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US Policy Outlook For Renewable Energy

A panel of veteran wind industry lobbyists spoke at a finance forum hosted by the American Wind Energy Association in April in New York about whether Congress is likely to extend tax subsidies for wind farms, block the Obama administration from regulating carbon, pass a clean energy standard that would require a certain percentage of electricity in the United States be generated using renewable energy and take other actions that affect the economics of windpower in the United States. The panelists are Rob Gramlich, senior vice president of public policy for the American Wind Energy Association, Greg Wetstone, vice president for governmental affairs for Terra-Gen Power, and Jon Chase, vice president of government relations at Vestas Americas. The moderator is Keith Martin from the Chadbourne Washington office.

Budget Battles

MR. MARTIN: Rob Gramlich, does the fact that Congress reached a budget deal in April to avert a government shutdown, but only after a tremendous effort to find just $38.5 billion in spending cuts, bode well or ill for the wind industry?

MR. GRAMLICH: The difficulty working out a deal is a sign of how terrible an environment it is to get anything done in Congress. Luckily, the wind industry does not have anything it is waiting on Congress to do in the near term. We are spending the time meeting with members and staff trying to lay a foundation for things / continued page 2

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CONGRESS may look at taxing partnerships and other pass-through entities with at least $50 million a year in revenue like corporations.

Senator Max Baucus (D-Montana), head of the Senate tax-writing committee, suggested on May 4 that his committee will look at the idea. The Obama administration is reportedly working on a proposal to send Congress. Michael Graetz, a respected tax law professor, suggested such a step in testimony before the Senate tax-writing committee in March during hearings on corporate tax reform. Pamela Olson, assistant Treasury secretary for tax policy under President George W. Bush, told an American Bar Association tax section meeting in Washington / continued page 3

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we might need in the future.

MR. MARTIN: The shutdown debate was merely a skirmish compared to what will follow when the debt ceiling needs to be increased in May and compared to the 2012 budget debate this summer. For what should wind companies be watching when we get into the larger debt limit and budget debates?

MR. GRAMLICH: I would keep an eye on a couple things.

First, watch for signals about the prospects for an extension of production tax credits beyond 2012 when the credits expire for wind projects. Initial signs are good from the House Republicans with whom we have spoken.

We should be able to keep ourselves out of the line of fire in most of the budget battles this year and next year. However, we have a lot riding on the general direction the budget reduction effort takes. If Congress ends up looking to reduce the deficit not only by cutting spending, but also by increasing revenue, then tax credits could be in trouble. The wind industry is fortunate that support for wind farms is through the tax code rather than direct spending, because direct spending will be the first to go. Even though taxes affect the deficit as much as spending, Republicans have been more interested in continuing to reduce revenue for the government than in increasing it to cover spending.

The other thing to watch is the general tax reform debate. Both Republicans and Democrats have proposed stripping many tax credits and deductions from the tax code in order to reduce corporate tax rates. The discussions are still at an abstract stage. There is not nearly enough activity currently to see tax reform getting done in this Congress. It looks like something for the next Congress in 2013 to 2014. Even the mortgage interest deduction on which middle class voters rely is not safe if tax reform really gains traction.

MR. MARTIN: So the message is duck—stay out of the line of fire of the budget cutters this spring and summer.

Sticking with tax reform, Republicans are calling for a reduction in the corporate tax rate from 35% to 25%. A study by the Bush Treasury Department suggested that the only way that you can get there is by stripping every tax incentive out of the tax code, including accelerated depreciation, and that would still only get you to a 28% rate. Jon Chase, do you agree with Rob Gramlich that corporate tax reform is unlikely before the November 2012 elections?

MR. CHASE: I agree with Rob. There will be talk about corporate tax reform, but no action until after the next elections. I think we still have a pretty strong case for keeping production tax credits; they promote fuel diversity and clean energy. However, everything will be on the table once we get into that debate.

MR. WETSTONE: That's three votes. I agree it is an issue for the next Congress. Don't underestimate the difficulty. For example, various incentives for the oil and gas industry would have to be changed to pay for a pretty substantial chunk of the lowering of the corporate tax rate. Those provisions are very tough to change. Democrats tried in the last Congress when they had more votes than they do now, and they got nowhere. It is hard to see how oil and gas incentives can remain in the tax code without leaving incentives for renewable energy.

Wind industry lobbyists are hopeful that they will be able to persuade Congress to extend production tax credits for wind farms beyond 2012.

MR. MARTIN: What happens to people who already made investments? They are expecting 10 years of production tax credits, or perhaps they are in the process of investing in a deal. The tax law changes. Are they out of luck?

MR. CHASE: Congress usually provides transition rules that let companies that have already committed to investments when the law changes see them through. The investment tax credit was repealed as part of tax reform in 1986. Companies that had signed binding contracts to build projects before the House Ways and Means Committee unveiled its tax reform package were grandfathered. They were given another four years to complete their investments and still claim tax credits.

MR. MARTIN: Let me just finish on the budget with this question. Congressman Paul Ryan, the Republican budget committee chairman in the House, unveiled a budget blueprint this week that would cut $6.2 trillion over the next 10 years. The amount is staggering compared to the $38.5 billion on which President Obama and House Speaker John Boehner agreed to avert a government shutdown. Rob Gramlich, does the Ryan budget have legs, and is there anything in the blueprint that caught your eye?

MR. GRAMLICH: The Ryan proposal is a serious proposal. That said, whether he stretched too far and will be able to bring a lot of people with him is unclear. The proposal has set up a partisan fight. He did not reduce defense spending. He wants to cut taxes further. He went after spending on Medicare and Social Security for the elderly. There is no detail at all in the proposal about taxes, other than that he wants further tax cuts. The details will be left to the tax-writing committees to figure out.

MR. MARTIN: Does it have legs, Greg Wetstone?

MR. WETSTONE: I think it becomes a focal point for debate, but it is not going to be enacted. Unfortunately, like a lot of what we are discussing, most of this is basically framing the debate for the next elections in November 2012.

Treasury Cash Grants

MR. MARTIN: Jon Chase, will the Treasury cash grant program be extended again by Congress?

MR. CHASE: Ha, I get the easy one. [Laughter] It will be difficult. We had a heck of a fight trying to get it extended last December 17 for another year. Those of us who are in Washington know how close a call we had. There was a four-day period leading up to December 17 when it could have gone either way. The ideological battle lines make it harder to see being extended again in the current Congress. Republicans have more votes in the current Congress. They see the cash grant as a stimulus program. They voted *en masse* against the stimulus when it passed originally and are not keen to see any parts of it extended.

MR. WETSTONE: It would be very tough to get another extension through the House. The industry is looking hard at other ways like a renewable energy version of the master limited partnership to deal with the problem of scarcity in the tax equity market.

MR. MARTIN: We will come back to / *continued page 4*

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in May that one problem with the last major overhaul of the US tax code in 1986 is that it has led to a gradual erosion in the US corporate income tax base as businesses convert into pass-through entities.

It is hard to tell whether the idea has life or will follow the same arc as the Donald Trump presidential bid.

Between 40% and 50% of business income is now reported by pass-through entities. According to Graetz, only 0.2% of partnerships had revenues of more than $50 million, but they account for 60% of total partnership income.

Meanwhile, the debt ceiling debate in the United States threatens to come to a head in late July or August. The US has a limit on the amount of money the government can borrow of $14.294 trillion. The government hit the limit on May 16, and will eventually need to borrow more to fund operations, including paying interest and principal on outstanding debt. Current projections show the government running out of money after August 2 unless the ceiling is increased. Republicans and some Democrats are unwilling to vote to increase the current debt ceiling unless Congress agrees at the same time on a plan to reduce massive federal budget deficits.

Evan Liddiard, a senior aide to the top Republican on the Senate tax committee, Orrin Hatch (R-Utah), said in early May that any bill to increase the debt limit may ultimately include tax increases as well as spending cuts.

> *Most industry groups are hunkered down hoping their programs will avoid the spotlight. Any bill that moves will take shape quickly and offer little chance for input.*

THE US DEPARTMENT OF ENERGY sent letters on May 10 to project developers whose renewable energy projects are in the loan guarantee queue notifying them whether they made the cut of a couple dozen projects that DOE feels are all it can accommodate by the September 30 deadline to close on financing. / *continued page 5*

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renewable energy partnerships. Rob Gramlich, Senator Schumer and others were strong critics last year about stimulus dollars going to support US projects that use Chinese-made equipment. The US has a case pending against China before the World Trade Organization hoping to knock out domestic Chinese subsidies for Chinese manufacturers. Has the anti-China rhetoric subsided on Capitol Hill?

MR. GRAMLICH: It remains a sensitive issue in Congress. The wind industry was dragged into a larger debate. A majority of turbines used in US wind farms were made overseas. That has been changing. We now have a large domestic turbine manufacturing capacity, and it is growing rapidly. We had a 12-fold increase in domestic manufacturing. We have over 400 manufacturing facilities around the country. Perceptions are still hard to change. During the last campaign cycle, the issue of US wind farms using foreign-made equipment was still coming up because it was a great talking point. There were some Republicans who picked it up toward the end of the last campaign, and if you look at the Republican National Committee website today, there is still some of that rhetoric. However, we have a lot of people in both political parties who understand how many jobs the wind industry has created in this country.

I think eventually, we will be fine. We have had a constructive engagement with the steelworkers' union, Senator Schumer and some of the others who were concerned initially about the issue.

MR. MARTIN: Jon Chase, what is your sense of where this issue stands as the manufacturer on the panel?

MR. CHASE: We think it is still a live issue. If we could develop a longer-term energy policy in this country that promotes renewable energy, the manufacturing base would come. We work every day on increasing our domestic supply chain, and we feel confident that we would meet any domestic content requirement, but we do not think there should be such a requirement because it inhibits trade and causes markets to stagnate. A trade war helps no one.

PTC Extension

MR. MARTIN: All three of you expressed some optimism that production tax credits might be extended. Rob Gramlich, when do you see that happening if it does?

MR. GRAMLICH: The timing is unclear. There is no bill moving currently through Congress that might serve as a vehicle for an extension. Congress has a tendency to wait until the last moment. We will work as hard as we can to get it sooner than the end of next year.

MR. MARTIN: What are you hearing from people on Capitol Hill, particularly Republicans, about the chances of an extension?

MR. GRAMLICH: The House Republican leadership and the leaders of the House Ways and Means have been very understanding and positive, and they understand the need for predictability and stability for business planning. A lot of new House Republicans who were elected last November have business backgrounds. They were not state legislators. They also understand the need for predictability. They have been very receptive. Again, our mission this year is relationship building and making sure they understand the need to provide more certainty to the market, and I think we are in good shape in that regard. That is just the first step. There are more steps in the legislative process, but I think we are looking good in terms of step 1.

MR. MARTIN: So we're still in the dating phase; no marriage yet.

MR. CHASE: The timing of an extension turns on how the tax process moves forward. Congress has tended to fold everything into a single omnibus tax bill late in the year. That is usually our only vehicle. I have worked on nine of them, and none of them has passed until close to the deadline, if not after.

MR. WETSTONE: I agree with Rob and Jon. The only thing I would add is it is not a great time to be asking for anything from Congress given the singular focus on the budget deficit. Maybe it is just as well that we don't need this until 2012. I think that is when we will see action. I am optimistic that we will get there, but it will be a bumpy road.

MR. CHASE: The one thing that could give us a shot at earlier action is if there is an energy bill, perhaps driven by voter concern about escalating gasoline prices. Members of Congress go back to their districts and do town halls, and they keep hearing about gas prices going up. Any energy bill would have a tax component. If action on energy were certain, it would have happened earlier, but it is the one thing that might provide us an earlier vehicle for an extension.

MR. MARTIN: The *Onion*, a satirical newspaper, has a broadcast service. A reporter went up to Capitol Hill a few months ago and interviewed old timers who remember how to pass a bill. [Laughter] It has been so long since anything has been done by Congress that people have forgotten the procedure.

Carbon

MR. MARTIN: The Senate voted this week on four amendments to block the Environmental Protection Agency from regulating carbon. Each of the amendments was defeated. Where do you see this going? Will the Environmental Protection Agency be barred from regulating carbon? Do you see any US effort in the next two years to control carbon?

MR. WETSTONE: You have a Clean Air Act in place and EPA regulations in place to enforce it, and you have an effort in Congress to limit the EPA role. In this case, Congressional inaction leaves the status quo, which means EPA regulation of carbon. Attention is now shifting to the courts.

I can certainly see the possibility of delay or a limit on EPA's authority to regulate greenhouse gases as part of a deal on a broader energy bill, but I think we saw with the votes this week in the Senate that there is not enough of a consensus to get anything all the way through Congress. Remember, too, that the President would need to sign whatever passes Congress.

Therefore, absent a somewhat surprising change— I don't want to rule out completely the possibility that the President might cut a deal in the debt limit or budget battles—I think we will continue on the path we are on. We do not have a national energy policy, but we do have this regulatory effort that is focused on some of the larger sources of carbon emissions, and that is now proceeding through the courts.

MR. MARTIN: Jon Chase, Obama has defensive power; he does not have any offensive power. He can block things, but he cannot pass his program. How does that play out in carbon?

MR. CHASE: EPA is playing a lot of defense on Capitol Hill, and I think it will continue to have to do that. There is gridlock in the Senate. The group that wants to limit EPA action needs 60 votes. It has more than 50, but not 60. I do not see action on carbon in the current Congress.

MR. MARTIN: As Greg Wetstone said, that allows EPA to start enforcing its greenhouse gas regulations.

MR. CHASE: It does.

Clean Energy Standard

MR. MARTIN: Rob Gramlich, Obama wants a clean energy standard that would require 80% electricity be generated with clean energy by 2035. Clean energy includes natural gas. What are the odds that this Congress will enact such a standard?

MR. GRAMLICH: We are pleased to see that all of the push to date from the President has been about the need for predictability in the market. We don't know where the / continued page 6

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The law also requires the projects be under construction by September 30. Estimates are that between 30 and 50 projects failed to make the shortlist.

The Solar Energy Industries Association sent a letter to Congressional leaders on May 11 asking for more money and more time to fund projects that failed to make the cut. Industry lobbyists say privately that it is a "heavy lift" to get more money for the program given the current focus in Washington on cutting spending.

THE US TREASURY said it will reimburse developers for 30% of the cost of improvements to some existing renewable energy projects.

The Treasury also appears to be relaxing a rule that only one grant will be paid per project.

The grants are paid under the so-called section 1603 program. Congress directed the Treasury as an economic stimulus measure in February 2009 to pay developers who agree to forego tax credits on new wind, solar, geothermal and other renewable energy projects in the United States 30% of the project cost in cash.

The program applies to new projects that are completed during 2009, 2010 and 2011 or that start construction by December 2011 and are completed by a deadline. The deadline is 2012 for wind farms, 2016 for solar and fuel cell projects and 2013 for other renewable energy facilities.

Grants will be paid on two types of improvements under the new policy.

One type is improvements to older projects that were originally put into service before 2009.

If the project is of a kind that qualifies potentially for production tax credits — for example, a wind, geothermal, biomass or landfill gas project — then the improvements qualify for a 30% cash grant only if the original project qualified in fact for production tax credits. Thus, for example, an open-loop biomass plant would have had to have been originally placed in service after October 2004.

If a grant is paid on / continued page 7

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clean energy standard will go, but we plan to keep focusing on the mantra of a more predictable market, particularly to grow manufacturing and bring more investment in this country. It could lead to a clean energy standard or it could lead to something else like a long-term tax credit. Certainly by the end of this Congress, we will need action on something—at least extension of production tax credits.

MR. MARTIN: Jon Chase, how did the nuclear disaster in Japan affect the odds for a clean energy standard?

MR. CHASE: It was not helpful. Most people think a clean energy standard cannot pass the Senate without promoting nuclear. That is not the only reason why a CES could struggle. We have not seen a lot of momentum for it. Most members of Congress are caught up in the budget debate. All other issues are noise at this point.

MR. MARTIN: Greg Wetstone, is a standard that promotes natural gas something that is attractive to the wind industry and, if so, why?

MR. WETSTONE: Any standard that has wind competing directly against natural gas on a one-for-one basis is not good for wind and not very good energy policy either. The utilities will use gas without any encouragement from Congress. Therefore, it is not clear to me why Congress needs to take action to encourage utilities to do what they would do anyway.

In the last Congress, the President identified offshore oil drilling as a key part of US energy strategy. Then we had the Gulf oil spill. Nuclear energy was something else we were going to promote, and you see where we are today. Life is obviously pretty complicated.

We are going to need a change in the current political dynamic to get a clean energy standard enacted.

MR. MARTIN: Just to be fair on the natural gas part, I think Obama is proposing that only half the credits be given to natural gas compared to wind. A clean energy standard will not get through Congress without a broad enough coalition to support it.

Moving to the next subject, there was a lot of talk last year about a clean energy bank or CEDA. We haven't heard as much talk this year. However, Senators Kerry and Hutchison have introduced a bill for a national infrastructure bank. Rob Gramlich, is CEDA dead or is the infrastructure bank likely to move?

MR. GRAMLICH: CEDA's timing has been off. The advocates missed the train on the big spending program that was the Recovery Act, also known as the economic stimulus, and trying to find money for it after that train left the station has been difficult.

Master Limited Partnerships

MR. MARTIN: The renewables trade associations have been lining up behind a proposal for a renewable energy partnership. What is it, and what path do you see forward for it?

MR. GRAMLICH: We have had early discussions, probing other options to use tax credits now that the section 1603 Treasury cash grant program is about to expire. We would like to be able to go to Congress and say, "Look, we're open to a few different options. Which ones might you be willing to work with us on?"

The idea is to allow renewable energy companies to use the same types of master limited partnerships that are used currently by the oil and gas and low-income housing markets to raise capital. The specific policies that would need to be put in place for renewable energy are a little different, and so we are working on that and trying to gauge interest among the industry and the financial community. We think there is a potentially broad pool of investors around America who would love to be able to invest in renewable energy. It would be nice to find something that would allow the public to take more of an ownership stake in America's clean energy future.

MR. MARTIN: This is an idea for how to tap individual investors as a source of tax equity. Has there been any discussion about how much capital might be raised in the retail market?

MR. GRAMLICH: Discussion, yes; answers, so far, no. But there are early signs that this would be a worthwhile effort.

MR. MARTIN: Has any of you had any feedback from tax committee staffs on Capitol Hill about the proposal?

MR. CHASE: I think we are still at the stage of deciding how to present any proposal. We have talked about master limited partnerships in the past with tax staffs, and there has been some push back. It was one of the options on the table in late 2008 when people were looking for ideas for dealing with the economic crisis. While the tax staffs have had concerns in the past, the economy today is different. We think opening up the investor pool would be a huge opportunity for the industry. At Vestas, we support the proposal.

MR. MARTIN: Denise Bode said last year at an industry outreach effort in London that things might be harder the next two years to promote renewable energy at the federal level and that maybe we need to shift focus back to the states. There has been some good news at the state level, at least in California, in the last two weeks. Greg Wetstone, tell us what happened and whether you see any other chance for progress in other states.

MR. WETSTONE: The California legislature voted to increase the renewable portfolio standard to 33% by 2020. Governor Brown said he will sign the bill. This will provide some stability and assurance of continued market growth in California. It happened more rapidly than many of us anticipated.

MR. MARTIN: Is there something else you guys are working for in another state that also looks promising?

MR. GRAMLICH: After the election last November, there was concern that some states would reverse direction and roll back their renewable portfolio targets. There have been a few efforts to roll back, we have been able to hold the line for the most part. Not all the state legislatures have concluded their sessions. Remember, they have much shorter sessions than Congress, so it is a six-month push.

MR. MARTIN: Last question. Three years ago, I met with the tax committee staffs in a big meeting in the Joint Tax Committee conference room. I was trying to get a change in the production tax credit statute, and I asked which member on each tax committee staff is carrying the water on production tax credit issues. There is usually one member in each of the House and Senate who takes the lead on a particular issue. The staff members just smiled and said, "Everyone thinks he is an advocate for renewable energy." Has that changed on Capitol Hill? Would I get a different answer today and, if so, why?

MR. GRAMLICH: I don't think it has changed. We have a lot of support from both political parties. We used the word "duck" earlier to indicate we want to stay out of the middle of the broader ideological and partisan battles that are the main focus currently on Capitol Hill. If we can duck some of that and stay focused on the thing that matters to us and have good relationships with members on both sides of the aisle, then we should be in pretty good shape.

MR. CHASE: It is a constant effort. We are continually seeking champions. We had a huge turnover in the last Congress. A lot of the districts, including the two in Colorado where we have manufacturing facilities, changed. We have Republicans in those districts now, and it is a new opportunity to gain new friends.

MR. WETSTONE: It is a polarized and partisan world we live in. The President has said he really likes renewables and he wants to reduce some of the oil and gas tax incentives. There are many in Congress who may be 180 degrees / continued page 8

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improvements to such a project, then no more production tax credits can be claimed on the project.

Improvements to an older solar project qualify for a cash grant even if the project did not qualify for an investment credit when it originally went into service.

The other type of improvement that qualifies for a grant under the new policy is an improvement to a new renewable energy project that originally went into service in 2009, 2010 or 2011. The Treasury had had a policy of paying only one grant per project as a rule of administrative convenience.

Ellen Neubauer, the cash grant program manager, said in May that Treasury will pay grants on improvements to such projects. The improvements must be under construction by December 2011. They must be capital additions rather than repairs. They must be a case of additional work being done on a project after the original grant application was filed rather than failure to wait to tally up all the costs that had been incurred before the original application was filed.

The deadline to apply for grants is September 30, 2012. Therefore, there is still time to apply for grants on improvements that were completed in 2009 or 2010.

BIOMASS POWER PLANTS that burn *gas or liquid* fuels made from biomass qualify for Treasury cash grants for 30% of the project cost, the Treasury said in April.

Cash grants will also be paid on the gasifier, biodigester or other equipment that converts the biomass into fuel. It does not matter that the gasifier, biodigester or other conversion equipment is at a different location than the power plant or even that it is owned by someone else. However, it must be considered an "integral part" of the power plant. Factors that suggest it is an integral part are if both it and the power plant went into service at the same time, the fuel output is dedicated to the / continued page 9

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on the other side from the President when it comes to oil and gas, and they may be less positive about renewables. We have work to do. I think the wind industry has done a good job reaching out in a bipartisan way to Congress, but there are new cross currents that are making life more complicated than it used to be. ◎

New California Rules May Complicate Financing of Renewable Energy Projects

by William Monsen and Laura Norin, with MRW & Associates, LLC in Oakland, California

Proposed changes in market rules and in future power purchase agreements could significantly complicate the financing of intermittent renewable projects being developed for the California market.

