 25% over four years. The new rates will be 21% in 2014, 22.5% in 2015, 24% in 2016 and 25% in 2017.

The bill is expected to be approved in September.

It would also impose thin capitalization rules that will limit the extent to which developers can "strip" earnings from Chilean projects by pulling them out as interest on shareholder debt. In the future, interest paid by a Chilean company on loans from related parties would be re-characterized as dividends to the extent the company has a debt-equity ratio of more than three to one. Debt from third parties would be counted in determining whether the company is too highly leveraged, but the only interest that would be treated as dividends is interest on loans from related parties.

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Local Goals and Incentives by Province (continued)

Province	Goal for new PV installations in 2014 (in MWs)			Incentives
	Total	Distributed solar	Utility-scale	
Henan	750	550	200	For distributed solar in Luoyang city: the operator will be provided an additional RMB 0.10 per watt for three years based on the installed capacity. The project must be completed and connected to the grid by the end of 2015 with priority given to projects that use modules manufactured locally in Luoyang.
Jiangxi	380	300	80	RMB 0.20 per KWh for 20 years. Alternatively, separate investment subsidies are available for rooftop projects under a special program in Jiangxi.
Beijing	300	200	100	A multi- tiered grant is expected.
Fujian	350	300	50	N/A
Hubei	400	200	200	N/A
Hunan	250	200	50	N/A
Shanxi	450	100	350	N/A
Inner Mongolia	550	50	500	N/A
Tianjin	220	200	20	N/A
Liaoning	250	200	50	N/A
Jilin	150	100	50	N/A
Heilongjiang	100	50	50	N/A
Sichuan	100	20	80	N/A
Chongqing	10	10	—	N/A
Tibet	60	10	50	N/A
Shaanxi	500	100	400	N/A
Gansu	550	50	500	N/A
Ningxia	500	100	400	N/A
Qinghai	550	50	500	N/A
Xinjiang	650	50	600	N/A
Xinjiang Production and Construction Corp.	200	—	200	N/A
Guangdong	1,000	900	100	N/A
Yunnan	110	10	100	N/A
Guizhong	60	30	30	N/A
Hainan	110	20	90	N/A

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were set at the start of 2014. In Shandong and Zhejiang provinces, both of which are key areas for distributed solar, applications were filed for only 4.15 MW and 44.8 MW of new installations in the first quarter. Most other provinces had no filings. This suggests a lack of confidence among solar companies whether they will be able to arrange financing for projects.

Recent announcements by local governments that they are adding to the subsidies is leading to greater interest in the market. Construction started in May on 50 megawatts of solar on rooftops of 130 factory buildings in a high-tech zone that the government designated as one of the 18 solar priority zones.

Also in May, a subsidiary of China Aviation Supplies Holding Company signed a contract with Xinjiang Airport Group to install distributed solar on the rooftops and ground at the airport. The airport will end up owning the systems under what is called an "energy performance contracting" or EPC model in China. The contractor will design, invest, construct and operate the systems. The owner of the airport will pay the contractor for the generated power each month. The payments will last for around 18 years or long enough to give the contractor a return. The airport will have unfettered use of the systems after that.

The biggest rooftop solar project in the country to date is a 32-MW solar installation on buildings making up a factory used by Midea Group, a leading consumer appliances and air conditioning systems manufacturer in China. The solar equipment was installed by the local utility, China Southern Power Grid, under an EPC contract with a term of 25 years.

Challenges

The bearing capacity of Chinese rooftops varies considerably. Two types of materials are used for the rooftops in urban and industrial zones: concrete and color plate. Most concrete rooftops have sufficient bearing capacity if they are not more than 20 years old. However, many color plate rooftops cannot meet the bearing capacity requirements.

Another challenge is how much longer the building is expected to last and, in cases where the occupant merely leases the building, how many years remain on the lease. The average building life in China is 30 years / *continued page 26*

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Jessica Power, co-head of the tax group at Carey, a premier law firm in Santiago, said the company would also be treated as having too much debt to the extent interest and other financing costs in a year exceed 50% of the company's taxable income before deducting such costs. The thin capitalization rules would apply starting on January 1, 2015. They will apply to existing shareholder loans, said Power.

Many developers capitalize Chilean project companies with debt in an effort to reduce the Chilean taxes on their projects. By distributing earnings as interest on such loans, the project company can deduct the distributed earnings, and interest paid cross border attracts a lower withholding tax — 4% or 15% depending on the facts — compared to 35% on dividends. These are the statutory withholding rates. Actual withholding may be lower where the developer is a tax resident of a country with a favorable tax treaty.

The tax reform bill would also move to taxing shareholders in Chilean companies on their shares of company earnings in the year the earnings accrue even if the earnings are not distributed until later. Earnings would be considered to accrue even before a dividend is declared, according to Jessica Power. Thus, this would have the effect of taxing shareholders on earnings that a company retains for reinvestment.

Expenses on transactions with related parties — for example, interest on shareholder loans — would be deductible only in the year actually paid.

Interest on loans to acquire equity interests or bonds could not be deducted. Rather, it would have to be capitalized into the basis in the equity or debt instruments acquired. This would not apply to borrowing to acquire assets.

A carbon tax would be imposed on emissions from any boiler or turbine with a capacity of at least 50 megawatts. The tax would be a minimum of the Chilean peso equivalent of US$0.10 per ton of particulate matter, nitrogen oxide or sulfur dioxide emitted, according to Manuel José Garcia with Carey. The tax rate / *continued page 27*

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due to poor construction quality and frequent urban renewal. A rooftop distributed solar system should normally last 25 years. This may be longer than the building or lease.

The ownership of rooftops is also a complex issue. The time and expense to search ownership records and discuss with the owners and other users of the rooftops can be a major headache. Here is one place where local governments may be able to help.

Other challenges are tariff settlement and collection, quality of solar modules, and problems connecting to the grid. This has led to a wait-and-see attitude among potential investors.

Financing

Financing for distributed solar is not well developed.

Without project financing from banks or other financial institutions, the boom in distributed solar will be slow to develop. A meeting was organized recently by the National Energy Administration, the People's Bank and the China Bank Regulatory Commission to talk about how to bridge the gap. Representatives from other major banks also attended.

The China Development Bank, as a policy bank, is the only bank that is extending credit currently to distributed solar projects. The term can be 15 years with extensions of another two to three years. The other commercial banks are still worried about potentially hidden risks in such projects.

Some insurance products related to distributed solar are under discussion and may become available later this year. These may help other banks get over their fears about the risks of lending.

China is keen to promote solar as a way to reduce air pollution.

The National Development and Reform Commission published a notice on May 18, 2014 to encourage private investors, including foreign investors, to participate in the construction and operation of 80 infrastructure projects independently or via joint venture. Thirty of the 80 infrastructure projects are for distributed solar in zones where the government has made it a priority to install solar.

The anti-dumping duties against Chinese solar modules in the United States, Europe and Australia may spur China to ramp up the domestic Chinese market for rooftop solar more quickly. ◎

Geothermal Market Poised For Growth

by Sohail Barkatali, in Dubai

Geothermal power is currently a niche market. However, growth is expected to accelerate in the next few years aided by new players in the market, the development of new technologies supported by feed-in tariffs and international development agencies in developing countries. The future for geothermal energy is looking good.

Electricity was first produced from geothermal steam in Italy in 1904 at an experimental installation constructed in Larderello. Today, approximately 22 countries generate electricity from geothermal sources. This number is growing. The United States and The Philippines have the largest installed capacity of geothermal power. Six more countries are expected to have installed geothermal power plants by 2015, and another seven will have done so by 2020.

This article looks at some aspects of the resource, the risks associated with a geothermal project and how the "geothermal risk mitigation facility" in East Africa mitigates some of the exploration risk associated this form of power generation.

Capacity Forecasts

Geothermal power is derived from the heat contained in the crust of the earth. Heat is produced in the earth from the decay of radioactive material that exists in the core of the planet. The heat moves to the surface through a process of conduction and convection. Some of the best geothermal fields are found along volcanically-active areas and are often located near boundaries of tectonic plates.

Commercially-viable geothermal power generation technology relies on underground sources of extractible steam. As of 2013, the total geothermal power market in the world accounted for approximately 11,500 megawatts. The market has historically grown at an annual rate of 3%, but growth is increasing with projections of installed geothermal capacity in the world of as much as 24,000 megawatts by 2020.

Although the highest concentration of geothermal energy is associated with the tectonic plate boundaries, some form of geothermal energy can be found in most countries. For example, ground source heat pumps can be used almost anywhere in the world to produce heat from the ground.

Geothermal resources are classified in a number of different ways depending on the type of heat transfer, heat source, reservoir temperature, utilization, physical state and geological settings.

The United States, Japan, Iceland and New Zealand are the leaders in using geothermal resources for electricity generation.

In Asia, Indonesia has enormous geothermal potential and has plans to add up to 3,000 megawatts of new capacity from geothermal resources by 2020. The Sarulla geothermal project with a capacity of 330 megawatts will be the largest geothermal power project in the world. The project is being undertaken by Medco Power Indonesia (a consortium of Medco, Itochu Corporation, Kyushu Electric Power and Ormat International) at a cost of approximately US$1.6 billion. The Philippines, Malaysia and Papua New Guinea are other countries that are likely to add new capacity from geothermal resources by 2020.

In Africa, the East African Rift Valley is the region with the largest geothermal power potential. Kenya leads in the harnessing of geothermal resources for electricity generation through the establishment of a state-owned company, the Geothermal Development Company, which is responsible for exploiting geothermal fields. With one exception, existing geothermal power plants in the country are all owned by the state-owned generation company, KenGen.

Djibouti and Ethiopia are the other countries in Africa that are likely to increase their generation capacity by the addition of new geothermal-based electricity generation. Ethiopia is said to have at least 5,000 megawatts of geothermal power potential. It has signed an agreement with the Icelandic International Development Agency for geothermal surface exploration. In addition, a deal has been signed between Reykjavik Geothermal and the Ethiopian Electric Power Corporation for the development of geothermal power projects in the Caldera of Corbetti. In Djibouti, the Lake Asal region offers the best potential for geothermal energy.

Test drilling of wells is underway in Uganda, Rwanda, Burundi, the Democratic Republic of Congo and Zambia, and these countries may see the development of pilot projects in the short term. Other countries that provide good prospects in Africa include Tanzania, Eritrea, Sudan, Malawi, Mozambique, Madagascar, the Comoros and Mauritius.

In Latin America, Mexico, Nicaragua, El Salvador and Costa Rica are expected to continue to develop geothermal power generation plants. Other countries that offer good prospects are Peru, Chile, Argentina, several / continued page 28

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could be higher under a formula tied to the concentration of pollutants in the local area. The tax on carbon dioxide emissions would be US$5 a ton. The tax would be an annual levy payable for the first time in April 2018 on 2017 emissions.

A stamp tax collected on loans would increase from the current range of 0.033% to 0.4% to flat tax of 0.8% for any loan with a term of more than two months.

ROOFTOP SOLAR has the potential to take away about 7% of retail electricity sales from US utilities, according to a report by Bernstein Research, an independent Wall Street research firm, in early June.

The figure is only 2% if the current 30% investment tax credit for solar equipment drops to 10% after 2016 as currently scheduled and only 1.6% if the credit is eliminated. All three estimates assume that the cost of the average US solar rooftop installation will fall to $2.20 a watt compared to about $4.60 in the fourth quarter 2013. The figure $2.20 is what the average solar system cost late last year in Germany.

Distributed solar generation today is just 0.2% of US electricity supply, leaving significant room for growth under any of the forecasts.

More than 75% of current distributed solar capacity is in five states: Hawaii, California, Arizona, New Jersey and Massachusetts. The fact that the amount of sunlight varies so significantly in the five states speaks to the importance of retail electricity rates and state incentives in driving rooftop installations.

Bernstein estimated the highest possible percentage of distributed solar penetration in the US is 24% assuming universal deployment by all residential, commercial and industrial customers. However, nearly 50% of residential properties may not work for solar because of shade and other physical barriers.

It calculated utility by utility which customers have the greatest incentive to install solar given retail electricity rates and the potential savings. The 11 utilities facing the greatest danger and the percentage / continued page 29

Geothermal

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Caribbean island states as well as Guatemala, Honduras, Colombia, Ecuador and Bolivia.

The table shows the installed and forecasted capacity of geothermal power plants around the world.

Country	2012 (MW)	2015 (MW)	2020 (MW)
USA	3,187	4,136	5,442
Philippines	1,972	2,112	3,447
Indonesia	1,335	2,325	3,453
Mexico	990	1,208	1,208
Italy	883	923	1,019
New Zealand	750	1,350	1,599
Iceland	675	890	1,285
Japan	537	568	1,807
Kenya	205	402	560
El Salvador	204	287	290
Costa Rica	201	201	201
Nicaragua	124	209	240
Turkey	115	206	1,232
Russia	82	190	194
Papua New Guinea	56	75	75
Guatemala	52	120	141
Portugal	29	39	60
China	24	60	84
France	16	41	42
Germany	12	92	184
Ethiopia	7	45	70
Australia	1	43	70
Chile		40	160
Honduras		35	35
Nevis		35	35
Argentina		30	300
Canada		20	493
Thailand		1	1
Bolivia			100
Iran			50
Peru			40
Armenia			25
Tanzania			20
Norway			5
Switzerland			3

Benefits

There are many benefits from geothermal energy. It can be distinguished from other sources of renewable energy. First, geothermal power is not intermittent. It can be relied upon as a stable source of baseload power regardless of prevailing ambient conditions. This clearly benefits utilities and permits them to plan and schedule power generation to meet electricity demand. Second, geothermal power plants are reliable and operate at high availability factors of over 90% (and in some cases at over 99%), notwithstanding the relatively high investment costs. The absence of fuel costs and the high availability factors help to compensate for some of the heavy initial investment costs.

Third, geothermal projects do not require too much land or space. This allows for economies of scale. Fourth, since geothermal power is practically free from dependency on fossil fuels, it provides a natural hedge against energy price fluctuations while contributing to a country's security of supply requirements at the same time.

Fifth, the environmental benefits are immense as geothermal energy can help reduce emissions of CO2 and air pollutants to negligible levels per unit of electricity generated. Sixth, geothermal power generation usually uses conventional steam-cycle generation technologies. The operational and maintenance risks associated with such plants are well known and have been financed.

Four Technologies

The technology available for the exploitation of geothermal resources typically requires the drilling of production wells that deliver subsurface liquids to the surface that are normally injected back into the original formation through reinjection wells after the liquids have been used to generate power.

There are four types of power plants typically associated with geothermal energy: binary, flash (single and double), back pressure and dry steam.

Flash plants —- whether single or double – are the technology used to generate electricity from steam with temperatures above 200°C. This is a conventional steam cycle. In a single flash steam plant, hot water or steam from the wellhead enters a separator where steam is separated from liquid and expanded through a turbine.

A double flash steam cycle, while more efficient as a source of generation and in terms of using the geothermal resource, differs from a single flash cycle plant in that fluids are passed through successive separators at different pressures. Steam enters a dual-entry turbine in which steam at different pressures flows to different parts of the turbine. Double flash steam plants cost more than single flash plants.

A binary plant uses a secondary working fluid with a low boiling point and a high vapor pressure at low temperatures. The geothermal liquid heats the secondary fluid through heat exchangers where the secondary fluid is heated and vaporizes. The vapor drives a turbine. Binary plants are usually deployed in geothermal fields that are dominated by liquid with temperatures up to 200°C. Binary units can be produced in sizes of between 0.1 to five megawatts and can be deployed in isolated or remote areas.

Geothermal capacity additions are expected to accelerate in the next few years.

