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A Look Forward Into 2009

A new president and a new Congress will take office in January determined to play an active role in restoring the economy and to push the United States in the direction of "green" energy. Although the United States prides itself on having a market economy, the government is a very important actor in the energy sector. Changes in government policy can be important pivot points for investors.

Four Washington lobbyists talked in mid-December about what to expect from the incoming Obama administration in a webinar organized by Infocast. The four are Jonathan Weisgall, vice president for legislative and regulatory affairs for MidAmerican Energy Holdings Company, the holding company through which Warren Buffet makes energy investments, Joe Mikrut, the tax legislative counsel for the US Treasury Department during the Clinton administration and now a partner with Capitol Tax Partners, Richard Glick, senior policy adviser to the US Secretary of Energy during the Clinton administration and now director for government affairs for Iberdrola Renewables, and Tony Kavanagh, vice president for governmental affairs for the American Electric Power Company, a large midwestern utility. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Jon Weisgall, most power industry lobbyists expect three major bills from the next Congress: an economic stimulus bill in January to get the economy moving again, an energy bill sometime later in 2009 and then legislation to control US carbon emissions. What do you think will be the timing?

MR. WEISGALL: Congress will return on January 6. There is some / continued page 2

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SEGREGATED FUNDS may not have to be reported as income.

A utility sold a nuclear power plant and also transferred the nuclear decommissioning fund to the new owner. It promised its regulators that it would return an amount equal to its book gain on the sale to its customers. No details had been worked out by the time of sale, so the buyer paid the portion of the purchase price that the utility promised to pass through eventually to customers into a segregated account. The account earned interest.

Some time later, the two state regulatory commissions with jurisdiction over the utility issued orders directing the utility / continued page 3

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talk of getting the stimulus bill done so that President Obama can sign it on or soon after he takes office on January 20. The Democrats can push the stimulus bill through the House quickly, but I just don't think it can move that quickly through the Senate. My guess is we will see the stimulus bill enacted sometime between January 20 and mid-February when Congress breaks for the President's Day recess.

Congress is expected to pass an economic stimulus bill by mid-February and a separate energy bill by as early as the summer.

The energy bill will be more policy oriented and tackle such things as a national renewable portfolio standard and transmission reform as well as other policy issues. I don't see it clearing Congress until the summer.

Climate change is anybody's bet. The absolute earliest it could get through Congress is next fall. Most likely, the debate will start then with the bill making it to the president sometime in 2010.

MR. MARTIN: Tony Kavanagh, does that timetable sound right to you?

MR. KAVANAGH: It does.

MR. MARTIN: Rich Glick, do you agree?

MR. GLICK: Generally, but I would move up the timing for the energy bill. There is some talk on Capitol Hill of starting to move the energy bill soon after the stimulus passes. The energy committees in the House and Senate may hold hearings and even mark up the bill by March. I think we might see an energy bill completed by the summer, but the initial legislative work might actually begin in the late winter or early spring.

Economic Stimulus

MR. MARTIN: Joe Mikrut, if Congress returns for work on January 6, what is the earliest we will get a look at the contents of the stimulus bill?

MR. MIKRUT: The Senate Finance Committee is considering marking up a bill as early as January 8. If that happens, then the committee chairman would probably have to distribute an outline of the bill, called a "chairman's mark," by January 7 at the latest.

MR. MARTIN: Rich Glick, the stimulus bill is expected to include one or more proposals to help revive the tax equity market. Renewable energy projects in the United States rely on tax equity for a large share of their financing. The tax equity market is not as frozen perhaps as the debt market, but it is not much better off. What do you see happening in the stimulus bill on that subject?

MR. GLICK: This is a significant issue for the renewable energy industry. I can tell you from the standpoint of the wind industry alone, the problems associated with the tax equity market have the potential to reduce US wind energy capacity installations in 2009 by about 50% compared to 2008. That is a very big deal.

Renewable energy projects in the US are subsidized through the tax code. Most project developers cannot use the tax subsidies themselves because they don't have enough taxable income. We are hoping to persuade Congress to take some action that will make it easier to convert the tax subsidies into cash, at least in the short term if not also in the long term.

The industry has been urging Congress to make any tax subsidies that the owner of a project cannot use refundable in cash by the US Treasury. It also wants the option to carry back unused tax benefits up to 10 years and get refunds of taxes paid during that period.

MR. MARTIN: Is the focus just on relief for wind farms, or also solar, geothermal and biomass projects?

MR. GLICK: Wind, geothermal and biomass projects benefit from production tax credits that are tied to electricity output. Solar projects benefit from investment tax credits that are tied to the project cost. The lobbying has focused on trying to make it easier to get value for both types of tax credits as well as the tax depreciation for which these projects benefit. Depreciation amounts to more than half the tax incentive for some projects.

MR. MARTIN: Joe Mikrut, you have been on Capitol Hill working this issue for the American Wind Energy Association. The goal has been to try to secure relief for projects placed in service during a two-year period, right? If so, which two years?

MR. MIKRUT: Tax equity started drying up in 2008. The problem of too little tax equity is expected to stretch into 2009. The wind industry is looking for relief for projects placed in service at least during those two years.

MR. MARTIN: Is there any risk that the two years might be 2009 and 2010 or just 2009, with the result that 2008 is not included?

MR. MIKRUT: Yes. The effective date is usually the last thing the staff decides with respect to any proposal. There is a very good case to be made that certain projects that were put in service in 2008 need help. However, the tendency is usually to limit relief prospectively to future projects.

MR. MARTIN: Just to be clear, a wind farm qualifies for 10 years of production tax credits. When you say you want tax credits on 2008 and 2009 projects to be refundable, you are talking about refunds for the full 10 years of tax credits. Is the wind industry asking for a single refund at inception for the full 10 years of credits or annual refunds over the 10 years?

MR. MIKRUT: Those details have not been worked out yet. There are at least three broad ways to try to help the tax equity markets. One is refundability, which we have just been discussing. Another is tradability, which would allow companies that cannot use tax credits to transfer them to other companies that can use them. The last option that has been on the table is to expand the class of potential tax equity investors by allowing individuals to invest. Individuals would need relief from passive loss and at-risk rules that make it hard currently for them to invest, and they would need a statutory change to allow them to invest through publicly-traded partnerships.

The staff will have to decide first on the general approach and then it can start filling in details. The industry has lined up largely behind refundability.

MR. MARTIN: The other two options are still in play?

MR. MIKRUT: Yes. The other two remain */ continued page 4*

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to use the segregated funds to provide credits over the next 18 to 36 months on bills to customers in the two states. The Federal Energy Regulatory Commission also ordered a one-time refund of some of the funds to other customers in the form of a check or billing credit.