The new rules provide strong economic incentives for utilities to "curtail" — or cut back — electricity from intermittent resources during periods when market electricity prices are falling. Changes recently approved to the form contracts used by the large California utilities to buy electricity from independent generators make it likely that a portion of the curtailment risk will be passed from the utility to generators.

The proposed market rules would also remove protections that currently shield intermittent renewable resources from much of the risk of incurring liability for uninstructed energy payments that are required when a generator delivers more or less energy than scheduled during an hour.

As such, the proposed market changes will at minimum complicate estimation of project revenues and could at worst erode a project's profitability.

Revenue Risks for Renewable Contracts

Recent power purchase agreements for wind and solar projects in California have typically been structured as "must-take" agreements with fixed prices per megawatt hour. The offtaker accepts power from the plant owner regardless of the current market price, pays the plant owner the agreed-upon fixed price for the power, delivers the power to the grid operator, and receives payment based on the current market price. As such, the utility or its ratepayers bear the market price risk while the project owner assumes the production risk.

Meteorological conditions and project performance characteristics are the key factors in determining production risk. Reasonable estimates of plant production can be developed using site-specific historical meteorological data and technology-specific performance data. Therefore, production risk does not generally impede project financing as long as the plant is sited in a suitable location and built with high-quality components.

Potential changes in California's market rules may provide economic incentives for intermittent generators to allow curtailment of deliveries when market conditions are unfavorable. This is called "economic curtailment." At the same time, regulators are encouraging utilities to shift some of the market price risk from ratepayers to project owners by not fully compensating suppliers for lost revenue in the event of an economic curtailment. Similar shifts are occurring in other jurisdictions nationwide.

Economic curtailments can cause a significant loss of revenue even when limited to a certain number of hours per year, since curtailments can occur when a project's output is high. The risk is generally greatest for wind projects, since wind is often blowing the strongest when demand is low and curtailments are most likely to occur.

The risk to project revenues can be bounded only through an understanding of the rules governing economic curtailment, current and future market conditions that may contribute to curtailments, the utility's incentives to curtail, the ability of project owners to receive production tax credits and renewable energy credits for curtailed deliveries, and contract provisions for compensation in the event of a curtailment.

Changing Rules for Renewable Curtailments

Curtailment incentives for project owners and utilities can diverge when market prices fall.

Since wind and solar projects generally have low marginal costs of production, it is in the interest of project owners with fixed-price contracts to keep their plants operating regardless of the market price. This incentive is particularly strong for projects that are eligible for tax credits or renewable energy credits that are tied to production.

Utilities have different incentives: when the market price falls below the contract's fixed price, the utility has a negative contribution to margin for each unit of energy purchased under the fixed-price power contract, meaning that it is generally in the interest of the utility to curtail purchases from the project.

As more renewable resources are being developed with insufficient transmission or load support, oversupply and congestion conditions are arising with increasing frequency, leading to electricity prices in certain locations that are significantly lower than prices in the power contract. In fact, it is not uncommon for market prices to be negative, particularly in areas with significant wind development.

Current market rules in California encourage must-take intermittent renewable power transactions to be self-scheduled outside of the market, meaning the owners of renewable power plants generate and deliver power to the purchasing utility regardless of market prices.

These transactions come with very high penalty prices for curtailment, effectively eliminating the opportunity for the purchasing utility to curtail output from the generator except if needed to preserve system stability or otherwise avoid an emergency situation. This provides a benefit to project owners, since they are guaranteed the price in the power contract plus relevant tax credits and renewable energy credits for nearly all the power that they can produce. It conflicts with the interests of the purchasing utilities, which would prefer to curtail their purchases from projects when market prices fall below the price in the power contract.

The California Independent System Operator or "CAISO" has proposed market rule revisions that would encourage intermittent resources to allow curtailment in the event of very low market prices. The proposed changes will almost certainly increase the frequency of curtailments and the amount of uninstructed energy penalties for intermittent renewable projects.

Currently, prices in the CAISO markets have a floor of -$30 per mWh. At a market-clearing price of -$30 per mWh, a supplier to the CAISO would have to **pay** $30 per mWh to deliver power to the CAISO. The proposed market rules would reduce the floor price to -$300 per mWh in an */ continued page 10*

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power plant and the power plant uses it as the sole source of fuel.

It is not usually considered an integral part if less than 75% of the fuel is dedicated to the power plant.

The latest guidance opens the door to cash grants on cellulosic biofuels plants provided at least 75% of the biofuel is dedicated to a power plant that could qualify for production tax credits.

If only a fraction of the biofuel is dedicated to the power plant, then only that fraction of the biofuel plant qualifies for a grant.

Separate grant applications would be filed where the gasifier, biodigester or other conversion equipment and the power plant are owned by different parties.

The conversion equipment can be built after the power plant. Thus, for example, a grant might be paid on a cellulosic biofuel facility on which construction starts in 2011, provided it is completed by 2013, to supply biofuel to an existing power plant, depending on the facts.

DEPRECIATION BONUS rules that the Internal Revenue Service issued in late March were more favorable to project developers than expected.

Congress voted last December as an additional stimulus measure to allow a 100% "depreciation bonus" to be claimed on new equipment put into service after September 8, 2010 through December 2011 or 2012, depending on the equipment. That means the owner can deduct his full tax basis in the equipment immediately in the year the equipment goes into service. He gets no other depreciation.

A 100% bonus is worth 4.45¢ per dollar of capital cost for wind, solar and geothermal projects. It is worth 18¢ per dollar of capital cost for coal-fired and combined-cycle gas-fired power plants.

Wind, solar and geothermal projects have until December 2011 to be completed to qualify for a 100% bonus. Coal- and */ continued page 11*

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attempt to encourage more projects to bid a price point for economic curtailment. In other words, the bidder would submit a price at which it would be willing to allow the CAISO to curtail deliveries in order to avoid potentially paying as much as $300 per mWh to deliver.

In addition, the CAISO would phase out its "participating intermittent resource program" and eliminate the benefits that the program confers to participants. Currently, participants agree to a number of conditions, including self-scheduling and paying for CAISO meteorological forecasts, in exchange for being shielded from some of the cost of output variability. In particular, other resources are subject to "uninstructed energy payments" if they do not deliver to the CAISO the expected amount of energy in each 10-minute period. However, program participants are liable for these payments only for deviations from expected amounts of energy deliveries over an entire calendar month. Without this program, intermittent projects would lose this benefit, and their uninstructed energy payments would be calculated every 10 minutes without the benefit of netting over-deliveries and under-deliveries over the month.

The CAISO's proposal is subject to considerable controversy. Market participants have proposed alternatives that may subject intermittent resources to less market risk.

One approach is to follow more closely the framework that the Federal Energy Regulatory Commission approved in February to bring wind resources into the Midwest Independent System Operator's security-constrained economic dispatch process. Under this framework, many wind projects will be required to participate in the MISO market instead of using self-scheduling. However, projects will be allowed to update their schedules up to 10 minutes prior to the time of delivery, and, as with other resources, they will be assessed uninstructed energy payments only for deviations that remain outside an 8% tolerance band for four or more consecutive five-minute intervals within an hour. In addition, these requirements will apply only to wind projects that began operating after March 2005, that do not meet certain requirements demonstrating that the project has firm transmission rights, and that are not "qualifying facilities" under the Public Utility Regulatory Policies Act. (See related article in this issue starting on page 21.) Notably, MISO had requested to apply these requirements equally to both wind and non-wind intermittent resources, but FERC ruled that non-wind intermittent resources should continue to be allowed to self-schedule.

The CAISO has not responded directly to the proposal to model its curtailment rules after the MISO rules. However, given the contentiousness of its initial proposal, the CAISO has announced that it will issue a revised proposal that will again be open to public comment. This will delay approval of the proposal until the end of June at the earliest. Further delays are possible.

Renewable energy projects entering into new power contracts with California utilities risk curtailment when the contract prices are above market.

Curtailment Risk Sharing

Economic curtailment can be used to shift some of the market price risk from the purchasing utilities to project owners.

The amount of risk that is shifted and how the risk sharing is structured can vary significantly depending on the terms of the power contract.

In April, the California Public Utilities Commission (CPUC) approved very different risk-sharing structures for the 2011 renewable procurement form contracts to be issued by the state's two largest utilities.

For Pacific Gas & Electric's contract, it approved a provision allowing 5% of expected annual generation to be curtailed for economic reasons with generators receiving their full contract price for all curtailed energy. However, generators would receive no reimbursement for lost production tax credits.

For Southern California Edison's contract, the CPUC approved a provision allowing curtailment without compensation or reimbursement for lost tax credits up to an agreed-upon cap of between 50 and 200 hours per year, with compensation and a discounted buyback option for any excess curtailment.

This decision is likely to be challenged by wind developers and renewable power advocates, particularly since its economic curtailment provisions were substantially revised just days before the decision was approved. Even if implemented as adopted, these form contract provisions are only the starting point for negotiating a power contract and project owners can attempt to negotiate more favorable terms.

As part of the power contract negotiation process, generators should insist on contractual clarity and specificity with regard to the process and rules regarding curtailment. Without such clarity, projects can face significant effect on net income. For example, three wind farms owned by FPL (now called NextEra) were forced to pay $29 million in deficiency payments last year because their contracts with TXU omitted a common contract provision that would have allowed curtailed energy to be counted as if it were generated for the purpose of evaluating compliance with output guarantees.

As curtailments become more frequent, more contract disputes are likely.

Potential disputes are already brewing in California, where Southern California Edison claimed — to the shock of many of its counterparties — that its *existing* renewable energy contracts allow it an expansive right to curtail without compensation to the generator.

In addition, given that there are often differences between scheduled output and delivered energy from variable renewable resources, disputes regarding the amount of energy that has been curtailed are likely to arise if contracts are not clear on how the amount of curtailed energy should be determined.

Implications for Project Owners

The consequences of economic curtailment for an individual project will depend critically on the market rules and the contract provisions for curtailment procedures and payments.

In general, for projects located in areas with large amounts of wind and insufficient transmission access or local load, project owners and their lenders should anticipate curtailments for new (and possibly for existing) projects.

The amount of curtailment will depend on factors such as the location of the project and the current and planned load, generating capacity, and transmission / continued page 12

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gas-fired power plants have until December 2012.

There had been fears that the 100% bonus would prove illusory for most power projects.

The fear was that the 100% bonus could not be claimed on projects on which work was too far advanced last September 9 when the 100% bonus took effect.

The IRS said in late March that even if a project was too far advanced, the owner can still claim a 100% bonus on the portion of the work completed after September 8, 2010 in most cases.

It also made it easier to conclude that a project was not too far advanced and to treat tax basis as building up after September 8 when the bonus increased to 100%.

A project on which a 100% bonus cannot be claimed should still qualify for a 50% bonus. A 50% bonus means that half the tax basis can be deducted immediately and the other half is depreciated normally.

To qualify for a bonus, a project cannot have been too far advanced before a key date.

That date is September 9, 2010 for the 100% bonus. It is January 1, 2008 for the 50% bonus.

The IRS said that it will interpret the 100% bonus in a way that makes it easier to conclude that a project was not too far advanced before last September 9.

The rules are complicated.

They differ depending on whether the developer is "acquiring" or "self constructing" the project.

Most utility-scale power plants are considered "self constructed." A power plant is self constructed, even though the developer hires a contractor to build it, as long as the construction contract was "binding" before worked started on the project and the contract is not later substantially amended during construction.

A self-constructed project was too far along if construction started before the key date. However, a developer can take the position that construction did not / continued page 13

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capacity in the project's vicinity. Market rules will determine the level of curtailment, whether intermittent generators risk imbalance charges when they deliver more or less power to the grid than expected, and other market risks.

Contract terms are equally important, as they will determine how parties share these risks. As evidenced by the FPL and Southern California Edison disputes, specificity and clarity of curtailment terms in power purchase agreements can avoid large financial surprises.

Unless all curtailment risk is borne by the purchasing utility, curtailment and market risks inject additional uncertainty into the projection of project revenue, which may make it more difficult to finance intermittent power projects.

Project owners and lenders will need to examine carefully the economic curtailment provisions in the PPAs as well as the correlation between generation patterns and market prices: low market prices during periods of high generation could significantly reduce project revenues if the offtaker is not obligated to provide some sort of make-whole payment for curtailed generation.

Understanding these conditions will allow developers and lenders to incorporate curtailment and market risks into revenue projections and price them into power supply bids.

Properly incorporating market risks into the PPA price increases the probability of meeting financial targets and allows projects to be financed with lower risk premiums. ◎

Effect of UK Bribery Act on Project Finance Market

by M. Scott Peeler in New York, Heidi Lawson in London, and Ramsey Jurdi in Dubai

Companies with any tie to the United Kingdom — beyond just share listings in London — will be subject to a tough new anti-bribery statute that takes effect on July 1.

The new law is expected to have an effect on the project finance market.

Its scope is similar to the US Foreign Corrupt Practices Act, with three important expansions. First, accepting a bribe from or paying a bribe to *any* individual is prohibited, no matter where it occurs. A bribe paid to an employee of a private company is illegal. This is a much broader prohibition than the US Foreign Corrupt Practices Act, which makes it illegal to offer anything of value only to foreign government officials and employees of international public organizations. Second, a company can be held strictly liable for bribery if the company fails to put in place procedures to prevent corruption. Third, there is no limit on the size of fines, and the potential prison sentences are longer.

What is Illegal

The UK Bribery Act 2010 makes it illegal to make or accept a bribe, under any circumstances, whether to a private individual or public official. The Bribery Act does not only apply to UK companies or companies listed on the London Stock Exchange. In fact, listing securities in London does not, by itself, subject a company to the Bribery Act. Rather, the Bribery Act applies to anyone who conducts business in the UK.

The very nature of project finance makes the industry particularly susceptible to violations of this ambitious statute. Its far-reaching jurisdictional reach, along with the well-used and successful US Foreign Corrupt Practices Act playbook, is shaping up to be a new strategy in the war against corruption.

In order to comply fully with the Bribery Act, it is necessary to understand its meaning and applicability to companies involved in various projects around the world.

By doing so, companies that were not previously subject to the Foreign Corrupt Practices Act or "FCPA" will be able to immediately assess the risk involved with the implementation of the Bribery Act and the effect of any violation.

If a company arranges financing, uses an agent, supplies or purchases goods or does any other "part" of its business in the United Kingdom, it is likely subject to, and must comply with, all of the provisions of the Bribery Act. Merely visiting London to conduct business meetings or using London as a place to negotiate contracts is not enough by itself to subject a company to the statute.

The Bribery Act applies to any bribe regardless of whether it took place in the UK.

For example, a US company arranging financing in London for a project in Africa could be held responsible under the Bribery Act if any one of its agents makes or accepts a bribe on the company's behalf. It is also important to note that, unlike the FCPA, the Bribery Act does not have an exception for facilitation payments, such as those used to speed up the process for obtaining a building permit or import license. If such a payment is found to occur, this will be a violation of the Bribery Act.

The Bribery Act puts a heavy burden on management and the board of directors to ensure company compliance.

Once the Bribery Act comes into force, for instance, it will be a criminal offense if a company fails to prevent relevant acts of bribery. If there is such a failure to comply, individuals could be subject to prison sentences and companies could be subject to unlimited fines. To make matters worse, the UK's Serious Fraud Office, the government agency in charge of enforcing the Bribery Act, may hold companies strictly liable. The only defense available would be if the company could establish that it had in place "adequate" procedures aimed specifically at bribery prevention.

Many companies, along with the attorneys who advise them, are struggling with the enormity of "strict liability" and wonder what specifically must be done to establish "adequate procedures" sufficient to prevent it from being imposed. Recent guidance by the UK Ministry of Justice tried to clarify that very question.

There are a few clear action items that companies should take as soon as possible.

Step 1: Assess Risk

The first step in assessing risk is to determine whether a company falls within the Bribery Act's jurisdiction.

Generally, the entirety of the Bribery Act applies to UK citizens, residents and incorporated entities. Even if a company is not incorporated under British law, it should assess whether it conducts any "part" of its business in the UK and, if so, the Bribery Act's prohibitions will apply. It is hard for any international company to not have part of its business touch the UK in some way.

The next step is to assess the nature and extent of its exposure to the risk that bribery may be committed, **directly** by its employees or **indirectly** by third-parties acting on the corporation's behalf. A good place to start is to identify those countries where the company does business — for example, where is it located, where are its customers and where do the products necessary for it business originate? Then, by simply using the same tools relied upon by government agencies tasked with enforcing these laws, such as the Transparency International's Corruption Perceptions Index, a company can determine the level of risk associated with its entire global / *continued page 14*

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start until more than 10% of the project costs were incurred. Even then, the IRS said it will take a liberal approach for the 100% bonus of allowing a 100% bonus to be claimed on costs incurred for components after September 8, 2010, provided the project is completed by a deadline.

The deadline is December 2011 for equipment like wind turbines, solar panels and landfill gas generators that would otherwise be depreciated over five or seven years. It is December 2012 for equipment like gas- or coal-fired power plants or some interties at wind and solar projects that would otherwise be depreciated over 15 or 20 years.

A developer who wants to claim a 100% bonus on components, even though work on the larger project started too early, can do so by including a statement with his tax return for the year the project is placed in service.

Equipment that a developer "acquired" — as opposed to self constructed — does not qualify for a 100% bonus if it was acquired before September 9, 2010. An example might be rooftop solar panels, depending on the facts. However, the panels are not considered acquired until the costs are incurred. Costs are "incurred" only by taking delivery, with one exception. They may be incurred by making payment in cases where payment is made and delivery is reasonably expected within 3 1/2 months of payment.

The following examples show how the rules work in practice.

Suppose a wind developer signed a binding turbine supply agreement in 2009 to order turbines for a project on which significant physical work commenced at the site in December 2010. The project is self constructed. The entire project qualifies for a 100% bonus provided it is completed by December 2011. If it is not completed until 2012, then it qualifies for a 50% bonus, with two exceptions. Individual turbines that go into service in 2011 qualify for a 100% bonus, and it is possible that part of the intertie qualifies for a 100% bonus even if completed in 2012.

Suppose instead that significant physical work started at the site / *continued page 15*

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operation. This is essential in tailoring corporate compliance efforts where they are needed most.

Another key element of assessing risk can be found through a careful examination of a company's specific industry and practices unique to it. In the world of project finance, for example, joint ventures, consortia and acquisitions present clear risks, as a company can be held liable for bribery committed by its partner or, in some cases, even for improper acts of an acquired company that occurred prior to the acquisition. Further, these complex deals often involve government entities and officials, which increase the risk of corruption in many countries. The common practice of using local agents in foreign countries also increases risk, as does the giving or receiving of business gifts, entertaining and the covering of travel-related expenses of government officials. Guidance issued by the Ministry of Justice indicates that assessment of such risks must be periodic, informed and documented, overseen significantly by top management and appropriated adequate resources.

The new UK Bribery Act makes it a crime to bribe any individual—not just a government official. US companies with ties to the UK will have to comply.

Step 2: Implement Meaningful Procedures

Once risks have been identified, a company must issue a meaningful global anti-corruption policy.

At first blush, this step appears deceptively easy. Typically only a few pages in length, an anti-corruption policy describes the organization's tireless commitment to bribery prevention and delineates the very prohibitions, guidelines and limits that will mitigate risks and hopefully prevent bribery from occurring. Once finalized, the policy should be translated into all relevant languages and circulated widely to every employee, agent involved in business activities and sometimes even clients and customers.

However, simply issuing a policy or paying it lip service is far from adequate and will assuredly expose a company to unnecessary risk.

The companies that have been most successful in avoiding violations of the FCPA, for example, are those with a demonstrable and unshakeable top-level management commitment to anti-corruption initiatives. As with many things in business, leadership is key—employees and business partners alike must witness management's commitment to a zero-tolerance policy toward bribery. That commitment can be demonstrated in many ways, but none more powerful than turning away a potentially-lucrative business opportunity if it includes any act of impropriety. Management must also spread the message downward, so that everyone knows that the company will never offer, pay, reimburse or condone a bribe.

A company must also design and enforce effective, workable procedures that are proportional to its risk.

Of these, none is perhaps as important as performing thorough due diligence on customers and agents hired to assist with business activities. This can include retaining companies to conduct background checks, requiring business partners and agents to complete questionnaires designed to quickly uncover red-flags, and forcing business partners and agents to certify in writing that they will abide by the company's anti-corruption policy. Of course, companies will be expected to monitor the activities of these parties to ensure compliance.

Step 3: Training, Training and More Training

Finally, a company must institute strong and effective training on these values, policies and procedures. The UK government guidance requires a company to ensure that its bribery prevention policies and procedures are embedded and understood at all levels. This frequently includes live and online training sessions and periodic refreshers on core topics such as the ever-changing world of anti-corruption laws. The frequency, intensity and format of training will depend to a large degree on the company's risk profile.

Risks for Project Finance

The risk that a bribe will be offered or paid increases as a company expands into developing markets, as business ventures increase in size and scope and as a company cedes control to local entities or persons located thousands of miles from its headquarters. Project finance matters are often subject to these risks and more.

Government tenders present a particular risk of corruption. Lavish entertainment, gifts or an advantage of any sort that is given to a government official — including employees of state-owned entities — for a specific business advantage (think *quid pro quo* or "I'll scratch your back if you scratch mine") will likely violate the Bribery Act or give rise to an appearance that it has been violated.

Giving a job to a government official's relative can also be considered a bribe, as well as taking a government official and his family on a lavish vacation.

In short, a bribe can be *anything* of value, tangible or not.

Often, local agents are retained to facilitate business overseas or dealings with foreign governments, and these third-parties pose a specific and concrete corruption risk. Local agents have historically led to the prosecution of many companies under the FCPA. Therefore, a company must know its agents before retaining them and keep a careful watch on their activities afterward.