Back-pressure units are steam turbines that exhaust the steam from the geothermal resource directly into the atmosphere. While they remain simple to install and they are cheap and easy to run, they are less efficient than other technologies. The lack of a reinjection and potential effect on the environment (depending on the chemical composition of the fluids and steam being exhausted) make them less attractive units to deploy.

Dry steam technology is normally used when a geothermal reservoir produces pure hot steam. The technology is similar to conventional steam or flash technology, but without a separator to separate fluids from steam as that is not necessary. These units can be large and are capable of operating efficiently.

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of retail electricity sales each could lose are as follows: Arizona Public Service 34%, Public Service Company of New Mexico 31%, Pacific Gas & Electric 26%, San Diego Gas & Electric 25%, United Illuminating Company 25%, Southern California Edison 23%, Northeast Utilities 21%, Hawaiian Electric Companies 20%, Central Hudson 15%, Consolidated Edison 14% and SCANA 14%.

Several of these utilities are protected by state regulatory regimes that decouple the utilities' revenue from electricity sales. If sales fall below the forecast, then the regulators must allow the utility to increase what it charges per megawatt hour of electricity to stabilize revenues at the target level.

The move to rooftop solar could also affect prices for fossil fuels. According to Bernstein, 7% of US demand for natural gas is at risk as well as 3% of US demand for western coals and 1% of demand for eastern coals.

A EUROPEAN FINANCIAL TRANSACTIONS TAX moves closer.

Finance ministers from 10 countries said in a joint statement in May that their countries will impose a financial transactions tax starting January 1, 2016. The 10 countries are Austria, Belgium, Estonia, France, Germany, Greece, Italy, Portugal, Slovakia and Spain. The tax will apply initially to transfers of shares and other equity instruments and to some derivatives transactions and then be expanded over time. The countries are expected to finalize details of the tax by the end of this year.

The European Union has been talking about such a tax since September 2011. The original proposal was for a tax of at least 0.1% on the trading of shares and bonds and a tax of at least 0.01% on derivatives. For cross-border transactions between one party in a country with the tax and another in a country without the tax, the party in the country with the tax would be

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Geothermal

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Risks

Several risk factors will influence the appetite for undertaking a geothermal project.

Most risks associated with a geothermal power plant are no different than those faced by any power generation project: construction risk including delay, offtaker risk, market risk, operational risk and regulatory risk including potential changes in subsidies or other government policies.

However, there are two additional inter-related risks that apply to geothermal power projects: resource risk and financing risk, especially where there is a long lead time between the initial investment and the commencement of payments under the power purchase agreement. The two risks go hand in hand.

The exploration risk associated with a geothermal project is not very different from that associated with an oil and gas project. The exact depth of a well or the exact steam output from a geothermal well cannot be accurately predicted until production wells are drilled. The simple economics of a geothermal project depends on the productivity of the geothermal field and on the success of being able to tap into the resource. The amount of electricity that can be produced from the geothermal field is dependent on the number of wells that are drilled and the production capacity of each well. There have been several notable failures of geothermal projects in the US and central America where the resource proved disappointing or far more money had to be spent on wells than expected.

Not surprisingly, lenders do not like to finance power projects where the feedstock risk is unknown nor do they like to provide debt for projects where the nature and extent of the resource is unknown. So how can the resource risk be mitigated? Funds are needed to finance the exploratory stage of a geothermal project.

It helps to have a dedicated agency or state-owned company take the lead in geothermal field exploration and the assessment of the quality of the resource. In any case, if a government is serious about developing this resource, then it has to take the first step in exploring and exploiting the resource. There are some notable examples of where this has been done successfully.

In 1976, the government of The Philippines established a subsidiary of the national oil company, Philippine National Oil Company. This subsidiary, PNOC Energy Development Corporation, became responsible for exploration and development of the Tongonan and Palinpinon geothermal fields. Since its inception, it has explored and developed various geothermal resources in the country and was eventually privatized in 2007 and now operates under the name EDC.

There is a similar story from Mexico. Geothermal exploration was the remit of the national power utility, CFE, under which Mexico has become the world's fourth largest power producer from geothermal resources.

In Indonesia, Pertamina Geothermal Energy was established in 2006, and it is responsible for all aspects of geothermal. It is currently implementing the government's program to increase capacity by 1,050 megawatts by 2015.

When Kenya did its first geothermal independent power project at Olkaria III in 2000, the geothermal field risk was borne by the independent power producer, OrPower 4 Limited. While the Olkaria III IPP project has proven to be a success for the country and has increased in size from 8 megawatts in 2000 to 110 megawatts today, the latest geothermal IPP being undertaken in Kenya (Olkaria VI) shows that Kenya, too, has now established a state-owned company to champion geothermal exploration.

A multilateral fund to assist with geothermal drilling costs will help in East Africa.

The Geothermal Development Company was established in 2008 for the purpose of exploring and developing geothermal resources. GDC undertakes the initial exploration, drilling, risk assessment and promotion of direct utilization of geothermal energy. In undertaking these activities, GDC absorbs the early development risks and opens up the possibility of the public and private sector participating in the development phases of a geothermal project. The Olkaria VI project anticipates that GDC will sell the geothermal resource to KenGen that will resupply the geothermal resource to the independent power producer.

The funding for these activities will not come from commercial banks. Multilateral funding is a major source of funding for initial geothermal development in many emerging markets. Banks such as the European Investment Bank and the World Bank are significant sources of debt that is needed to develop geothermal resources. In addition, the German government through KfW and the Japan International Cooperation Agency are also playing a leading role in funding the development of geothermal resources. These are important initiatives towards mitigating the up-front cost of geothermal development and of assessment of the optimal location of wells. Like an oil and gas exploration process, there are several steps that have to take place before the construction phase of a geothermal power project commences. These steps include preliminary surveys, exploration, test drilling, steam field appraisal, project review and planning and field development and production.

These upfront costs can be significant. Development of geothermal projects in emerging markets is hampered to an extent by the lack of available funding for these activities. However, East African countries now benefit from a facility that can provide grants to cover some of the costs.

Geothermal Risk Mitigation Facility

The African Union, the German government and the EU-Africa Infrastructure Trust Fund, via KfW Entwicklungsbank, established a geothermal risk mitigation facility in April 2012 to fund the development of geothermal resources in east Africa. The program is intended to assist with the financing of surface studies and drilling projects. Currently €50 million is available for funding.

The fund was initially open to geothermal development in Ethiopia, Kenya, Uganda, Tanzania and Rwanda, but is now being extended to Burundi, the Comoros, Democratic Republic of Congo, Eritrea, Zambia and Djibouti, too.

The geothermal risk mitigation facility is / *continued page 32*

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expected to pay the tax for both parties.

The United Kingdom and Sweden oppose the tax and have complained about its extraterritorial reach.

France and Italy have moved ahead in the meantime with a tax without waiting for the other countries. France has been collecting a 0.2% tax on acquisitions of shares in French-listed companies with market capitalizations of more than €1 billion since August 1, 2012. Italy began imposing a tax on transfers of shares and other equity positions on March 1, 2013.

EFFORTS TO SLOW RENEWABLE ENERGY fail in three states, but lead to a freeze in one.

An organization backed by the wealthy Koch brothers has been making a concerted push to roll back renewable energy standards that require utilities to supply a certain percentage of their electricity from renewable energy in 29 states and the District of Columbia. The effort has been running into opposition from some Tea Party groups that see distributed generation as a move toward democratization of the electricity supply.

In Oklahoma, the lower house in the state legislature failed in May to take up a bill that would have imposed a three-year moratorium on construction of new wind farms in the eastern third of the state, effectively killing the bill for the current session. The bill passed the state Senate by 32 to 8 in March.

The Kansas house failed in early May by a vote of 60 to 63 to phase out the state renewable portfolio standard. The current standard requires utilities to supply 20% of their electricity from renewable energy by 2020. An effort to repeal the standard failed earlier in the year. The latest vote was on a compromise to increase the current 10% target to 15% in 2016 and then to eliminate the target after 2020.

A federal district court in Colorado rejected claims in May by the Energy and Environment Legal Institute that the Colorado renewable portfolio standard / *continued page 33*

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available for surface studies to find the optimal location of wells in known geothermal fields. This can include geophysical surveys as well as supporting infrastructure that is needed to conduct the surface study. The fund is also available for drilling once the optimal location of wells has been established. The cost of drilling wells that are within certain specified measurements can be supported by the fund as can the cost of infrastructure required for exploration drilling. In addition, the fund can support a feasibility study where it forms part of a drilling program.

Grants are provided through a competitive two-stage application process. The first stage is a pre-qualification process that invites applicants to submit expressions of interest within a certain period of time. Expressions of interest that score over a certain threshold are short-listed and those applicants are invited to participate in a mandatory pre-bid workshop and to submit an application.

The purpose of the pre-bid workshop is to explain the application process as well as the evaluation and procurement processes.

The second stage, which is the application process, requires applicants to submit their applications within a certain period of time. Applications that score above a certain threshold can then enter into contract negotiations with the African Union Commission.

Where a negotiation is successful, grant agreements will be concluded between the African Union Commission and the applicants. The grant agreements establish requirements for monitoring and reporting on the surface studies that are being undertaken and on details regarding the reservoir drilling and testing.

The second application round commenced in October 2013. It normally takes a year from the application to the grant. The third application round is expected in October 2014.

Mexico is Set to Open its Power Sector

by Raquel Bierzwinsky, in New York and Mexico City, and Carla García, in Mexico City

Mexico is moving to create a competitive power market open to private investment in almost all areas.

The Mexican president, Enrique Peña Nieto, sent a draft package of nine new laws and proposed amendments to several existing laws to Congress in late April.

The legislative package has been scheduled for debate and votes in Congress beginning in mid-June. Amendments to the package are already being discussed among the political parties.

The new laws implement changes to the Mexican constitution that were made in December 2013 to open the power and oil and gas sectors in Mexico to private participation. (For earlier coverage of the constitutional reforms, see "Mexico Opens its Energy Markets" in the February 2014 *NewsWire* starting at page 57.)

A Competitive Power Market

The package of nine new laws includes a draft new electric industry law (*Ley de la Industria Eléctrica*) that would allow the private sector to participate freely in the generation and sale of electricity, while leaving the electricity grid under the operational control of a state-owned agency.

The new electric industry law will create a new wholesale electricity market (*Mercado Eléctrico Mayorista*) to be operated by the Centro Nacional de Control de Energía (CENACE), currently a unit within the Comisión Federal de Electricidad (CFE). CENACE will also become the independent system operator for the entire grid.

The Ministry of Energy and the *Comisión Reguladora de Energía* (CRE) will have regulatory and supervisory authority over the wholesale power market.

The Ministry of Energy will be responsible for issuing the market rules, and the CRE will be responsible for issuing permits to participate in the wholesale market as a buyer or seller of electricity. The CRE will also be responsible for setting tariffs for transmission, distribution and basic retail services, setting general conditions for market participants, issuing forms of interconnection contracts, and managing clean energy certificates and emissions certificates. It will also issue a form of contract that CENACE, the independent grid operator, will enter into with wholesale market participants.

Operational control over the national grid (*Sistema Eléctrico Nacional*) and the transmission and distribution of electricity are considered strategic areas that will remain in the hands of the Mexican government through a state entity. However, the private sector will be able to participate in transmission and distribution of electricity through agreements and joint ventures with state-owned agencies.

CFE will become a fully competitive entity as a "productive state enterprise" under the new law and will be permitted to participate, through separate subsidiaries, in the different market activities, but it will no longer be responsible for the control and operation of the national grid. CFE will continue to be the provider of basic retail services to residential users and small and medium-sized commercial users under regulated tariffs. None of CFE's assets will be privatized.

Wholesale Market Participants

The electric industry law would prohibit a single company from participating in more than one of the following activities: generation, transmission, distribution, commercialization and supply of electricity or basic resources for the electric industry. However, a common parent can participate in all the activities as long as it does each through a separate subsidiary. "Commercialization" of electricity refers to buying and selling electricity and clean energy and emissions certificates.

The law divides wholesale market participants into a number of categories: generators (*Generadores*), retail service providers (*Suministradores*), traders (*Comercializadores*), smaller customers under five megawatts called "basic service users" (*Usuarios Básicos*), larger customers over five megawatts called "qualified users" (*Usuarios Calificados*), transmission providers (*Transportistas*) and distributors (*Distribuidores*).

Generators, retail service providers and qualified users may become direct participants in the wholesale market by entering into the relevant agreement with CENACE and then providing a performance bond to CENACE.

Each such party will have to inform CENACE of each power plant or load point it intends to represent or use to tap into the grid.

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violates the commerce clause of the US constitution. The Institute argued that Colorado is effectively forcing its policies on electricity generators in neighboring states who want to supply electricity to Colorado utilities, thereby inhibiting interstate commerce. The court did not buy the argument. The case is *Energy and Environment Legal Institute v. Epel*.

The Ohio legislature voted in May to suspend its renewable portfolio standard for two years while a legislative panel studies the issues. The state requires utilities to supply at least 25% of electricity from renewables by 2025. The action freezes the target at current levels through 2017. If the legislature takes no further action after the panel reports its findings, then the 25% target would be reinstated, but utilities would have another two years until 2027 to comply.

A TAX PLANNING MEMO was not privileged and had to be disclosed to the IRS after the company shared the memo with its lenders.

The memo, written by Ernst & Young, analyzed the tax consequences of a corporate restructuring and weighed the strength of possible IRS challenges.

A federal district court in New York ordered the memo turned over to the IRS in late May in a case called *Schaeffler v. United States*. The case is now before a US appeals court.

George F.W. Schaeffler owned 80% of a three-tier chain of companies headquartered in Germany that manufacture and distribute bearings and other automotive and industrial components.

The group made a tender offer for shares of Continental AG, another German auto and industrial parts supplier. It expected to acquire less than 50% of the shares, but ended up buying 89.9% at €70 to €75 a share for a total cost of €11 billion. The acquisition closed in July 2008. Over the next seven months, the share price plummeted to €11 a share. The acquisition was financed by a consortium of banks. The falling share price left the */ continued page 35*

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The CRE will establish rules for retail service providers and qualified users. The CFE will remain the principal electric utility in Mexico and will continue to be the exclusive service provider to basic service users.

Generators

The electric industry law puts generators into one of two categories: those authorized to generate electricity from power plants and agents for or resellers of electricity from such power plants.

With the exception of exempt generators, all power plants will require permits from the CRE to be able to generate and sell power into the market. Exempt generators own power plants that are used exclusively for private use during emergencies or service interruptions and are only allowed to sell energy through retail service providers.