The Internal Revenue Service ruled privately that the utility did not have to report the purchase price deposited in the account, or the interest earned on the account, as income. It made the ruling public in December. The IRS said the utility had no income in the sense of an "accession to wealth," and it had no control over the funds. The segregated account remained subject to oversight by the public utility commissions until the funds in the account were fully credited to customers. The ruling is PLR 200852002.

The ruling is interesting because the IRS is usually reluctant to rule that amounts are not income at all. It has fewer qualms about ruling that an amount that would normally be income does not have to be reported in a particular case because of an "exclusion" in the tax code. The ruling also suggests planning possibilities.

The IRS said it did not matter that the funds were eventually turned over to the utility when the utility provided billing credits to its customers.

MUNICIPAL UTILITIES and other government entities will have to withhold 3% of payments for property or services starting in 2011. This includes payments by municipal utilities for electricity or gas.

The IRS issued proposed regulations in late December explaining when withholding will be required. The withholding is required under section 3402(t) of the US tax code.

All federal, state and local agencies and instrumentalities will have to withhold. Indian tribes will not. A partnership that has government entities as partners must withhold if they own at least 80% of the partnership.

However, a local govern- */ continued page 5*

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in play because, while it is fairly easy to make a case for refunding tax credits and the proposal is fairly easy to draft, the other significant tax benefit for renewable energy projects is depreciation. Depreciation may be worth anywhere from 40% to 60% of the tax benefits for a project. The problem is that it may be harder to persuade Congress to make depreciation refundable. There is no precedent for refunding depreciation, and many other industry groups would want the same benefit.

If, for whatever reason, Congress balks at refunding depreciation but is fine with refunding tax credits, then we have to think of some other option for the depreciation component. Depreciation and the credits go hand-in-hand. You really need both to put these projects back in the position they were in before the tax equity markets collapsed.

MR. MARTIN: Someone in the audience asked whether municipal utilities and tax-exempt entities would also be able to apply for refunds of unused tax credits?

MR. MIKRUT: That's something for Congress to decide. Tax-exempt entities could not benefit from the tax subsidies directly before the tax equity market collapsed because they do not pay any taxes. You could make a case that whatever relief Congress grants should apply across the board, but you would have to coordinate it with some of the other benefits that are available today only to municipal utilities and other tax-exempt entities. They have the ability to use tax-exempt financing and to issue clean renewable energy bonds that do not require the issuer to pay interest, but that give the lenders federal tax credits instead. It would be unusual for Congress to provide relief while also leaving these other benefits in place.

MR. MARTIN: Jon Weisgall, renewable energy companies have also been pressing Congress to extend the deadline to place wind, geothermal and biomass projects in service to qualify for production tax credits by another five years through 2014. Is an extension likely to be included in the stimulus bill and, if so, how long?

MR. WEISGALL: There has been talk about an extension of anywhere from three to five years. It would make sense to address it in the stimulus because an extension would provide the certainty developers need to order more parts and turbines, and it would be consistent with the fundamental goal of getting people back to work and getting the economy going again.

The stimulus bill will include provisions aimed at reviving the tax equity market.

MR. MARTIN: Rich Glick, what are you hearing about an extension?

MR. GLICK: I think an extension is likely given the emphasis the Obama administration wants to put in the stimulus bill on creating green jobs. However, I would bet on two to three years rather than five. The American Wind Energy Association just had an independent consultant study how many new jobs would be created with an extension of five years. The answer was another 90,000 jobs in the wind industry alone. If you add that to the new jobs that would be created in other segments of the renewable energy industry, it could make a significant dent toward the 2.5 million jobs that President-elect Obama wants the stimulus to create.

MR. MARTIN: Biomass companies have been asking for parity. Wind and geothermal companies can claim production tax credits of 2.1¢ a kilowatt hour currently on the electricity they produce. Biomass projects qualify for tax credits of only 1¢ a kilowatt hour. Do you see a move to increase the credits on biomass projects?

MR. GLICK: It has certainly been under discussion. What has held it back in the past is the cost to the US Treasury. They are talking about a stimulus on the order of $600 billion to $1 trillion. Certainly, if there has ever been a time to try to reach parity for biomass and some other technologies that qualify for reduced tax credits, this is it. The cost of these proposals would be insignificant when measured against the size of the overall stimulus.

MR. MARTIN: Tony Kavanagh, focusing still on the stimulus, Obama spoke repeatedly on the campaign trail about the need to upgrade the nation's electricity grid. Do you see anything happening on transmission in the stimulus bill or is that for the energy bill later in the year?

MR. KAVANAGH: There has been discussion about tackling transmission in both the stimulus and the energy bill, but we have been hearing more lately that it is a complicated subject that may be better addressed later in the energy bill.

Rich Glick just mentioned that the stimulus could reach $600 billion to $1 trillion.

The bill will have two parts: it will have investments and it will have a tax piece. In the investment section, they are talking about a green energy bank that would make low-interest loans for energy projects, both renewables and I think also transmission, and they are considering including broadband as part of transmission.

The US transmission grid is badly in need of updating. Bill Richardson called our transmission grid "third world" when he was Secretary of Energy in the Clinton administration. I wouldn't agree with that description, but it does speak to the fact that we have a long way to go to improve the electricity grid in this country. If nothing else, if we want to rely more heavily on renewables, we need more transmission capacity since renewable energy projects tend to be far away from population centers.

MR. MARTIN: So transmission is probably a subject for the energy bill and not the stimulus bill.

MR. KAVANAGH: If I had my way, it would be in the first one and it would be done quickly, but I think it is complicated. It will probably be in the energy bill.

MR. WEISGALL: I think it is still possible we will get something in the stimulus on transmission even though the broader subject is addressed in the energy bill. One goal of the stimulus bill is to spend money on shovel-ready projects, but projects that are considered shovel ready might take as long as 36 months to get underway.

When people talk about doing something about transmission, they are talking about a series of issues.

One is siting reform: making it easier to get permission to build new transmission lines. Obviously / continued page 6

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ment entity — but not a federal or state agency — is exempted from withholding if its total payments for property and services two years before were less than $100 million. For example, a municipal utility would look at what it paid for property and services in its 2009 accounting year to determine whether it must withhold on payments it makes in calendar year 2011. Wages paid to employees are not counted.