With regard to joint ventures and consortia, the UK government guidance to the Bribery Act states that a joint venture partner will be liable for an act of bribery by the joint venture if the bribe was paid with the intention of "benefiting" that member. While the mere existence of a joint venture does not automatically trigger liability, partners must be aware that this possibility exists and take meaningful steps to guard against it. The Bonny Island joint venture to construct liquefied natural gas facilities in Nigeria is a particularly jarring example of what can happen under the US Foreign Corrupt Practices Act. A total of $1.5 billion in fines were levied against members of the joint venture between 2009 and 2011, non-US citizens have been extradited and guilty pleas have been entered.

With regard to acquisitions, due diligence is key. An acquiring company will often become liable for the past acts of the company it acquires. By way of example, General Electric settled FCPA charges in 2010 and agreed to pay $23.5 million for not only its own violations, but also for those committed by Amersham and Ionics, two companies it acquired after their violative conduct. The risk of acquiring liability, / continued page 16

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in August 2010. The developer may still be able to take the position that construction did not start until after September 9 if no more than 10% of the costs were incurred before September 9. Each turbine, pad and tower is considered a separate project.

Suppose that the project was too far along before September 9: it was under construction too soon. The developer can still take a 100% bonus on the costs incurred on or after September 9. Costs are not ordinarily incurred until delivery.

Another issue on which the market had been awaiting guidance was whether a company can choose not to take a 100% bonus on equipment that qualifies and take a 50% bonus instead.

The IRS said it will allow such a choice for projects put into service in 2010 but not in 2011 or 2012. It is the 100% bonus or nothing for projects put into service in 2011 or 2012 if they qualify otherwise for a 100% bonus. However, elections to opt out entirely can be made selectively just for all the 5-year property put into service in 2011, for example, while keeping a 100% bonus on the rest of the project. A new election can be made each year.

Many renewable energy developers have had difficulty persuading tax equity investors to take any bonus. The tax equity market remains short on tax capacity. Many tax equity investors would prefer to spread their scarce tax capacity over a larger number of transactions. In addition, depreciation, including the bonus, is viewed a timing benefit that does not add to earnings, unlike tax credits.

CALIFORNIA PROPERTY TAXES have become a nettlesome issue for solar developers.

Efforts are underway in the state legislature to clarify a key issue.

California generally assigns a value to property for property tax purposes at one of three times: at the end of construction of new equipment, when the / continued page 17

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however, can be substantially mitigated through pre-acquisition due diligence.

Rabid Enforcement

While the FCPA has been on the books for 34 years, the first 25 years were relatively quiet, with only a handful of prosecutions each year.

To expect the same for the Bribery Act would be foolish.

British prosecutors will speed through the learning curve normally associated with implementing new and complicated legislation, and are expected to run the "FCPA playbook" from start to finish. Who can blame them? The United States has extracted *more than* $3 billion in the last three years alone from corporations that ran afoul of the FCPA, while establishing itself as a global leader in the war against corruption.

Companies must recognize that the Bribery Act places no limits on the monetary fines that can be levied for violations and, unlike the FCPA, the Bribery Act allows executives who violate the law to be jailed for up to 10 years. ◎

Renewables Opportunities in Mexico

by Raquel Bierzwinsky, in Washington

Mexico has set an ambitious goal of having 35% of all energy production derive from renewable energy sources by 2024. In the next 15 years, national energy consumption is expected to grow at an annual pace of 3.7%.

The country is expected to have 13 to 14 operating wind farms within three years.

Solar has been slower to develop.

The government has begun planting the seeds, through legislation and incentives, for the increased participation of private capital in the sector.

Background

The private sector's participation in the power industry in Mexico did not commence until 1992 with legal reforms that allowed private entities to participate in the generation of power.

Transmission, sale and distribution of power remain services exclusively provided by the *Comisión Federal de Electricidad* or "CFE," the state-owned utility.

Currently, Mexican law allows private entities to participate in five generation schemes: as independent power producers or "IPPs," in inside-the-fence projects called "self supply" or "*autoabastecimiento*," as cogenerators, as small power producers, meaning producers of less than 30 megawatts, and as exporters or as importers for self consumption.

Beginning in 1993 with the Mérida III IPP project, the Mexican government has awarded more than 25 IPP projects, mainly employing gas-fired and combined-cycle gas turbine technologies. Under the IPP scheme, electricity may only be sold to CFE under 25-year power purchase agreements awarded through competitive bidding procedures based on the lowest average generation price. IPPs currently represent approximately 35% of the aggregate energy production in Mexico.

In the past 12 months, CFE awarded the 433-megawatt gas-fired combined-cycle Norte II IPP project and is in the process of awarding the 217- to 294-megawatt Baja California III combined-cycle gas-fired power project.

The Mexican government recently included renewable energy projects under the IPP scheme, namely five wind energy projects, all located in the southern state of Oaxaca (in this case subject to 20-year PPAs).

Of all current Mexican power output, 77% derives from fossil fuels, while only 23% derives from alternative energy sources, mainly hydro.

Renewables Outlook

With the enactment in November of 2008 of the "Law for the Use of Renewable Energies and Financing of Energy Transition," the Mexican government of Felipe Calderón took the first steps in promoting the diversification of sources of energy through the use of renewables developed and operated by private entities.

However, renewable energy IPPs are not subject to the renewable energies law, but rather continue to be subject to the "Electric Energy Public Service Law," which governs generation from conventional power sources.

In terms of development of renewable energy projects different from IPPs, the *Comisión Reguladora de Energía* or "CRE," the government agency responsible for granting all private energy production permits and licenses, had issued 113 permits for the development of wind, biomass, hydro and biogas energy projects, which, once operational, are expected to generate over 3.5 gigawatts of power, with wind power constituting almost 75% of the technology used followed by biomass with 16%, hydro with 8% and biogas with 1%. Notably missing are licenses for private geothermal and solar power projects.

Most of the permits granted are under the small production and self-supply schemes, with the majority being under the latter. Under the self-supply scheme, the power producer must form a venture with its offtakers (*socios autoabastecidos* or self-supplied partners), whereby the offtakers must commit to purchase the entire power output of a plant under 15- to 20-year power purchase agreements.

The Mexican government has adopted certain schemes to support development of privately-owned renewable projects, including 100% depreciation in the first year for all renewable energy capital investments and the abatement of annual government fees. Another important incentive may come from the implementation by the Mexican government of mechanisms established by the Kyoto protocol (under which Mexico is designated as an Annex II country, eligible for clean development mechanism (CDM) projects) allowing renewable energy projects to obtain certificates of emission reduction, representing an additional source of financing for the projects.

On the regulatory front, CFE has developed special transmission agreements derived from open season processes for electricity generated from renewable sources, providing for reduced transportation rates, and is assisting in negotiating land rights for the construction of the transmission lines.

The Crown Jewel — Wind Projects

Wind projects have taken off in Mexico. Prime areas for the development of wind projects include the Istmo de Tehuantepec region in the state of Oaxaca, the Baja California region, the Yucatán peninsula, the states of Zacatecas and Veracruz, and along the northern Pacific coast. The state of Oaxaca leads the way with an estimated wind potential of over 10,000 megawatts, followed by the Baja California region with an estimated potential of over 5,000 megawatts.

The Istmo region presents some particularly advantageous conditions for wind power projects, as the average wind speed in Oaxaca is above 8.5 meters per second — approximately 30 empty trailer trucks are turned over by the wind current in the Istmo every year — and the measured load factor is above 50%.

The Istmo region, one of the poorest in / continued page 18

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equipment is sold or when the project company that owns the equipment undergoes a change in control.

A special rule lets solar equipment go unassessed at the end of construction. That means that property tax assessors ignore the increase in value to a building or house from adding solar panels.

However, there has been some confusion about whether selling an interest in solar equipment to a tax equity investor triggers an assessment. For example, such a sale might be viewed as a change in control of the project company that owns the equipment.

The staff of the State Board of Equalization has advised informally that bringing in a tax equity investor to own equipment during construction will not trigger an assessment of solar equipment during or at the end of construction. Some tax equity investors have been uncomfortable relying on such informal advice, and there is no rulings process that would give the investors enough comfort. Therefore, they prefer to invest in deals before construction starts.

A bill has been introduced in the state Assembly to clarify how the rules work. The bill is A.B. 15. Discussions are still underway with committee staff in the state Senate about the text.

PARTNERSHIP FLIP TRANSACTIONS have been edging away from strict adherence with guidelines that the IRS issued in 2007 for such transactions.

Richard Probst, a lawyer in the IRS national office, warned during a talk at a tax conference in Chicago in May against giving the tax equity investor a "put" to force the developer to buy back the investor's interest after the flip.

He also said the developer cannot guarantee that the "wind will blow" and said the investor cannot have a guarantee from anyone against losing his investment.

Probst had a role in writing the original guidelines. / continued page 19

Mexico

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the country, requires major investment in transmission lines and interconnection capacity to serve all new projects being developed. To that end, CRE and CFE launched an initial open season invitation for private entities to reserve transmission capacity. Self-supply developers initially subscribed 1,900 megawatts of transmission capacity to be built by CFE, requiring letter-of-credit support from these private entities to guarantee construction. Such reserved capacity was later reduced to 1,491 megawatts as a result of forfeiture of capacity and adjustments in the existing transmission lines. A new 400 kv transmission line with a 2,000 megawatts transmission capacity was placed into operation in 2010. Existing transmission capacity was also reinforced and expanded by 330 megawatts.

A second open season process is expected to be launched in 2011, but CRE has not confirmed the timing for this to occur.

CFE has now awarded five wind IPP projects, all in the state of Oaxaca: the 102.85-megawatt La Venta III, sponsored by Iberdrola, the 102-megawatt Oaxaca I, sponsored by ACS, and the Oaxaca II, III and IV projects, currently under development by Acciona Energy, with an individual capacity of 102-megawatts per project. These IPPs, along with CFE's La Venta I and II projects jointly will have 590 megawatts of installed capacity.

However, the capacity and power output of these CFE projects only represent 10% to 20% of total wind power capacity in the country, as the majority of commercial wind projects in Mexico are being developed under the self-supply scheme. CRE has so far issued permits to develop over 2,000 megawatts, and it is expected that by 2014 there will be 13 to 14 wind projects installed with an aggregate output between 2,500 and 3,000 megawatts.

The forecast is for Mexico to have at least 7,000 megawatts of installed wind capacity by 2025.

Notable self-supply projects that have been or are in the process of being developed within the last year include the 250-megawatt Eurus project in Oaxaca, developed by Acciona Energy and financed by the International Finance Corporation (IFC), the Inter-American Development Bank (IADB), the Corporación Andina de Fomento, Germany's DEG, France's Proparco, Spain's Instituto de Crédito Oficial, Mexico's Nacional Financiera and Bancomext, along with participations from commercial banks BBVA and Banco Espirito Santo, as well as the World Bank Clean Technology Fund. The Eurus wind farm will supply power to Cemex plants throughout Mexico.

Mexico is expected to have 13 or 14 operating wind farms within three years. Solar has been slower to take hold.

Another notable self-supply wind farm in the past year is the 67.5-megawatt La Mata-Ventosa project in Oaxaca, developed by Eléctrica del Valle de México S. de R.L. de C.V., an affiliate of EdF Energies Nouvelles SA of France, supplying power to Wal-Mart stores across the country, and financed by the IFC (along with a loan from the World Bank Clean Technology Fund), the IADB and the Export-Import Bank of the United States.

One of the most significant projects in the country is a 396-megawatt wind farm that Macquarie and FEMSA are developing in Santo Domingo, Oaxaca, to supply power to several FEMSA and Heineken subsidiaries across the country.

Finally, there is a 90-megawatt wind project also in Oaxaca under development by Renovalia's Mexican subsidiary Desarrollos Eólicos Mexicanos, with Grupo Bimbo's plants as offtakers.

In addition, Iberdrola was recently selected by Gesa Eólica de México to build the 228-megawatt Piedra Larga wind project also in Oaxaca.

The Baja California region also has a pipeline of wind projects developed or under development, beginning with Spain's Unión Fenosa's 10-megawatt La Rumorosa and two 800-megawatt projects currently under development by a venture between Unión Fenosa and Sempra Energy. These three projects have the goal of transporting and selling the power output to the California energy market under the export scheme.

The Aubanel project, located near the town of La Rumorosa, just 15 miles south of the Mexico-US border and 60 miles east of San Diego, will be jointly developed by Gamesa and Cannon Power in several stages and is projected to have a total capacity of 1,000 megawatts. This project is expected to sell its output initially to Mexican consumers under the self-supply scheme, but at a later stage is planned to export electricity to the California market.

What the Future Holds

Unlike wind power, development of projects from other renewable sources has yet to flourish.

Even though Mexico has some of the highest potential for solar power use in the world with average isolation potential of 0.6 kWhs per square foot, large-scale and utility-size solar power projects are yet to be developed. Solar power has been used for thermal solar applications for water heating and photovoltaic applications for the provision of electric power at isolated sites and settlements, including by Pemex for the use of photovoltaic panels to power monitoring systems for its offshore oil and gas production platforms, and in private, roof-mounted PV projects, which represent a total of 18 megawatts of off-the-grid capacity.

High costs and technology concerns have been cited as the main impediments to development of large-scale solar projects.

CFE has announced the development of 12 megawatts of solar energy projects, while, on the private side, only a few developers have proposed solar projects ranging in size from 80 acres to 400 acres contiguous to electric substations in the states of Veracruz and Chiapas, with estimated costs per project ranging from US$50 million to $250 million.

Hydro power is the biggest non-fossil fuel source of energy in Mexico, with large-scale utility projects, such as the 2,300-megawatt El Cajón project in the state of Nayarit, being exclusively developed and operated by CFE. Mexico has seen a slow stream of small-scale privately-owned hydro projects being developed in the past few years under the self-supply schemes, representing 292 megawatts of capacity. The Papaloapan basin in the state of Veracruz has been identified as having significant potential for mini-hydro generation. The National Commission for Energy Savings has developed studies of the potential of the Rio Blanco River in the state of Veracruz along Mexico's gulf coast.

Existing geothermal projects have been developed only by CFE and amount to 960 megawatts of / continued page 20

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MUNICIPAL UTLITIES will have to start withholding 3% of what they pay for electricity to independent generators starting as early as 2013 under new regulations the IRS issued in May.

US military bases will have to do the same.

Congress directed all federal, state and local government entities to withhold 3% of payments for "property or services" after learning that many contractors working for the US government during the Iraq war were not paying income taxes on their earnings under government contacts. The amounts are turned over to the IRS. The contractor can claim a credit against income taxes later when it files its tax return.

Withholding was originally supposed to start in 2011. Congress delayed it to 2012 in the American Recovery and Reinvestment Act. The IRS delayed it again to 2014 in May in order to give federal, state and local government agencies more time to program computers to withhold taxes. However, withholding will start earlier — in 2013 — on new contracts that are signed in 2013 or on existing contracts that are materially modified in 2013.

Withholding is required when a municipal utility, military base or other government entity pays a contractor to build a power plant for it.

It is required on prepayments under "prepaid service contracts" where a municipal utility prepays for a share of the electricity it will receive over a long-term power contract.

The US Department of Energy is guaranteeing the debt on some wind, solar and other renewable energy projects. If the debt goes into default and the government forecloses on the project, then payments the project company makes after foreclosure to third parties for property or services will become subject to withholding.

Withholding is on the gross amount of payments, even though part might be deducted later to pay sales taxes.

However, no withholding is required on a variety of payments. / continued page 21

Mexico

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installed capacity. Mexico is the world's third largest user of power from geothermal plants. CFE has announced an intention to develop an additional 125 megawatts of capacity in the near future, but has not hinted at any possibility of these being developed by the private sector.

Finally, permits for the development of biomass and biogas projects have been issued for just over 620 megawatts of capacity. The largest use of biomass for power generation in Mexico comes from sugarcane bagasse and from waste. Waste-to-energy projects have been actively promoted by state governments. A handful of projects based on the use of methane and other gases extracted from municipal landfills have been developed, including the Energía de Nuevo León project, which utilizes gas extracted from the landfill in the city of Monterrey and has a production capacity of 7.4 megawatts. Other landfill projects are being considered in Mexico City and the State of Mexico. The World Bank has been monitoring regulatory changes in Mexico for the promotion of biogas projects at landfills.

In conclusion, Mexico offers a wide variety of resources for the development of renewable energy projects. However, a key element for a more robust renewables market depends on the government's willingness to diversify energy sources for public consumption and to allow development of large-scale projects by private entities, under IPP and other schemes, from sources such as wind, solar, hydro and geothermal, of which Mexico has an abundant supply.

For the time being, self-supply and export schemes, along with CFE's periodic bids for IPP projects, present the most viable path for private sector development of renewable projects in Mexico. ◎

Wind Energy is Going Real Time in the Midwest

by Bob Shapiro, in Washington

The Federal Energy Regulatory Commission approved a proposal by the Midwest Independent Transmission System Operator or "MISO" in March that will require most wind farms that are MISO members to make themselves available for automatic dispatch by MISO in the "real-time" market.

This could mean an additional source of revenue for wind farms that sell into the real-time market. It could also mean penalties for such projects that are unable to dispatch as directed.

Whether or not a wind farm that has a long-term power purchase agreement with a utility in MISO will be subject to the economic benefits or penalties of participating in the real-time market will depend on the terms of the individual PPA. The same is true for wind farms that sell output through agents, known as market participants, in MISO: the terms of the agreement with the market participant will dictate the allocation of risk.

Most wind farms have until February 2013 to install equipment required to respond to automatic dispatch signals. The requirement to participate in the real-time market commences on March 1, 2013.

The new rules do not apply to some older wind farms originally completed before April 2005 or to wind farms with certain network designation and firm transmission rights.

MISO is the independent operator of the electricity grid in parts of Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Montana, North Dakota, Ohio, Pennsylvania, South Dakota and Wisconsin.

The wind farms that are required to make themselves available for automatic dispatch in the real-time market are called "dispatchable intermittent resources" or "DIRs."

DIR is a new category of intermittent resources (essentially renewable) that is to be treated in a manner substantially similar to other conventional generation resources in certain real-time energy markets.

The FERC order may serve as a model for other regional transmission organizations that are trying to incorporate more wind resources into their generation mix using market mechanisms that are comparable to those for conventional generation.

Several parties have asked for a rehearing. However, FERC is unlikely to modify its decision in any material way.

A Tale of Two Markets

MISO has two trading markets: the day-ahead market and the real-time market. The day-ahead market permits generators to bid to provide energy to customers over the following day — hence "day ahead." In the real-time market, on the other hand, generators make energy available for sale during the same day that the energy is delivered — in other words, in "real time."

In MISO, intermittent resources (solar, wind, run of river hydro, biomass) are treated similarly to conventional generation resources in the day-ahead market. In the day-ahead market, the generator can choose to self schedule (essentially, to offer all energy available to be produced and be a price taker to assure delivery) or to offer to sell at a particular price.

However, under existing MISO rules, real-time generation must be dispatchable by the system operator. Intermittent resources are not considered dispatchable in real time due to the fact that they are forecast-dependent resources. In other words, the system operator assumes that it cannot ask an intermittent resource to increase or decrease its output automatically, and therefore all intermittent resources are excluded currently from the real-time markets.

MISO claimed that its inability to dispatch intermittent resources in the real-time energy market means that it cannot redispatch these resources properly to manage congestion on the system that may occur during different hours of the day — for example, during periods when transmission is in short supply or when electricity demand is low.

MISO asked FERC to let it dispatch intermittent resources in the real-time market. It argued that this would reduce congestion costs, make the system more efficient, and save millions of dollars a year.

How DIRs Will Operate

Conventional generators in the real-time market are required to give forecasts of available generation every hour and half hour in advance of the "operating hour" in which the energy is to be produced.

The DIR will also be required to give forecasts, but its forecasts will be different.

It will be required to give 12 forecasts in five-minute intervals prior to the operating hour. The DIR will have the ability to modify its forecast up to 10 minutes prior to each interval and, thus, will have the right to adjust its maximum available output forecast, called the "forecast maximum limit."

The MISO is developing its own five-minute interval forecast model for wind resources that would be used as a default forecast in the event that the DIR fails to update its forecast as it is permitted to do. The DIR can only be dispatched at or below the forecast maximum limit. The DIR will be able to make an economic offer — or an offer to sell at a particular price — in real time and be dispatched up to its forecast maximum limit based on its most recent five-minute forecast (or / continued page 22

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It is not required on government grants.

It is not required on payments by government utilities or other government agencies in Puerto Rico and other US possessions. It is not required on payments by Indian tribes. It is not required on payments to tax-exempt entities, even if the payments are taxable to the tax-exempt entity as "unrelated business taxable income." It is not required on interest. It is not required on rents to lease land, buildings or office space.

Municipalities do not have to withhold unless they pay more than $100 million a year for property and services.

A municipality should look at its spending for its fiscal year that ends two years before the year it is trying to decide whether it must withhold taxes. Thus, for example, a municipal utility that uses a June 30 fiscal year and is trying to decide whether to withhold on payments in 2013 should look at what it spent on property and services in its fiscal year that ended in 2011. It has the option instead of using its average spending in four of the five fiscal years ending in fiscal 2011.

When doing the $100 million calculation, the municipality should not count payments of a type that are exempted from withholding — for example, rent to lease office space.

RENEWABLE ENERGY PROJECTS IN PUERTO RICO qualify in some instances for investment credits — and, by extension, Treasury cash grants — the IRS ruled privately in May.

The ruling involved a utility-scale solar project.

Whether an investment tax credit can be claimed depends on the ownership structure for the project. The project was owned by a local company in Puerto Rico, but that company was owned 100% by a US limited liability company that had, in turn, two US corporations as owners.

Investment credits may not be claimed on property used predominantly outside the United States. US posses- / continued page 23

MISO

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MISO's default forecast) and will be subject to its approved ramp rates, or the speed with which it can reach full output.

Real-Time Benefits and Risks

By being required to participate in the real-time market, DIRs can either self schedule or submit "economic offers" to sell energy at particular prices, and they will be paid for all energy that clears the market.

They are also eligible for make-whole payments from the system that will cover costs if the energy dispatched after the day-ahead market closes does not compensate the generator fully for its costs.

Along with the potential benefits of participating in the real-time market, DIRs also will be subject to potential penalties for non-performance or poor performance. It is this aspect of the proposal that has elicited the most comment from intervenors at FERC.

The DIR must produce energy as dispatched by the system operator within an 8% tolerance band. In other words, the DIR must not deliver more than 108% or less than 92% of the requested dispatch amount over each dispatch interval. If the DIR deviates by more than 8% for four or more consecutive dispatch intervals, and the deviation is by more than 6 megawatts, then the DIR will be subject to system penalty charges.