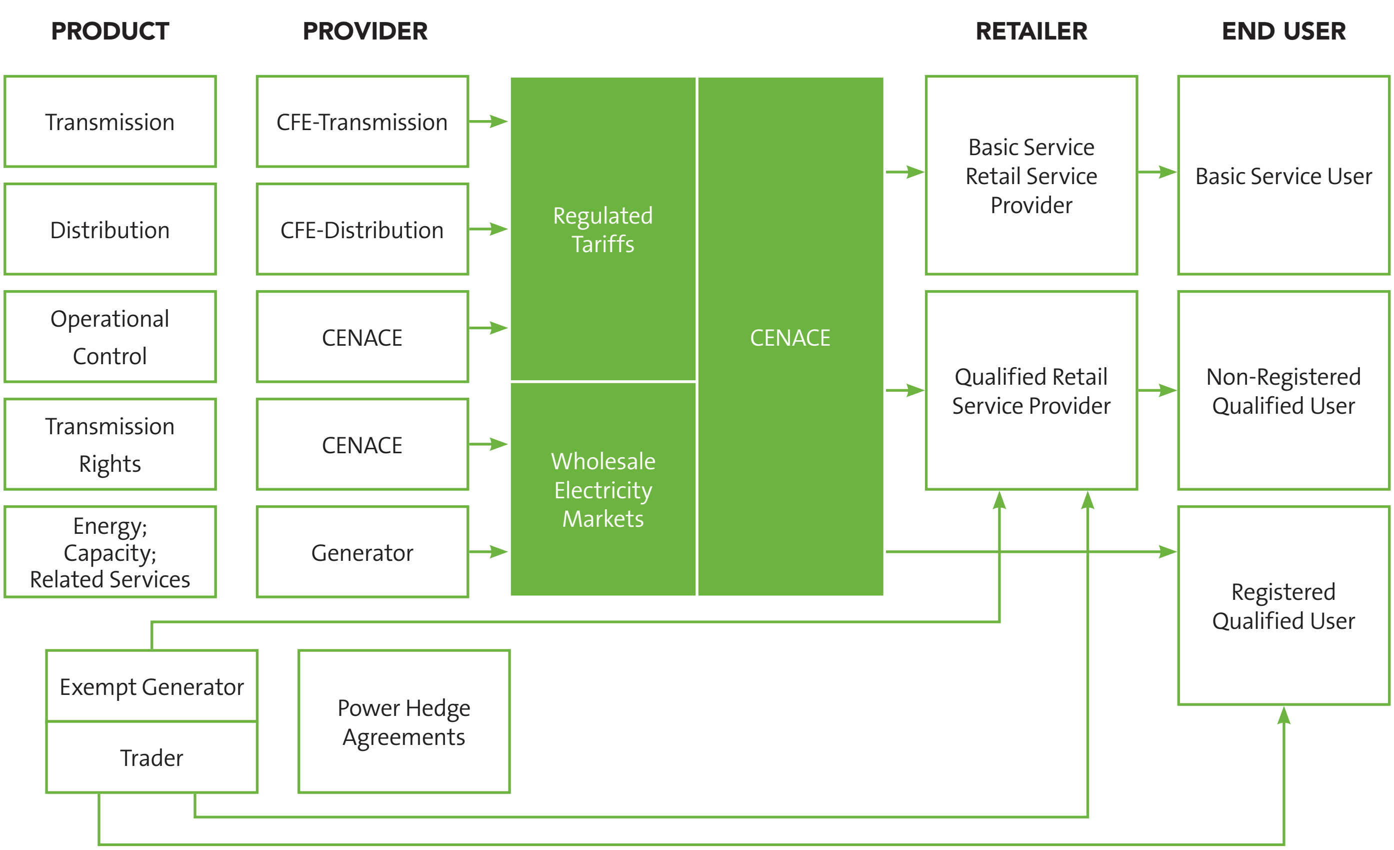
Generators are not permitted to provide retail, transmission or distribution services directly.

Generators will be permitted to sell power directly into the wholesale market through CENACE, to a qualified user or both. They will also be allowed to sell power for self-consumption, meaning from an inside-the-fence project, or for export, in each case without interconnecting to the national grid or the general distribution networks. Each generator participating in the wholesale electricity market will be able to set its price for electricity, but will have to report its cost of operations to CENACE on a daily basis. CENACE will maintain a data base of the costs of operations for all generators and will be able to determine whether prices are being offered competitively.

End Users

End users with an aggregate consumption above five megawatts, as well as those who prior to the enactment of the electric industry law operated under the self-supply (*autoabastecimiento*), cogeneration and energy import schemes, are classified as "qualified users" and are permitted to purchase energy directly from CENACE or from a generator. The five-megawatt threshold is not a set threshold, but rather it is one that the Ministry of Energy will be able to modify from

Mexican Wholesale Electricity Market



time to time. It is expected that this threshold will be reduced over time.

End users with an aggregate consumption below five megawatts may only buy electricity from retail service providers.

End users may register with CENACE as qualified users for certain load points, while remaining basic service users for other load points.

Commercialization

The electric industry law uses the term *comercialización* to refer to a wide range of things. They include selling electricity, clean energy certificates and emission reduction certificates, entering into power hedge agreements and buying transmission and distribution services.

Retail service providers will sign contracts to buy electricity from generators or from the grid and resell it to customers in the regions where the retailers operate. The law provides for three types of retail service providers. All retail service providers will require a permit from the CRE and must be registered market participants.

Basic service providers will only be permitted to sell power to basic service users and will be required to enter into power hedge agreements. For the time being, it is expected that only CFE, through a retail subsidiary, will provide these services.

Qualified service providers will be able to sell electricity to larger customers called qualified users and act for exempt generators in placing their electricity in the wholesale market.

Emergency retail service providers may only provide emergency power services to qualified users, at the maximum regulated price and for a limited time period, to maintain continuity in the supply of electricity. They also may represent exempt generators in the wholesale market.

Qualified users that are registered market participants will be permitted to do any commercialization activity other than sell electricity to third parties. Power traders will be able to operate in the market.

Transmission and Distribution

Although the distribution and transmission of electricity will remain under the control of the state, the government will be authorized, through productive state enterprises (mainly, CFE subsidiaries), to enter into agreements or joint ventures with private parties to finance, install, maintain, manage, operate and expand the transmission and distribution network.

The CFE is expected to launch public / *continued page 36*

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Schaeffler group close to insolvency and forced it to refinance the debt and restructure.

Schaeffler hired Dentons and Ernst & Young to help figure out a plan and advise on the tax consequences. The restructuring took place over the period 2009 to 2010. Ernst & Young wrote a long tax planning memo as part of the process.

Schaeffler received a favorable private letter ruling about the transaction from the IRS in August 2010. The favorable ruling did not stop the IRS from auditing the 2009 and 2010 tax years of the company in 2012. The IRS asked for all "tax opinions and tax analyses that discuss the US tax consequences of any or all of steps of the restructuring," and it issued a separate administrative summons to Ernst & Young directly for "all documents created by Ernst & Young" that relate to the refinancing and restructuring.

Both the company and Ernst & Young responded that the tax memo was privileged.

US tax law recognizes two types of privileges. One is for attorney-client communications about legal matters. Section 7525 of the US tax code extends this privilege to communications between a client and a "federally authorized tax practitioner." The other privilege is a work-product privilege for documents prepared in anticipation of litigation.

Both privileges may be lost if documents are shared with third parties.

The bank consortium and Schaeffler entered into an "Attorney Client Privilege Agreement" during work on the transaction in which they expressed a desire to share confidential documents and analyses of the transaction without waiving privileges. The Ernst & Young memo was shared with the bank group. The banks agreed to let Schaeffler pay up to €885 million in personal tax liabilities ahead of repaying the debt.

The court said the memo lost any attorney-client privilege when it was shared with the lenders. The privilege would not have been waived if the memo / *continued page 37*

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international tenders for the construction and operation of transmission lines, with CFE acting as supervisor and remaining the middleman for dealing with CENACE, registered market participants and end users. The electric industry law imposes on private companies participating in these services joint liability as service providers. If not clarified or modified, this could become a major impediment to private sector participation. The tariffs for these services, as well as the terms of service, will be regulated by the CRE.

The law establishes a local content component for contracts and joint ventures to provide transmission and distribution services, except where an international treaty or commercial agreements provide otherwise. The local content requirement will be set by the Ministry of Energy, but it is not intended to be a barrier to private investment. The law also bars any transmission and distribution infrastructure from being granted as collateral security.

The interconnection of power plants and load points with the grid will be regulated by CENACE. CENACE may direct transmission providers and distributors to interconnect to power plants requesting interconnection under terms that are not unduly discriminatory. The law provides for an open access obligation, subject to technical and security requirements. Transmission providers and distributors will be obligated to enter into interconnection agreements using forms issued by the CRE within 10 days after issuance of an order by CENACE.

Generators and end users can install interties, at their own expense, or may request CENACE or the transmission providers and distributors to build such facilities as part of their network expansion and modernization plans or may contract with them for the construction services, at the generators' and end users' own expense.

Other Information

Generators and qualified users will be permitted to enter into private power purchase agreements. CENACE will act as the go-between. It will ensure delivery of the electricity required by a qualified user, even if the electricity needed exceeds what the generator produces. CENACE will bill for any excess electricity at spot market prices.

Unfortunately, the electric industry law is mostly silent about renewables as it does not differentiate among technologies. However, it allows accelerated depreciation of renewable energy projects similar to what the existing legislation provides, and the Ministry of Energy will implement a mechanism for trading clean energy certificates and emission reduction certificates to promote clean energy and diversify energy sources.

Electricity customers will be able to engage in net metering with their retail suppliers. The CRE will issue a form of contract to be used and decide on the payment methodology.

Implementation of the Reforms

Debate over the new legislative package in the Mexican Congress is expected to be heated, notwithstanding that the President's party, the PRI, controls the most seats in both houses of Congress. It is possible that modifications to the current drafts will be made. However, the laws are expected to pass.

Once approved, the reforms are expected to be implemented in stages. The first stage will require the creation of CENACE as an independent state agency and independent system operator, the establishment of the wholesale electricity market, the issuance of market rules by the Ministry of Energy and the issuance by the Ministry of Energy and the CRE of implementing regulations.

This process is expected take approximately 12 months to complete. ◎

Mexico is opening its power sector to broad private-sector participation.

Outlook for Tidal Power

A group of ocean energy veterans talked at the 7th annual global marine renewable energy conference in Seattle in late April about what progress they are making to generate electricity from tidal currents.

The panelists are Christopher Sauer, CEO of Ocean Renewable Power Company, Ronald Smith, founder and president of Verdant Power, Craig Collar, assistant general manager of the Snohomish Public Utility District in Washington state and supervisor of a pilot tidal energy project in Puget Sound, Dr. Ralf Starzmann with the Josef Becker Research Institute in Spay, Germany, and Bill Bolin, a distinguished engineer adviser with Anadarko Petroleum. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Chris Sauer, your company has been in business for 10 years. Your major achievement so far has been an eight-month test of a small project off the coast of Eastport, Maine. You just pulled it out of the water to evaluate its condition. Why does it take 10 years to get this far?

MR. SAUER: This was actually our third project where we have generated electricity in the water, and our project this summer in Alaska will be the fourth. It did not take us 10 years to get something in the water. That said, this stuff is hard to do, and that is why it has not been done before. The biggest constraint is capital. It is hard to raise the capital to do things in a timely manner.

MR. MARTIN: You pulled the project out of the water. It is a group of turbines each of which is 100 feet long and tube shaped?

MR. SAUER: There are four turbines each of which looks like a twisted water wheel in an underwater proto-magnet generator. The water wheel is about 100 feet wide. It sits about 10 meters off of the bottom and has a rated capacity of 150 kilowatts. It was actually in the water off and on for about a year. We pulled it out.

Our Federal Energy Regulatory Commission license and our US Department of Energy funding require us to do an annual teardown. We also had some issues. The interesting thing is that none of the issues had to do with the technology. They had to do with other things like bolts and connectors that are standard parts that are available off the shelf.

After we pulled it out, we did a complete teardown and inspected it and decided that it would / continued page 38

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had been shared as part of an effort by the parties to formulate a common legal strategy, but theirs was a commercial interest rather than a common legal interest. An example of a common legal interest is where the parties could become co-parties in litigation.

In contrast, any work-product privilege for the memo was not waived by sharing the memo with the banks. The work-product privilege is waived only "when the disclosure is to an adversary or materially increases the likelihood of disclosure to an adversary," the court said. The parties took steps to prevent the memo from falling into the government's hands by marking it confidential and entering into the joint sharing agreement.

However, the court said there was no work-product privilege for the memo since the memo was not prepared in anticipation of litigation.

> *Schaeffler argued it had good reason to expect an IRS audit and eventual litigation. The memo ran through the transaction steps and their potential tax consequences, but — the court said — there was no discussion of any litigation strategy. It was a transaction memo rather than a litigation memo.*

MORE SOLAR PANELS from China and Taiwan will be subject to US import duties, the US Department of Commerce said in early June.

The duties are "countervailing" duties of 18.56% for panels made by Trina Solar, 35.21% for Suntech panels and 35.21% for panels from other manufacturers. These are preliminary figures. The final duties will be settled in the fall.

Importers must begin posting cash deposits immediately to cover the duties. The Commerce Department is expected to announce by July 24 whether additional "anti-dumping" duties will also be imposed on the products.

SolarWorld, which filed the complaint that led to imposition of duties, says the Chinese solar panels in question are being dumped in the United States at 165.04% below their price in other markets. It says the / continued page 39

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be a wiser use of our scarce financial resources to put the money into optimizing the design rather than fixing it and putting it back in the water because we knew, based on the performance, that we need to improve the efficiency. We are in the middle of doing that and hope to have it back in the water as part of a five-megawatt project in about a year and a half.

MR. MARTIN: Is it bolted to the seabed or suspended from a buoy on the surface?

MR. SAUER: The system has three parts. There is a steel bottom support frame that goes in first and that holds the turbine-generator unit. Next, we attach the underwater power and data cable to the frame. Then we lower the turbine-generator unit on to the bottom support frame, plug it in and secure it and start generating electricity.

Tidal power still costs as much as $7 million an installed megawatt.

MR. MARTIN: You said you need to alter the design to improve the efficiency. What is the number one design change on which you will be working?

MR. SAUER: One of the issues has been too much friction in the drive line, so we are changing the type of bearings we use. As one of our senior electrical engineers used to quip, friction is a drag. It was stealing kilowatt hours from us. There is a whole laundry list. None of them is earth shaking or critical, but there are just so many opportunities for improvement. If we are going to make money in this business, we have to have the most efficient machine.

Evolving Business Plan

MR. MARTIN: Like any good company, you modify your business plan as you go along. You started out calling yourselves "Ocean Renewable Power Company." Your next project is suspending one of these turbines in a fast-moving river outside a small village in Alaska. Do you foresee more remote power generation in rivers than ocean energy in the future?

MR. SAUER: No, I think it will be a combination of both. The core technology is turbine-generator units that should work equally well in rivers and tides. The basic technology is the same in both applications. The river unit is just much smaller.

The idea for the river unit came out of discussions that Doug Johnson, who leads our efforts in Alaska, and I had at the Artic energy conference in Anchorage in 2007 where we went to talk about our tidal technology, and people asked us whether we could do the same thing in rivers. "We have a need here," they said. So we started design work on our riv-gen system. The riv-gen system will require a different business plan. These are systems that we will perfect and then sell and service. The tidal part of our business will remain a build, own and operate business in which our revenues will come from electricity sales.

MR. MARTIN: The small town in Alaska where you plan to test the riv-gen system this summer has a population of about 70. Where will the money come from to pay for the system?

MR. SAUER: Most of the money will come from the Alaska Energy Authority. There will also be some private capital.

MR. MARTIN: Moving back to Maine, you have a contract with Emera, a Canadian utility, to put in a five-megawatt system in the Passamaquoddy Bay between Maine and Canada. When does the power contract require the system to be in commercial operation?

MR. SAUER: It is a very forgiving contract. I spent a lot of years of my life negotiating power purchase agreements. This is the best such agreement, as we are not required to do anything by a set date. When we install our equipment and deliver electricity to the utility, which is the former Bangor Hydroelectric Company, now called Emera Maine, we get paid for the electricity. If we never deliver any electricity, there are no penalties. The contract requires the project be in a particular location and that it use tidal energy to generate electricity.

MR. MARTIN: How much will Emera pay you for the electricity?

MR. SAUER: We will earn 30¢ to 32¢ a kilowatt hour initially. That consists of an energy price of about 21.5¢, plus about 6.5¢ for renewable energy credits and then another small amount when some congestion is cleared up on Emera Maine's transmission system.

MR. MARTIN: Is your technology currently economic at that price?