Certain payments are exempted from withholding. No withholding is required on payments from one government entity to another or on payments to tax-exempt entities or foreign corporations. Most payments to foreign corporations are already subject to 30% withholding at the US border unless waived by treaty. Withholding is not required on interest payments or on rent for use of land or buildings. It is not required on individual payments of $10,000 or less, unless the payments are purposely sized to avoid withholding.

Many people complained that it is unfair to require withholding on payments under existing contracts that were signed before companies doing business with governments were on notice about the withholding. The IRS agreed. It said no withholding will be required under "binding" written contracts that are in effect on December 31, 2010 or, if later, six months after the IRS reissues the proposed regulations in final form. However, payments under such a contract will become subject to withholding if the contract is later materially modified. "Binding" is a term of art. For example, a contract is not binding if it limits the damages that will have to be paid upon cancellation to less than 5% of the total contract price.

Payments by government agencies to private prime contractors will attract withholding. There is no further withholding when the prime contractor makes payments to its subcontractor.

Any company that has money withheld will get a credit for the withholding that it can use against its income taxes. Companies that do not use the calendar year as / continued page 7

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that's policy. It requires debate. It will probably have to wait for the energy committees to hold hearings. Rich Glick said earlier he thinks the hearings will get underway as early as March. It is not an idea for putting money to work immediately on shovel-ready projects.

A second part of the transmission debate is cost recovery or incentives for more investment. How should the cost of new transmission lines be paid — by utilities and their shareholders, by ratepayers or by developers who need the grid to expand to be able to get their electricity to market? That's policy as well. It will probably have to wait for the energy bill, but there is a push to address it in the stimulus.

Then there is a third area that lends itself more readily to the stimulus, and that is federal utilities like the Bonneville Power Administration, Western Area Power Administration and Tennessee Valley Authority have shovel-ready upgrades that they can make to their grids.

MR. GLICK: Both the Senate majority leader, Harry Reid, and the House speaker, Nancy Pelosi, have been calling for additional funding for the federal utilities as part of the stimulus to build extra transmission lines and increase the capacity of existing lines. This sort of construction can be done quickly. It gets steel in the ground and adds jobs, especially in the western part of the country where Reid and Pelosi are from.

MR. MARTIN: When the federal government talks about spending on shovel-ready projects, it is talking about giving money to federal utilities and to state and local governments and not to private utilities, like American Electric Power and MidAmerican, right?

MR. KAVANAGH: Partly correct, but there has also been discussion about the federal government making low-interest loans to power companies to get projects underway that can't be financed in the frozen credit markets.

The bigger problem is regulatory barriers to siting new transmission lines. American Electric Power has a very large 765-kilovolt transmission system. Our last addition was completed in 2006, but it took us 16 years to build. That was 14 years to get the permits and two years to get the project up and electrified. We need regulatory reform before we can even get to the point of needing financing.

A national renewable portfolio standard will probably be enacted this summer. It will act as a floor alongside existing state programs.

MR. WEISGALL: Adding to what Tony said about low-interest loans, you could have the federal government provide funding as a backstop to cover any shortfall in revenue due to unsubscribed capacity on a new transmission line. Obviously, you would need a process. You would need a finding of need by an agency like the Federal Energy Regulatory Commission, but I could see that as a possibility.

I think the vast majority of the dollars in the stimulus will go to federal entities or states. I think we will see most of it go to existing programs. It is hard to establish new programs in the time period Congress has to work on the stimulus. For example, we will see additional spending on state weatherization programs — which already exist — or possibly funding for programs that were authorized in the Energy Policy Act in 2005 but that have yet to be funded.

We may also see additional funding for research and development for such things as carbon capture and sequestration, battery storage and plug-in electric hybrids. Most of it would go to the national laboratories.

MR. MARTIN: Does any of you foresee any special action in the stimulus bill to jump start the credit markets and, if so, what?

MR. KAVANAGH: There has been talk about helping individuals refinance existing adjustable-rate mortgages, perhaps at a 4 1/4% rate. The objective is to keep as many people in their homes as possible.

Turning to businesses, certainly some businesses would be better served if they had the ability to borrow or sell their commercial paper at the Fed window. The federal government already allows certain types of companies to do that. It could expand the class of eligible entities. That would help unfreeze credit.

MR. MARTIN: Let me ask another audience question quickly and get a brief answer, and then let's move to the energy bill. Several people asked whether you see any special effort to push energy efficiency projects in the stimulus, beyond just funding state weatherization programs.

MR. WEISGALL: Yes. Everyone knows that energy efficiency is the lowest hanging fruit. Look at insulation. Look at what can be done in retrofits. I don't think they are looking particularly at using the stimulus on energy efficiency for new housing or new buildings, but in the retrofit market, there is a lot to do, and it is good policy to address. There are benefits in terms of reducing greenhouse gas emissions. Retrofits also produce jobs quickly.

MR. MARTIN: What form might it take?

MR. WEISGALL: It goes back to what we were saying earlier. Can you funnel money to the private sector? That's going to be hard. But I can certainly see full funding for a number of state programs and state energy efficiency offices. Many states run energy efficiency programs through their public utility commissions. Most of the programs are funded currently through special charges on utility bills, but some rely on state appropriations. I could see a whole panoply of energy efficiency programs move forward and contribute quickly to new job growth.

MR. MIKRUT: Although I think it is hard to see the spending side of the stimulus bill being used to help private companies directly, there is more room to help on the tax side of the bill. For example, Congress could extend or amplify two tax provisions that were just enacted as part of the economic bailout bill in early October.

One is a tax deduction for energy efficiency improvements to commercial office buildings. Developers making such improvements can deduct up to $1.80 per square foot of the cost immediately. Congress extended the deduction in October for another five years. It could increase the cap, at least for a short period of time, to stimulate that market. When the deduction was originally proposed, the cap was $2.25 a square foot, but the cap was reduced for revenue reasons. */ continued page 8*

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their tax years may have to wait until the next year to claim a credit. The credit is claimed in the company's tax year that started in the calendar year the withholding occurs. Thus, for example, a company that reports taxes using a November 30 year and has money withheld in 2011 will have to wait until it files its return for 2012 to claim a credit. However, the credit can be taken against estimated tax payments during 2012. The IRS said it is aware this may be unfair and asked for suggestions about how to fix it.

Withholding will start on January 1, 2011 or six months after the IRS reissues the proposed regulations in final form, whichever is later.

LLCS WITH SEPARATE "SERIES" of assets are becoming the latest tool for structuring transactions.

At least seven US states have limited liability company statutes that allow limited liability companies to create different pockets or cells of investments, each potentially with different owners, a different managing member and different assets. In three of the seven states, each series can have a separate right, in its own name, to sign contracts, hold title to assets and grant liens and security interests in the assets belonging to that series. The debts of a particular series may be enforceable only against the assets of that series.