The American Wind Energy Association, which generally supported the MISO proposal for DIRs, asked FERC to adopt a somewhat different and somewhat more lenient standard for permissible deviations from dispatch. AWEA asked FERC to adopt the standard utilized in the so-called nodal protocols by the Electric Reliability Council of Texas or "ERCOT." FERC determined that the MISO proposal on penalties for deviations was supported by data and reasonable, and thus approved it without modification.

On the other end of the spectrum, a group of financial players in the MISO market, representing interests that make virtual sales but do not own power plants in MISO, has asked for a rehearing of the FERC order, claiming that the proposal would allow wind projects to "escape" a number of potential performance penalty payments — known as "revenue sufficiency guarantee charges" — to which conventional generators and non-generators (virtual suppliers) are subject. In particular, they object to the basic structure of the proposal that would allow wind resources to update their forecasts on short intervals in real time. FERC is unlikely to change its mind on this point on rehearing.

Many wind projects in the Midwest will have to make themselves available for automatic dispatch by the grid. It could mean more revenue and also penalties.

It should be noted that DIRs will only participate in the *real-time* energy market. DIRs will not be permitted to compete to provide operating reserves in the real-time market. However, such eligibility may become possible in the future as a result of greater experience and data analysis for wind resources.

Who Must Become a DIR

Not all wind farms will be required to become DIRs. Wind farms that are "qualifying facilities" or "QFs" under Public Utility Regulatory Policies Act that are currently not registered members of MISO will not be required to register, although such QFs would be permitted to do so, and other intermittent resources, including solar, hydroelectric and biomass resources, will not have to become DIRs.

Starting March 1, 2013, all other wind farms must become DIRs *unless* they lack the technical equipment to be capable of set-point instructions and fall into one of two categories. A project without the technical equipment does not have to become a DIR if it was originally placed in service before April 2005. It does not have to become a DIR if it has network resource interconnection service or has been designated as a generator network resource or the energy the wind farm produces is subject to an agreement for long-term firm point-to-point transmission service.

The argument for exclusion of older (pre- 2005) wind farms from the DIR requirement is that they would not have installed, and it would be too expensive to require those older resources to add, technology capable of following automated dispatch instructions. They can elect, but are not required, to become DIRs.

The argument for exempting generators with firm interconnection, firm transmission or network resource designations is that the projects have already been determined to be able to reach any load, and they do not need to be capable of following automated dispatch instructions. Again, such wind farms can elect, but are not required, to become DIRs.

The intermittent resources that are not DIRs would be required to participate in the day-ahead market only.

The delayed start date of March 1, 2013 is supposed to give wind farms built after April 1, 2005 time to install the necessary equipment to permit automatic dispatch by MISO.

Once In, Always In

FERC determined that a wind farm that becomes a DIR cannot elect to drop out from that designation at a later date. Thus, after March 1, 2013, even if a wind farm DIR signs a contract for firm point-to-point transmission service or network resource interconnection service, thus satisfying one of the allowed exceptions to DIR designation, it cannot avoid being required to continue to participate in the real-time market.

AWEA asked for a rehearing on this point, arguing that failing to allow this switch is unduly discriminatory in favor of wind farms that are currently eligible for exemption from DIR designation, since wind farms currently eligible for exemption from DIR designation could switch to DIR status if they felt it was more economically advantageous to do so. It is unlikely that FERC will be persuaded by this argument, because currently exempted wind farms would also be required to remain DIRs once they elect to switch to DIR designation. ◎

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sions like Puerto Rico are considered outside the United States for this purpose. However, the US tax code makes an exception for property used in possessions as long as it is owned by a US corporation or citizen.

The IRS said it was fine with the ownership structure for the solar project because the Puerto Rican project company was "disregarded" for US tax purposes — it was treated as if it did not exist — and the US limited liability company, even though treated for US tax purposes as a partnership, that owned it was owned entirely by US corporations. In other words, the IRS looked though both the project company and the partnership and found the project was owned by US corporations.

It is unclear whether the IRS would have reached the same conclusion if the project company had a Puerto Rican investor as a part owner or if the two US corporations had owned the project company through an offshore entity.

The ruling is private. The IRS is expected to release a redacted version and assign a number to it in August.

US RETAIL ELECTRICITY PRICES ranged from a high of 21.21¢ a kilowatt hour in Hawaii to 6.08¢ a kilowatt hour in Wyoming.

The four most expensive states after Hawaii are Connecticut, New York, Massachusetts and New Hampshire. All New England states, except Vermont, are in the top 10 states in terms of high electricity prices. Vermont is number 13.

The two states where rooftop solar developers are gaining the most traction are California and New Jersey. California ranks eighth with an average retail price of 13.24¢. New Jersey ranks sixth at 14.52¢.

The figures are for 2009. The US Energy Information Administration released them in late April. Total US generating capacity in 2009 was 1.025 million megawatts. */ continued page 25*

Outlook For Private Investment In US Infrastructure

The United States has been engaged in steady hand wringing about crumbling infrastructure, but the dire fiscal condition of the federal and state governments is making it difficult to find the money to rebuild. Other countries have made wider use of public-private partnerships. Chadbourne hosted a roundtable discussion in late March at its offices in New York about trends in the use of such arrangements in the United States. The following is an edited transcript.

The panelists are Gregory Carey, chairman of the public sector and infrastructure department at Goldman Sachs, Jacob S. Falk, acting director of the office of infrastructure finance and innovation at the US Department of Transportation, Stuart Marks, senior investment director for Meridiam Infrastructure North America, Fadi Selwan, chief operating officer of VINCI Concessions/Development, James S. Simpson, commissioner of the New Jersey Department of Transportation, and Thomas Suozzi, a senior advisor to Lazard Frères & Co. The moderator is Doug Fried with Chadbourne in New York.

MR. FRIED: Greg Carey, the Port of Miami Tunnel and the I-595 highway were structured as availability-based transactions in which Florida will pay the private concessionaires an amount based on the availability of each project rather than having each concessionaire take traffic risk by tying its compensation to the tolls it can collect.

The Goethals Bridge replacement project is also expected to be an availability-based deal.

Canada has a market structured around availability-based deals.

Do think this will become the predominant model in the United States?

MR. CAREY: No, it will not be the predominant model, but you will see it in certain places. Each of the 50 US states has its own politics. You will see availability payments when a state is looking to shift risk. Look at the Denver FasTracks deal, which is availability based. You will see a lot of availability-based deals in transit because people will not take the fare box risk.

I believe you will see a lot of the new builds, greenfield-type projects like the West-by-Northwest highway in Georgia and the Midtown tunnel in Virginia. Each is different. The trend is for greater private sector participation in new builds. If you look at LBJ (I-635) and the North Tarrant Expressway in Texas, Texas put about a billion dollars of equity into both of those deals. Five years ago, it would not have done so. The market has evolved. Availability deals shift construction and operating risk to the private sector.

As the states get more tight fisted with dollars, they will look for alternative delivery methods.

MR. FRIED: Stuart Marks, is there a future for traffic-based deals in the US?

MR. MARKS: Yes. The procuring authorities have to consider a range of financial and political considerations when deciding whether to undertake a project. They play into the decision first whether to do a public-private partnership. P3s are just one method of procurement that governments consider across a range of different tools. Once the decision has been made to do a P3, financial and political considerations determine whether to do a traditional toll risk-based deal or an availability-based deal or a managed lane deal, which is a unique product in between.

Managed Lanes

MR. FRIED: Will there be more managed lanes projects in the US going forward?

MR. MARKS: I think so. It is a new and innovative procurement methodology. The fact that two projects have now closed successfully — LBJ and North Tarrant — has built investor confidence in the model. However, it is not for the faint hearted.

Investors benefit from having an existing data base of traffic performance.

MR. FRIED: What was the greatest challenge you faced in trying to close LBJ and North Tarrant?

MR. MARKS: The fact that it was a relatively new product. We spent a lot of time educating funders and the credit agencies about why we think it made sense. It helped that the Dallas Police and Fire Pension Fund invested as it shows support of a local pension fund. We expect to see more pension funds involved in projects.

MR. FRIED: Fadi Selwan, how does your analysis of a managed lanes project differ from a pure toll deal or some other transaction?

MR. SELWAN: For me, managed lanes are a service we are providing to the commuters. When we build managed lanes, it is usually on existing roads. You add two lanes and you manage them, or you extract two lanes from the road and you put them in the managed lanes system. They are just a service you provide commuters.

MR. FRIED: How reliable are the traffic projections given the nature of a managed lanes project?

MR. SELWAN: I know that of all the traffic studies that have been done in the last 20 years, almost none has been right. The managed lanes are on an existing road. You know what the traffic is today, and you know that by improving the road you might increase the traffic. Then you have to estimate how many drivers will decide to switch to the managed lane. How many will be prepared to pay $5, $10 or $20 just to gain 15 minutes?

The main issue is to calculate the value of time. It varies by country, state, city and suburb. If you can calculate the value of time, then you can evaluate how much of the traffic will switch to the managed lanes.

MR. FRIED: Do you think managed lanes are an easier sell politically because use of the lanes is optional?

MR. SELWAN: Yes. We are operating a managed lanes project in California, and it is working well. The toll can increase by a factor of five in the course of the day. No one is complaining because they know that they have a choice.

MR. SUOZZI: A single driver's behavior can change from day to day depending on whether he has a meeting that day, what is going on with his job and the economy.

The politics may not be as straightforward as the question suggested. Some drivers will see more choices. Others will see a reduction in free lanes.

MR. FRIED: The demographics of the area and the average income of the people in the area will have an effect.

MR. SIMPSON: It is very difficult in a dense urban area to take away one lane. You just can't do it. It is a lot easier to add capacity.

A lot of up-front work needs to be done by the private sector before coming in to see public officials about a potential project. Developers should focus on the problem they are trying to solve. Are we trying to fight congestion or we are trying to improve performance or improve operating costs?

MR. CAREY: When managed lanes started being discussed 10 years ago, they were called Lexus lanes. People complained, "You are only doing it for the rich." Has that complaint disappeared or are you still hearing it in northern New Jersey?

MR. SIMPSON: It is still an issue.

MR. FRIED: Jake Falk, there is PR-22, a brownfield procurement underway currently in Puerto Rico. People are also waiting for the brownfield procurement for the Luis / continued page 26

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CONNECTICUT enacted a new tax on electricity generators on May 4. The tax applies to nuclear and fossil fuel power plants. Renewable energy facilities are exempted. The rate is 0.25¢ a kilowatt hour. It is expected to go into effect on July 1.

An earlier version of the tax from which the legislature backed away would have imposed a tax of 2¢ a kilowatt hour on nuclear projects, with lower rates on other fuels. As a result, most revenue from the tax would have been collected from a 2,180 megawatt nuclear power plant owned by Dominion. After lobbying, the state backed off.

The industry has been told that the tax is to remain in effect for two years to help the state overcome a large budget deficit, but there are still unhappy independent generators who see the tax cutting significantly into their expected profits from building plants in the state, and there is skepticism that the tax will be allowed to expire.

CALIFORNIA increased the share of electricity that utilities must supply from renewable sources to 33% by 2020. The target had been 20% by 2010. The three investor-owned utilities supply an average of 18% currently from renewables. Another 21,000 megawatts of new renewable capacity is needed to meet the higher target. The governor signed a bill with the new target on April 12.

THE RENEWABLE PORTFOLIO STANDARD in Arizona is legal, a state appeals court said in April.

Arizona requires electric utilities to supply at least 25% of their electricity from renewables by 2025. The standard was set by the Arizona Corporation Commission, which regulates utilities. Customers of Arizona Public Service challenged the authority of the state regulators to impose such a standard. / continued page 27

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Muñoz International Airport in Puerto Rico. What do you think the prospects are for brownfields in the US market going forward, or will the US be mainly a greenfield market?

MR. FALK: I will call it an existing asset rather than a brownfield so that we don't have any confusion with Superfund sites. The trend in the last few years has been to move away from big privatizations like the Chicago Skyway, the Indiana Toll Road, the Northwest Parkway and the Pocahontas Parkway, toward greenfield or new-build projects. However, this will vary ultimately by jurisdiction.

We may also see a hybrid or joint model in the future that has some brownfield components and some greenfield components. There are benefits from the standpoint of public sector acceptance to combining these components into a single project where you can see we are not just selling an asset, but we are also getting additional new infrastructure in return.

There are fewer private bidders on public infrastructure projects in the United States than in other countries. One reason is states sometimes pull back projects after putting them out for bid.

New Jersey

MR. FRIED: Jim Simpson, last year Richard Zimmer of the New Jersey Privatization Task Force said that the state was preparing P3 legislation. What is the status of the task force's recommendations?

MR. SIMPSON: We need P3 legislation. New Jersey Transit has P3 legislation. We are doing an RFP for parking. We have so many parking facilities that are run like mom-and-pop organizations. Some are free, some charge, but there is no overall plan. New Jersey Transit is not in the parking business, so we put out this RFP for parking.

As far as the other recommendations, we have a proposal that just went out for the Turnpike because our costs are so high. They are high across the state. This is where the opportunities are for P3s. The backdoor way is to come in and handle all the maintenance first, lower the costs and inject the DNA for a profit motive. There is no penalty for nonperformance in a lot of the states. I have been a private sector guy most of my life, and my DNA is about bottom line and cost efficiencies. There is none of that in government.

Transit agencies across the country are the most inefficient operations in the United States.

MR. FRIED: This is why we need the private sector.

MR. SIMPSON: I am leading up to that point, but the public doesn't always like it. When I go to public meetings, we have to have bomb-sniffing dogs. There are 500 protesters. I do not use the term privatization. I call what we do outsourcing. The public does not understand the difference between privatization and P3. Both have become dirty words, at least in New Jersey.

We are moving forward, but we do not yet have P3 legislation. We are looking at how Pennsylvania did it as a possible model.

Funding Gap

MR. FRIED: Let's shift gears. Stuart Marks, how do we fill the funding gap?

MR. MARKS: With a number of sources — taxable and tax-exempt debt, private equity and federal funding like the TIFIA program. It would help if private activity bonds were available for social infrastructure projects.

MR. FRIED: Jake Falk, tell us what is happening with TIFIA. Will it be expanded? Will it expire?

MR. FALK: Demand for TIFIA funds is several times the available funding.

The Obama administration is asking for an increase of $450 million in funding for the program in fiscal year 2012. That would triple the amount of loans that the program can handle. Both Republicans and Democrats pressed the Department of Transportation last week in a Senate hearing to expand the program. There is also significant support among House Republicans for an expansion.

MR. FRIED: So we are heading in that direction?

MR. FALK: It is too early to say. With Congress focused on deficit reduction, it is not clear whether there will be additional money for anything.

MR. CAREY: Congressman John Mica, who heads the transportation committee in the House, is making a push to shorten the environmental process and move projects more quickly through the selection process. His big issue is how long it takes these projects to get done. Look at the SR 125, road project near San Diego. The environmental process took 11 years. Jake, can you talk about that?

MR. FALK: There is a broad agreement that the project delivery mechanisms are inadequate.

We have fallen into a pattern of the design-bid-build environmental process, and it is an approach that needs to be updated. The administration definitely hears that. President Obama talked a lot earlier this year about the regulatory process and how we fix it. There is a lot of interest on the Hill to deal with that.

P3s have done a very good job over the last few years demonstrating an alternative delivery approach that works. Looking back on the last five years, we have some really positive experiences with P3s. For example, the Capital Beltway project and the innovation that the private sector was able to bring to that project changed the view of the public sector about how project delivery can work.

We expect the issue of how to fix the delivery process to be an important part of any reauthorization discussion this year in Congress.

MR. CAREY: All the TIFIA money over the last 18 months seemed to go to mass transit projects that have metal wheels.

MR. FALK: To be fair, not all the money went to metal wheel projects; there have been others. An example is the TIGER program where we are working with the US 36 road project near Denver. The trend with TIFIA until recently was that it was much more of a toll road type of program. The administration has brought in a lot of other types of infrastructure that would not have received TIFIA funding before. TIFIA is much more of a multi-modal program now. Highway projects will continue to receive funding, but expanding TIFIA to mass transit projects and multi-modal facilities is a good thing.

National Infrastructure Bank

MR. FRIED: Senators Kay Bailey Hutchison and John Kerry introduced the BUILD Act recently. It would */ continued page 28*

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A SYNFUEL PLANT was in service for tax purposes even though it produced little output and sat idle for four years while the developer tried to find a buyer.

The IRS reached that conclusion in a "technical advice memorandum" or ruling by the national office to settle a dispute between a taxpayer and an IRS agent in the field. The agency made the contents public in April.

The synfuel plant was built with the aim of supplying synfuel to a company that went bankrupt. The plant had to be moved into storage shortly after producing a limited amount of synfuel.

The US government offered tax credits for producing synthetic fuel from coal and other substances starting in 1980 after the Arab oil embargo. The credits could be claimed through 2007. However, a plant had to be placed in service by June 30, 1998 to qualify.

Roughly 53 small facilities were built before the deadline that made synfuel by spraying chemicals on raw coal. The IRS challenged whether the output from many of the plants was different enough from the raw coal to qualify as synfuel. It also challenged whether some of the plants made it into service in time to qualify for tax credits, since most were rushed into service close to the deadline and produced synfuel only sporadically for months or years after the deadline, in some cases while continuing to tinker with the equipment.

The new ruling is interesting because it is now years after most of the plants were audited.

The IRS national office said, in siding with the taxpayer, that a plant does not have to reach its design capacity to be in service, but it must be "ready and available to produce on a sustained and reliable basis in commercial quantities." The owner must also have its doors open for business. In this case, the facility was dismantled and stored, but the IRS said that it remained in service because the owner showed no intention to abandon it. */ continued page 29*

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create a national infrastructure bank to provide financing for transportation, water and energy projects. They want the bank to have $10 billion in initial funding. People have been saying that the bill could leverage up to $600 billion in private infrastructure investment.

Tom Suozzi, what are your thoughts about a national infrastructure bank, and do you think it could fill the funding gap?

MR. SUOZZI: It would help fill the funding gap.

People have been talking about a national infrastructure bank for decades. Felix Rohatyn in our office has been pushing for such a bank for a long time. The President came out last year in favor of a national infrastructure bank, but he wanted to house it in the Department of Transportation and focus on transportation projects. Representative Rosa DeLauro has been talking about it for a long time. She wants to do a $50 billion national infrastructure bank.

Now two Senators — a Republican and a Democrat — have taken up the cause in the Senate, and they have co-sponsors, including Senator James Inhofe, a very conservative Republican. The focus is no longer just transportation.

One of the things you see in the Kerry and Hutchinson proposal is that a certain percentage of the funding has to go to rural projects. The politics of the Senate, with two Senators from each state, mean that any bank that emerges will have to make sure that some of the money is directed to smaller states like South Dakota. The figure is on the order of 5% or 10%.

There are two major parts to any national infrastructure bank: how do we fill the funding gap and how do we take politics out of deciding which projects get funded?

The bank will be government owned, but it will not be a federal agency. It will be managed by a board with seven outside directors — private sector types of people — that will pick projects. This is itself a political issue because we would be taking away a prerogative that members of the transportation committees in Congress have enjoyed in the past to direct federal funds to favored projects.

MR. FRIED: President Obama offered his own infrastructure bank proposal as part of his 2012 budget. Are all these proposals evidence that our national political leaders are becoming more aware of the potential uses of PPPs?

MR. SUOZZI: Certainly there is an awareness in Washington. You have a guy like John Mica who is very good and understands his stuff. You have Kerry, Hutchison and Inhofe. You have the Obama administration. They all get this stuff. But Congress is dealing with some very large issues this year. The issues include Libya, federal budget deficits and high unemployment. It is hard to break through that fog and talk about a policy issue like funding for toll roads.

I talked with a colleague of mine in our office in Spain. I asked, "Why do you think the rest of the world has been so much better at getting the private sector involved in public infrastructure when compared to the United States?" Very simple answer: America never had to do it before. We always had the money. Other governments could not raise the capital in the public sector, so they had to go to the private sector. America is now in a new situation. It needs new approaches. The job for people who want to see more deal flow and want to see these projects happen is to do a better job educating the policymakers and the public about how the private sector can help fill the funding gap.

MR. FRIED: Fadi Selwan, you have done projects around the world, so you have a broad perspective on what makes these projects work. From your perspective now coming to the United States and trying to develop projects, do you think that the states and the federal government are doing enough to help finance infrastructure projects?

MR. SELWAN: It is a tough question. I am not able to say how US policies are doing. However, what I can say is that we have been here for two or three years now, and in those two or three years, we have already had two bad experiences. The first was in Pittsburgh, where we bid on a project and it was cancelled. The second was with the Florida High Speed Rail project, which was cancelled two weeks ago. The government had been pushing eight foreign companies to come, and just poof, like this, the governor said, "I don't want it any more."

Those examples are very hard to live with.

You have the availability scheme, and you have the traffic risk scheme. Which one is selected turns on whether the government wants the end user to pay. Neither type of project is able to support itself without some kind of government involvement. That is why a national infrastructure bank is important.

You have such arrangements already all over the world, but not in the US. If you don't have interest from the state, then the project will die. The state may think it is saving money, but in fact it is losing a lot of money because it is not improving the local economy.

MR. SIMPSON: I do not think there is an awareness in

Washington. The national infrastructure bank is a great idea, but if you look at the authorization plan that the Obama administration came out with, $10 billion for a bank is absolutely nothing for the whole country. It is two or three rail projects.

In a six-year authorization, the Federal Transit Administration had about $13 billion to give out for rail projects, and that barely scratched the surface. It frightens me that people don't understand what $10 billion will really get you on a nationwide basis.

The high-speed rail plan is a red herring. Just take a look at Washington, DC and New York on Google Earth. Then look at Tampa and Orlando, and put them side by side. Look at the differences in density. First, there are not enough people in Tampa and Orlando to support a project between those two points. Second, there is not a large enough business community to support a high-speed rail project between those two points. Third, who wants to go 170 miles an hour with two stops when you are only going 87 miles. The project doesn't make sense, and the costs were underestimated, which happens across the country. The estimate was that ridership would equal Acela. That's impossible.