MR. SAUER: No. That is why we are continuing to work on the design. We believe the new turbine-generator unit will work at that price.

MR. MARTIN: How large will each turbine be at commercial scale? Your Eastport one was 150 kilowatts.

MR. SAUER: The design optimization will take it to about 250 kilowatts. We are planning within five years after that to move to 450-kilowatt units.

MR. MARTIN: You have two more projects potentially in the works. One is in the Bay of Fundy where I think you plan to be merely an equipment supplier?

MR. SAUER: We have been working in Nova Scotia since 2007. We have not locked in yet to a specific project, but we have good relationships with everybody there and eventually that will become a priority for us. Alaska is our next priority. We have also gotten very involved in Chile. We have formed a subsidiary, ORPC Chile, and we have somebody representing us in active discussions for projects. There are still small projects of maybe a half a megawatt to two or three megawatts.

Verdant Power

MR. MARTIN: Ron Smith, Verdant is as well known a name in tidal or ocean energy as Ocean Renewable Power Company. You, too, have been in the business for a long time: 14 years in your case. You have had a demonstration project in the East River in New York City near Roosevelt Island. It has been at demonstration scale since 2006. You are now planning to increase the generating capacity. The larger project should be operating by 2015. Let me ask you the same question I asked Chris Sauer: why does it take so long to get this far?

MR. SMITH: We incorporated in 2000, started working in the East River in 2002, and deployed two turbines in late 2006. During that whole time, there was no / continued page 40

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dumping margin on the affected Taiwanese panels is 75.68%. This suggests that the additional, anti-dumping duties could be large.

The US already collects duties of 23.75% to 254.66% on imported Chinese solar cells. The new duties apply to a different set of products: Chinese and Taiwanese solar modules made with cells "completed or partially manufactured" outside the country where the modules are completed.

SolarWorld complains that the existing duties on Chinese solar cells are being circumvented by making solar panels in China using cells made in Taiwan. Reports suggest that as many as 70% of Chinese solar panel manufacturers that export panels to the United States use cells made in Taiwan. The existing duties do not cover Chinese modules made with non-Chinese cells.

Although the latest duties also apply to solar panels made in Taiwan, a questionnaire that was sent to solar panel manufacturers in China and Taiwan has led to speculation that solar modules manufactured and assembled in Taiwan without Chinese solar cells may be dropped from the case. The questionnaire asked manufacturers whether their cells are produced partly in China.

The US government is under pressure from US solar companies that use Chinese panels to try to work out a settlement with the Chinese government.

Duties must be paid by the US importer of record. The preliminary duties announced in early June are subject to adjustment later in the year. A final decision on the duties is not expected before mid-October at the earliest. US importers are retroactively liable for any difference plus interest if the final duties are higher than the preliminary amounts.

Under US tariff law, if the foreign manufacturer reimburses its customer for the duty, then the reimbursement is itself collected as an additional duty.

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infrastructure like the folks sitting in the room today. We were out there by ourselves working with the regulators. We were helping to define what the regulatory process should be for these types of projects. It took from December 2003 to December 2006 just to work through the regulatory maze to be able to put six turbines in the East River. So that is reason number one.

Reason number two was the world was not ready for this kind of thing in 2006. We got some funding in 2006. We deployed in 2007 through 2009. By 2008, interest in tidal and ocean energy had grown enough that the industry had its first global marine renewable energy conference in New York City. Then the financial crisis hit in the fall 2008. Since 2008, the pacing factor has been availability of capital.

MR. MARTIN: Your East River project was in the water for three years before you pulled it out. There was a problem with degradation or rust on the blades. Is that the main issue? Did the experience suggest ways to improve the design?

MR. SMITH: We deployed a field of six turbines from May 2007 and pulled them out of the water in September 2009. In 2008, we started working with various US Department of Energy labs — Sandia, NREL, Oak Ridge and others — to address design and reliability issues for a commercial system starting with five-meter rotors. We have the five-meter system ready to go. We put the rotor in the water in September 2012. The next step is to traverse the valley of death to which so much attention was given when the Obama administration first took office — the notion that money can be raised for pilot tests and for full-scale projects that use commercially-proven technologies, but there is almost no money for the effort in between of scaling up from pilot scale to prove the technology.

MR. MARTIN: You plan to go next to 30 turbines with a total generating capacity of 1.05 megawatts?

MR. SMITH: Yes, in the East River. The East River is a little over ten meters deep, and our rotors are five meters in diameter. Each of the 30 turbines will have a capacity of 35 kilowatts. We could just as easily put in 60-kilowatt turbines, but they would not be optimal for the site. At deeper sites, we will move to 11- to 12-meter rotors and depending on the water speeds, the 11-meter rotors could support up to 350- to 400-kilowatt turbines.

MR. MARTIN: What will happen to the 1.05 megawatts of electricity?

MR. SMITH: We hope to sell it to Cornell University, which is building a graduate school on Roosevelt Island. Cornell is interested in a zero-energy phase one for the new campus.

MR. MARTIN: We heard from the previous panel that one of the big problems with generating equipment in rivers in Alaska is it is taken out by floating debris. No generating equipment put in an Alaska river has lasted more than a year and a half before being flattened by debris. Is debris a problem in the East River?

MR. SMITH: No. Our turbines yawl with the tides, so as the turbines rotate, the small amount of debris just passes with the tide.

MR. MARTIN: Your turbines are mounted on poles that are affixed to the riverbed?

MR. SMITH: That was true of the first six turbines we had in the water from 2006 through 2009. We wanted to get these turbines and array in rapidly to show the potential of the technology, so we did it with known technology, which was basically six monopiles driven into the bedrock of the East River. That is not cost effective. In the future, we will be deploying the turbines on what will look like monopiles potentially in a triframe shape.

MR. MARTIN: One thing that Chris Sauer did not mention, but that is true of both your companies is that both companies do consulting for other tidal and ocean energy developers. You were the early pioneers of this technology. You are not afraid to share what you have learned with others who may become competitors — or customers. Doug Johnson with Ocean Renewable Power Company said on the previous panel that his company is helping others who want to do projects in Alaska benefit from his experience there.

In your case, you are helping a utility in Turkey that got a grant from the US government to explore a 17-megawatt hydrokinetic project near an existing hydroelectric dam. Is the idea to use your turbines eventually near that dam?

MR. SMITH: Yes. We are doing a resource assessment. A significant amount of the funding is coming from the US Trade Development Agency. The project is for the national electric utility in Turkey, Electricity Generation Turkey.

Installed Costs

MR. MARTIN: What is your installed cost currently per megawatt of capacity?

MR. SMITH: We have done a lot of modeling with five-meter rotors and then moving to larger systems. We have a pipeline that runs out to 2021. The early projects, including the Turkish project, have an installed cost of approximately $7 million a megawatt eventually moving toward slightly less than $4 million by the end of that pipeline.

MR. MARTIN: Why does such a high installed cost work for a 17-megawatt project in Turkey?

MR. SMITH: As we just heard about rural Alaska, there are a lot of places in the world that marine energy has a lot more value than it does in the lower 48 US states. Seventy-five percent of Turkey's energy comes from gas imports from Russia, Iraq and Iran. Turkey has a strong incentive to use indigenous resources to generate its own power.

MR. MARTIN: Craig Collar, Snohomish Public Utility District is a small utility. It has a normal load of about 1,000 megawatts and a peak load of about 1,600 megawatts?

MR. COLLAR: Yes, that is about right.

MR. MARTIN: So your peak load is a little less than the peak load of the municipal utility in Yakutat, Alaska, which we heard from the previous panel has a peak load of 1,700 megawatts. The Yakutat fisheries cause a spike in electricity demand during the summer.

The Snohomish PUD is required to deliver, 15% renewable energy by 2020. Hydro does not count as renewable for this purpose. Where are you in relation to the target?

MR. COLLAR: We are at about 10% now, but you can also meet the renewable portfolio standard through the amount you invest. If we invest 4% of our annual retail revenue requirement in renewable energy facilities, then that will close the gap to 15%, and we have done that.

MR. MARTIN: What percentage of the 10% is wind?

MR. COLLAR: Almost all of it.

Puget Sound Test

MR. MARTIN: The reason you are here is you have been working on a pilot-scale tidal project in Admiralty Inlet in Puget Sound. I think you are still two years away from completing the pilot?

MR. COLLAR: Yes. Our target at this point is to get the hardware in the water in 2016.

MR. MARTIN: How long will the test run after that?

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ARIZONA will start collecting property taxes in 2015 from solar companies that retain ownership of rooftop solar systems and lease them to customers after an effort failed in the legislature to overturn the tax.

The tax is expected to run $152 a year for a typical system, eating up about 42% of the $360 in annual savings a homeowner realizes by adding solar. Leases may require homeowners to reimburse the solar company for such taxes.

By statute, a system that a homeowner owns and uses to generate electricity for his own use is not considered to add to the value of the house for property tax purposes. The Arizona Department of Revenue said in a 2013 memo that this provision does not provide any relief from property taxes to a solar company that owns a system independently from the house.

The solar company must value the system for property tax purposes at 20% of its depreciated cost.

ETHANOL PLANTS must be depreciated over seven years, the IRS said in May.

Some ethanol producers have been depreciating their plants over five years on the theory that the plants are used to produce chemicals. Assets used for the "manufacture of chemicals and allied products" belong in asset class 28.0 and may be depreciated on an accelerated basis over five years.

However, the IRS said such plants belong in a different asset class, 49.5, used for "waste reduction and resource recovery plants" as this category includes equipment used to "process . . . biomass to a . . . liquid . . . fuel." The difference in depreciation is worth 2¢ per dollar of capital cost. The loss in tax subsidy to a typical ethanol plant is about $4 million.

The IRS made the announcement in Rev. Rul. 2014-17. The ruling described a facility that produces ethanol from corn and sells carbon dioxide as a by-product.

The latest ruling does not come as a surprise. The IRS released / continued page 43

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MR. COLLAR: The plan is to run the turbines for three to five years under the license we got a couple weeks ago from FERC for the pilot test. That's an applause-worthy kind of accomplishment! [Laughter and applause.]

Each of the turbines will produce power at a peak of about 300 kilowatts, but the goal is really just to gather data. We want to understand the technical, economic and environmental viability of tidal energy development in Puget Sound.

MR. MARTIN: I believe your FERC permit suggests that any follow-on project built to scale would be 29.3 to 75.3 megawatts. Do I have that right?

MR. COLLAR: That might have been what was in the permit, but really we tend not even to speculate about what a commercial project would look like. We need the data first.

MR. MARTIN: What would you need to see from this project in order to move to scale?

Its best uses in the near term are in remote locations like rural Alaska and Caribbean islands.

MR. COLLAR: The project would have to meet or exceed our expectations in terms of the output of the turbines, the durability and the maintenance cycles, but it will probably depend a lot more on what happens in the world around us: prices on carbon, where the region goes with wind and the success of our energy storage efforts. We will be installing about eight megawatt hours of battery capacity during the next year or so. A lot of things could happen over the next several years that will probably have as much influence on whether a commercial project makes sense as the success of this pilot.

MR. MARTIN: You said in 2011 that you need to see electricity from tidal at about 15¢ a kilowatt hour to have a realistic shot at supplying power to your system. Is that still the breakpoint?

MR. COLLAR: It is hard to say. We are at least several years away from a commercial tidal project. A lot of things will affect the breakpoint. Electricity prices have been falling lately. We had a recession. We have had a huge glut of wind in the region. In the spring when the load is light, the price of energy goes negative. These are all things that probably will change in unpredictable ways between now and the middle of the next decade.

MR. MARTIN: You are using a turbine supplied by OpenHydro Group in Ireland for your pilot-scale project. How does its turbine differ from the ones that Chris Sauer and Ron Smith described?

MR. COLLAR: The OpenHydro turbines are permanent-magnet direct-drive generators. They sit on gravity-based foundations. One of the reasons we selected OpenHydro almost five or six years ago was that the turbines had several years of operating history. We were also attracted to the simplicity of the device. There are no gear boxes or other power train elements, which hopefully will translate into robustness. This was also something that frankly we thought we could get permitted in the Puget Sound. We do not have any reason to believe the OpenHydro design is less harmful to fish or marine mammals than other turbine designs, but it looks like it is. And, frankly, that makes a difference. It really does.

MR. MARTIN: How far down underneath the water surface will the turbines sit?

MR. COLLAR: They will sit in about 200 feet of water.

MR. COLLAR: We heard on the previous panel someone had an energy conversion efficiency factor of 30% for his turbine and 50% for another turbine. Do you know the conversion factor for the OpenHydro turbine?

MR. COLLAR: You cannot do an apples-to-apples comparison. The turbines we will use have been designed to gather data as opposed to maximize output. It probably makes more sense to talk about this project in terms of dollars per unit of information than it does in terms of kilowatt hour.

Schottel

MR. MARTIN: Ralf Starzmann from the Josef Becker Research Center, what do you do at the center?

DR. STARZMANN: Basically the center was created to diversify Schottel's product range.

MR. MARTIN: Schottel is a manufacturing company that makes propellers or propulsors for ships?

DR. STARZMANN: Marine propulsion systems basically. Schottel invented the rudder propeller, which is used mostly in harbor vessels, including here in the Seattle harbor. The company has been building propulsion systems for ships for nearly 70 years. The idea was to create a research center to diversify the product range, and one of the first ideas was to build a turbine that can be used in water instead of a propeller since it requires more or less the same skills. A turbine is rotating machinery in seawater, and that is our specialty.

MR. MARTIN: I looked at a diagram of your device. A gravity base sits on the riverbed. There are two arms that stretch upward from the base and that hold a horizontal array of small propeller-like turbines, like two arms holding up a shield to the current. The array has 16 or 36 small turbines attached to it. I could not tell whether the array is also held in place by something floating on the surface.

DR. STARZMANN: You are describing the support structure. How do you install a turbine? How do you maintain the turbines? Our experience with ship propulsion systems makes us quite sure that we need regular maintenance in these conditions. We do not believe in the fit-and-forget approach. There were some ideas, some sketches, about how to mount multiple small turbines on a support structure and, after a Google search, we found a company in the UK called TidalStream that already develops a kind of semi-submersible floating platforms. They are basically moored with two rigid tether arms to the seabed on a single point mooring, and the platform basically pivots around the mooring depending on the flow direction of the tides.

MR. MARTIN: Is there a barge or something similar permanently above the turbine array?

DR. STARRZMAN: No. The platform is surface piercing so we can have access to the electrical equipment in situ. You can deballast the whole system to get the / continued page 44

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an internal legal memo in 2008 suggesting that it was challenging ethanol producers on their depreciation.

AN INDIVIDUAL WAS AT RISK for half a loan even though he was unlikely to have to pay on his guarantee of the loan and may not have been able to do so.

Michael Moreno used a limited liability company he owned to buy a Learjet for $7.9 million. The LLC borrowed the full purchase price from GE Capital. Both Moreno and another company with substantial assets of which Moreno owned 98% guaranteed repayment of the loan. It appears that the LLC was a disregarded entity for tax purposes.

Moreno claimed $4.775 million in depreciation on the jet in the year the LLC bought it. The IRS disallowed the amount because it said Moreno was not at risk for the purchase price. Individuals, S corporations and closely-held C corporations, meaning corporations in which five or fewer shareholders own more than half the stock, can claim losses only to the extent such taxpayers are at risk. Ordinarily, the fact that an individual personally guaranteed repayment of a loan used to pay the purchase price means the individual is at risk.

The IRS said the guarantee in this case was illusory.