The structure opens a number of possibilities. For example, wind companies that build out projects in 100- or 200-megawatt increments using a single interconnection agreement may have trouble getting consent from the utility to divide up the interconnection rights among separate project companies. If a series LLC were used, then the interconnection agreement could remain in the name of a single LLC.

In early January, the tax section of the American Bar Association asked the IRS to allow each separate series to be treated as a separate entity for tax purposes. Therefore, some could be treated as separate partnerships at the same time that the parties might */ continued page 9*

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Another place the stimulus might help is with so-called smart meters or the smart grid. The bailout bill last October cut the depreciable life for such property to 10 years. You could go farther and provide an even shorter depreciable life, especially for meters, of perhaps five years.

Congress will take steps to encourage construction of new transmission lines.

Energy Bill

MR. MARTIN: So, Congress will be hard at work in January on an economic stimulus bill to send to the president sometime between January 20 and the President's Day recess in mid-February. If we believe Rich Glick's timetable, the energy committees might be at work as soon as March on an energy bill that could be on the President's desk sometime in the summer.

We had a prep call before this session. The main items we thought would be in the energy bill are a national renewable portfolio standard — I'll come back to that — some action on transmission to make it easier to build transmission lines, possibly a clean energy bank and possibly some action to improve an existing loan guarantee program run through the US Department of Energy.

Let's talk about the renewable portfolio standard first. Rich Glick, what is a renewable portfolio standard? What targets do you see Congress setting? Is it a foregone conclusion that there will be a national standard by this summer?

MR. GLICK: A renewable portfolio standard is a law requiring utilities to supply a certain percentage of their electricity from renewable sources. Such programs are often administered by requiring utilities to turn in renewable energy credits at the end of each year representing the quantity of renewable electricity that they are required to supply. They can earn credits by generating the electricity themselves or they can buy credits from independent generators who use wind, sunlight or other forms of renewable energy. There are mandatory renewable portfolio standards already in 27 states and the District of Columbia.

Some of the state programs set more aggressive targets than Congress is likely to adopt in any national standard. Some are less aggressive and have a number of loopholes. There is a general belief among renewable energy advocates that a national standard is a good idea, not to replace state standards, but as a way of establishing a national floor. States would still be allowed to set more ambitious targets. A national standard would also create a national market in which to trade renewable energy credits.

President-elect Obama campaigned for a national RPS of 10% renewable energy by 2012 and 25% by 2025.

The US House of Representatives voted for a national RPS in a close vote in 2007 that would have set a target of 15% by 2020. The proposal failed in the Senate. The backers were unable to muster the 60 votes required in the Senate to break a Republican filibuster.

Some observers believe that an RPS stands a better chance of passing the Senate the next time around because the Democrats will hold more seats in the Senate and some of the most vocal opponents of the national RPS were defeated in the last election.

However, it is not as clear that there will be 60 votes in the Senate for the Obama target of 25% by 2025. We are expecting the final target to be somewhere between 15% and the 25% proposed by Obama. My guess is it will be in the 18% to 20% range.

MR. MARTIN: Let me break this down. Is there anyone on this call who thinks a national RPS will not be enacted in 2009?

MR. KAVANAGH: I think there is an opportunity to get a national RPS, but it will be hard for the same reason that the proposal lost in the Senate in 2007. There are regional issues. Some states — for example in the southeast — will have a harder time reaching any target the federal government sets because they are not as good places to build wind farms. They lack the wind you have out west, in the Great Plains and in Texas. The recession will also make this more difficult. Utilities and their ratepayers will have a harder time bearing the additional costs given the current state of the economy.

Look for the definition of what qualifies as renewable energy to be expanded. For example, utilities might be given more credit in the early years of the program for conservation measures that reduce electricity usage.

MR. WEISGALL: The debate will play out on two giant tectonic plates. One is the economic crisis. The other is the commitment both by President-elect Obama and a much more Democratic Congress to enact what I'll call broadly climate change-type legislation. Whether it is transmission for green energy, whether it is an RPS, whether it is a longer production tax credit, all of this plays into the climate change debate. Tony is absolutely right, the ground is unsteady. The plates have the potential to crash into one another.

There is one other point. The fact that a majority of states already have their own RPS programs should make this an easier lift politically in the Senate where each of the 50 states has two votes. I agree with Rich Glick that whatever Congress does will probably be a national floor and not a program that preempts the states. A tradable nationwide renewable energy credit would give Wall Street something new to play with.

MR. MARTIN: Jon Weisgall, some projects have made forward sales of renewable energy credits at the state level. Is it your view that we will end up with both state RECs and national RECs? A utility may need both? A national RPS would not alter the value of state credits that may have been sold forward?

MR. WEISGALL: Absolutely correct. I met with a senior staffer on the Senate side about this issue yesterday. I asked about the potential impact on state credits. He said we are going to create federal RECs and there will not be an attempt in any way to interfere with existing state programs.

MR. MARTIN: Rich Glick, do you see any national RPS having a solar set aside? Will it require that a fraction of the percentage come from solar?

MR. GLICK: I don't. And I want to preface it by saying the Solar Energy Industries Association is / *continued page 10*

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choose to treat others as corporations. The IRS is working on guidance that it has set an internal deadline to issue by June.

Last year, the IRS issued a revenue ruling about a "protected cell company" that was a lot like a series LLC. A "sponsor" formed a master entity. The master entity had two separate cells underneath it. The sponsor owned all the common stock associated with each cell, but company X owned the preferred stock in cell X and company Y owned the preferred stock in cell Y. Each cell insured certain risks of its preferred shareholder. The preferred shareholder paid a "premium" for the insurance. The ruling addressed whether the purported insurance was really insurance so that the premiums could be deducted, or whether they were something else so that what the preferred shareholder called a premium was really a capital contribution or deposit.

A contract between a parent and a wholly-owned subsidiary is not normally insurance. The IRS found in the case of one of the cells that the arrangement was not insurance because there was no shifting or spreading of risk among a large number of parties. The contracts written by the second cell were insurance because risks were spread among a dozen professional service companies that were subsidiaries of the preferred shareholder in cell Y. The ruling is Rev. Rul. 2008-8.

A few weeks later, the IRS suggested in Notice 2008-19 that it would treat each cell as a separate entity for tax purposes as long as the assets and liabilities of the cell are segregated from the assets and liabilities of each other cell and of the master company.