You need to pick the right project. The Transportation undersecretary was very proud that they put a high-speed rail project together in two days. The government was looking for a shovel-ready project. That is a recipe for disaster. Why not take that money and put it into the Washington-to-New-York corridor where that system is falling apart?

MR. SELWAN: Everywhere in the world you have high-speed trains. Everywhere people are developing them. The US government found a project that may not have been economically viable, but it was a prototype for high-speed rail to be used more broadly in the US. This is what the states and the government should support. If they do not support this kind of project, then future projects will never be built.

Greenfield Projects

MR. FRIED: Stuart Marks, without a robust brownfield market, will more infrastructure funds look to invest in greenfield projects?

MR. MARKS: There is a different set of risks. Investors will have to get comfortable with construction risk, for example. The investment horizon of the funds is important. The Meridiam Fund, for example, and other greenfield funds have long-term horizons. We are a 25-year fund, and that's important when you are looking at greenfield projects because some of them have a four, five or even six-year construction / continued page 30

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The IRS said the main issue in the case was whether the facility was able to produce the intended product before the owner dismantled it. The plant was tested using three different feedstocks.

The plant barely produced any synfuel before July 1998 using the feedstock it planned ultimately to use, but the IRS said the plant had shown it could produce synfuel using one of the other feedstocks and no changes were needed in the equipment to produce the final product.

PRODUCTION TAX CREDITS for generating electricity from wind, geothermal energy and "closed-loop" biomass are 2.2¢ per kilowatt hour in 2011.

They are 1.1¢ a kilowatt hour for generating electricity from "open-loop" biomass, landfill gas, incremental hydroelectric projects and ocean energy.

The credits are adjusted each year for inflation. They run for 10 years after a project is originally placed in service. The IRS said the credits this year are 2.17¢ per kilowatt hour. It made a similar mistake last year when announcing the credit amount for 2010. The tax code requires that the credit amount be rounded to the nearest tenth of a cent.

The credits phase out if contracted electricity prices from the particular resource reach a certain level. That level in 2011 is 11.5672¢ a kilowatt hour. The IRS said there will not be any phase out in 2011 because contracted wind electricity prices are 4.68¢ a kWh going into the year, and it does not have data on contracted prices for electricity from the other energy sources.

The information was published in the Federal Register *on April 19.*

A TAX CREDIT TRANSACTION was stuck down by a federal appeals court in late March.

Three individuals persuaded 282 investors in November 2001 through April 2002 to invest $6.99 million in a large / continued page 31

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period. Shorter-term funds cannot support those types of projects.

MR. FRIED: Fadi Selwan, what fundamentals are investors currently looking for when deciding whether to invest in a greenfield project?

MR. SELWAN: We look for steady cash flows guaranteed, a high internal rate of return, and some upside without paying for it. That's what most investors are looking for.

But most important of all is a viable project. What I mean by "viable" is an accepted project that will not be under continuing pressure from the politicians and the public because it is not the right project for them.

Investors also look for a steady partner — that's normally an industrial partner — who will be able to handle the operations and maintenance over the long term.

Budget deficits are expected to push more states to look at public-private partnerships.

Finally, the most important thing for me is that I need steady rules and regulations. I don't want to have to renegotiate everything in two or three years because the rules have changed. We need a stable political climate.

MR. SUOZZI: Predictability, yes.

MR. FRIED: Tom Suozzi, Stuart Marks mentioned the Dallas Police and the Fire Pension System investment in the LBJ and North Tarrant road projects. We have heard that the Oregon Public Employees Retirement Fund wants to invest and the California State Teachers Retirement System may want to do so as well. Do you expect to see more pension funds entering this market?

MR. SUOZZI: When I looked into this last fall, there were about $200 billion in private funds and $30 to $40 billion in pension funds earmarked for these types of investments. The hard part for pension funds is that they don't necessarily have the staff to evaluate these types of projects.

Pension funds are a source of long-term capital with modest rates of return. It is patient money. These projects are perfect. The problem is that it will be difficult for them to do direct investment because of the lack of confidence that these deals get done in America. Let's say you have five or 10 people working on your staff. You can't afford to have someone devoting all of his or her time and energy looking at a project that is very speculative.

MR. FRIED: Jake Falk, talking about politics, I need to come back to you, since I know you have become a Washington insider. How does the current administration view public-private partnerships? What's really happening inside? Tell us something we don't know.

MR. FALK: I don't think you need to be an insider to answer this question. President Obama told the US Chamber of Commerce earlier this year that one of his priorities is to get the $2 trillion in private sector money that is potentially available for infrastructure invested and putting people to work.

MR. FRIED: But does the President mean it? The reason I ask is that when the stimulus package first came out, everyone was saying infrastructure, infrastructure, but the money was spent on short-term projects. That wasn't infrastructure. If the administration wants to build infrastructure, it will create jobs and attract private investment.

MR. FALK: Clearly, in the current economic situation, there is a tension between short-term investment to create jobs and long-term reinvestment in infrastructure. It is the long-term area where I understand you think the private sector can play a significant role. The administration's 2012 budget calls for a large investment in traditional road work. The budget also calls for an infrastructure bank and transportation leadership awards to reward jurisdictions that are reforming the way they do business and working effectively to adopt private sector best practices.

It may be that $30 billion sounds like a drop in the bucket, but to get the private sector involved in infrastructure, you have to reduce the percentage of funds that is allocated through traditional formulas. The main thing the administration has done in its proposal is to start incorporating more programs that rely on discretion and competition to reward state and local jurisdictions for making tough choices.

MR. FRIED: What is happening with reauthorization of federal transportation programs?

MR. FALK: The reauthorization debate is underway. The administration provided an outline of what it would like in the budget. The committees on Capitol Hill are talking about reauthorization. Obviously any spending measure faces an uphill battle in Congress with the current focus on deficit reduction. However, the national infrastructure bank, TIFIA and similar programs have an advantage because of the amount of private sector funds they can leverage.

MR. SUOZZI: I am advising states to create their own state infrastructure banks instead of waiting for Washington to act. South Carolina has had success with its bank, and other states are looking at it as a possible model.

MR. FRIED: Where would the money for state banks come from?

MR. SUOZZI: They can raise money for a bank by issuing bonds or by privatizing or monetizing brownfield projects.

MR. FRIED: Fadi Selwan, what approaches are other countries using to stimulate private sector investments that the United States should adopt?

MR. SELWAN: Just to give you some examples, France decided, when the economic crisis started, that it could not afford to slow down capital investment in high-speed trains, so it put up €8 billion of guarantees. That was enough to keep €20 to €25 billion in projects on track. We are closing an €8 billion project within the next few weeks based on the fact that the lenders have a bank guarantee of €1.5 billion, and we have additional subsidies from the state for about €3.5 billion.

Other countries rely on the European Bank for Reconstruction and Development for direct funding of projects. Russia is asking government banks to finance projects.

Another thing these countries understand is that the more competition you have, the more the prices go down. There is a lot of competition in Europe. You have huge competition in India where you sometimes see up to 40 concessionaires compete in bids. You have four to five competitors in Russia. These countries put a lot of projects on the market, they see / continued page 32

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partnership or fund that used the money, in turn, to buy tiny interests in other partnerships that were renovating historic buildings in Virginia in exchange for state tax credits to which the partnerships were entitled. Virginia allowed a tax credit at the time for 25% of the cost of renovating such buildings.

The fund organizers promised the investors they would receive $1 in tax credits for each 74¢ to 80¢ invested, but that they would receive little else. The fund used the $6.99 million to pay 15 developers $5.13 million to buy $9.2 million in tax credits, or about 55¢ per dollar of tax credit. The rest was profit.

The fund filed a partnership tax return in April 2002 and sent the investors Form K-1s advising each investor what share of the tax credits it could claim. The fund then exercised an option to buy out all the investors for a total of $7,000.

The IRS argued that the fund organizers had used the fund partnership to mask what was a bare sale of tax credits by the fund to the investors. It said the fund should have reported $1.53 million in gain on the sale.

The court agreed.

The IRS had argued that the investors were not real partners. The court said it did not have to reach that question because section 707 of the US tax code gives the IRS authority to treat the transaction as a "disguised sale" of the tax credits by the fund to the investors. The fund argued that section 707 does not apply because it only applies to disguised sales of "property" and the particular tax credits are not "property." The court said the credits are "property."

The timing and lack of any entrepreneurial risk — the investors paid their money, got the tax credits almost immediately and then were bought out — were fatal. The case is Virginia Historic Tax Credit Fund 2001 LP et al. v. Commissioner. *The appeals court released its decision on March 29.*

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them through and they sign contracts at the end of the bid process. They are modernizing their infrastructure in a way that will improve their economies in the long term.

MR. MARKS: I agree with Fadi. State guarantees like we have seen in Australia and the UK are an underpinning of financing that also addresses the risk of nonappropriation. Dedicated procuring agencies like Infrastructure Ontario in Canada would be a great benefit in the US.

The US also needs to establish a more robust track record. Every time a project is pulled from the market, it has huge ramifications, not just for the state that withdrew the program but also more broadly.

Opportunities in Particular States

MR. FRIED: Jim Simpson, how has the financial condition of New Jersey affected your infrastructure plans? We know that the governor cancelled the Access to the Region's Core. What's next?

MR. SIMPSON: The ARC project was the largest public works project in the country. It was an $8.7 billion project. There is a lot of risk associated with a project that size. The forecasts were unrealistic, both in ridership and cost.

We had a project that started at $5 billion and, while still in preliminary engineering, escalated in cost to $8.7 billion. The costs always go up further from preliminary engineering to final design to construction and then to completion. We just couldn't afford it. The risk was too great that the project would end up costing $15 or $16 billion dollars. It would have broken New Jersey.

No one has the money for these mega projects. Florida did not have the money. We do not have the money.

Our strategy in New Jersey is safety — safe bridges, safe highways — fix the potholes, keep everything in a state of good repair, focus on system performance, and expansion.

The benefits for that project were not there. Transportation projects exist for one reason: to get people from point A to point B as quickly as possible. This project didn't do that, and the cost vastly outweighed the benefits.

The fatal flaw with that project was that it dropped the Penn Station connection, so Amtrak would not have been able to use the new track. This was done to get the shovel in the ground two years faster on a 100-year project. The advocates said just build it and don't worry about the finances. You can't do that in this world that we live in.

Unfortunately, the federal government only offered us a TIFIA loan for support. This was the number one public works project in the country. We could not do it ourselves.

We would have had to cannibalize the rest of Jersey Transit to build the project. We would have been deferring maintenance on all the other transit stations, all the other parking lots, and so on.

MR. FRIED: What opportunities will there be in the future for private investment in New Jersey infrastructure?

MR SIMPSON: The opportunities are you have to come to New Jersey or any place else and tell us where you see the opportunities. At the end of the day, we are caretakers for the public dollar. You can't just tell us here is some up-front money. Tell us the business purpose, how the project will be financed and how it will benefit the state. We can borrow in the bond market to build our own projects. Tell us why what you are proposing is better.

The New Jersey Turnpike is a good example. Tell me the business reason why I should grant a concession on the Turnpike. Take a look at our balance sheet. It is on line. Let's say it is costing us $300 million a year to collect $1 billion. It will cost us $300 million a year to collect $1.5 billion next year when the tolls go up. What can you do that will let us collect the same or more revenue at lower cost?

The opportunities in New Jersey are probably more on the operating side. A dollar I spend in labor is a dollar I don't have for the capital plan, because when the fare box revenue comes in, I have two choices. It can go to fund operations or it can go for capital improvements.

New York City Transit and the Metropolitan Transportation Authority are paying for the equivalent of 120,000 workers because of all the pension benefits and work rules. That's where I think the private sector can do a better job. We are tackling the problem one project at a time.

The opportunities are on the operations side and some selected new capacity projects, like Scudder Falls Bridge, the Goethals Bridge and maybe the Bayonne Bridge. They are not to buy the New Jersey Turnpike.

MR. FRIED: Greg Carey, Texas was an early leader in the industry and then it imposed a moratorium. Is Texas coming back?

MR. CAREY: Even with the moratorium, a number of deals got done. I think the vilification of the Texas DOT is over.

However, the problem with Texas is that the projects that made the most sense have now been done. The next tier of projects will require a joint effort by the state and private sector to get done because you don't have a road that makes a lot of sense apart from the Grand Parkway in Houston. You have stuff in El Paso, but that's a tough place to get things done.

California will always be difficult; every project in that state has stops and starts because of the environmental process and the unions. The SR 125 road project near San Diego was awarded in 1991 and got done in 2003.

Virginia is a good state in which to do projects. Florida has fits and starts, but there will be more projects there.

MR. MARKS: There is nothing like successfully reaching commercial and financial closure on a project to establish credibility. Florida has made a great start with the Port of Miami Tunnel and I-595; we expect to see more projects in Florida.

Georgia has not closed a project yet. We hopefully will see West by Northwest toward the end of this year or early next year. The transportation commissioner has demonstrated that he is a leader in P3. Georgia is a state to watch.

California is another state to watch having successfully done Long Beach, and with the Presidio Parkway not too far away. Commercial close occurred last year, and financial close should occur within a couple months. California has a good base on which to build.

MR. FRIED: What about Pennsylvania?

MR. MARKS: It is looking at a mix of brownfield and greenfield projects. The fact that the state is considering enabling legislation is particularly noteworthy, given what happened earlier with the Pennsylvania Turnpike. We are focused on greenfield and, although we are not expecting to see a greenfield project in Pennsylvania before early next year, we are expecting big things.

MR. FRIED: Talking about big things, Tom Suozzi, I was interviewed the other day about the Tappan Zee Bridge.

MR. SUOZZI: The symbol of everything wrong in New York state.

MR. FRIED: Why are we starting to hear about the Tappan Zee Bridge again?

MR. SUOZZI: Because everybody's afraid that it will fall down. It was built to last 50 years and it is now probably about 65 years old.

It is a very important bridge for the entire region. It is important to New Jersey even though it is entirely in New York. You are talking about the biggest project in / continued page 34

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FOREIGN CORRUPT PRACTICES ACT prosecutions of US businesses for bribing foreign government officials are on a notable upswing.

The CEO and CFO of Lindsay Manufacturing Co. were found guilty in May of paying bribes, including a $300,000 Ferrari, to two officials of the *Commisión Federal de Electricidad,* the national electric utility in Mexico. The two US executives face up to 30 years in prison and fines of up to $750,000 each. Sentencing is scheduled for September 16.

The US Securities and Exchange Commission has reportedly delivered letters of inquiry to at least 10 hedge funds, banks and private equity funds requesting information about their dealings with sovereign wealth funds. The letters suggest the SEC views employees of such funds as foreign government officials.

The Foreign Corrupt Practices Act makes it a crime for a US company or citizen to give anything of value to a foreign government official or employee of an international public organization in an effort to win or retain business or secure any improper advantage.

A foreign company may become subject to the Foreign Corrupt Practices Act by raising money in US capital markets.

The US Chamber of Commerce has hired a former US attorney general, Michael Mukasey, to lobby Congress for changes in the statute.

The Chamber wants five changes, including a compliance defense: a company should not be held liable when an employee circumvents internal procedures to pay bribes. It also wants to limit successor liability. Under current law, a company can become liable for crimes that a company it acquires or becomes associated with by merger committed before the merger.

SUCCESS FEES in acquisitions need to be capitalized only in part, the IRS said in April.

A success fee is a fee paid by one company acquiring another company or project to an adviser for help putting / continued page 35

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America. It is an estimated $16 billion project.

MR. FRIED: You could do it in pieces, though, right?

MR. SUOZZI: There is the deck up top, and then there is the possibility of putting rail on the bottom. People have been talking about the Tappan Zee Bridge for many, many years. It's a very important project. Building something new while trying to maintain existing traffic is always a big challenge. The goal is to get it started in 2015. The problem is it will not get done without help from the federal government.

There is a big philosophical debate about transportation infrastructure. Government has historically built infrastructure. The reason you have high-speed rail throughout Europe is the governments paid for it, and they help cover the operating costs. The private sector may have done it, but not without government help.

We are talking today about the private sector and P3s, and we all want the efficiencies that private sector involvement brings, but the private sector is not a silver bullet. Government will still have to help pay the cost. Most infrastructure loses a lot of money.

Final Thoughts

MR. FRIED: We are at the end of the session. There is time for each of you to offer a final thought. Tom Suozzi?

MR. SUOZZI: The dam will break, and there will be a lot more deal flow over the next several years. It just requires us to do a better job of educating policymakers and the public about the benefits of private sector involvement. It is a very complex field. A layperson will not get it on his or her own. There is too much jargon and too much complexity.

MR. SELWAN: I hope the dam will break very soon.

I think P3s are the solution. Other countries have proven that they work. Other countries have proven that with a good concession agreement that holds the developer to performance, a construction budget and a construction schedule, the state will know what it is paying for and will not pay a dime more than it expected.

The states should focus on encouraging competition. When you have competition, you have better services at better prices.

> Most projects are expected to be new builds rather than privatizations of existing assets.

MR. SIMPSON: The biggest opportunities in the New York area are on the transit side. New Jersey has the ability to enter into P3s. We had the first P3 in the Hudson Bergen Light Rail project. We have a second one in south Jersey, the Camden Light Rail project. We have a couple of other light rail lines as well. We see the P3 model as successful, particularly in transit, for a number of reasons, including risk transfer. There is real opportunity to enter into P3 arrangements on the operations side.

MR. FALK: One trend that we did not discuss much today is that performance will become increasingly important in an era of scarce resources at all levels of government. Governments everywhere will be focusing more closely on how proposed projects help reach their objectives and how they expect the projects to perform. That's a trend that I would follow closely. Pay attention to where the value is being added.

MR. CAREY: This is a process of evolution. In the 1980s, we had waste-to-energy energy plants that were public-private partnerships. In the 1990s, it was all about labor and outsourcing.

We are probably in the sixth inning of a nine-inning dialogue. Some deals have worked well. PPPs are not a dirty word anymore. The states have no choice but to consider them given current economic conditions. It is tougher to implement such projects in the north and the northeast. The politics are tougher. They will never be a tidal wave, but we will see more and more use of them.

MR. MARKS: Let me underline two key points. Governments need to understand that P3s are not just an alternative way to finance infrastructure, but they are a means to deliver a service. We have seen great progress over the last five years, but I don't think the dams are ready to break yet. It would be interesting to have the same discussion in another two to five years.

The UK's Green Future

by Paul White, in London

In the United Kingdom, the Conservative-Liberal Democrat coalition, which has been in power since May 2010, has set itself the target of being "the greenest ever" UK government.

This article looks at how the government intends to make good on what could prove to be an expensive promise while maintaining the support of the public and business leaders and keeping the UK's nascent economic recovery on track.

The government launched an ambitious "Plan for Growth" in March 2011 as an "an urgent call for action" to put the UK on a path for sustainable, long term economic growth. It is a 126-page policy document jointly authored by the Treasury and the Department for Business Innovation & Skills that, at a high level, covers everything from tax policy to the scheduling of public holidays.

The Plan for Growth identifies four main policy targets. The first two, which have been considered in previous editions of *Project Finance NewsWire*, effectively restate the chancellor's mantra that "Britain is open for business" and are the commitments that the UK will establish the most competitive tax system in the G20 and become one of the best places in Europe to start, finance and grow a business. The other two targets are to encourage investment and exports as a route to a more balanced economy and to create a more educated work force that is the most flexible in Europe.

One of the measurable bench marks identified by the government on the route to a more balanced economy is increased investment in low-carbon technologies. The Plan for Growth argues that taking action now to put the whole economy on a low-carbon, resource efficient path which maintains UK competitiveness will lay the foundations for strong and sustainable growth in the future.

The government acknowledges that there will be significant transitional costs but, equally, UK businesses have already shown a willingness to pursue environmentally-friendly initiatives. In 2008-09, the UK low carbon and environmental goods and services sector was worth £112 billion, */ continued page 36*

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together the transaction. The fee is contingent on a successful closing.

It is usually better to deduct such fees immediately than to have to fold them into basis in shares of the company being acquired. However, where assets are purchased, it may be better in some cases to add the fee to basis in the assets.

IRS rules require that any fee paid to someone to *facilitate* the transaction must be capitalized, or added to basis.

This has been an area of controversy. In a peace offering, the IRS said that it will no longer challenge taxpayers who deduct 70% of the fee and capitalize 30%. The theory is that only 30% of the success fee is for facilitating the transaction while the rest is for other activities.

The IRS announcement is in Revenue Procedure 2011-29.

GRANTS paid by the US Department of Energy for projects that use clean coal technologies or capture carbon dioxide at industrial facilities do not have to be reported as income, the IRS said in April.

Grants must usually be reported as income.

However, the IRS said these grants do not have to be reported if they are made under its Clean Coal Power Initiative-Round 3 or under the FutureGen 2.0 program, but only if the grant recipient has a legal right to retain ownership of its inventions.

The grant recipient must also be a corporation.

If it is a partnership, then the grant will be taxable. That's because the IRS used as its theory for waiving tax on the grants that they are capital contributions to a corporation by someone who is not a shareholder. There is no similar concept of a person who is not a partner making a capital contribution to a partnership.

The IRS announcement is Revenue Procedure 2011-30. */ continued page 37*

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an increase of 4.3% on the previous year, and it employed 910,000 people.

A recent report by one of the large accountancy firms notes that in 2010 the UK, together with Germany, replaced the Iberian peninsula as the focus for renewable deal making in Europe. The United Kingdom's share of total deals in 2010 put it in second place in the European league table but, at 11%, that was still some considerable way behind Germany in first place with a 27% share. The report also revealed a downward trend in deal sizes from previous years. Although this may be viewed positively in that an increasing number of small- and medium-sized businesses are already turning to green technologies, larger-scale projects are likely to be more attractive to the debt markets.

It is clear that the coalition government has an ideological commitment to green technologies but, while the economic recovery remains relatively weak and many of the previously announced public spending cuts are only now beginning to bite, it cannot afford to be seen to add to the financial burden of industry and consumers purely for ideological reasons. This has clearly been recognized within government so there has been an emphasis on the long-term nature of the policies, with many of the changes stretching out more than 20 years. Also, as with its approach to general tax reform, the government has actively engaged with the most affected groups before announcing specific policy initiatives.

So, for example, February 2011 saw the first meeting of the "Green Economy Council," which brings together a cross-departmental group of government representatives and more than 20 business leaders and trades union representatives from a range of industries and sectors.