It pointed to internal GE Capital memos showing that GE Capital looked solely to the other, corporate guarantor and did not mention Moreno as a possible source of repayment when evaluating whether to make the loan. The IRS also said Moreno had only $11,537 in liquid assets at the time. Moreno said he had a net worth of $27 million consisting largely of shares in another company. Finally, the IRS said that because Moreno owned 98% of the corporation that was the other guarantor, he would make sure it paid on its guarantee before he had to do so.

A federal district court in Louisiana held in late May for Moreno. It said the government cited no legal authority / continued page 45

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platform to the water surface and then have access to the turbines for maintenance.

MR. MARTIN: You tested this device with the help of a tugboat. Your next step is to move to the Bay of Fundy where the Nova Scotia government is allowing you and OpenHydro to use your devices in the Bay. Tell us a little more about what is planned there.

DR. STARZMANN: The tugboat was used for a pushing test just of the turbine without the support structure, so the support structure and the turbine are two separate topics. We were awarded one of two berths three weeks ago to test the TidalStream Triton platform together with our small Schottel STG turbines, and OpenHydro is of course testing its own technology on another berth that was also awarded three weeks ago.

MR. MARTIN: How has the development effort been funded so far? We heard from Ron Smith and Chris Sauer their biggest challenge is money. Is all of your money coming from Schottel?

DR. STARZMANN: Yes. We are not Siemens or Alstom, so we are not one of the big players, but we are a quite significant company. We have a turnover of roughly €330 million per year. We got a small grant for the development of just the turbine in Germany, but all the other research and development of the STG turbines is funded by Schottel.

Company Burn Rates

MR. MARTIN: How much are you spending per year on developing this?

DR. STARZMANN: It has been increasing. It is roughly about €2 million per year right now.

MR. MARTIN: Chris Sauer, what is the burn rate of your company per year?

MR. SAUER: It depends on what projects we are doing. If you separate just the burn rate of the basic company, it is $2 to $2.5 million a year, but when you start putting hardware in the water, it gets very expensive. We will be closer to $6 million this year with the riv-gen project.

MR. MARTIN: Ron Smith, what is your annual burn rate as a company?

MR. SMITH: It can range from $1 to $4 or $5 million a year.

MR. MARTIN: Bill Bolin, your company, Anadarko, is a big petroleum company. Why is it interested in tidal energy?

MR. BOLIN: We work in the deep Gulf of Mexico. We have spars that are in 1,800 to 7,000 feet of water. We are putting one now in 7,000 feet of water, and we get loop currents at that depth. A loop current is like the Gulf Stream. We have looked at getting renewable energy out of the flowing ocean currents. The deep water does not scare us, but the type of turbine you would need in water that deep is awfully large. It needs to be in the 40- to 45-foot range.

MR. MARTIN: What capacity?

MR. BOLIN: If you look at the propeller, you would say, “This sucker is huge and has tremendous forces on it.” There would be tremendous challenges making the typical propeller work. We came up with a different design and tested it a 1/10th scale at the University of Michigan hydrodynamics lab, and it worked. So we built an 8-foot propeller and tested it in the Gulf of Mexico. The next step is to build four 40- or 45-foot propellers and generate one megawatt of power. If you’re not generating a megawatt worth of power in the deep water, you will not make any money.

MR. MARTIN: Is this an effort by Anadarko to diversify out of petroleum? Or is it an effort to generate power for use in your own offshore rigs?

MR. BOLIN: Offshore rigs do not need the additional electricity. They have lots of generators and lots of power. In fact, the underwater turbines would probably be in the way of tie-down buoys and all this stuff that we have to hold everything in place. The goal is to get renewable energy out of the flowing oceans like the Gulf Stream. The Caribbean islands, South Africa and Japan have strong ocean currents but little space on land to put power plants. This could be a real boon to such countries.

MR. MARTIN: How far offshore would the devices be situated?

MR. BOLIN: You do not want the generator to reverse. It depends on where you are and how deep the ocean is. You probably need to be 1,200 to 3,000 feet deep before there would be any reversals. The water is moving at six feet per second and maybe a little faster than that in the Gulf Stream.

MR. MARTIN: Are you developing the technology internally? Do you have engineers? Or are you contracting out the engineering work and design to the University of Michigan or others to design and build for you?

MR. BOLIN: We designed, built and patented it. We have the resources and the know how to do stuff in the water. We use some outside firms for things like the mooring systems, but as far as the rest of it, once you have the propellers, the rest is fairly straightforward. It needs to be able to operate 200 to 500 feet below the water.

MR. MARTIN: It sounds like you have had one pilot-scale facility working. For how long?

MR. BOLIN: We tested it by pulling it around for four days in the Gulf of Mexico. There is no test facility in the world that tests ocean currents. Florida Atlantic University is working on one. We hope they get it going, as we would love to have a grid-connected one where we could build and test our turbine on the grid.

MR. MARTIN: You dragged the turbine around for four days. What is next?

MR. BOLIN: We need to build a full-sized unit, install it in someplace that actually needs the power and connect it to the grid.

MR. MARTIN: When do you think that will occur?

MR. BOLIN: It depends on our partners. We have three potential partners to whom we are talking now.

MR. MARTIN: These are other oil companies?

MR. BOLIN: No. They are investors.

Target Markets

MR. MARTIN: Let's broaden the discussion to the larger panel. A lot of what each of you described is still very expensive, but it is economic in remote places. It is economic in Turkey. It is economic in rural Alaska. Do you see in the near to medium term that being your primary market or are you really competing for the utility-scale business against other renewable and thermal generators?

MR. BOLIN: In the Caribbean, people are paying at least 40¢ to 45¢ a kilowatt hour for electricity. Some of those Caribbean islands have 60% to 80% of their gross national product tied up in buying hydrocarbons. A lot of it comes from unstable places like Venezuela. This could be a paradigm shift for them.

MR. SMITH: I think you have to work up a scale. We start with projects where there is some local economic value that justifies current costs. The utility-scale projects come later.

MR. SAUER: We are targeting the high-cost markets to start, and those are not necessarily rural markets. There are countries where the cost of power is fairly high. For example, in Chile you can be on the grid and pay 26¢ a kilowatt hour. Our philosophy has always been to do smaller projects, / *continued page 46*

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that a guarantor must have liquid assets to support its guarantee. Liquidity of assets is not the test. It said the government also cited no authority for its proposition that where there are two sureties, and the evidence shows the lender was looking only to one, the guarantee of the other is ignored.

The court treated Moreno as at risk for half the loan because of cross indemnities requiring each guarantor to reimburse the other if there is a claim. The case is Moreno v. United States.

MINOR MEMOS. The IRS may withdraw a private letter ruling it issued in 2012 that said investment tax credits can be claimed on solar projects owned by Indian tribes. The ruling involved an inverted lease transaction. The issue is whether such a project is "used by" the tribe. At least two IRS branches are recommending withdrawing the ruling. The ruling is Private Letter Ruling 201310001 . . . . An IRS branch chief warned that the agency is looking more closely at captive insurance pools. If participants in such a pool are required to repay the pool with interest for any claims that are paid by the pool, then the pool is not really insurance and "premiums" paid to it are not deductible. The branch chief, Sheryl Flum, made the comment during an American Bar Association webinar in late May.

— contributed by Keith Martin and Robert Shapiro in Washington

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primarily in remote areas, because the costs are high and we can provide benefits from day one. Such projects help us to refine our technology and bring the cost down with volume.

Over time as we reduce costs, we can move to grid type of applications in countries where costs are in the 15¢ or 20¢ range per kilowatt hour. Will we be able ultimately to compete with old coal plants in Pennsylvania? I don't know. But there are not a lot of tidal sites in Pennsylvania, so we are not too worried about it.

Timetable

MR. MARTIN: Lay out a timetable. How do you see the tidal part of the industry unfolding? There will be a period of how many years when you are still dabbling in the Turkey project, the Alaska project, doing pilot projects in Passamaquoddy Bay, and then when do you think you get to utility scale and be able to compete at least on the coasts with other forms of independent generation? Ron Smith, I think you said three to five years.

No turbine put in Alaskan rivers has lasted longer than 18 months before being taken out by debris.

MR. SMITH: Right now, our plan is to deploy and prove the technology in the East River by 2015 to 2016. In 2016, we will begin laying the foundations for deployment of one or two projects in Turkey and potentially the United Kingdom that would be built out from 2016 through 2018. We will operate those for a couple of years and, in the meantime, begin deploying additional projects in 2018 through 2020. Our hope is the technology will become commercial in five to seven years.

DR. STARZMANN: We plan for deployment at FORCE in 2016.

MR. MARTIN: Deployment at FORCE means the test project in Nova Scotia?

DR. STARZMANN: Yes. It will be a 2.5-megawatt installation, so we think this is not only a technology demonstration but also a commercial demonstration. We think that we can get a significant internal rate of return on this demonstration, so we believe that we will be commercially at a rather good stage after we demonstrate the technique.

MR. MARTIN: The project will go in service in 2020?

DR. STARZMANN: Earlier hopefully. As indicated, our goal is to be in operation in 2016.

MR. MARTIN: Craig Collar, you look at these companies as potential suppliers of electricity to you. When do you think the tidal part of this industry will have reached a commercial stage?

MR. COLLAR: I think it will take another seven to 10 years.

MR. MARTIN: Bill Bolin from Anadarko, when do you think your device will be commercial.

MR. BOLIN: It depends on our financing. We can build the unit, and power cables are available. We could actually install it fairly quickly, but we don't have the financing today to do it.

One of our problems is we can earn a lot more money from drilling oil wells than from undertaking this kind of project. We think we have some unique talents that could help people who live on islands and for whom energy is very expensive. The ocean currents run all the time. However, it would take a paradigm shift on some of these islands and maybe even Japan that are importing a lot of oil.

MR. MARTIN: So, hard to predict . . .

MR. BOLIN: Hard to predict when our project will get financing.

MR. MARTIN: Is Anadarko experimenting with other renewable energy technologies or are you putting all your eggs in the tidal basket?

MR. BOLIN: We own the tops of some of the mountains that have wind turbines on them, but beyond that, this is not our core business.

MR. MARTIN: Chris Sauer, how do you see this industry developing and over what time period?

MR. SAUER: It depends on what you call commercial scale. I don't think we will see 200-megawatt projects built because potential investors will want some operating history before investing. We need to do smaller projects first, and get the operating data, including data on the environmental effects. We just released our second annual environmental report under our FERC license for our Penobscot Bay project, and it contains great news because it says the same thing as the first annual report but with a lot more data to support the conclusion. There are no known adverse impacts to the marine environment. That is good for the whole industry.

Raising Money

MR. MARTIN: Chris Sauer and Ron Smith, you both suggested one reason it has taken you both so long to get as far as you have today is the difficulty raising money. Where does the money come from? Has the venture capital community dried up for clean energy projects like yours?

MR. SAUER: The venture capital community has never been in this business. I can't tell you how many years I spent pitching to early-stage green venture capital funds, but they were not interested. They consider the business too risky. We have relied primarily on large family offices, strategic investors and small targeted funds. Thankfully, the US Department of Energy has also been absolutely critical. None of us would be here were it not for the Department of Energy and state agencies like the Maine Technology Institute and the Alaska Energy Authority.

MR. MARTIN: Ron Smith, how much of your time do you spend trying to raise money?

MR. SMITH: A little over half, probably 50% to 60%.

MR. MARTIN: Does the money come from the same places Chris Sauer mentioned?

MR. SMITH: Yes. One of speakers this morning said that one of the lessons he learned at Google was the significant difference between information technology and energy technology. It has to do with time frame. IT can be done and get a return in two to three years. Energy technology is a 10- to 15-year endeavor. You have to find the type of investor who is willing to take a long-term view.

MR. MARTIN: Bill Bolin, where are you looking for partners to develop your device?

MR. BOLIN: Actually, they have come to us, but the time frame for these new technologies to be proven is the big unknown. Investors in the oil side of our business will know within a few years whether drilling a large oil well has paid returns.

Future Promise

MR. MARTIN: This is my last question. Chris Sauer, you came out of a big company, PG&E National Energy Group, and Ron Smith, you had other work experience, but now you have spent 10 to 14 years, and it could be another five years before you get to commercial scale. Why spend potentially two decades working on a product that is so hard to get off the ground, while having to spend 50% to 60% of your time begging for money along the way, when you could have taken an easier career path? What is the promise of the tidal business?

MR. SAUER: Insanity. Actually it sounds corny, but I spent 27 years in senior management positions in big companies. I decided to go out and do my own thing. This is my third startup company and, as corny as it sounds, here is something where my colleagues and I can apply our life experiences and hopefully make a difference. It is a worthwhile endeavor for the planet in an area where we bring something to the table, so why not us? Now, if you would have told me 10 years ago that we would be where we are today and still trying to scratch money . . .

MR. MARTIN: Treading water?

MR. SAUER: Maybe, but the thing that always brings me back, and I am sure Ron Smith agrees with this, is the team that you bring together, the incredibly talented and dedicated people who are in it with you. They are real heroes in my mind because they know that this is a very, very risky business and they are at the beginning or in the middle of their careers and not at the end as I am, so they have a lot more at risk and they are every bit as zealous as I am.

MR. MARTIN: Ron Smith, what is the promise?

MR. SMITH: Sustainable energy is the defining challenge of the 21st century, and we are engaged in that race. Beyond that, marine energy is uniquely positioned. It is at the heart of the water-energy-food nexus that is so fundamental to survival.

MR. MARTIN: Ralf Starzmann, what is the promise of the tidal business?

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DR. STARZMANN: We think we can create a business out of it.

MR. MARTIN: Bill Bolin, you are in the most interesting position of all, because Anadarko, a big oil company that has easier ways to earn a profit, has decided this is the way to go.

MR. BOLIN: We built the first spar in the Gulf of Mexico 20 years ago, and it is still out there and we are putting more in. They are floating facilities. They use moorings. There is a lot of subsea infrastructure. We want to help with renewable energy.

MR. MARTIN: You could have done solar, you could have done fuel cells, you could have done any number of things, but you chose tidal.

MR. BOLIN: We know water. We think we can use our experience to do this correctly and have a big impact.

MR. MARTIN: Craig Collar, you as a utility could have put your time into any number of other renewable energy projects, and maybe you are, but you also chose tidal. Why tidal?

MR. COLLAR: We have looked at most forms of renewable energy that are potentially viable in the Pacific Northwest, including solar, wind, geothermal and small hydro, but the reason we are interested in tidal is it is clean renewable energy that is both predictable and close to load in the Puget Sound area and that alone makes it worthy of rigorous investigation.

Wind Turbine Outlook

A panel of wind turbine manufacturers talked at the Global Windpower 2014 convention in Las Vegas in May about what changes are likely in wind turbines in the next five years, their order backlogs, whether the industry is headed for a shake out, how the manufacturers view the US, Canada, Latin America and other markets, how uncertainty about construction-start issues in the US is affecting turbine manufacturers, what they would do differently next time if Congress extends the deadline to start construction of new projects to qualify for tax credits, what customers are asking in meetings, and the manufacturers' forecasts for the levelized cost of energy from wind.

The panelists are Scott Baron, global product line director for Acciona Windpower, Gonzalo Onzain, vice president of sales and marketing for Gamesa Technology Corporation, Keith Longtin, general manager of the wind product line for GE Power & Water, Renewable Energy, Daniel McDevitt, president and CEO of Nordex USA, Peder Nickelsen, head of product integrity for Siemens Energy, Duncan Koerbel, CEO of the Suzlon US subsidiary, Suzlon Wind Energy Corporation, and chief technology officer of the global parent company, and David Hardy, vice president of sales for Vestas. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Keith Longtin, will there be significant turbine technology advances in the next five years or are we in a refinement stage where we are just tinkering with what we already have?