The IRS asked for comments on how to treat similar segregated arrangements that do not involve insurance. The segregated arrangements have many names: protected cell companies, series LLCs, segregated account companies and segregated portfolio companies.

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working hard for a solar set-aside. It wants to require that 30% of all the renewable energy credits must come from solar energy. The idea does not appear to be gaining much traction yet on Capitol Hill. Solar energy has not yet reached cost parity with other forms of electricity. The solar industry is concerned that any RPS that fails to provide a preference for solar in the early years will end up not providing much of a boost for solar. The industry expects to become competitive with other renewable technologies within five to 10 years. However, these estimates turn in part on more widespread use of solar so that the industry can benefit from economies of scale on the manufacturing end of the supply chain.

The bill that passed the House, but failed in the Senate, in 2007 would have awarded extra renewable energy credits to anyone generating electricity from a distributed generation facility of one megawatt or less in size. This was aimed at small solar installations. Such generators would have been awarded triple credits. The US Energy Information Administration said this triple credit mechanism would have led to solar receiving 20% of all renewable energy credits.

MR. MARTIN: Let's move to transmission. One of the proposals that has been batted around, but may not be able to get through the Senate, is to give the federal government the same power of eminent domain to push through new transmission lines that it has currently to push through gas pipelines. Tony Kavanagh, do you see any possibility that such a proposal can make it through the Senate?

MR. KAVANAGH: Yes, I do. I participated in a meeting with a member of Congress last week, and we went over this same point. I reminded this member that we both participated in hearings before the House energy committee after the blackout in 2003. Partly because of the blackout, Congress established an office in the Department of Energy in 2005 to identify transmission corridors of national significance and it gave the federal government backup authority to push through needed transmission upgrades. This has not led to much tangible progress. No one wants to sit through another blackout hearing.

There is growing interest in a federal clean energy bank.

MR. MARTIN: Jon Weisgall, do you agree there are 60 votes in the Senate for federal eminent domain power?

MR. WEISGALL: I do not. You are going to have 50 state public utility commissions and the National Association of Regulatory Utility Commissioners saying they don't want to give up power. It is a turf battle. There may be many state commissions that would be delighted not to have to deal with these siting issues, but there will be significant pushback. I don't see 60 votes for it.

I do see a possible compromise where the Federal Energy Regulatory Commission might make a finding of need, but then leave the siting with the states. I can also see a move to federalize or at least create a one-stop federal shop for that part of transmission siting that goes across federal lands. Congress tried to do that in 2005 and it made the Department of Energy the lead agency, but DOE became little more than a paper pusher. The Bureau of Land Management, the US Forest Service and Fish and Wildlife all still do their own environment impact statements.

I think the idea of moving federal siting to the Federal Energy Regulatory Commission is gaining traction.

However, Tony Kavanagh is absolutely correct about a larger point. The fact of the matter is you cannot love renewables and hate transmission. Transmission is emerging as probably the biggest impediment to renewable energy development in the long term. He is absolutely right that we need a national policy. The problem is preempting the states on transmission siting is a very heavy and ambitious lift.

MR. GLICK: I think both Jon Weisgall and Tony Kavanagh are right. There is a question whether there are enough votes in the Senate, but there will certainly be an effort to enact some sort of federal siting mechanism.

Even more important is the issue of cost allocation. There is no uniform national policy about who should pay the cost of upgrades to the transmission grid. Sometimes the generator that causes the upgrade to be built has to pay a portion of the cost. Sometimes the utility building the line has to pay the whole cost. Adding additional transmission capacity can get pretty expensive if the costs cannot be spread over a large pool of electricity consumers.

Thus, there is talk about tackling not only transmission siting, but also establishing some sort of mechanism that would allow the cost to be spread over an entire region, especially for new transmission lines and grid improvements that produce some sort of public benefit, like bringing a lot of renewable energy to market. Cost allocation may be an even bigger barrier to new construction at the moment than the difficulties with siting.

MR. MARTIN: Tony Kavanagh, do you see Congress wading into this question of who pays for the upgrades?

MR. KAVANAGH: I think Congress has no choice. There are also the related issues of financing and regulatory lag. If you are going to get the lines built as quickly as we believe is necessary to reach the goals the new administration wants to set for renewable energy, then cost recovery will have to be rapid. Congress will have to decide how costs will be allocated and make sure that utilities that have to bear the costs in the first instance can recover them quickly.

MR. MARTIN: Rich Glick, Jeff Bingaman, the chairman of the Senate energy committee, introduced a bill to create a clean energy bank as a standalone agency that would make loans and loan guarantees to support clean energy. Do you see that going anywhere as part of the energy bill?

MR. GLICK: It could even be part of the stimulus bill in January, but I think there is a fairly good chance it will get into either the stimulus or the energy bill.

On a related subject, almost everyone knows that Congress created a federal loan guarantee program for energy projects in 2005 and directed the Department of Energy to run it. Critics charge that the program is taking too long to get off the ground. Without getting into the merits, I think there is an emerging consensus that more needs to be done to get newer and more expensive clean */ continued page 12*

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A STATE GRANT did not have to be reported as income.

A company agreed to expand its business in a state by buying another building with help from a state fund set up to encourage economic development in the state.

Grants must normally be reported as taxable income, but the US tax code makes an exception in cases where the grant can be viewed as a capital contribution to a corporation by someone who is not a shareholder. The IRS ruled privately that the grant was such a capital contribution by the state. Corporations do not report capital contributions as income.

The key for the IRS was that the state fund was looking for a general public benefit in return: expanding the company's operations would bring new jobs to the state. The money was used by the company to make a capital investment rather than to pay operating expenses. The ruling is PLR 200901018. The IRS made it public in early January.

Some solar companies have argued that rebates that utilities pay to their customers to encourage them to install solar panels on rooftops and take other actions to reduce demand for electricity from the grid are nonshareholder contributions to capital of the utility customers, at least for customers who file tax returns as corporations. The utilities raise money for the rebates by adding a special charge to utility bills. They usually do so under direction from the state legislature.

An IRS official said the grant ruling should not be read as suggesting commercial customers of utilities can avoid reporting utility rebates as income. He said the agency would have a "very hard time" extending the principles in the grant ruling to cases where an amount is paid by a utility to a customer.

A US TAXPAYER who wants an agreement from the IRS about a position it plans to take on a tax return can apply for a "pre-filing agreement," but the agency has */ continued page 13*

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energy technologies off the ground and that what may be required is not only loan guarantees, but also direct federal lending.