As chairperson of the first meeting, the government's business secretary, Vince Cable, recognised that while the government is committed to the transition to a green economy, there is also a "need to minimize the burdens on business and industry during this transition, while [the government] create[s] the necessary conditions for green growth and investment in the green economy." The Green Economy Council is a forum for representatives from the Department for Business, Innovation & Skills, the Department of Energy and Climate Change and the Department for Environment, Food and Rural Affairs to liaise with the business community on the investment and business environment needed for a transition to a growing green economy. Many green policies add to the costs of business, at least in the short term, but the government clearly expects the process of change to be eased if business leaders are actively engaged in development of green policies.

The three government departments represented on the Green Economy Council are also charged with developing a "Road Map to a Green Economy" that is expected to be published before the summer and is intended to "articulate the business and investment environment the government will provide to make possible the shift to a growing green economy." Until then, the Plan for Growth identifies a series of action points on the road to achieving the "greenest ever" UK government objective, some of which have already resulted in specific policy announcements.

There is inevitably considerable overlap between green initiatives and tax reform, and the "new approach" to tax policy-making recently instigated by the government includes a commitment to consultation that effectively mirrors the methods already being used in the development of green policies.

Carbon Price Levy

In his March 2011 budget, the chancellor, George Osborne, announced the introduction of "a carbon price floor" the main tenets of which were suggested in a December 2010 consultation document that elicited 155 detailed responses. The new policy, which will take effect from April 1, 2013, is not, despite its name, a government-guaranteed minimum price for carbon but an extension of the "climate change levy" or "CCL."

CCL was introduced in 2001 as a per-unit charge on "taxable supplies" of "taxable commodities" to encourage the use of renewable energy by taxing the business use of most traditional sources of energy.

Currently, CCL is levied on most supplies of electricity, gas, solid fuel and liquefied gas for non-domestic use. The obligation to account for CCL falls on the supplier, but the economic cost is invariably passed on to the business consumer. Accordingly, CCL acts to encourage businesses to reduce their energy usage or turn to renewable sources of energy.

In addition to the relief for domestic use, CCL includes a number of other key exemptions that will be removed or limited under the government's new policies. Currently, energy used in the production of other forms of energy is exempted from CCL. This avoids a double charge to the tax for business users and prevents the CCL directly affecting domestic energy prices.

In broad terms, the proposed carbon price floor will tax the use of fossil fuels used in most forms of electricity generation under the auspices of the CCL while oil that is used in electricity generation will become liable to fuel duty so that domestic users will effectively suffer the direct cost of CCL for the first time. Clearly mindful of the political consequences of spiralling domestic energy prices, the government has also already announced its intention to develop a framework to cap the impact of energy and climate change policies on energy bills.

The "carbon price support rate" at which suppliers will be charged will be calculated by reference to the average carbon content of the fuel and the price of carbon. The calculation for arriving at the "carbon price support rate" is the carbon price floor for each year minus the market carbon price.

It is currently expected that the carbon price floor will start at around £16 per ton of carbon dioxide and move on a "linear path" to a target price of £30 per ton in 2020 and eventually to £70 per ton by 2030. So, applying this methodology, the carbon price support rates for 2013-14 will be £16, being the carbon price floor, less the futures market price for carbon that is around £11, which results in a rate equivalent to £4.94 per ton of carbon dioxide.

Once the carbon price support rate has been calculated for any year, it is multiplied by the standard carbon emission factor of the relevant fossil fuel to arrive at the tax rate of CCL and fuel duty.

The extension of CCL to include a carbon price floor is not the only change to CCL already announced.

Presently, combined heat and power (CHP) qualifies for beneficial CCL treatment in that energy provided for use in good quality CHP is excluded from the charge as is electricity generated from CHP sources. The December 2010 consultation document envisaged that the carbon price floor might apply CCL to fossil fuel supplied to CHP facilities. Although the original proposals have been modified in light of representations from the CHP industry, CCL, at a reduced rate, will apply to CHPs, and the current exemption for electricity generated from CHP is to be removed from April 2013. Acknowledging industry concerns, the government has announced its commitment to working with the CHP industry to explore how to keep incentives for CHP.

Certain "energy intensive" industries that might otherwise have suffered most from CCL have been able to benefit from discounted CCL rates by signing up to "climate change agreements" through 2013. Typically, representa- */ continued page 38*

IN OTHER NEWS

THE US PATENT OFFICE is reexamining a patent it issued in 2003 to the Wealth Transfer Group LLC to protect a method the group claimed it invented to reduce gift taxes.

The method involves use of a grant or retained annuity trust or GRAT.

The Wealth Transfer Group sued the CEO of Aetna for patent infringement charging that the insurance company was using the same technique without its permission.

There had been a number of articles in trade papers about how GRATs work before the Wealth Transfer Group applied for a patent. The Patent Office said in a reexamination order in May that it now appears the idea was "*prime facie* unpatentable."

Meanwhile, Congress is moving to bar patents for tax strategies. The Senate voted 95-5 in March and the House Judiciary Committee voted 32-3 in April to ban such patents. Patents would still be allowed on software for preparing tax returns and making tax filings.

— contributed by Keith Martin, John Marciano and Amanda Forsythe in Washington.

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tive associations have entered into umbrella agreements with the government under which particular industries have committed to improve their energy efficiencies and reduce carbon dioxide emissions. The government announced in March that the scheme, to which 54 industry sectors have committed, would be extended for a further 10 years to March 2023. As the result of changes announced in the 2010 budget, the discount rate was reduced from 80% to 65% with effect from April 2011. However, the 80% discount rate is to be reinstated for supplies of electricity from April 2013. In addition, the government will shortly begin consulting with industry on ways to simplify the operation of the scheme.

The encouragement of commercially-operated carbon capture and storage or "CCS" facilities is a key element in the government's green policies, and it has confirmed its commitment to building a £1 billion demonstration CCS facility. A further three facilities that were to be funded by a newly-introduced CCS levy will now be funded from general taxation and the levy announced by the previous government will not now be introduced. Both demonstration plants and commercial CCS plants will be entitled to relief from carbon price support rates in proportion to the amount of carbon captured and stored.

The government is also committed to promoting the development of new markets in green goods and services. The so-called "green deal" is intended to enable households and businesses to invest in energy efficient measures at no upfront cost. For example, benefits of more than £7 billion over the next 20 years are expected from the introduction of smart meters.

In March the government also announced a £860 million "renewable heat incentive" to create a new market in renewable heat. The incentives will be available to encourage the industrial, commercial and public sector installation of green equipment such as renewable heat pumps, biomass boilers and solar panels. Announcing the initiative, Chris Huhne, the energy secretary, said, "Renewable heat is a largely untapped resource and an important new green industry of the future . . . . This incentive is the first of its kind in the world." Further details of the renewable heat incentive are expected to be published in May.

Green Investment Bank

The government remains committed to the establishment of the Green Investment Bank and in the March budget, its initial capitalization was set at £3 billion and its start date accelerated by one year to 2012-13. The government's October 2010 "spending review" had already allocated £1 billion to the bank, and the government is aiming for the remaining £2 billion to be funded from the sale of assets including the £775 million net proceeds from the sale of High Speed 1, the Channel Tunnel rail link. A further £15 billion of private sector investment is expected enabling the bank to bring about an additional £18 billion of investment in green infrastructure by 2014-15. While the government's announcements in relation to the bank were generally welcomed, there was some disappointment that it will not have borrowing powers until 2015-16.

There can be no doubting the government's commitment to green initiatives. Also, its eagerness to consult with interested parties both on green policies and general tax reforms has been broadly applauded. But, what currently seems to be missing is a single vision for the UK's green future that may, in part, be due to the involvement of several government departments in policy development. As mentioned earlier, the government is expected soon to publish its "Road Map to a Green Economy," and it is to be hoped that it will bring the currently disparate strands of green policy together as a unified vision. ◎

How Close Are Large-Scale Ocean Energy Projects?

Five CEOs of companies that are developing devices that can generate electricity from waves and tidal currents participated in a roundtable discussion at the 4th annual Global Marine Renewable Energy Conference in Washington at the end of April. They were joined by a senior manager from a west coast utility that is experimenting with ocean energy. The following is an edited transcript of the discussion.

The panelists are Cameron Johnstone, CEO of Nautricity, Chuck Dunleavy, CEO of Ocean Power Technologies, Derek Robertson, CEO of WaveBob, John McCarthy, CEO of Ocean Energy, Ltd., Reenst Lesemann, CEO of Columbia Power Technologies, and Craig Collar, senior manager for energy resource development with the Snohomish County Public Utility District in Washington State. The moderator is Keith Martin from the Chadbourne Washington office.

MR. MARTIN: Lawyers talk about laying a foundation for a discussion to follow. Let's start with Cameron Johnstone from Nautricity. Tell us about your technology. What is it?

MR. JOHNSTONE: Our focus is tidal energy. In the early days of tidal power, the first movers were basically taking wind turbines, modernizing them and putting them into the water. We believe there are limitations with that approach, so we went back to the drawing board to design a new technology. We eliminated the rigid monopole support system that one finds in wind turbines. We introduced two counter-rotating rotors. That opened up the opportunity to eliminate the gear box. What you end up with is a generator that rotates faster than a traditional turbine, allowing you to adjust the weight and size.

MR. MARTIN: You put this device in currents or tides or both?

MR. JOHNSTONE: We put it into tidal currents. It is a generator with rotors or blades bolted straight on to the body of the generator. It is submersed in water.

MR. MARTIN: Is there a difference between a tide and a current and, if so, what?

MR. JOHNSTONE: There are thermal currents that cross the ocean floors, much like the trade winds, and there are also tidal currents that exist because of the gravitational pull of the moon. A tidal current has a higher velocity than a thermal current.

MR. MARTIN: The device looks a lot like two propellers, one in front of the other. One spins in one direction and the other spins in the other direction?

MR. JOHNSTONE: Correct. The device looks like a torpedo with propellers. It has a flexible mooring system that keeps it in location. It can be suspended from a buoy above or below the surface that is anchored to the seabed. We look to position the device in the sweet spot in the vertical column between the buoy and the seabed floor.

MR. MARTIN: How much electricity does the standard device produce?

MR. JOHNSTONE: Up to 500 kilowatts. We don't have materials that are robust enough yet to withstand the forces that a one megawatt device would encounter.

MR. MARTIN: That is Nautricity's product. Let me go next to Chuck Dunleavy with Ocean Power Technologies. You have a power buoy, I believe. Describe it.

Power Buoys

MR. DUNLEAVY: It is an ocean-going buoy of a type that has been in use for decades. It has a fairly straightforward geometry: a central spar is held steady. A float encircles it. The float moves up and down with the passing waves. The buoy is positioned in at least 50 meters of water and more likely 50 to 100 meters. The passing waves cause the float to move up and down in relation to the stationary spar. The up and down motion actuates a power take-off inside the system.

There are a couple of interesting aspects to the technology.

The power buoy is versatile. It can accommodate different power take-off systems, such as hydraulics, direct-drive systems and linear generators.

Another important differentiator is our technology has an automatic electronic-based tuning system. That is to say, we use electronics, not brute mechanical force, to enable the system to tune itself automatically as wave conditions change. That is important for optimizing power conversion. There are so many places from tide or wave to grid where you have an opportunity to lose energy. We have focused on using electronic means to minimize those losses and, in fact, enhance output.

MR. MARTIN: Your standard model is a PB-150?

MR. DUNLEAVY: We have a PB-40 that is connected currently to the grid off the coast of Hawaii. It was originally put in the water in December 2009, so it has been in place now for a year and a half.

We are working now on our PB-150, which is a 150 kilowatt system. We expect to go into ocean trials with the first one off the coast of Scotland to be followed later this year with another PB-150 off Reedsport, Oregon.

One final point about our product offering is that we are also making and selling what we call an undersea sub-station pod that sits on the sea bottom. It is a universal platform that can accommodate the power output from multiple structures, not just power buoys.

MR. MARTIN: Derek Robertson from WaveBob, I think you have a power buoy also, is that correct?

MR. ROBERTSON: We call it "WaveBob" but, yes, it is in many respects similar to what Chuck Dunleavy described in that it looks like a buoy. There are two main challenges when trying to work with wave energy. One is how to absorb lots of energy so that you have a basis for generating electricity. The other is how to design any device for survivability. The ocean is a harsh environment.

It is easiest to achieve one without the other. Bringing both together is the real challenge.

Our device has two distinct floats. One is a lightweight life ring that floats on the surface and that is / continued page 39

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coupled with something that is akin to an iceberg. It is a float above surface that is attached to a large mass below the surface. You capture a big slug of seawater. By virtue of your ability to open or empty the tank, you add energy as well as some survivability features by being better able to tune the device.

MR. MARTIN: Sticking with you and Chuck Dunleavy, how do your two buoys differ from each other?

MR. ROBERTSON: What distinguishes the WaveBob is tenability. First, the tank venting concept allows a degree of tuning to adjust to the waves. Second, two floats are linked through the power take-off system. Third, we have a unique and proprietary control algorithm that allows the power take-off not only to absorb the energy from the up-and-down motion of the waves but also to convert that energy into electricity with greater efficiency.

MR. DUNLEAVY: The way our respective technologies differ is in tuning capability. From our viewpoint, we would much rather effect this tuning using electrons or electrical systems than by causing large amounts of water to rush in and out of the buoyant structures.

MR. MARTIN: John McCarthy, your device also floats on the waves, but it produces electricity a little differently.

MR. McCARTHY: Yes. Our device is a floating, oscillating water column that uses the energy in the waves to push air that rushes through an air turbine to generate electricity. We have a quarter-scale device on a government test site at the moment as part of a $6 million European Union research program.

It is part of an industry research project in collaboration with a number of European-based universities to look at different issues. We are looking at moorings, telemetry, power control systems, the turbine. The information will be shared across the research and industrial community. The components can be used with other technologies.

There is a lot more room for collaboration within the ocean energy industry. A lot of research and testing that you are just starting to undertake in the States has already taken place in Europe. The information can be transferred to the States. There is a lot that the US industry could learn from what we have already tried in Europe.

MR. MARTIN: Your device looks like the back third of a ship. You said the turbine generates electricity from air passing through it. How does the air get up to the turbine?

MR. McCARTHY: The air is pushed through the turbine by the movement of the waves.

It is actually a hollow, L-shaped device. You have the long part of the L underneath the water, and as the water rushes into the device, it pushes the air column at the rear of the device upwards and through the air turbine.

Our test unit is at a government test site in Galway Bay and is approximately one mile offshore.

MR. MARTIN: How much electricity is the device producing?

MR. McCARTHY: About 30 kilowatts. The full-scale device will be approximately 1.75 megawatts.

MR. MARTIN: Reenst Lesemann of Columbia Power Technologies, you are also harnessing wave technology, but you are doing it differently. Describe what you are doing.

MR. LESEMANN: Our device is a rotary point absorber. It absorbs energy from the heat and surge of every wave.

It has a forward wing and a stern wing with a long cylindrical nacelle in between. Each wing is coupled to a permanent magnet generator. The generators are inside the nacelle. Our view is that simple is better, so we have cut down on as many moving parts as possible. Each wing is directly coupled to its own generator and, for the most part, those are all the moving parts in the device. More moving parts would mean more things that the sea can break at some point.

MR. MARTIN: You are relying on the heat in the water itself for energy?

MR. LESEMANN: No. It is a heave and surge device. We take energy off of each passing swell. This creates a rotary motion.

The power take-off is a direct drive permanent magnet generator. We originally licensed a linear magnet generator technology from Oregon State and then worked to convert it into a rotary design. We are borrowing lessons learned from the work that others are doing with offshore wind turbines and direct drive systems. Direct drive is efficient. It is simpler. There is no gearbox between the hub and the generator to break. Again, we are trying to be simple rather than complex. We are trying to learn everything we can from what is a significantly larger industry — offshore wind — than the wave industry is at this point.

MR. MARTIN: Craig Collar with the Snohomish County Public Utility District. What is the interest of the PUD in ocean energy? How do I put this delicately: why are you here? [Laughter]

MR. COLLAR: I feel like the odd man out since we are not a technology developer.

Our utility is located just north of Seattle. We are the twelfth largest public utility in the United States. Our customers — not investors — own us. Our mission is to provide safe, cost-effective and reliable power to our customers. We have a couple key challenges moving forward to achieve that mission. One is meeting projected load growth. Our average load is currently about 1,000 megawatts. We peak at about 1,600 megawatts in the winter. The other challenge is how to meet our obligations under the renewable portfolio standard in Washington State. We are required to supply at least 15% of our electricity from renewable energy by 2020.

Several commercial-scale ocean energy projects are expected to go into the water in the next few years.

MR. MARTIN: How close are you currently to meeting that goal?

MR. COLLAR: It depends on your definition of "renewable." We get over 80% hydropower from the Columbia River system, but it does not count toward the target.

We are probably in the range of 6% to 8% today. Most of that is from wind. Wind is the only really commercial scale utility resource available to us to meet our state's RPS target today. We have the highest percentage of wind of any utility in the Pacific Northwest. As a consequence, we are one of the first utilities in the Pacific Northwest to start bumping up against some of the integration and transmission constraints associated with wind. Wind is unpredictable. The wind farms are physically distant from the coast far down the Columbia Gorge on the other side of the Cascade Mountains, so even if we had more wind, it would not do us much good.

We would like to get to a position of not having to rely at all on fossil fuel. Coal is completely off the table and has been for a while, but even natural gas is off the table for our utility. That forces us to look at other renewable energy options, specifically ones that are predictable, like tidal energy, or baseload resources like geothermal.

MR. MARTIN: How far along are you in the search for tidal energy?

MR. COLLAR: We started our search for tidal energy four or five years ago. Snohomish County borders on Puget Sound, one of the larger estuaries in the United States. We hired consultants to do site studies and eventually selected Admiralty Inlet as the location for a pilot plant. There are currents there of as much as seven knots.

MR. MARTIN: Who will own the pilot plant?

MR. COLLAR: It is our project. We hope to submit the final license application to the Federal Energy Regulatory Commission in a few months.

MR. MARTIN: What technology will you use?

MR. COLLAR: We went through a rigorous technology selection process three years ago and eventually selected the OpenHydro Group in Ireland. Our project will involve installation of two OpenHydro turbines that will be grid connected.

MR. MARTIN: These are traditional hydroelectric turbines that just happen to be in Puget Sound?

MR. COLLAR: No, there are not traditional hydro turbines. OpenHydro offers a direct drive, permanent magnet generator. Our mission with the project is not necessarily to produce cost-effective energy from day one but to learn. We want to collect technical data. We want to understand the environmental viability of tidal energy.

Long Haul

MR. MARTIN: Let me ask the following question of each of you, starting with Chuck Dunleavy. It takes a long time to develop a new technology. How long have you been at it, and how much longer do you think it will take to get to a commercial-scale project?

MR. DUNLEAVY: Our first in-ocean test commenced in late 1997 and, since then, we have had 14 or 15 systems in the water. Throughout that period, we have had terrific support from a number of entities, including the US Navy and Department of Energy, as well as a number of private investors.

We believe we are at a very important inflection point from the standpoint of commercial develop- / continued page 42

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ment. We are just starting to move to a commercial scale. Our grid-connected PB-40 is at about eight or nine on a scale of 10 for technology readiness. We will be deploying two PB-150s off Scotland and Reedsport, Oregon this year. We expect a commercial market for our PB-150 to develop. We are working on two, good-sized projects: one for 19 megawatts in Australia and another for 1.5 megawatts off Reedsport. We have a preliminary FERC permit for the Reedsport location for up to 50 megawatts. So these are substantial sites that will be using the PB-150.

MR. MARTIN: Do you have long-term contracts to sell the electricity to utilities?

MR. DUNLEAVY: Not yet, but we have candidates to buy electricity from the Reedsport project and we have had encouraging discussions with a number of large companies in Australia.

MR. MARTIN: When will the Australian project be built?

Costs are expected to come down to $3 to $5 million an installed megawatt over the same period.

MR. DUNLEAVY: It will be built in phases over three years. We are working with a strategic partner to raise funding. We were fortunate to receive a grant of A$66 million from the Australian central government. The project should take three years to build from the point the financing is nailed down.

MR. MARTIN: So 24 years in the effort and maybe another three or four years away from building a 19 megawatt project off the coast of Australia. How many buoys will the 19 megawatt project involve? How much space?

MR. DUNLEAVY: It will be about 45 buoys in total. The first phase is a group of PB-150s. The last two phases are expected to include our PB-500, which is the next stage of our system and on which we are working now.

MR. MARTIN: Reenst Lesemann, how long have you been at this, and how much farther do you have to go?

MR. LESEMANN: We licensed our technology from Oregon State in 2005. We refer to that as our first generation. We did a sea trial and worked on the first and second generation linear devices. We shifted to the rotary design. If we were at a technology readiness level one or two in 2008, we had marched to TRLs three and four by last year. Right now, we are at five and six. By the end of next year or beginning of 2013, we will be on the cusp of seven and eight, which is a utility-grade device. We are 18 months away from our initial open water test of that utility-grade device. It will have taken roughly five years to get to that level.

MR. MARTIN: That gets you to pilot testing, correct? How much longer do you think it will be before you have a commercial-scale project like Chuck Dunleavy described?

MR. LESEMANN: We are not trying to be a project developer ourselves. The initial projects will probably have some element of cost sharing with our customers.

MR. MARTIN: So you are thinking like an equipment manufacturer. Derek Robertson, how long have you been at it; how much longer do you have to go to get to commercial scale?

MR. ROBERTSON: WaveBob was founded in 1999 and originally focused on basic research. We matured over the years toward more proof-of-concept testing. We, too, are at an important inflection point where we are trying to become a more focused product development company. We are putting together relationships, including a joint venture with Vattenfall in Europe. We agreed in 2008 to build a commercial wave facility off the west coast of Ireland. We hope to enter into low-rate production in about five years.

Scottish Feed-In Tariff

MR. MARTIN: Cameron Johnstone, how long have you been at it, how much farther is there to go?

MR. JOHNSTONE: We started with fundamental research in 2000. We completed technology readiness levels one and two by 2002. We then moved to levels three and four, with extensive time testing of devices, and that takes us up to 2005. In 2005, we built our prototype device and deployed it in the sea. That has taken us up to technology readiness levels five and six, and now we are building a peak commercial device for deployment in 2012.