MR. LONGTIN: GE has invested more than $2 billion in wind turbine technology in the last 12 years. The levelized cost of energy from wind farms has fallen more than 60% over that period. Looking forward, we will continue to invest. Investing in technology to create differentiated products is both our heritage and our future. The trend is toward bigger rotors and bigger generators.

MR. MARTIN: David Hardy, will turbines continue to improve at the same pace as in recent years and, if so, where do you expect the improvements?

MR. HARDY: You will see wind projects being built in North America with much lower electricity prices than ever before. Vestas strives to be a market leader. The industry needs us to continue to drive LCOE down, but it will be challenging to do so at the same pace as over the last decade.

MR. LONGTIN: Over the last few years, rotors have moved to diameters of 130 to 140 meters and towers are pushing into the 120-meter range. I would not call those refinements. A lot of great work has been done in order to allow that to happen throughout the supply chain. The laws of physics still apply and, at some point, the machines will become too big and heavy to be cost effective to move. What will be the next breakthrough? I think it will be in blades and towers.

MR. BARON: One interesting feature of the US market is that you cannot innovate too much because the tax equity investors and banks who finance the projects do not want to take risks on unproven technologies. As a manufacturer, we are better off making incremental improvements rather than wholesale changes. We also try to set up sustainable supply chains. You cannot come out with a new turbine model that is dramatically different every few years without having to rebuild the supply chain.

The levelized cost of energy from wind has fallen by 60% in the last 12 years.

MR. MARTIN: Peder Nickelsen, where do you see improvements in next five years?

MR. NICKELSEN: Improvements will occur in a number of directions. Our technology pool for bringing down the levelized cost of energy is far from tapped out. I expect improvements in the intelligence part in terms of software. We can get a lot more out of our hardware with better software. I see both bigger hardware and more intelligent turbines.

MR. KOERBEL: The stability of the market is probably the most important thing to everybody in this room. It is not a stable market when we go from 13,000 megawatts of new wind installations one year to 1,000 megawatts the next year. It is very challenging to maintain an industrial base in that kind of market. At the end of the day, if we can get stability, we already build machines that have 160-meter diameter rotors offshore. There is no limit in sight to what we can do onshore. We will have to come up with two-piece blades to solve some logistical problems.

MR. HARDY: Two things affect the levelized cost of energy. They are technology and cost. We are confident of further advances on the technology side. We are also all working on the cost side, but the cost side is challenging in such a cyclical market.

Turbine Prices

MR. MARTIN: That is a good bridge to the next question. Any predictions about turbine costs?

MR. KOERBEL: They will keep falling.

MR. LONGTIN: They have been falling over the last four years. I think the question is whether they will continue to fall over the next two to four years. Look at power prices from four years ago to today; there has been a 50% reduction. Power prices are not going to zero. The issue is how much money there is in the system to pay developers, banks, turbine manufacturers, construction contractors and others with a role in each project.

MR. BARON: There is a certain amount of economic rent in the system. Sometimes a larger share of it has gone to the manufacturers: for example, when we have a turbine-constrained market. Sometimes it goes more to the developers. Sometimes it goes more to the financiers. Sometimes it goes more to the utilities. We are in a market now where energy demand is not growing. It is a PPA-driven market. More of the economic rent goes to the utilities in such a market. That is what is driving the LCOE to such a low level.

MR. MARTIN: It sounds like a recipe for turbine manufacturers to get squeezed.

MR. BARON: Everybody gets squeezed.

MR. MARTIN: There may be developers in this audience who are preparing to bid on power contracts. / *continued page 50*

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Assume they don't have to start delivering electricity for three years. What assumption should such a developer make about where turbine prices will be three years from now?

MR. HARDY: It is hard to give a number because there are too many variables that are outside the manufacturers' control. Technology is a main driver in the LCOE, but there are lots of components in a wind turbine — a lot of steel, a lot of composite. Overall energy prices affect the price of steel, the cost to transport everything and so on.

MR. NICKELSEN: When demand spikes after a trough, it is difficult to source parts like towers, and they become more expensive. The relatively high volatility in the market is not necessarily supporting reduction of LCOE.

MR. MARTIN: Are there any other suggestions for developers who are trying to decide what to assume in a bid model three years from now about the cost to deliver power?

Industry Shakeout?

MR. KOERBEL: I expect a shake out in the next year and a half because a large number of projects got under construction right at the deadline at the end of last year to qualify for tax credits, but a lot of these deals are pretty thin. Some are based on power purchase agreements with very aggressive pricing. The turbine manufacturers will say we can help so much, but we cannot go that far.

MR. MARTIN: A shake out among developers, among projects, among turbine manufacturers?

MR. KOERBEL: Projects. The developers are an entrepreneurial bunch. With the tax credit deadline looming, people took a lot of risk. I think you will see things come to a defining moment where the turbine guys will say we can only do so much. Everyone will get squeezed, but the deal will not happen. There will be some fallout from that.

MR. MARTIN: There is a sense in the market that the pace of innovation has slowed. Let me give you some figures from the latest statistics book that the American Wind Energy Association released this spring. The levelized cost of energy for wind fell steadily to 2005 then it increased slightly after 2005 before falling again starting in 2008 but at a slower rate than before. The LCOE has been largely static the last two years. Some have suggested this is because people are pursuing projects in low wind areas, but that does not account for the rush into the Midwest. To what do you attribute the static nature of the LCOE the last two years, and what would it take to have another large breakthrough, Keith Longtin?

MR. LONGTIN: We disagree. The LCOE has definitely come down at a steady pace over the last couple years.

MR. KOERBEL: These are large machines, and the development cycle takes a while, so I would not take a year-over-year set of data points. You need to draw a trend line. The costs have been falling and will continue to do so.

MR. MCDEVITT: The LCOE may have leveled off because we are starting to move into low-wind sites that could not be developed earlier, but now can be with the improved turbines. You are seeing higher towers and bigger rotors and that affects the cost as well.

Growth Markets

MR. MARTIN: Fair enough. Gonzalo Onzain from Gamesa, how would you characterize the current market for turbines? Start with the US, then Canada and then Latin America.

MR. ONZAIN: Crazy? The US is in a race to complete projects within the next 18 months. That has a lot of implications. There was a race to start construction last year. There was an evident way to qualify and a not-so-evident way to qualify, and those who chose the not-so-evident way to qualify are in a grey situation now. We all have customers who are telling us they would love to move forward, but I am not sure if their projects will move forward.

The consequences are that if we do not know soon, a lot of projects will not be able to be completed by December 2015, and no one will issue a notice to proceed for a turbine order with the expectation that the construction-start deadline for tax credits will be extended. The market is not in a bad position right now, but if we wait three more months and the construction-start rules have not been clarified, then it will turn into a bad situation.

MR. MARTIN: The American Wind Energy Association said roughly 11,000 megawatts of projects were under construction in time to qualify for tax credits. Scott Baron from Acciona, do you see the US market the same way?

MR. BARON: One of the things I have taken away from this convention, echoing Gonzalo Onzain's point, is that there was a lot of optimism about the methods for starting construction, but whether projects were under construction in time has come under more intense scrutiny than when the numbers were submitted for that database. A number of these projects may not come to fruition because of that scrutiny.

MR. MARTIN: Keith Longtin from GE, Gamesa and Acciona describe the US market as a little skittish. What about Canada? What about Latin America?

There is disagreement about the direction in which the LCOE is headed in the near future.

MR. LONGTIN: We announced 3,900 megawatts of orders for the US market, and I think we are comfortable all of those turbines will be delivered. That said, they are right that some US projects will not get built. We see room for growth in Latin America, particularly Brazil. The world as a whole is a 55,000-megawatt market per year.

MR. KOERBEL: South America will continue to grow. There are 133 million people in Brazil. Australia, which has been a decent market, has only 23 million people. Sao Paulo has 30 million people in one city.

MR. LONGTIN: The thing that is interesting about that market is that wind is competing without subsidies.

MR. KOERBEL: I think there will be sustained growth in South America because the installed base is proportionally much smaller than in the US and Canada. Coming back to the US, I think the 11,000-megawatt number exceeds what will actually be built. A lot of these projects will not pass muster when they reach the stage of trying to secure financing.

Construction-Start Issues

MR. MARTIN: What do you think is the more realistic number?

MR. KOERBEL: We had a discussion at dinner last night about best case, worst case and most likely worst case. People said 50% of them will make it. I bet we will see at least 30% fallout.

MR. HARDY: I have a slightly contrarian view. Some of the larger wind developers started construction of projects by taking delivery of wind turbine components. I think the tax equity market has pretty much backed that. The developers who are having trouble are the ones who merely did a little physical work on site in 2013. They are trying to secure financing and, unfortunately, time is the enemy because waiting three months for the Treasury to give more guidance is eating up time that is really precious, as these projects have to be completed by December 2015.

MR. MARTIN: How is the wait for more guidance from the Treasury affecting you as manufacturers? Is there any effect? You still have the orders.

MR. HARDY: There is a big difference between having an order and receiving something called a notice to proceed.

MR. MCDEVITT: The tension and time pressure are starting to build.

MR. NICKELSEN: The tension travels all the way down the supply chain. Everyone is ready to start, but you do not really know whether you have a firm order.

MR. MARTIN: So what happens, Peder Nickelsen of Siemens, if you have an order, but you have not yet received the notice to proceed? Do you have to hold space for a 2015 delivery to someone? When do you release the turbine slot?

MR. NICKELSEN: In principle, we never give up. You need a large and agile organization to have the flexibility, stay in very close contact with your customer and then have weekly or even daily planning with your supply chain to remain ready to move on the order. It is not easy. It is also not the most cost-effective way of doing things, but this is the way we are working for the time being.

MR. MARTIN: There was a big rush in 2013 by developers to purchase turbines or turbine components for delivery within 3 1/2 months of year end. Congress may extend the deadline to start construction to qualify for tax credits by another two years through 2015. If that happens, what advice do you have for developers about what to do next time based on what you saw happen in 2013?

MR. HARDY: The challenge is that many developers are not well capitalized. If a project is a mature project, then the developer may be able to get the equity

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investors lined up, get access to capital, and incur at least 5% of the project cost by year end 2015. That is the safest way to qualify for tax credits.

MR. MARTIN: What did you as manufacturers learn from the rush in 2013? What would you do differently in 2015?

MR. HARDY: At Vestas, we worked closely with a lot of our customers. We tried to be creative, and I think we are in a decent position now. We would follow the same path. We learned some lessons about the need to focus on your partners and how real their projects are. It used to be that one could treat a project as real if it had a power purchase agreement. It is no longer enough to be told the project is a contracted project.

MR. KOERBEL: There is plenty of money for good projects. There really is. You have to make sure you have good projects. People will not take a lot of risk if there is any doubt whether the project was under construction in 2013.

Order Backlogs

MR. MARTIN: So the best advice is to start working now on power contracts in case the construction-start deadline is extended, and plan to incur at least 5% of the project cost by the deadline.

I gather your order books are full for 2014 deliveries. What about 2015? What about 2016?

MR. ONZAIN: How many of those orders fall through? As you said, 2014 is fairly full. It is too late to order for 2014 delivery. Most of 2015 is also fairly well booked, but there are still opportunities for late 2015. The situation may change if some of the existing orders shake out.

MR. BARON: There are really only a couple months left to place orders to get turbines in time to complete projects by the end of 2015.

MR. MARTIN: Is there some strain now? Many of you took orders in 2013 for deliveries by the end of 2015. If the deliveries slip into 2016, there will be questions about whether the project qualifies for tax credits. Is there some strain beating the 2015 deadlines if you are still waiting for notices to proceed this far into 2014?

MR. HARDY: There could be. It is easy to sell a turbine. The hard part is manufacturing and delivering that turbine. It does not work to have one or more dead months of manufacturing. There are a lot of people sitting idle all the way down the supply chain. The more uncertainty there is, the more difficult the supply chain is to manage.

MR. KOERBEL: And there are the balance-of-plant construction contractor, construction cranes and everything else, so it is a big dance.

Customer Trends

MR. MARTIN: You are all in the business of providing something to developers that they want. What trends do you sense among the development community when it comes to turbines?

MR. BARON: One trend is an interest in higher performance testing. The industry wants a higher degree of confidence as we put out bigger turbines that we can stand behind the power curves.

Another trend is an interest in bigger rotors as developers move to sites with lower wind speeds.

MR. HARDY: We are putting a stronger focus into service after the turbines have been delivered in an effort to drive down operations and maintenance expenses, as these are another factor in the levelized cost of energy. The focus is on more reliable turbines, a better after-market supply chain, best-in-class labor strategies and remote monitoring. Trying to squeeze cost reductions out of the service side of the business is important.

MR. KOERBEL: We ran a blade extension program for turbines that are in areas with lower wind speeds than they were designed to handle. You section the blade and put an insert in so that you are basically growing the rotor. This leads to a 20% increase in electricity output.

MR. MARTIN: What is a standard warranty at this point for a turbine.

MR. MCDEVITT: We get a lot of requests for 10 years. Ten years is what we would call a premium service contract. Many developers want bumper-to-bumper protection, while others prefer to minimize up-front costs and take their chances.

MR. ONZAIN: I think it depends on the type of customer. Customers that are more utility or independent generator type tend to be more short-term focused. People who are more financially driven have a longer-term view. Ten years is the usual tenor of tax equity.

Customer Meetings

MR. MARTIN: Peder Nickelsen, at past AWEA conventions, the turbine manufacturers had rooms and developers shuttled in and out to negotiate orders and play the group of you off one another. How has this convention been for such meetings?

MR. NICKELSEN: I think it has been fine. [Laughter.] We have been having a lot of confidential dialogue with customers.

MR. MARTIN: Let me press you on that because you don't have room in your order book for 2014 or 2015 orders. Are people talking to you about 2016? There may not be much demand for turbines in the US at that point depending on what Congress does with subsidies. What are people asking you about? Are they ordering turbines for 2016 delivery?

MR. NICKELSEN: Many customers are interested in what will be the next advances in technology. We are discussing what kind of boundaries there are in logistics, noise restrictions and height restrictions. These are important points of reference to report back to the engineers as we try to optimize turbines as much as possible and still have a generic fit for the market.

MR. MARTIN: Keith Longtin, how has this convention compared to past conventions for turbine orders.

MR. LONGTIN: We have our customers here, and we meet with them continuously.

MR. KOERBEL: There is a positive and upbeat tone this year. Many developers think Congress will extend the construction-start deadline so that there will be more opportunity in the future. Developers are talking not only about current projects, but also potential future projects.

MR. MARTIN: What are the main questions people are asking in meetings?

MR. KOREBEL: Everyone wants to know what is going on with the Suzlon and Senvian merger. We have given our customers the inside scoop.

MR. MARTIN: David Hardy, what questions are people asking in meetings with Vestas?

MR. HARDY: This is a convenient way to meet a lot of people. My calendar shows back-to-back meetings for three days straight. It has been a marathon.

MR. MARTIN: What questions come up most frequently in those meetings?

MR. HARDY: Most of the discussions have been about short-term things. We are talking getting 2015 projects across the finish line. That is the front of the line for us. We are also talking about longer-term opportunities.

MR. MARTIN: If someone is planning ahead at this point, what is he planning to do with you? Is he planning to order more PTC components by the end of 2015?

MR. HARDY: There is some talk about how to extend into 2016 under the current regime. That has become a little difficult because we are having challenges getting some of the 2015 equipment qualified. We are also talking about what happens if Congress extends the deadline. How do you secure your price and slot in exchange for starting to work on that stuff now.

MR. MARTIN: Scott Baron, what do you end up discussing in meetings?

MR. BARON: There is a lot of focus on locking things down for 2015 and meeting that deadline. We also have an interest in finding ways to work on later-stage projects to make them successful.