Carbon Controls

MR. MARTIN: Finally, let's move to carbon. Tony Kavanagh, I think the consensus among this group is that carbon controls will not be addressed before the fall at the earliest, and the debate could well spill into 2010. Two questions for you: Do you think the Congress that will take office on January 6 and remain in office for two years will address carbon controls? Will the controls take the form of cap-and-trade rather than a tax?

MR. KAVANAGH: I think they will begin to address it. It is an extremely complex issue. The Clinton administration wrestled with it. The Bush administration probably didn't wrestle with it as much. The United States will probably opt ultimately for a cap-and-trade program. A tax would be a difficult way to lower carbon emissions unless it is accompanied by a cap because it would have to be a fairly high tax to have the desired effect. New taxes are very hard to put through Congress.

We have been pretty successful at controlling sulfur dioxide emissions in this country through a cap-and-trade program, but there have been some problems with cap-and-trade for carbon dioxide in Europe. Congress has been eager to learn what went wrong in Europe and to learn from the mistakes.

MR. MARTIN: Joe Mikrut, do you see any appetite on Capitol Hill for a carbon tax?

MR. MIKRUT: No, not at this time. The Clinton administration tried to persuade Congress to adopt a Btu tax in 1993. The House voted for the measure. It was a tough vote politically. The Senate then voted it down. House members were not very happy. Many of them lost their seats in the next midterm election and the majority in the House flipped from the Democrats to the Republicans. I don't see the House as particularly anxious to go down that road again.

MR. MARTIN: Jon Weisgall, carbon controls could be a huge event financially. They could require enormous payments by power companies to buy allowances to cover their carbon emissions. Do you think the federal government will auction off allowances, give them away for free or do some combination of the two?

Congress is expected to vote in 2010 to limit carbon emissions from power plants.

MR. WEISGALL: That's a tough question to answer when we are probably still more than a year away from any consensus on Capitol Hill about what to do and how to design the program. People point to the success of the acid rain program with its allowances for sulfur dioxide, but one thing you have to realize is something like only 3% of sulfur dioxide allowances are auctioned.

Reasonable people differ. Some argue the government should reward clean energy generators who have nuclear plants or renewable energy plants by awarding them a share of the allowances that they can then sell to raise additional capital for their projects. On the other hand, you have coal generators who are saying they built their plants with full regulatory approval, including an assurance that they would be able to recover the costs through rates, and now they are being asked to shoulder an additional and unanticipated burden of installing pollution control at great expense. They say they deserve the allowances to help cover the cost.

How the allowances get allocated and what, if anything, the government charges for them will be a huge debate.

President-elect Obama is calling for a 100% auction. Drafts of a possible House bill before John Dingell was replaced as chairman of the House energy committee called for an increasing percentage of the allowances to be auctioned over time. Those drafts may no longer be operative.

You are dealing with what is in reality a gigantic wealth transfer. No matter how the program is handled, the allowances will generate a huge a amount of money. The question is how to spend that money. I can't tell you how it will come out, but I can tell you it will be the most painful part of the debate.

MR. MARTIN: Rich Glick, Jon Weisgall mentioned that wind and solar companies are pressing for a share of any CO_2 allowances the government distributes. Do you think that's a very likely outcome? If so, it might represent an additional source of revenue for renewable energy projects.

MR. GLICK: I think it is fairly likely. The point is to award allowances in a way that promotes activities that reduce greenhouse gas emissions.

There is some precedent in the global warming bill that was considered in the Senate last year, the Lieberman-Boxer-Warner bill. There was a set aside of allowances for carbon sequestration facilities. The bill would have set aside 4% of allowances as a reward for sequestration. The wind and solar industries came in and said, if you are going to set aside allowances for carbon sequestration, then you should do the same for renewables. Had the bill made it through the Senate, I think you would have seen a set aside for renewables.

MR. WEISGALL: Let me throw out a rhetorical question. If we do end up with a cap-and-trade system and we "price" carbon in the marketplace, what will that do to the production tax credit? What will that do to the renewable portfolio standard? Won't people say that now that we have fairly priced carbon in the market, why do we need these other special programs for renewables? I just want to flag that as an issue.

MR. MARTIN: Joe Mikrut, that's probably a good question for you. If Congress adopts a national RPS and also takes action on carbon emissions, what will that mean for tax credits for renewable energy projects?

MR. MIKRUT: The staffs of the tax-writing committees are already considering this issue. I think the timing of the bills will help those who want tax credits. There will probably be a longer-term extension of production tax credits in the stimulus bill in January and something to help revive the tax equity market. But when Congress turns later to a national RPS and carbon controls, policymakers may ask whether having both a mandate and an incentive is necessary. I think you will see a move to coordinate the tax piece with the RPS, perhaps by having the tax credits phase out as the RPS target increases.

MR. MARTIN: When people talk about / continued page 14

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made the process prohibitively expensive in most cases.

The IRS said in late December that it will collect a filing fee of $50,000 for "each separate and distinct issue." It made the announcement in Rev. Proc. 2009-14.

The pre-filing agreement program was an experiment started in 2001. The agency said in December that it is making the program permanent. The program applies only to large companies. Such companies can apply to the IRS for feedback about positions they plan to take on tax returns that have not been filed yet. The IRS does not have to act on the request. However, the idea is to save time by not having to argue later on audit when the facts are less fresh.

In the past, the IRS entertained requests for pre-filing agreements about only a limited number of issues. There is no longer any list. However, the transaction must have already occurred to be eligible for the program. A pre-filing agreement is essentially a way of triggering an audit for a completed transaction before a return is filed.

This is not likely to be a sensible course for most companies. Companies also have the option to apply to the IRS national office for a private letter ruling. The filing fee for a private ruling is only $11,500, and a ruling can cover multiple issues.

The IRS will issue private rulings before *a transaction closes. However, a pre-filing agreement may be the only option where a company needs certainty about its tax position by a deadline and the national office has declined to rule because the matter is too factual.*

A WIND FARM that was financed in part with a low-interest loan from the federal Rural Utilities Service did not benefit from "subsidized energy financing," the IRS said.

The owner of a US wind farm can claim production tax credits of 2.1¢ a kilowatt hour on the electricity generated in / continued page 15

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phasing out the tax credits, are they talking about just not extending or extending at lower levels rather than taking away what has already been enacted?

MR. MIKRUT: I don't think any changes will apply to projects that are already in service, but anything is possible for new projects. I could see Congress shortening the period tax credits have to run. For example, the later you place a project in service, the shorter the period the tax credits would have to run. Another option would be to reduce the amount of the tax credit or credits over time as the RPS ramps up, which may be a better way to coordinate the two policies.