In parallel to that, we are in the process of setting up a single-purpose entity to take forward commercial development. We expect to start construction of a project near Aberdeen in 2012 that will run eventually to 50 megawatts by 2015.

MR. MARTIN: Who will be the offtaker for the electricity?

MR. JOHNSTONE: The project will be owned by the single-purpose vehicle that will then sell the electricity into the network and earn revenue from ROCs or renewable obligation certificates. There is a high-value feed-in tariff in the UK.

MR. MARTIN: Correct me if I am wrong, but in the UK, you have a power pool and the ability to sell on a merchant basis into that pool. Is there an economic dispatch principle where generators bid to supply electricity, and they are dispatched by the grid from least expensive to most expensive until demand for electricity has been filled?

MR. JOHNSTONE: The tariffs that individual generators receive vary with the technology that each is using. Generators have two options: to sell into the pool or to enter into a direct contract with a customer.

MR. MARTIN: You are sure of being able to sell all 50 megawatts?

MR. JOHNSTON: Yes. We will get ROCs that we can then sell into the open market.

MR. MARTIN: It sounds like the rest of these guys ought to join you in the water off Scotland. You have a sure market. [Laughter]

MR. JOHNSTON: The purpose of the tariff is to stimulate growth. That's why you are seeing a lot of interest in Spain as well as the UK.

MR. MARTIN: What price will you get ultimately for the electricity?

MR. JOHNSTON: For tidal power? You are looking now at what we call three ROCs, or about £160 an mWh.

MR. MARTIN: And at the current exchange rate into US dollars?

MR. JOHNSTONE: About $240 an mWh.

MR. MARTIN: It is a little higher than some of the offshore wind developers are getting in the United States. John McCarthy, how long have you been at it, and how much farther is there to go?

MR. McCARTHY: We have been developing our device since 2001. We probably have another two to three years to go before we have a device ready for commercial production. We started in 2001 with a 1/50th scale device that we tested in the sea. We progressed to a 1/15th scale device that we tested in France, and then moved to a full-scale prototype that we expect to start testing sometime early this autumn.

MR. MARTIN: How do you define commercial scale?

MR. McCARTHY: Commercial scale will be 50 meters long and 25 meters wide and have a capacity of 1.75 megawatts.

MR. MARTIN: Do you have a place yet in mind where you will deploy the first commercial-scale device?

MR. McCARTHY: The location will be driven by a number of factors. The main factor is the price we can get for the electricity output. In Scotland, for example, electricity from wave energy can be sold currently for about $400 per mWh. The figure is a little lower in Ireland, but the incentive is still there. Scotland, Ireland and Portugal all have attractive feed-in tariffs currently to stimulate development of the technologies locally in order to create jobs and potentially large-scale new industries.

Political Risk

MR. MARTIN: Ireland is having economic troubles; Portugal is as well. Many US developers had looked longingly at the feed-in tariffs in Europe as a better way to promote renewable energy than the tax subsidies that developers are offered in the US but have a hard time using. However, as economic troubles mount, renewable energy subsidies end up being scaled back. Spain is an example. Do you foresee any pressure to reduce the tariffs in Ireland and Scotland?

MR. McCARTHY: Absolutely.

Financing is a challenge. The maritime technology development period does not match with the venture capital fund requirements in terms of time for a return. A report published last month by Renewable Energy UK suggested that the best way to develop the technologies is to do it in a three-stage process. The first stage is pre-commercial prototypes, and the report suggested this stage would have to be driven primarily by government grants. The next stage is to build small-scale installations, and the money will have to come from a combination of grants and private funds pulled in by attractive feed-in tariffs. The last stage is commercial-scale projects that will have to be driven by commercial factors, but feed-in tariffs will remain important at this stage, at least until the industry can reach scale.

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MR. MARTIN: Are you worried that the feed-in tariffs will have been dismantled by the time you are ready to mount a commercial-scale project?

MR. McCARTHY: We think the tariffs will remain in place because they produce long-term economic benefits for Scotland and Ireland. There are hundreds of thousands of jobs available to these countries. We have a lot of wind farms in Ireland, but they produce very few jobs: only one job per megawatt of installed wind capacity.

MR. MARTIN: Cameron Johnstone, do you think by the time you complete your project off the Scottish coast, the feed-in tariff of $240 an mWh will still be there?

MR. JOHNSTON: Yes. Indications are that the new government is considering introducing a wider feed-in tariff for carbon capture and storage technologies, although the wider tariff might not be in place until 2016.

MR. DUNLEAVY: We have been talking about feed-in tariffs. Let's also not lose sight of green tags as another source of revenue. Certain technologies qualify for three ROCs in the UK. Some qualify for five ROCs. In Australia, there are RECs or renewable energy certificates, but they are the same concept. As we try to work out a business model in the commercial market that will make money for project developers, the monetization of green tags will be very important.

Cost Per Megawatt

MR. MARTIN: Reenst Lesemann, how much does your device cost today per installed megawatt and where do you hope to be?

MR. LESEMANN: We have not set a price yet. It is too early given where we are with our technology readiness level. That said, I think where everybody would like to be ultimately is in the $3 to $4 million per megawatt range.

MR. MARTIN: And you are five years away from that? Six? What do you think?

MR. LESEMANN: It depends on scale and production. We are still optimizing the design. Once we settle on a final design and start to invest in tooling, then we will be able to see more clearly how far down we can drive the cost of energy.

MR. MARTIN: Cameron Johnstone, how much does your device cost per installed megawatt, and where do you hope to be?

MR. JOHNSTONE: We are looking at about $4 to $5 million per megawatt.

MR. MARTIN: That is the current cost?

MR. JOHNSTONE: Yes. That includes about $0.4 million per megawatt for the mooring system and $0.5 million for physical installation with vessels.

We can foresee future cost reductions through further development of the generator technology. We certainly see the cost dropping easily to below $4 million per megawatt. Further reductions should also be possible as production scales up. We believe we will eventually undercut offshore wind.

MR. MARTIN: How long before you expect to drop below $4 million in cost?

MR. JOHNSTON: Around 2015.

MR. MARTIN: You need a lot more production to reach these goals.

MR. JOHNSTON: Economies of scale will have an impact, but the major impact by a factor of two is in the direct costs of the device.

MR. MARTIN: Chuck Dunleavy, what is your cost per installed megawatt?

MR. DUNLEAVY: The way we approach the cost per megawatt is for a full turnkey wave power station connected to the grid and fully deployed. Our target costs, in volumes of four hundred power buoys per year, are $4 million per megawatt.

We need to look as well at the levelized cost of energy associated with these numbers. The operations and maintenance component obviously is a significant line item in our customers' financial models.

An installed cost of $4 million per megawatt translates into about 15¢ a kWh. Our roadmap over the next few years as we roll out our PB-500 will take us considerably lower than that. We are targeting a cost of energy of 8¢ to 10¢ a kilowatt hour.

MR. MARTIN: Do these prices include the cost of mooring, ships, deployment, etc. as Cameron Johnstone's figures did?

MR. DUNLEAVY: Yes. They are all inclusive.

MR. MARTIN: So if you need $150 per megawatt hour, you are already economic — if not wildly profitable — if you deploy off the coast of Scotland.

MR. DUNLEAVY: I'll leave the adjective "wildly" to the analysts. [Laughter] But I sure hope that it comes to fruition. We think we can make a lot of money with our PB-150. We have deployed systems on three or four continents and have a very good supply chain set up. The good news for governments is we use local entities: divers, tugboats, fabricators, welders and that is a great part of the marine energy story.

MR. MARTIN: Derek Robertson, how much does a WaveBob cost per installed megawatt?

MR. ROBERTSON: We hope to deliver our systems fully deployed at $3.5 to $4 million per megawatt.

MR. MARTIN: Where do you think you are now, and how much time will it take to get to this target?

MR. ROBERTSON: Our target for getting into production is about five years. We are at a premium to the target right now: maybe not double that cost, but not too far from it.

Our most important target is levelized cost of energy. We are going ultimately to succeed or hang ourselves on the operations and maintenance costs. Our levelized cost of energy target, in the early stage of production, is more conservative than the figure Chuck Dunleavy used: something on the order of 25¢ per kWh, which is in line with some of the feed-in tariffs introduced in European member states as well as what we see as some of the niche market opportunities for discreet targeted applications.

MR. MARTIN: So you think these devices need $250 per mWh to work. John McCarthy, how much does the floating air turbine cost per installed megawatt?

MR. McCARTHY: At commercial-scale production, we expect to be in the region of $3.5 million per mWh installed, with a cost of energy somewhere between 12¢ and 15¢. That is where we expect to be when about 300 megawatts of devices have been installed. In the long run, the cost of electricity will come down the more devices are in the water because of the economies of scale that are developed in terms of laying the devices.

It is not the cost of the device alone that you take into account. You have to take into account the distance offshore and your cable to shore. You have to take into account the potentially substantial interconnection costs of the cables to reach the devices. You have to take into account the cost of hiring a crew to lay the moorings. There are lots of costs that turn on the location and the depth of the water.

MR. MARTIN: Each of you is looking for the same target, which is $3 to $4 million per installed megawatt. Craig Collar, do those prices sound like something that your PUD would find attractive?

MR. COLLAR: We tend to focus more on the levelized cost of energy, but $4 million per installed megawatt is within the ballpark. We tend to compare the cost to wind because that is the only renewable energy resource we have. It is difficult to predict where wind prices will end up. If we were to buy new wind electricity today, it would end up in the 12¢ range. That is 8¢ to 10¢ for the electricity and the rest to integrate it.

We are talking about alternative sources of renewable electricity that are probably under 15¢ a kWh today.

MR. MARTIN: So you will need your fellow panelists to get under 15¢ a kWh before you find their electricity attractive?

MR. COLLAR: If it were today, yes. But keep in mind that their projects are still a few years down the road, and a lot of things could change by then. Gas prices, how much more wind comes on line in the Pacific Northwest and what kind of storage opportunities are developed will all affect pricing but, today, that is what I would say.

MR. MARTIN: At what levelized price are the OpenHydro turbines you are testing capable of producing?

MR. COLLAR: This is a pilot project, of course. OpenHydro would probably say it is aiming for something around 10¢ or so long term. I could not tell you over what kind of time frame it expects to achieve that. We are technology agnostic.

Scotland supports ocean energy development through a very high feed-in tariff.

Potential Funding Sources

MR. MARTIN: One of the challenges for developers who are trying to develop new technologies is to find the money. Derek Robertson of WaveBob: where does your money come from today and what is your financing strategy going forward?

MR. ROBERTSON: Our money today / continued page 46

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largely comes from a combination of government agencies, friends and family.

MR. MARTIN: Can you break it down? What percentage of it has been from government sources?

MR. ROBERTSON: More than half. We believe going forward that there is probably not a business model that will allow us to remain an R&D-focused design house for wave energy converters. Our patient sources of capital and partnerships are going to require some vertical integration through the value chain. We have shied away from assuming any kind of role as project developer or manufacturer. That is a tough transition to make, and I don't think it is a realistic one for us, but I think with some vertical integration, we will be able to support our development program and go to market.

MR. MARTIN: Vertical integration means you might be acquired by a larger manufacturer?

MR. ROBERTSON: Yes.

MR. MARTIN: Reenst Lesemann, you have a partnership with Oregon State University?

MR. LESEMANN: Yes, we have a number of partners. Oregon State was one of the original ones, but we have moved to more of a proprietary commercial set up. Our funding to date has come from a mix of public and private sources. We have moved remarkably fast from technology readiness level one toward level seven and eight. Our model depends on strategic partners. We have a core competency in designing these devices, but the actual manufacture will depend on our partners. For us, it is a mix of funding sources, and we expect it to remain that way.

MR. MARTIN: What percentage has been government funded so far?

MR. LESEMANN: Through 2010, it was about 65% public to 35% private.

MR. MARTIN: Is that mainly federal government or state governments?

MR. LESEMANN: Mainly federal. It would be impossible under a private-only funded path to have gotten as far as quickly as we have done.

MR. MARTIN: John McCarthy, tell us where your money has come from and where you see it coming from in the future.

MR. McCARTHY: Our money has come from a combination of sources: private equity primarily and roughly 35% from the Irish government. In the future, we expect the funds to come from the industrial community.

What the private investors want is to see the industry players getting involved in the manufacturing of the components and supply of devices so that creditworthy warranties can be provided to customers. They want the security to know that these devices will be operating in 10 or 15 years' time. Having industry players on board will accomplish two things. It will provide the equity that is needed, and it will provide security in terms of the device's performance to the ultimate end user.

MR. MARTIN: Cameron Johnstone, where is your money coming from?

MR. JOHNSTONE: I think we are relatively unique in our development story in that our company started within an academic university environment. In 2000, we secured funding from the UK Research Council. In Scotland, we are fortunate to have a program called proof of concept with our local enterprise agency, Scottish Enterprise. It covers breaking this out from fundamental research to full commercialization. The Scottish Enterprise proof of concept fund allows you to build prototype systems and test them to prove robustness.

MR. MARTIN: So 100% is coming from universities or the government?

MR. JOHNSTONE: Through proof of concept. Since then, we have managed to tap into the Scottish offshore oil and gas industry, and we were fortunate to secure a lucrative deal with a private oil and gas company.

MR. MARTIN: So an oil and gas company has now provided some funding. Can I ask how much?

MR. JOHNSTONE: Around $15 million.

MR. MARTIN: It's no fun raising money. Are you sorry you left academia? [Laughter]

MR. JOHNSTONE: Let me tell you in about 18 months' time. In the commercial scale-up phase that we have now entered, the developments will be done through single-purpose vehicles. Individual project companies are formed and raise the hundreds of millions of pounds or dollars required to develop commercial sites. We as a company will not have an equity stake. We will be the technology provider. We have the sole international license for the technology.

MR. MARTIN: Chuck Dunleavy, your bio says that you have raised $150 million so far for your company from strategic, institutional and individual investors. That is a significant amount of money. What percentage of it has come from the government?

MR. DUNLEAVY: Roughly $40 to $50 million has come from government sources.

MR. MARTIN: So a quarter to a third from the government. What's the secret to raising so much money from the private markets?

MR. DUNLEAVY: It is a tremendously hard task to raise money. You need to present a good team — the employees you have, your advisors as well as the initial sponsoring customers — and have a strong technology plus luck when it comes to market timing.

Government Policies

MR. MARTIN: Derek Robertson, is there anything more governments should be doing to help ocean energy?

MR. ROBERTSON: The biggest help would be stable support. Investors and potential industry partners have a positive outlook about the future cost of energy from marine renewables. The concern is in the perceived volatility of market prices and government support.

MR. MARTIN: If you could pick one thing the government should do — one program — what is the most effective?

MR. ROBERTSON: Investment tax credits are effective. Developers have a hard time using them directly, but they are a carrot to attract strategic partners.

MR. MARTIN: Reenst Lesemann, same question: what is the most effective thing the government can do?

MR. LESEMANN: Institute a feed-in tariff. However, if we are trying to answer the question from the standpoint of a potential investor, the answer is a stable policy that one can feel confident will still be in place in the time it takes for the technology to mature.

MR. MARTIN: Craig Collar, does the government have a role to play here and, if so, what would be most effective?

MR. COLLAR: Government support through the US Department of Energy water power program has been essential for us. We would not be in this game today if not for the support of DOE. About half the cost of our pilot-scale project will have come ultimately from the DOE and the other half will have come from us. Beyond that, utilities tend to be sensitive about unfunded mandates to purchase electricity. Putting a price on carbon, either from coal or natural gas, would be a significant shift in market signal here.

MR. MARTIN: Is the future of ocean energy large utility-scale projects or is it smaller applications?

MR. LESEMANN: It is both. Many of the devices that people are trying to bring to market can be used in remote locations to generate electricity for local use, but our goal is for large-scale utility projects.

MR. JOHNSTONE: It has to start at utility scale to drive down the capital costs of the technology. Doing that then opens up the distributed generation option.

MR. MARTIN: That's very interesting. You need large-scale projects to bring down the cost. That is the reverse of how the solar photovoltaic industry is developing. ◎

US Offshore Wind Projects Move Toward Financing

by Thomas P. Byrne, in Los Angeles

The US offshore wind industry is gaining momentum. The first US projects are already in the market seeking financing. How is the market likely to respond? The experience with offshore wind projects in Europe provides some useful insights.

More than a thousand offshore wind turbines have been installed in Europe and the second offshore wind farm is under construction in China, but offshore wind development in the United States has been frustratingly slow. Not a single commercial turbine has been installed in US coastal waters despite exceptional offshore wind resources and deep onshore wind experience.

Significant breakthroughs in 2010 are finally giving the industry momentum. Federal and state governments are encouraging offshore development. Google, Good Energies and Marubeni bet on the sector by backing a 6,000-megawatt transmission line that Trans-Elect proposes to build off the mid-Atlantic coast.

Smart From the Start

One of the obstacles to offshore wind development in the United States has been a confusing regulatory landscape. The unveiling of the "Smart From The Start" program by the Obama administration late in 2010 will help. The program, which is be managed by the newly-renamed (after the BP oil spill) Bureau of Ocean Energy Management, Regulation and Enforcement, or "BOE," streamlines the permitting and leasing of offshore sites for new projects in federal waters, with a near-term focus on the Atlantic coast. Federal waters start three miles off the coast.

The BOE is supposed to work with the / continued page 48

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"Atlantic Offshore Wind Energy Consortium," a group of representatives appointed by the governors of 10 eastern states, to identify areas that are best suited for offshore wind projects. So far, BOE has identified such areas off of the coasts Massachusetts, Rhode Island, Delaware, Maryland, New Jersey and Virginia, and it is expected to designate others off the coasts of Maine, South Carolina, North Carolina and Georgia.

Once an area is designated, then BOE issues a request for proposals from developers interested in building projects in the areas. This triggers an environmental assessment. If the environmental assessment comes back clean, then leases will be issued. The streamlined program has already led to NRG Bluewater Wind being offered a lease for its project off the Delaware coast.

There are two types of leases available: a commercial lease and a limited lease.

A commercial lease grants all the rights necessary to conduct studies and construct and operate the wind farm. Such leases have a term of 30 years, and come with a price tag that could approach $100,000 annually prior to production. A developer can terminate the lease if it abandons a project and cut off the obligation to continue making lease payments. Nothing already paid would be refunded.

A limited lease only allows a developer to study the particular area, and the term is five years or less. Since the lease does not automatically roll over into a commercial lease, a developer will have to re-apply if it decides to move forward with a project. The limited lease, a number of which have been granted, may appeal to smaller developers that do not want the commitment and cost of a commercial lease.

While Smart From The Start relieves a lot of complexity, it does not eliminate all. A number of federal and state agencies still have permitting authority over various aspects of development and will need to be engaged during the development process. Projects built in federal waters will have to cross state waters (zero to three miles from shore) to an onshore interconnection point, implicating state permitting and regulatory regimes. Further, developers will still have to contend with the Endangered Species Act, Coastal Zone Management Act, Clean Water Act, Clean Air Act and other federal statutes.

State Incentives Gaining Traction

Many states are becoming enthusiastic supporters of offshore wind.

New Jersey is leading the way. More than 1,000 megawatts of projects have been proposed off the New Jersey coast by such developers as Fishermen's Energy, Deepwater Wind and NRG Bluewater Wind.

New Jersey enacted an Offshore Wind Development Act in August 2010 that creates offshore renewable energy credits — called ORECs — and requires New Jersey utilities to buy enough ORECs to support the development of 1,100 megawatts of offshore wind capacity. The law also authorizes the New Jersey Economic Development Authority to provide up to $100 million in tax credits to offshore wind projects that are built in designated wind energy zones and interconnect in New Jersey.

In Maryland, the governor, Martin O'Malley, is urging the state legislature to pass an ambitious bill that would require Maryland utilities to sign a total of 600 megawatts in long-term power purchase agreements with offshore wind projects. The bill is currently stalled in the legislature but has a fairly good chance of passing in the next session.

A similar bill was introduced recently in North Carolina that would require utilities to enter long-term power purchase agreements with offshore wind projects for a total of 2,500 megawatts. The outlook for the bill in the state legislature is unclear.

In Virginia, utilities get triple credit for renewable energy credits purchased from offshore wind projects for the purposes of compliance with the state renewable portfolio standard. In Delaware, the state decided that a 350% multiplier would apply to each renewable energy credit purchased from the NRG Bluewater Wind project.

Other states have formed committees to develop policies supporting offshore wind. Only time will tell whether conversation turns into prescription, but there seems to be a genuine interest on the east coast and throughout the Great Lakes to advance policy measures in support of offshore wind.

Financing Challenges

Europe has had a significant head start on working out financing structures.

Early offshore wind projects were financed primarily on the balance sheets of utilities. Lenders and investors largely steered clear because of the unknown risks in permitting, construction and operation.

In 2006, non-recourse project financing emerged as an alternative to balance-sheet financing. A syndicate of banks joined forces to finance the Prince Amalia wind farm, a 120-megawatt wind farm off the coast of the Netherlands. Shortly thereafter, in 2007, the C-Power Thornton Bank wind farm, a 30-megawatt wind farm off the coast of Belgium, secured project financing from a syndicate of banks.

In both cases, the construction contractor assumed substantial risk. Both projects were supported by long-term power purchase agreements and contracted sales of the associated green attributes.

In 2007, the non-recourse model appeared to be the future for financing offshore wind projects. Then the credit crisis hit in late 2008 and made it difficult to secure project financing for any type of project. Quasi-governmental entities stepped in to fill the gap in order to push projects to financial close.

The Belwind project, a 165-megawatt wind farm off the coast of Belgium, was the first project to obtain project financing post-recession in 2009. While commercial banks participated, the European Investment Bank, a bank formed to support European Union policy objectives, and Eksport Kredit Fonden, a Danish export credit agency, took on most of the risk. The EIB contributed approximately €300 million of the credit facility, and the commercial banks contributed the remaining €182.5 million of which half was guaranteed by EKB.

Subsequent financings followed a similar model. In 2010, C-Power secured a €1.16 billion loan for the balance of the Thornton Bank project, consisting again of a significant EIB debt contribution, a syndicate of commercial banks contributing smaller amounts, and guarantees from the EKF as well as Euler Hermes, the German export credit agency.

The participation of the EIB and other national institutions has lured banks to the offshore wind sector, providing a bridge to commercial bank-driven financings in the future.

Offshore wind projects in the United States are likely to need 30% or more equity to be financed.