More Growth Markets

MR. MARTIN: Let me go back to particular markets. Within Latin America, which are the hottest countries? Keith Longtin, you mentioned Brazil. There is a local content requirement. Where else?

MR. ONZAIN: I think Mexico is the market.

MR. BARON: Mexico and Brazil are the two biggest ones, at least for us.

MR. MCDEVITT: Chile is pretty interesting as well.

MR. NICKELSEN: If you want to avoid local content requirements, then the best countries are Chile, Uruguay, which is a short-term market, and Peru. There are other markets in South America that are starting to develop. The questions are how much, how long, and what are the barriers to get in and make them work?

MR. BARON: It is not as easy as simply turning to another market when the US is having a slump. Brazil is a local content market. Quebec is a local content market. The manufacturers had to make the right investments and be in those markets ahead of time. It takes forward planning.

MR. MARTIN: Keith Longtin, GE is in Brazil. What is it manufacturing in country to meet the local content requirement?

MR. LONGTIN: Hubs, machine heads and blades.

MR. MARTIN: Does anyone else have a strategy for Brazil? Is it a big enough market to justify setting up a factory?

MR. BARON: Acciona has 650 megawatts of orders in Brazil. There is a progressive local content requirement. We have a hub facility. We have a partnership with a local blade manufacturer. We have our own tower factory.

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MR. KOERBEL: Brazil is a big enough market to justify the investment. It has a 60% local content requirement. You are not going to put a blade factory in Uruguay when that market is only maybe 200 megawatts annually. We have the same issue with Quebec. You have to pick your places. Consistency in government policy is very important.

MR. HARDY: Vestas is a global wind manufacturer. We operate in 73 countries. There are growing markets around the globe. The US market can be big or small from one year to the next, but Brazil, China and India will all be growth markets and they are highly competitive markets as well. What it takes to be successful in the US is a low cost of energy. It takes the same thing in Brazil, China and India. Policy helps and local content can be a challenge, but it is technology and low cost of energy that will win in the end.

Turbine vendors are better off making incremental changes because new technologies are hard to finance.

MR. MARTIN: Are there other special issues in any western hemisphere countries? We mentioned production tax credits in the US and local content in Brazil and Quebec.

MR. BARON: Another issue we see in the US is tip height restrictions. There is a 500-foot limit for clearance from the Federal Aviation Administration. You can get a permit for a taller tower, but it is more complicated, time consuming and risky. Meanwhile, Europe is moving to taller towers.

MR. LONGTIN: They are permitting 140-meter tower height today in Europe, and there are requests to go to 150 to 160 meters.

MR. MARTIN: What is the key to going taller, and how much does it reduce the cost of energy?

MR. LONGTIN: The tower diameter cannot be more than four to 4 1/2 meters for logistical reasons. If you can open that up, then you can use less material in the tower, so we came up with an innovative design that permits shipping a 100-meter tower in 11 40-foot shipping containers.

MR. KOERBEL: We have about 6,000 lattice towers in India. The local wage rate is $5 a day. The cost of labor in India is so competitive that we have been building lattice towers for 20 years. The same tower is not competitive in the US because of the higher cost of labor. We are going have to stick to the 4.3-meter stuff with a tubular shape so that it can pass under highway bridges.

MR. ONZAIN: Another challenge is grid codes. The way we interact with the entire electrical system can be a constraint. Quebec is a nightmare.

MR. MCDEVITT: Various smaller countries in South America want in on local content requirements. You have to look at groups of countries in order to make a market. That is how a lot of us are looking at the smaller countries. Local content requirements in smaller countries are a challenge, but we are willing to try working with them if the opportunity makes sense.

MR. BARON: Mexico favors an EPC approach where the manufacturer is required to do the entire project. That's different from the US where we only supply the turbines.

MR. NICKELSEN: Logistical constraints are another issue. We are trying to develop our hardware so we can fit on the different roads and rail beds. For example, we can do split blades, but a split blade is more costly than a non-split blade. Longer blades are normally pre-bent in order to keep the tower at a safe distance. They come in a banana shape, which is also creating challenges in terms of logistics and transportation.

MR. MARTIN: David Hardy, you said Brazil, China and India will all be growth markets, and I guess the US if it allows more time to start construction will be as well. Do those sound like the top markets to the rest of you?

MR. NICKELSEN: I disagree about China.

MR. MARTIN: Why?

MR. NICKELSEN: Because it is difficult for any non-Chinese manufacturer to sell there; not to manufacture. We all have facilities there, but selling in China is . . .

MR. KOERBEL: I agree with them both. China is a big market, but as a non-Chinese manufacturer, we have been there, done that, and it did not go well. The Chinese market is huge, but we will probably invest in other places because China is difficult. India is obviously huge. We think South Africa has a lot of potential over the next 20 years.

US Local Content

MR. MARTIN: Speaking of domestic content, in the US, the domestic content of wind turbines increased from 25% to 72% from 2005 through 2012. Any sense in which direction it is headed?

MR. MCDEVITT: I wonder about that 72% number. Manufacturers that are building turbines here are still importing an awful lot of components. We do not have a purely domestic supply chain that supports generators, gear boxes, converters, castings, forgings, all the big, heavy, highly costly stuff that makes up probably 80% of the turbine. We still import a lot of towers. We saw the tower market decrease so if we did get to 72%, we are no longer there today.

MR. MARTIN: So local content in the US is declining. There were 12 utility-scale blade facilities, 14 tower facilities and nine turbine and nacelle facilities in 19 states in 2013. Are some of these factories closing? Who among the different types of manufacturers do you think is getting squeezed the most? Nacelles? Towers? Blades?

MR. MCDEVITT: We have seen towers take the biggest hit. They are more of a commoditized item that can be outsourced overseas. The blade manufacturers have bounced back with the surge in orders last year.

MR. MARTIN: Are nacelle factories closing in the US due to the uncertainty?

MR. HARDY: Vestas has four plants in Colorado: two blade facilities, a nacelle facility and a tower facility. We are hiring now. We have a domestic supply chain. We are committed to the US market, but it is challenging for us to keep that commitment given the cyclical nature of the market.

MR. MARTIN: If Congress provides more time to start construction, would there be an increase in the number of factories or the situation would simply stabilize?

MR. KOERBEL: I think you stabilize.

MR. HARDY: It is tough to continue to make big capital investments in this uncertain a market.

MR. MARTIN: Gonzalo Onzain, if the US is a somewhat unstable market as you characterized it at the start, where in the world are things more stable?

MR. ONZAIN: Probably nowhere, but two less unstable markets are India and Mexico.

MR. NICKELSEN: Some of our markets in Europe are relatively stable. The market for offshore wind turbines has been a good market for us, and it is one with longer time horizons.

MR. MARTIN: You made the comment in the prep session before the panel started that Europe is actually coming back as a good market which seems surprising when one reads stories about rollbacks in feed-in tariffs and other subsidies. What accounts for the growth?

MR. NICKELSEN: We have had quite a lot of new market development in Scandinavia as a function of the move to very tall towers. We have a steel tower at 120 to 140 meters that comes with de-icing and other features and is well suited for forestry terrain. This has opened a new market that is relatively stable for the time being. Individual countries within Europe are still volatile, but the fact that programs vary from one country to the next tends to level out compared to the US, which is a single market with a single policy.

MR. MARTIN: A question from the audience.

MR. PATTERSON: My name is Jim Patterson, and I am with the Federal Aviation Administration. We are busy revising our advisory circular trying to account for the next generation of turbines. We have heard that Europe is moving not only to larger turbines, but also to lattice-type towers versus the solid tube. Do you foresee lattice construction coming to the United States?

MR. KOERBEL: It is all about the best way to get the best solution in labor, material and logistics. I think you will see tower heights grow from 80 to 90 to 120 meters with bigger rotors. We will come to you more often for permission to put a rotor tip above 500 feet. Just be prepared to / *continued page 56*

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help our developers because the higher towers take better advantage of wind and land. It would be great if we could get a dialogue going on this soon. Thank you for coming. We are glad you are here.

LCOE Forecasts

MR. MARTIN: Last question. Tom Kiernan, the AWEA head, said that the levelized cost of energy is currently between $30 and $60 a megawatt hour in the United States. I would like each of you to make a prediction. Where do you think it will be in the US five years from now?

MR. HARDY: The US is a big market with lots of different wind regimes. Vestas has publicly committed to a strategy of bringing down the LCOE faster than the market average, and we are confident we can do that. In a very high wind regime with very efficient turbines, the LCOE could be $20 to $25, with an incentive similar to the production tax credit.

MR. KOERBEL: I don't think I will predict because there are other forces at work that are bigger than us. They include fracking and natural gas prices, electricity demand and government policy. Are we ever going to get serious about climate change? The UN just released the fifth panel report in Berlin on April 12. When my first grandkids are my age, the earth will be 8°F warmer than it is today. We have to address this. Policy changes have the potential to outstrip the effects of technology. Watch us respond to changes in policy. Developers installed 13,000 megawatts of new wind capacity in 2012 purely as a response to government policy. There are a lot of things that will move the cost of energy around.

MR. NICKELSEN: The industry may be moving over time to less optimal sites. That has a tendency to put upward pressure on LCOE. This will be a challenge for the industry.

MR. MARTIN: Dan McDevitt, we got a number out of David Hardy. Do you have number for us?

MR. MCDEVITT: Yes, $25. We are here in Las Vegas right? 25 black. [Laughter.] There are so many variables that I think Duncan Koerbel hit it perfectly. At this point, we are just speculating.

MR. LONGTIN: I am not predicting the future. All I can say is wind power is incredibly cost effective today. It is a zero-fuel-use, zero-emission and zero-water-use asset that should have a higher value going forward.

MR. ONZAIN: At the risk of being controversial, I think LCOE will increase less than inflation. It depends on what happens with steel prices, oil prices and gas prices. Wind will more be more efficient relative to what it is today, but I don't think it will be cheaper on a dollar-per-megawatt basis than it is today.

MR. MARTIN: So the LCOE is headed up.

MR. ONZAIN: I think so, but the rest will go up more.

MR. BARON: We should focus on grid parity. The real question is whether wind energy can be slightly cheaper than natural gas on the margin. If we can get there, then we will be really successful in the long run. ◎

US Takes Steps to Advance LNG Exports

by Donna J. Bobbish, in Washington

The US Department of Energy proposed changing its procedures in late May for acting on applications to export liquefied natural gas on a long-term, large-scale basis from the lower 48 states to countries with which the United States does not have free trade agreements that require national treatment for trade in natural gas.

Under the proposal, DOE will dispense with issuing conditional orders authorizing LNG exports while applicants complete the environmental review process and instead go directly to the final order. The proposal would also alter the order in which DOE acts on pending applications.

The proposal could expedite issuance of final orders for projects that have already received conditional orders authorizing LNG exports, and it could allow LNG projects with enough resources to initiate environmental review to move up in the queue for DOE action on their export applications.

DOE Role in LNG

Section 3 of the Natural Gas Act gives the Department of Energy authority over exports of natural gas.

Under the Natural Gas Act, LNG exports to countries with which the US has free trade agreements that require "national treatment" for trade in natural gas are automatically considered in the public interest. Applications to export gas to such countries must be approved without modification or delay. The US had such free trade agreements with 18 countries as of the

The Department of Energy is changing how it processes applications to export LNG.

end of October 2012: Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea and Singapore. "National treatment" for trade means treating an imported good the same as a locally-produced good once it enters a market.

Authorization to export LNG to countries without such free trade agreements, on the other hand, requires DOE to find that the proposed exports are not inconsistent with the public interest. In making this determination, DOE considers the domestic need for the natural gas proposed to be exported, whether the proposed exports pose a threat to the security of domestic natural gas supplies and other factors bearing on the public interest. Before authorizing exports of LNG to countries without favorable free trade agreements, DOE also must review the potential environmental effects of the proposed export under the National Environmental Policy Act.

Current DOE policy is to issue "conditional" orders authorizing long-term, large-scale LNG exports to non-free trade agreement countries while the agency finishes the environmental review process, when requested by applicants. The reason for issuing conditional orders was that the Federal Energy Regulatory Commission, as the agency that grants authorization for the siting, construction and operation of liquefaction and export facilities and, consequently, the lead agency in performing the environmental review, would benefit from a preliminary indication from DOE that a proposed LNG export is consistent with the public interest.

Since 2011, DOE has used issued conditional orders granting export authorization to Sabine Pass Liquefaction, LLC, Freeport LNG Expansion, L.P, Lake Charles Exports, LLC, Cameron LNG, LLC, Dominion Cove Point LNG, LP and Jordan Cove Energy Project, L.P. These conditional export authorizations are explicitly subject to the satisfactory completion of the environmental review, the issuance by DOE of either a "finding of no significant impact" for projects for which an environmental assessment was performed or a record of decision for projects requiring a full environmental impact statement, and the issuance by DOE of a final order reaffirming the finding that the proposed LNG export is not inconsistent with the public interest.

To date, DOE has only issued one final order authorizing LNG exports to non-free trade agreement countries to Sabine Pass.

In 2012, as the number of pending applications for export authorization increased, DOE announced that it would act on pending LNG export applications on a case-by-case basis, and that the order in which applications would be considered would be based on when an applicant began the pre-filing process with the Federal Energy Regulatory Commission for authority to build his project and the date the export application was filed with DOE.

Based on these criteria, DOE published a list of pending applications and the order in which each would be considered. The list is called the "order of precedence."

New Approach

Under the proposed new procedure, DOE no longer would act on applications in the order of precedence and no longer would issue "conditional" orders. Rather, DOE would act on applications only after it has completed its environmental review process and has enough information on which to base a public interest determination. It would act on applications in the order in which they become ready for final action.

DOE will consider an application to have completed the environmental review process 30 days after publication of a final environmental impact statement in the Federal Register for projects requiring a full EIS, upon publication by DOE of a "finding of no significant impact" for projects for which a less extensive environmental assessment / continued page 58

LNG Exports

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has been prepared, or upon a determination by DOE that an export application is eligible for a categorical exclusion from the need for an environmental impact statement.

The Department of Energy believes that the original justification for issuing conditional authorizations — to provide greater certainty for FERC — no longer is relevant because the environmental review process for many proposed LNG terminals has begun by the time a conditional export authorization would be issued by DOE.

Projects with money to initiate environmental review should be able to move through the queue more quickly.

If implemented, the new procedure should prioritize action on export applications that are otherwise ready to proceed since applications will be processed when they are ready for a final order. While there is no guarantee that all projects for which an environmental review has been completed will be financed and constructed, DOE believes that projects that have expended resources to complete the environmental studies are, as a group, more likely to proceed to financing and construction than those that have not. The new procedure will spare DOE from devoting resources to analyzing projects that have little prospect of being built.

The new procedure will not affect the continued validity of conditional orders that already have been issued by DOE. DOE will continue to act on requests for conditional authorizations while the proposed new procedure is under consideration.

Comments on the new procedure must be submitted to DOE by July 21, 2014.

Environmental Issues

DOE also issued in late May drafts of two documents for public comment addressing concerns that have been raised about the environmental effects of increasing natural gas production in order to serve export markets.

One of the two documents — called an "Addendum To Environmental Review Documents Concerning Exports of Natural Gas From the United States" — addresses the potential environmental effects of fracking and other unconventional forms of natural gas production.

The other document — a report called "Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States" — provides data on the life-cycle greenhouse gas emissions of US LNG exported for use in electric power generation. This report and any comments received on it will be included in the dockets of 25 pending applications for authority to export LNG by tanker from large-scale liquefaction facilities in the lower 48 states to non-free trade agreement countries.

Comments on the two documents must be submitted to DOE no later than July 21, 2014.

Environmental Update

The US Environmental Protection Agency proposed reducing US greenhouse gas emissions from existing power plants in early June by 30% by 2030 from 2005 emissions.