MR. MARTIN: But presumably, if a large solar thermal developer, for example, is working on a project that is five years in the making and he is counting on the eight-year extension of the 30% investment tax credit that Congress just enacted in October, he would not risk losing the full credit if he places the project in service within the existing eight-year window?

MR. MIKRUT: You would think. The one-time investment credits for solar projects are a little more difficult to coordinate with a phased-in RPS than are the periodic production tax credits. However, Congress will have to balance expected benefits in the form of tax credits with potentially unexpected benefits from a new national RPS. ◎

Tax Penalties for Restructuring Project Debt

by Eli Katz, in New York, and Jenny Kim, in Washington

Special-purpose companies created to develop, finance and operate large power and infrastructure projects have not been immune to the growing credit crisis. Owners of these project companies are often surprised to learn that they face significant tax consequences as they attempt to renegotiate the terms of the project debt.

These tax consequences result from broad application of a rule that requires a borrower to pay taxes when its debt is cancelled. A borrower may also trigger a tax when the debt is merely restructured.

This rule applies so broadly that it has consequences for nearly all project debt workouts, even those where only relatively minor changes are made to the project debt. It also affects debt-for-equity swaps and comes into play when project owners buy out the project debt.

In many cases, the project owners will find themselves saddled with a large tax liability at a time when they are least able to pay it. The size of this tax liability will often depend on the type of restructuring undertaken as well as the extent of the planning done to avoid or minimize these taxes. Project owners working in close cooperation with their lenders can minimize and even eliminate tax liabilities entirely when they restructure project debt. The key to accomplishing this is to identify the issues early in the restructuring phase and work closely with all project stakeholders.

Background

A typical project is owned by one or a small number of project owners who actively manage the the project's assets. The project is financed through equity contributions by the sponsor and large amounts of project debt held by banks and other financial investors. The project debt is usually concentrated with a small group of lenders, but can be held more widely and managed by an agent chosen by the lenders.

Some projects were still in the development or construction phases when credit conditions rapidly tightened. The lenders to these projects have begun to advance funds more slowly and demand more security from the project sponsors. Other projects are well into the operating stage and are finding their operating margins squeezed due to a non-performing offtaker or increased costs to operate the project. In either case, the lenders and the project owners have begun the search for ways to reduce or restructure the debt to keep the project afloat.

The tax structure common to project finance debt is what creates some of the pitfalls as well as the opportunities.

In most cases, the project owners are responsible for the project company's tax liability. This is because projects are usually held in a special-purpose entity that is either "disregarded" for tax purposes — it is considered for tax purposes to be held directly by the project owners — or is a tax partnership among a small number of project owners. The project debt is usually nonrecourse to the owners of the project; it is secured only by the assets and the contracts of the project. Also, the assets of an operating project are frequently written off, or depreciated for tax purposes more quickly than they are for book purposes, resulting in the undepreciated tax basis of the project assets being lower than its outstanding debt balance.

When Project Debt is Cancelled

Anyone whose debts are cancelled by a lender must pay taxes on the cancelled debt. This rule applies to a wide range of possible transactions. In its simplest application, the project owners are taxed if the project debt is cancelled or paid off by the borrower at less than face value. The borrower owes tax on the difference between the face value of the note and the value given to pay off the note.

Even when the project debt is not formally cancelled or reduced, project owners can be penalized if they renegotiate the terms of their project debt or convert the project debt into an equity stake in the project company.

When project debt is changed in a "significant" way, the tax rules create the fiction that the "old" project debt has been cancelled in exchange for new and restructured project debt. This fiction is maintained whether or not the old debt instrument is formally cancelled or whether a new debt instrument is actually delivered. The act of changing the terms of the loan is what triggers this result. If the new restructured debt is valued at less than the face amount of the old debt, the project owners can get stuck with a tax bill for the shortfall.

Project owners who convert project debt into an equity stake in the project are just as likely to trigger a tax. In a fairly common workout technique, the project lender exchanges its loan for an equity stake (usually a preferred equity stake) in the project company. In this case, the project company is considered to have paid off the debt for the fair value of the equity stake that it gave to the lender. If this equity stake is worth less than the outstanding balance on the loan, then the project will owe tax on the difference.

Thankfully, there are a few exceptions that can protect project owners from owing tax when the project debt is renegotiated. The three most likely to apply are the bankruptcy exception, the insolvency exception and a special exception for loans that are used to buy real estate. The bankruptcy exception allows the project owners to avoid tax if the restructuring happens during a title */ continued page 16*

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the first 10 years after the wind farm is put into service. However, if any part of the project cost is paid with government grants, tax-exempt bonds, "subsidized energy financing" or help from other federal tax credits, then the production tax credits must be reduced commensurately. The maximum reduction is 50%.

"Subsidized energy financing" is financing from a government program that has as a principal focus helping energy projects. However, the financing must be at subsidized rates.

A regional electric cooperative that generated electricity and supplied it to other cooperatives that were its members in rural areas planned to build a wind farm. It formed a taxable subsidiary to own the wind farm. The subsidiary entered into a long-term contract to sell all the electricity to the regional cooperative for resale by the regional cooperative to other cooperatives that were its members under older wholesale power contracts that the regional cooperative originally signed with members during the period 1962 to 1965.

The taxable subsidiary planned to claim production tax credits on the electricity.

There were three potential impediments.

First, the subsidiary took out a low-interest loan from the federal Rural Utilities Service to pay the project cost. The IRS ruled privately that the low-interest loan will not cause a reduction in production tax credits after the cooperative assured the IRS that the interest rate was no lower than on any loan it could borrow from a bank with a federal loan guarantee. In view of this assurance, the IRS said the federal loan was not "subsidized." Congress has said in the past that bare loan guarantees are not a problem.

Second, production tax credits can only be claimed on electricity sold to third parties. However, the IRS ruled publicly last summer that a sale to a related party is okay as long as it resells the electricity to someone unrelated. In this case, there were as many as two resales to get to someone unrelated. The IRS said that was okay.

Finally, production tax */ continued page 17*

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11 bankruptcy proceeding and the project debt is discharged by the bankruptcy court. The insolvency exception lets the project owners escape tax if the restructuring occurs when the project owners are insolvent. The real estate exception can be helpful to a project that is comprised of a significant amount of real estate.

Using any of these exceptions does not come free to the project owners. Project owners who avoid tax under these exceptions must reduce their tax attributes (or tax assets) up to the amount of debt that was cancelled. These tax assets include net operating loss carryforwards, existing tax basis in project assets and unused tax credits. Trading tax assets to avoid a current tax liability is usually advantageous. It allows current tax to be deferred at no cost to the project owners because the tax assets are used to reduce current tax instead of tax liability in the future.