Financing in the States

The US can learn from the experience in Europe.

Financing for any wind farm in the United States is a challenge. It is usually impossible to find the entire capital cost from one source. Chief financial officers at wind companies stack capital from cheapest to most expensive by tapping multiple sources.

None of the large-scale US offshore projects appears far enough along to be able to tap a Treasury cash grant for 30% of the project cost, as it requires starting construction by December 2011.

The next cheapest capital is debt guaranteed by the US government or by an export credit agency that is supporting the turbine sale. The high capital cost of offshore projects per installed megawatt makes some form of government loan guarantee or export credit agency support almost essential.

In the absence of such debt, the experience in Europe suggests that early projects are likely to require a balance sheet. Prior to the Prince Amalia wind farm financing off Holland in 2006, all European offshore wind projects were financed "on balance sheet." Even now, utilities dominate the sector.

In the United States, utilities have shown little appetite to own offshore wind farms. While they have supported the sector in concept and backed some pilot projects, none has an advanced commercial-scale project on its balance sheet. This leaves independent developers to drive growth, and since they are unable to self finance their projects, they must turn to banks to bring them on line.

No borrowing is possible without a bankable power purchase agreement, and such contracts have been elusive even for onshore projects. Of the dozen or so projects in the pipeline, only three have lined up offtakers.

The NRG Bluewater project off Delaware has a 25-year contract to sell its output to Delmarva Power.

In November 2010, the Massachusetts Department of Utilities approved the PPA between Cape Wind and National Grid. However, National Grid has only committed to purchasing half of the project's output, with the */ continued page 50*

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remaining output still uncommitted. The developers plan to build the project in phases.

Deepwater Wind secured a PPA for the entire output of its Block Island project, but that has come with some popular and legal resistance because of the high prices. Under the 20-year PPA, National Grid will purchase all of the project's output at 24.4¢ per kilowatt hour (increasing annually).

Some states are designing their renewable portfolio standards to encourage utilities to sign PPAs with offshore wind projects. New Jersey, Delaware, Maryland, and North Carolina are examples of states moving in this direction. With relatively weak solar and onshore wind resources, offshore wind offers Atlantic coast states a path to achieving their ambitious RPS targets.

Offshore projects are likely to need more true equity than onshore projects to be financed. In a typical onshore project financing, equity can account for up to 20% of the total project investment. Offshore projects in the US will probably follow the European example where equity accounted for 30% or more of the total project investment.

Public entities have played a critical role in bringing offshore projects in Europe through financing. They have provided the bulk of the debt, as well as the credit enhancements to satisfy commercial banks.

The Department of Energy loan guarantee program, which could prove critical for early offshore wind projects in the United States, may end up being of limited help. The window has already effectively closed on new applications. The recent budget deal that President Obama reached with the Republicans in the House to keep the US government operating eliminated what money there was to write new loan guarantees for projects that are not already in the queue for loan guarantees. The projects that are in the queue have until September 30 this year to close on the financing, with one exception. The budget deal made $1.183 billion in additional loan guarantee authority available for projects that are currently in the queue but that miss the September 30 deadline. The potential claims on this $1.183 billion are expected to be several times the amount.

The irony is that lack of such support may lead developers to use foreign-made turbines in order to benefit from financing from foreign governments through their export credit agencies.

An offshore wind coalition is urging Congress to extend the deadlines to qualify for a 30% investment tax credit or production tax credits of 2.2¢ a kilowatt hour on the first 10 years of electricity output. These credits are available currently only for projects completed by December 2012. The coalition argues that offshore wind is an early-stage technology like solar and needs the same ramp-up period as solar. Solar projects have until December 2016 to finish construction and qualify for tax subsidies. The tax subsidies, once accelerated depreciation is added to the tax credits, amount to at least 56% of the capital cost of a project. If they could then be converted into current capital in the tax equity market, that would fill in a significant piece of the permanent capital structure for US projects . ◎

US Hydropower Market

The following is an edited transcript from a webinar in mid-March hosted by Infocast about the US hydroelectric market. The panelists are Robert Larson, manager of Nelson Energy, Toni Volpe, CEO of Enel Green Power North America, Bernard (Bud) Cherry, CEO of Eagle Creek Renewable Energy, and Daniel Irvin, CEO of Free Flow Power Corporation. The moderator is Todd Alexander with Chadbourne in New York.

MR. ALEXANDER: Bob Larson, most new hydroelectric projects today seem to be 40 megawatts or smaller in size. Is the day of the large greenfield hydropower project over in the US?

MR. LARSON: Yes, for traditional large-scale hydroelectric projects at dams. We have no working knowledge of the construction of dams. There are not enough years left in my life to take on that portion of development. On top of that, building a new dam involves a number of risks. You hardly ever know what is underneath the river bed. Instead, we focus on adding incremental generation at existing dams, many of which do not yet have turbines. Most of those dams are owned by the US Army Corps of Engineers.

The number of existing dams that work with existing technology and the existing regulatory structure is very limited. Unfortunately, the cost of regulatory compliance does not scale to the size of the project. It is one size fits all. The National Hydropower Association is trying to persuade the federal government to develop regulations geared to small hydropower.

It is too early to say whether the effort will succeed.

MR. ALEXANDER: How long is the development cycle?

MR. LARSON: It is a 10-year cycle. Our coffer dams on our first project that we started in 2001 will be watered this week.

MR. ALEXANDER: Daniel Irvin, where do you see the potential for growth?

MR. IRVIN: Two challenges are how to scale an opportunity and make it cost effective and how to control risk over a development cycle. New hydro projects on existing dams are going to be less than 40 megawatts in size. The regulatory cost is not much less than it is for a project that is 1,000 megawatts. Our approach is to try to do projects in groups.

MR. ALEXANDER: When you do projects in groups, are they on the same river, and do they have the same owner?

MR. IRVIN: Same river. It helps also for projects with the US Army Corps to have the same owner. We have gotten states to cooperate. We have gotten US Army Corps districts to cooperate. When we started doing this, I think we had a lot of conventional wisdom thrown at us that we would not get more than one US Army Corps or US Fish & Wildlife Service district to cooperate at a time. If the cluster is big enough, it is worth the investment in time and money.

You asked about large projects. I agree with Bob Larson, with one exception. Large pumped storage projects are still possible. Many people have a sense that there are no longer any very meaningful opportunities left in the United States. I do not think that is true at all. There are opportunities, but it will take real effort to reform the regulatory process.

Most opportunities in the US hydroelectric sector involve installing turbines at existing dams.

M&A Activity

MR. ALEXANDER: Do you see any opportunity for industry consolidation?

MR. VOLPE: There is opportunity to consolidate small projects and dated projects that need to be re-engineered or partially rebuilt. That is a trend that will continue, certainly more frequently than pure greenfield development, which has a very low chance of happening in the future. It makes sense to look at greenfield development only where there is an existing dam.

MR. ALEXANDER: Is the M&A market more attractive for Enel than building new projects?

MR. VOLPE: We have an existing asset base that we can leverage and a set of competencies already, so a marginal asset sometimes can make a lot of sense. If it is already in a region where we are present, then we can leverage the people that we already have in that area.

MR. ALEXANDER: Bud Cherry, is your focus also buying existing projects?

MR. CHERRY: I agree that M&A is an easier road to growth than developing projects, but it is far from easy. Doing large greenfield projects in the US is very difficult, very time consuming and probably unlikely except in some isolated situations. In the aftermath of the nuclear catastrophe in Japan, the US may — and I stress may — look at the licensing, siting and other rules that are impeding development of new clean energy projects. No one wants to benefit from the kind of tragedy that hit Japan, but it could change the playing field in the US for clean energy.

In M&A, our focus has been on acquiring operating assets of reasonable scale. We have taken a look at advanced development projects and projects that are troubled. The troubled projects either have been mismanaged technically or have compliance issues.

MR. ALEXANDER: Toni Volpe, what is most challenging about trying to acquire hydro projects, and what is most challenging about managing your hydro portfolio as opposed to other types of renewable energy projects?

MR. VOLPE: There are not a lot of assets that end up on the market. Then there are a lot of interested */ continued page 52*

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buyers, so it is a fairly competitive sector. What separates bidders is the view each has of the capital costs to maintain the assets for 30 to 40 years. You are usually talking about assets that are already fairly old. Another area that can differentiate buyers is whether an asset falls within an area where there are existing locations that we can leverage and the options that you have to develop further the assets. In most cases, a license is about to expire and you can add additional minimum floater units or even put in a larger refurbishment for a more efficient power plant.

It takes 10 years in the US to develop a hydroelectric project because of heavy regulation.

Regulatory Barriers

MR. ALEXANDER: How do you view the posture of the federal and state regulators toward hydro and the difficulties of getting hydro projects permitted or obtaining approval for a change in control?

MR. IRVIN: There has been a strange hiatus for last 20 years in the United States during which there has been no new development. The focus has been on relicensing existing projects. The sector is waiting for legislative changes. The regulators are sympathetic to the need to make the regulatory process easier, but there is only so much they can do under the existing statutes.

MR. CHERRY: I think it is fair to say that next to nuclear power, hydroelectric generation is the most heavily regulated form of generating technology. There is little federal oversight in the solar business or wind business unless you happen to be working on federal land. There is a very modest degree of federal oversight in the geothermal business, but again mainly because many such projects are on federal land. The development cycle in the hydro space is the longest of any of the technologies, except perhaps if you are starting with a large greenfield coal project and you have to go through the whole environmental review.

MR. IRVIN: The hydro industry got a level playing field two and a half years ago when Congress authorized developers of incremental hydro projects to qualify for the same 30% Treasury cash grants as other renewable energy projects. Relicensing existing facilities requires a different kind of approach to the regulatory process. It is more risky and time consuming than one normally would tolerate for new development.

MR. ALEXANDER: How do you make decisions about projects not knowing what the tax climate will be, what the regulatory climate will be or even how favorably utilities will look toward signing a power contract by the time your project is ready?

MR. IRVIN: It is different than for a wind or solar project. A great deal is known about hydro. What you install can be there for 100 years. You do not know about the ultimate life of a new wind turbine. Everything that a hydro project can do to the environment is well known. That is not the case with many other types of renewable energy, and I think this will start to level the playing field a little more over time.

MR. VOLPE: When you talk about hydro, you talk fundamentally about a natural resource that is shared. There is only one use for wind or solar irradiation. So it makes sense that there is a more regulated process for hydro. The question is whether it is possible to have a simplified processes to make it last three years as opposed to 10 years. It would help with many of the issues that we have been talking about. Hydro can be in some circumstances extremely cost effective. That's why we are fairly optimistic that the regulators will adapt to the idea that a streamlined process might help development.

Returns

MR. ALEXANDER: What types of returns does one earn on the development capital?

MR. IRVIN: For pure development at a very early stage, 20% or more, but for a project that is already completely licensed with debt and a power contract in place, potentially low teens. The debt is typically in the 7% to 8% range. So, trying to finance the project from beginning to end is extremely expensive. If you try to develop a hydro project the way you would a wind project, you would look at market conditions and say, "power prices are high, let's do a wind project," and try to get it done before prices start to enter the down cycle. In hydro, you almost have to start a project when electricity prices are low because of the cycle.

MR. ALEXANDER: How do you analyze a developer's proposal to add generating capacity at an existing dam?

MR. CHERRY: We would look at where in the FERC process and what issues surround issuance of a license if the license has not already been issued. Beyond that, you would look at head flow and any other issues that might affect output. Do you control the flow? What is the typical annual variation in the flow due to rainfall or other factors?

MR. ALEXANDER: Bob Larson, how do you determine which projects are worth your time and money?

MR. LARSON: We put together an economic model that does not assume any tax benefits. We are not very good at predicting what the government will do. We try to be conservative about the cost of money. We try to be conservative about electricity prices. We put in huge contingency numbers. You do not know what a project will cost until you see the license, and even then you don't know.

MR. ALEXANDER: How do you see the current low natural gas prices affecting development of new hydro capacity?

MR. VOLPE: This is probably a good moment in the cycle to start developing projects. Hydro can be extremely cost competitive with other technologies. If you imagine a scenario in the long term where natural gas prices stay low and where renewables are going to have to compete with each other just on the basis of their costs, then hydro makes sense.

MR. ALEXANDER: Are projects under 40 megawatts too small to be done on a project finance basis?

MR. IRVIN: Lenders are attracted to a project finance model where they have a pool of projects. It is very, very difficult to finance a $5, $10 even a $20 million project. I think you start to get project lenders interested somewhere between $25 to $50 million and some of the major, most sophisticated lenders will not look at a project that costs less than $100 million. You can get to those levels with a pool of projects, but not a single project.

MR. ALEXANDER: Daniel Irvin, given that a lot of existing dams are small, what kind of strategies are you seeing people use to get a high quality team for operations?

MR. IRVIN: Again, I think you have to aggregate a team around a group of projects. If you look at the bigger owners of clusters or groups of hydro projects, you will see their projects are concentrated in a particular region.

MR. ALEXANDER: Can we provide a general rule of thumb about the minimum electricity price required to support a hydro project?

MR. VOLPE: In the past, we have owned or developed projects where the range went from $50 to $60 per megawatt hour to more than $100. It is a very broad range. Most hydro projects sell into the wholesale market at between $60 and $90 per megawatt hour. To provide perspective, wind farms probably sell on average at prices between $60 and $100.

Attention Shifts From A Clean Energy Bank to a Broader Infrastructure Bank

by Douglas M. Fried and William Nicholson, in New York

Four competing proposals for a national infrastructure bank — one from the Obama administration and three others in the House and Senate — are starting to take shape in Washington.

Under each proposal, the US government would provide loans and loan guarantees to qualifying projects.

The bills are not expected to move through Congress before 2012 at the earliest.

The bank would be authorized to fund transportation infrastructure projects under all four proposals. It would also have authority under the House and Senate proposals to fund energy, water and other infrastructure projects.

The goal of each proposal is to use government loans and loan guarantees as seed capital to stimulate private infrastructure investment. An example of the potential multiplier effect is the experience with the Transportation Infrastructure Finance and Innovation Act or "TIFIA" program run by the US Department of Transportation that has been able to generate up to $10 in TIFIA financing, and up to $30 */ continued page 54*

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in total infrastructure investment, for every federal dollar invested in the program. There has also been a multiplier of 13 private dollars for every dollar of federal loan guarantee under the loan guarantee program for renewable energy, nuclear and transmission projects run by the US Department of Energy, according to a recent letter by Senator Maria Cantwell (D-Washington) to Senate leaders in support of the program.

The infrastructure banks have bipartisan backing. Both Republicans and Democrats are listed as cosponsors in the Senate. The concept also has the support of the AFL-CIO union movement and the US Chamber of Commerce.

The US government is struggling with huge budget deficits. The bank is seen by some as a way to stretch scarce federal dollars farther by using them as a carrot to get the private sector to build needed public infrastructure.

Senate

Four Senators — John Kerry (D-Massachusetts), Kay Bailey Hutchison (R-Texas), Lindsay Graham (R-South Carolina) and Mark Warner (D-Virginia) — introduced a bill in mid-March to create an American Infrastructure Financing Authority or "AIFA." The bill is S. 652. It was referred to the Senate tax-writing committee on which only Kerry sits. Hutchison is retiring after 2012.

AIFA would be an independent agency. In its first two years of operation, AIFA would be authorized to make in the aggregate loans and loan guarantees of up to $10 billion per year. In years three through nine, AIFA would be authorized to make in the aggregate loans and loan guarantees of up to $20 billion per year. Thereafter, AIFA would be permitted to make in the aggregate loans and loan guarantees of up to $50 billion per year.

AIFA could finance transportation, water and energy infrastructure projects. To qualify for credit assistance, projects would need to involve at least $100 million in "eligible infrastructure project costs," meet specified "economic, financial, technical, environmental and public benefits standards" and have a "dedicated revenue source" (either from tolls, user fees, availability payments or the like). AIFA would give priority to projects that "contribute to regional or national economic growth, offer value for money to taxpayers, demonstrate clear public benefits, lead to job creation and mitigate environmental concerns." Additional consideration would be given to the ability to maximize private investment, among other factors. AIFA credit support would not be available to refinance existing infrastructure projects.

AIFA would provide loans and loan guarantees of up to 50% of a project's "reasonably anticipated eligible infrastructure project costs." Loans would have no more than a 35-year tenor, and would bear interest at rates not less than US Treasury securities of similar maturity. For direct loans, scheduled loan repayments would begin no later than five years after substantial completion of the project.

Prospective projects would be subject to a risk assessment, to be conducted by AIFA in conjunction with the federal Office of Management and Budget and a rating agency. At a minimum, the senior debt would need to have an investment-grade rating. A credit fee to cover AIFA loan assistance would apply to all AIFA-financed loans and loan guarantees. For AIFA-financed loans, the credit fee would be in addition to the base interest rate charged on the loan. Other credit and security terms typical of project financings — including similar security requirements — would be included as part of AIFA loan and loan guarantee credit documentation.

Five percent of AIFA funding would be set aside for rural projects. Rural infrastructure projects would only need to demonstrate $25 million in "eligible infrastructure project costs" to qualify for assistance.

The Obama administration and various members of Congress want to create a national infrastructure bank.

As the *NewsWire* went to press, two Democrats — John Rockefeller (D-West Virginia) and Frank Lautenberg (D-New Jersey) — introduced a competing proposal in the Senate to create an American Infrastructure Investment Fund or "AIIF." Their bill is S. 936. It went to the Senate Commerce Committee. The AIIF would be housed in the US Department of Transportation and be authorized to spend up to $5 billion in each of its first two years of operation. Its initial focus would be transportation projects. However, the sponsors said the intention is to broaden the scope to cover telecommunications, energy and water infrastructure projects after the first couple years.

White House Proposal

President Obama called in February 2011 for creation of a national infrastructure bank — called the I-Bank — to be capitalized with $30 billion in public money over a six-year period and with a mandate to finance transportation infrastructure projects only. The I-Bank would be housed within the US Department of Transportation.

The I-Bank would provide loans, loan guarantees and grants for qualifying transportation projects. Qualifying projects would be chosen based, among other factors, on how large a return they are likely to provide on taxpayer investment.

The existing TIFIA program would be folded into the I-Bank, according to InfraAmericas.com. The TIFIA program provides credit assistance in the form of loans, loan guarantees and standby letters of credit for transportation projects of regional or national economic importance. It has been in operation since 1998. The goal of the TIFIA program is to draw private investment to supplement federal transportation dollars. Demand for TIFIA funding has outpaced supply since 2008.

Funding for the TIFIA program is used to offset subsidy costs associated with the provision of federal credit assistance for infrastructure projects. The Obama administration wants an increase in funding for the TIFIA program to $450 million per year from the current $122 million. According to the US Department of Transportation, the current levels of TIFIA funding can support more than $2 billion of federal credit assistance. According to the Obama administration, the proposed increase in TIFIA funding could stimulate up to $13.5 billion in infrastructure investment, inclusive of federal credit assistance. To put the funding levels into perspective, TIFIA received 34 letters of interest for more than $14 billion in credit assistance for the 2011 fiscal year.

House

Rep. Rosa DeLauro (D-Connecticut) and 44 other Democrats introduced a proposal in the House in January for establishment of a National Infrastructure Development Bank or "NIDB." The bill is H.R. 402.

The NIDB would be an independent, wholly-owned government corporation with a 15-year charter. The bill would authorize the government to inject up to $5 billion a year from 2012 through 2016 for what it supposed to be 10% of the total share capital.

The NIDB would be authorized to fund transportation, environmental, energy and telecommunications infrastructure projects. Projects would be chosen based upon an analysis of project costs against a project's "economic, environmental and social benefits." Priority would be given to projects that "contribute to economic growth, lead to job creation and are of regional or national significance."

Other factors that would be considered by the NIDB include a project's ability to maximize private investment and public benefits.

Outlook

The politics of an infrastructure bank are complicated.

Developers and financiers in the transportation sector are concerned that a national infrastructure bank could compete with TIFIA for funding. Some industry executives, including those who took part in a recent roundtable discussion about toll roads hosted by *InfraAmericas* and Chadbourne, would like to see the TIFIA program expanded, arguing that Congress could do more to advance infrastructure investment by expanding the proven and successful TIFIA program, rather than initiating a new, albeit modest, infrastructure investment model. (See a transcript of the roundtable starting on page 24 of this issue.)

The huge budget deficits at the federal level make it hard to fund any new initiatives.

Members of Congress on the appropriations committees may see such a bank as ceding control to an outside agency over how federal dollars are spent.

An historical antecedent for the bank is the Reconstruction Finance Corporation during the Great Depression. However, proposals to create technology or energy banks have been introduced in Congress for a number of years. None has made much progress. There was a push in the last Congress to create a clean energy bank, called CEDA, but the effort lost steam, and the November 2010 elections that shifted / *continued page 56*

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Congress of the House to Republicans and that brought a large incoming class of new members of Congress backed by the Tea Party and determined to scale back government did not improve the bank's prospects.

Some analysts suggest Congress is more likely to expand existing federal aid programs than to create new ones. Three key members of Congress — John Mica (R-Florida), chairman of the House Transportation and Infrastructure Committee, Barbara Boxer (D-California), chairman of the Senate Environment and Public Works Committee, and James Inhofe (R-Oklahoma), the senior Republican on Boxer's committee — have said they favor putting more money into the TIFIA program.

There are important lessons to be learned from recent experience with other federal infrastructure aid programs. It took six years from 2005 to 2011 before the loan guarantee program in the Department of Energy was working effectively. Many thought during the wait that an independent agency, perhaps modeled on the Overseas Private Investment Corporation, would have been able to move more quickly. In this respect, the AIFA and NIDB proposals, which offer specialized, independent infrastructure banks, are attractive models for a national infrastructure bank. In a similar vein, a national infrastructure bank should not be developed at the expense of other successful and established programs, like TIFIA.

Congress should also be concerned not to let a national infrastructure bank serve as a vehicle for funding pet projects and other politically popular, but economically dubious, projects. Some argue that an independent agency is better able to deflect political pressure.

Finally, the lessons of the TIFIA program demonstrate that, for a federal credit assistance program to reach its full potential, supply must keep pace with demand. Modest investments and unrealistic funding projections will do little to address the infrastructure funding gap.

Regardless of the outcome, the federal government will have no choice, given budget pressures, to look to the private sector to fill the infrastructure funding gap. ◎

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