It said this is equivalent to taking two thirds of US cars and trucks off the highways.

However, the new rules are complicated. Each state has been assigned a different percentage reduction. The percentages range from 11% for North Dakota to 72% for Washington state. Each state goal is a pollution-to-power ratio for the future carbon intensity of existing power plants in the state that use fossil fuels.

The Environmental Protection Agency determined earlier that carbon dioxide is a pollutant as defined under the Clean Air Act because it endangers human life and health. Based on that finding, the law obligates EPA to regulate it. The agency proposed regulating carbon dioxide emissions from new power plants that use fossil fuels in January this year. The latest proposal takes the further step of proposing similar emissions limits for existing power plants.

The new limits would be administered by state and local regulators through a process similar to that used by EPA to approve state implementation plans for ambient air quality. States would have the option to reach the emissions targets they have been assigned or to convert that state target into a "mass-based standard," which would allow the state to establish a new cap-and-trade program for trading carbon allowances or join an existing regional program.

The message EPA tried to convey is flexibility. Instead of imposing a uniform standard for reducing power plant carbon emissions, it gave states room to adopt a range of measures to curb emissions. EPA identified four "building blocks" that can be used in any combination to comply with the new standards. States can make plants more efficient. They can encourage use of low-carbon power sources. They can use more zero-carbon power sources. They can increase energy efficiency.

EPA set individual state targets based on each state's current energy mix and the improvements that are achievable through these four building blocks.

For example, to comply, a state might order aging coal plants to close. It might increase its renewable energy portfolio standard. It might join a regional cap-and-trade program. It might even impose a state-level tax on carbon pollution.

There will be a period for comment, and then the new standards will become final in June 2015. States will then have one year, until June 2016, to prepare compliance plans, although the possibility of extra time is built into the proposal. States have the option to use a two-step process for submitting final plans if more time is needed. Individual states may also request one-year extensions, and any state participating in preparation of a multi-state plan may ask for an additional two years. EPA expects states to make "meaningful progress" toward reductions by 2020 despite extensions, and all states would be required to meet their reduction targets by 2030.

Coal-fired power plants will have to make the greatest reductions because they are by far the greatest source of greenhouse gases in the power sector. US coal plants are more than 40 years old on average, and the sector generates approximately 39% of the nation's power. Even after closures expected from the new rule, EPA projects that 30% of US electricity will still come from coal in 2030.

Critics and EPA are at loggerheads. Critics argue the new limits will cause electricity bills to skyrocket and lead to a catastrophic loss of jobs. Meanwhile, EPA says the plan will lead to more jobs and the increase in energy efficiency across the power sector will actually lead to lower electricity costs by 2030. EPA estimates that the new limits will cost the economy up to $8.8 billion a year, but produce between $55 billion and $93 billion a year in benefits by preventing premature deaths and mitigating respiratory diseases.

Other critics complain that giving the states the flexibility to design their own plans will lead to a patchwork of different rules that will complicate power company compliance.

Other critics dispute the need for any action on carbon emissions. For example, Senator Jeff Sessions (R-Alabama) takes issue with an EPA claim that climate change contributes to more violent weather like Hurricane Sandy in 2012. Sessions said the storm "was not even a hurricane when it hit land . . . . It just happened to hit the Northeast where people are not used to it, and it did a lot of damage."

As is the pattern with new environmental regulations, years of litigation and negotiation */ continued page 60*

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over compliance are sure to follow. However, the choice of 2005 as a baseline measure was received positively because many utilities have already spent money to curb emissions significantly since 2005. Thus, those early actors essentially get a credit for past steps.

The public will now have an opportunity to comment on the 645-page proposal. There will also be efforts in Congress to block enforcement, but the Democrats are likely to retain enough seats even after the November 2014 elections to prevent this from happening. The next elections in November 2016, when a new president will be elected, are too far away to predict the outcome or what public opinion polls will say about support for government action on climate change. The battles will move eventually from the courts and Congress to state capitals as stakeholders fight over implementation.

Cooling Water

The US Environmental Protection Agency issued new rules in May for cooling water intake structures at an estimated 1,065 existing power plants and factories.

There is a very good chance that these regulations will be challenged.

In the meantime, at a minimum, lenders involved with such facilities should determine the potential cost to comply with the new rules.

Many of these facilities cool their equipment by using large amounts of water taken from water bodies that are subject to federal jurisdiction. Cooling water intake structures can injure or kill fish and other aquatic organisms as result of entrainment (drawing organisms into the structures) and impingement (pinning the organisms against the intake screen or the intake structure itself).

EPA issued the new regulations under section 316 of the Clean Water Act in response to a settlement agreement with an environmental group. Section 316(b) of the Clean Water Act requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact."

The regulations apply to existing facilities that have or require a water discharge permit under federal rules and withdraw at least 25% of their water from a cooling water intake structure with a design flow intake of more than two million gallons per day from a water body. Because the issues associated with entrainment differ from impingement, the new rules address the two situations separately.

With respect to impingement, some environmental groups wanted EPA to require cooling towers and closed-cycle cooling systems that recirculate withdrawn water, which uses significantly less water (and, as a result, causes less harm to aquatic life) than facilities that withdraw water, use it once for cooling and then discharge it back into the environment. However, the use of closed-cycle cooling systems is impractical for many existing facilities since the technology may be prohibitively expensive or require additional land to install. As a result, EPA did not adopt closed-cycle cooling as the best technology available to reduce impingement. Rather, it concluded that modified traveling screens on intake structures represent the best technology available and offered seven options for doing as well or better than modified traveling screens. For example, one option is to use a cooling water intake

New limits on carbon emissions from existing power plants could prompt states to join regional cap-and-trade programs or even impose carbon taxes.

structure with a maximum through-screen intake velocity of 0.5 feet per second.

EPA said there is no nationally available technology that represents best technology available when it comes to reducing entrainment. The best approach to reduce entrainment will be determined on a case-by-case basis. This may include the use of fine mesh screens, variable speed water pumps or even closed-cycle cooling either alone or in combination with other technologies. Although this site-specific approach should benefit industry, it also creates uncertainty. Without a set standard, it is more difficult to determine whether any site-specific solution could be successfully challenged by an environmental group.

Under the new regulations, facilities that withdraw more than 125 million gallons of water per day will have to do additional studies to help determine the best technology available to reduce deaths from entrainment.

Existing facilities that have a design intake of less than two million gallons per day or use less than 25% of water for cooling are not left unregulated. Instead, EPA decided that these facilities will have to use best professional judgment to reduce harm to fish and other aquatic organisms (as opposed to best technology available) determined on a case-by-case basis. Under the regulations, EPA is also requiring that new electrical generating capacity added to existing facilities use technology that meets existing requirements for new facilities, which is essentially closed-cycle cooling or its equivalent. It is not considered a new unit to repower an existing power plant.

Critics claim that the regulations will increase the price of electricity and cause electrical reliability issues since many power plants are already strained by complying with the sometimes costly requirements imposed by other environmental regulations like the mercury and air toxics rule. Senator Jim Inhofe (R-Oklahoma) said he will try to overturn the regulations. At the same time, environmental groups complain that the regulations are inadequate.

The new rules will take effect 60 days after they are published in the *Federal Register*. Individual facility requirements will not be imposed until a facility is issued its water discharge permit pursuant to federal rules.

Federal Jurisdictional Waters

The US Army Corps of Engineers and EPA are trying to enlarge the scope of waters that are considered federally protected under the Clean Water Act.

The existing definition has been in place for over 20 years.

Even now, many developers move parts of projects to avoid such waters because of the added permitting burden. If the proposal stands, permitting requirements that would not have existed before could be triggered. For example, additional permitting requirements could be imposed on development projects that will affect wetlands because the determination of what a wetland is for purposes of federal jurisdiction relies on the definition of “waters of the United States.” This is the term that the Army Corps of Engineers and EPA are proposing to redefine.

The new proposal was published in the *Federal Register* in April. The government is collecting public comments on the proposal through October 20, 2014.

The existing definition of “waters of the United States” has left room for argument. The definition is important since it is used in many sections of the Clean Water Act, including sections that apply to permits under the national pollution, discharge and elimination system program and permits to fill wetlands.

In June 2006, the US Supreme Court addressed the definition of “navigable waters” in a closely-watched case called *Rapanos v. United States*. “Navigable waters” are considered “waters of the United States” for purposes of the Clean Water Act.

In the end, the Supreme Court failed to endorse one single test to identify navigable waters. In *Rapanos*, four of the nine justices decided that “navigable waters” are “only those relatively permanent standing or continuously flowing bodies of water ‘forming geographical features.’” Wetlands, according to those justices, were also “navigable waters” if they have “a continuous surface connection” to such bodies of water with “no clear demarcation between” them.

A fifth justice, Anthony Kennedy, proposed his own test. He suggested that a wetland would be subject to federal jurisdiction if that wetland had a “significant nexus” to traditionally navigable waters, meaning that federal jurisdiction, in Justice Kennedy’s view, should be asserted if the wetlands “either alone or in combination with similarly situated lands in the region, significantly affect

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the chemical, physical, and biological integrity of other covered waters more readily understood as 'navigable.'"

The Army Corps of Engineers and EPA propose to treat six categories of waters as "waters of the United States" by rule. They are waters that are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including water bodies that are subject to tides, interstate waters (including wetlands), territorial seas, all impoundments of these waters, tributaries that connect to them, and any water adjacent to such waters.

The government would also assert jurisdiction on a case-by-case basis over other waters that have a "significant nexus" to tidal waters, interstate waters (including wetlands) and territorial seas. This test is similar to Justice Kennedy's test in *Rapanos*; however, the term "significant nexus" would mean water (including a wetland) that drains to the nearest tidal water, interstate water (including a wetland) or territorial sea and "significantly affects the chemical, physical, or biological integrity of" any of those specified waters. The effect is "significant" if it is more than speculative or insubstantial.

Although the agencies are seeking comments on the proposal, the study on which the proposal is based ("Connectivity of Streams and Wetlands to Downstream Waters: A Review and Synthesis of the Scientific Evidence") is still in draft form. EPA said that its final rule will be based on the final report.

Cross-State Air Pollution

The US Supreme Court upheld the authority of the Environmental Protection Agency to hold upwind states responsible for cross-border air pollution that harms downwind states in a case called *EME Homer City Generation v. EPA* in late April.

In a six-to-two ruling, the court reinstated a cap-and-trade program, called "CSAPR," intended to cut emissions of sulphur dioxide and nitrogen oxides from power plants and other sources in 28 states. The emissions trading program was originally scheduled to take effect in 2012, but implementation was delayed pending resolution of various legal challenges.

The decision reverses an earlier US appeals court finding that the agency went beyond its authority in the way it apportioned the required emissions reductions among affected upwind states.

The CSAPR rules will let the market decide where pollution should be reduced by setting a limit on total pollution and allowing credits or allowances to be traded. The lower court suggested that the agency should have apportioned emissions reductions by state based on the amount of pollution each upwind state causes.

The Supreme Court also held that EPA may impose a federal solution where states have failed to comply, rather than letting the states amend their state implementation plans, or SIPs.

Downwind states complain that upwind states can be in compliance with air quality requirements within their borders while sending some of their air pollution to neighboring states, thereby interfering with the neighboring states' ability to meet their regulatory obligations. The affected downwind states are largely located in the Northeast and the mid-Atlantic, while the upwind states are mainly in the Midwest and use more coal to generate electricity.

The Supreme Court reversed and remanded the matter to the lower court for further proceedings.

New rules for cooling water intake structures will affect 1,065 existing power plants.

Adjustments to the CSAPR implementation schedule will certainly be needed as some compliance deadlines passed while the appeals were working their way through the courts. While some observers suggest much of the burden of complying with CSAPR as drafted has been blunted due to recent coal power plant retirements and the implementation of other EPA regulations, EPA could strengthen the emissions reductions required by CSAPR.

Despite this win for EPA, when the case returns to the lower appeals court, the appeals court will have to wade through other issues that could still conceivably derail the cross-state rule. The downwind states complain that several aspects of the rule, including the air quality modeling used to determine which upwind states are covered, the method for setting state emissions budgets and the compliance deadline, were all the result of arbitrary and capricious action by EPA. On the other hand, the appeals court struck down CSAPR earlier on probably the strongest possible grounds, and its decision was then reversed by the Supreme Court. The odds of CSAPR failing on the remaining grounds are reduced.

While the lower courts and EPA sort out these issues, a less stringent "clean air interstate rule," which preceded CSAPR, will continue to apply.

Opponents of CSAPR argue that the CSAPR rule, combined with the mercury and air toxics standards rule, could lead to the retirement of up to 60,000 megawatts of coal-fired power plants by 2020.

Climate Change

A series of scientific studies over the last several months suggest that the effects of climate change are coming faster and more furiously than previously believed.

The Intergovernmental Panel on Climate Change, a United Nations group that periodically summarizes climate science, released several reports over the last six months that conclude that climate change is already having sweeping effects on every continent and across the oceans. The panel warns that the problem is likely to grow substantially worse unless greenhouse gas emissions are brought under control. The current impacts described in the report include that sea ice in the Arctic is collapsing, water supplies are coming under stress, heat waves and heavy rains are intensifying, coral reefs are dying, and fish and other creatures are migrating toward the poles or, in some cases, going extinct. The report finds that the oceans are rising at a pace that threatens coastal communities and are also becoming increasingly acidic as they absorb carbon dioxide. Organic matter frozen in Arctic soils for millennia is now melting, allowing it to decay into greenhouse gases that will cause further warming.

The report noted that many businesses around the world are making plans to adapt to climate change. It noted that the impacts of climate change may be moderated by factors like economic or technological changes.

Despite that, it said there is an increasing risk that climate changes could overwhelm the efforts by businesses to adapt without a meaningful global effort to limit greenhouse gas emissions. While such emissions have begun to decline slightly in a number of wealthy countries, including the United States, the gains are being lost to emissions from rising economic powers like China and India.

The UN report is expected to receive attention as nations try to agree on a new global climate treaty when they meet in New York this fall and in Paris in 2015.

In the United States, a large panel of scientists overseen by the federal government issued the National Climate Assessment in early May. This region-by-region assessment documents how the effects of climate change are being felt throughout the country, with water growing scarcer in dry regions, rains increasing in wet regions, heat waves increasing in number and severity, worsening wildfires, and greater insect infestations in forests. In the Northeast, for example, the report found a substantial increase in heavy rains and risks from a rising sea level that could lead to further flooding of the sort that occurred during Hurricane Sandy. The report suggests that such sweeping changes have been caused by an average warming of less than 2 degrees Fahrenheit in most of the US over the past century. It says that if global greenhouse gas emissions remain on their current path, future warming could exceed 10 degrees by the end of this century.

The National Climate Assessment is the third such report in 14 years. It was supervised and approved by a large committee of experts, including representatives of two oil companies. The White House released it in May in part to build political support for contentious new climate change regulations that EPA issued in early June.

In addition, two other groups of scientists also recently concluded that a large section of / *continued page 64*

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the western Antarctic ice sheet is falling apart and its loss now appears to be unstoppable, a development that scientists have feared for decades. The separate findings were published in the journals Science and Geophysical Research Letters. The western Antarctic ice sheet sits in a bowl-shaped depression, with the base of the ice below sea level. Scientists report that warm ocean water is causing the ice along the rim of the bowl to thin and retreat. As the front edge of the ice pulls away and enters deeper water, it can retreat much faster than before. If the studies are accurate, then the melting could destabilize neighboring parts of the ice sheet and an eventual rise in sea level of 10 feet or more may be unavoidable.

— *contributed by Sue Cowell and Andrew Skroback in Washington*

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