Borrowers who renegotiate debt risk triggering a tax.

Project Workouts

Virtually all project debt restructurings raise a potential tax issue for project owners. In each case, it must be determined whether some of the debt has been "cancelled" under the tax rules and, if so, how much tax is still owed.

Typically, a restructuring of project debt involves some combination of the following techniques: the lender can forbear on its rights to demand payment on the debt for some period of time or renegotiate the financial covenants or debt service coverage ratios in the loan agreement. The parties may negotiate to defer a portion of the scheduled loan payments or agree to reduce the principal balance of the outstanding debt. Other commonly-used approaches include changing the rate of interest or life to maturity of the debt, or charging the project a restructuring or other accommodation fee to allow changes to the loan agreement. Some project lenders will require a project owner or other creditworthy entity to guarantee the debt or attempt to exchange the project debt for an equity interest in the project company.

Debt-for-Debt Exchanges

The Internal Revenue Service has regulations that describe when a modification to project debt will be considered significant enough to be considered an exchange of one debt instrument for another. These regulations give no weight to whether or not the parties physically "exchange" one note for another, or whether or not the lender formally cancels the first note and creates a second one. Regardless of the form the parties use to document the change to the terms of the project debt, the change will be considered an exchange of one note for another if the cumulative changes are a "significant modification" under these rules.

The regulations spell out specific changes that are considered significant, and also provide a general rule for types of changes that are not covered in the specific categories. The IRS has set a fairly low threshold for changes to project debt that will result in a significant change. The result is that many project loan workouts will be considered a debt-for-debt exchange.

If the yield on the debt is changed by an amount greater than 25 basis points per year, or 5% of the annual yield of the original project debt, the change will be considered significant. There is an important exception to this rule for yield changes that are triggered by operation of the original loan agreement. For example, it is not a significant modification if the original loan agreement allows the lender to increase the interest rate on the project debt in the event of a project downgrade or other agreed-upon circumstance. Deferral of a scheduled loan payment is significant if the deferral period is longer than the lesser of five years or 50% of the original term of the loan. Scheduled payments may be deferred by extending the maturity date of the loan or by simply deferring one or more payments due before the loan matures. A deferral of even a small payment all the way to the maturity date of the loan may well be considered significant if the maturity date is more than five years away.

Unsurprisingly, a change in the obligor under a nonrecourse project debt is not considered significant. The identity of the obligor under a nonrecourse loan is of little importance where the project lender must look solely to the project assets to recover its loan. Conversely, a change in the collateral or other forms of credit enhancement that secure the project debt will be considered significant, subject to a few limited exceptions. Requiring a project sponsor (or other creditworthy entity) to guarantee the project debt will almost always be significant, unless the guarantee does not change the project lender's expectation of receiving payment under the loan. It is often difficult to argue that a sponsor guarantee does not change payment expectations when the lender specifically negotiates for this feature in a project debt restructuring.

Additionally, it is a significant change if the project debt is exchanged for an equity interest in the project. There are at least two ways for a change of this type to occur. First, the lender can cancel its debt in exchange for membership interests in the project company that are clearly defined as equity interests. Alternatively, the lender can continue to hold an interest that is defined as debt but, for tax purposes, might be reclassified as an equity interest after it is modified. Drawing the line between debt and equity interests in a troubled project company can be a challenging endeavor. Some of the factors that might indicate that the project debt is in fact an equity interest include no fixed maturity date, relaxed default rights, the project company's debt-to-equity ratio and conversion or participation rights in the project.

As a general matter, changes to customary financial or accounting covenants from the project company are not significant. There is very little guidance on what is a "customary" covenant in the project financing arena, making this rule difficult to apply with any degree of certainty.

Aside from these specific categories, a change to project debt can be significant if the nature and degree of the change is economically significant based on all the facts and circumstances. When testing whether or not a / continued page 18

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credits cannot be claimed on electricity from wind farms that is sold under power contracts signed before 1987 unless the power contracts are amended to limit the amount of electricity that can be sold at prices above the "avoided cost" of the utility buying the electricity. "Avoided cost" means the amount the utility would have spent to generate the electricity itself. The regional cooperative assured the IRS that all of the electricity would be sold to its rural coop members at prices that are at or below the avoided costs of the members. On that basis, the IRS said that no amendments were needed to the power contracts.

The IRS ruling is PLR 200845008. The agency made it public in November.

INDIA said it will make claims for unpaid capital gains taxes in at least a dozen recent acquisitions of interests in Indian companies by offshore investors.

The announcement comes on the heels of the dismissal on December 3 of a challenge to a $2 billion capital gains tax claim by the Indian government against UK telephone company Vodafone in the Bombay High Court. Vodafone bought a 52% interest in an Indian mobile phone company called Hutchison Essar from Hong Kong-based Hutchison Telecom International Ltd. The purchase was a purchase by a Vodafone subsidiary in The Netherlands of shares in a Cayman company from another Cayman subsidiary of Hutchison Telecom International. The Cayman company whose shares were purchased owned a holding company in Mauritius that, in turn, owned the 52% interest in the Indian mobile phone company. Under Indian law, a buyer of shares is required to withhold any capital gains tax owed in India and pay it to the government.

Vodafone argued that the transaction had no nexus with India since it was a purchase of shares in a Cayman company two tiers up from the Indian company and the entire transaction took place outside India. / continued page 19

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change is significant, successive changes are tested on a cumulative basis. For example, if the yield on project debt is changed first by 15 basis points a year, and then is later changed again by another 15 basis points, then the cumulative change of 30 basis points may be significant under these rules.

In some project finance workouts, the lender will require a change to the interest rate or allow for a deferral of certain payments only if certain contingencies happen. One possibility might be that if the project EBIDTA falls below a certain benchmark, the interest rate will ratchet up to a higher level. Changes to the loan agreement might be dependent on future contingencies, for example, if the loan is changed so that if project EBIDTA falls below 1.2x debt service, the interest rate is increased by 50 basis points per year. There is no clear answer as to how much weight to give the likelihood of the contingency happening when measuring whether a change is significant.

When a debt workout is a debt-for-debt exchange under these rules, the project owners will owe tax on the difference between the principal balance of the old debt (before it is restructured) and the amount paid to cancel the old debt. The payment to cancel the old debt is the new restructured debt delivered to the lender. If the old debt was cancelled for a payment (issuance of the restructured debt) that is less than the principal balance outstanding on the old debt, then the project company will owe tax on the difference between these two amounts. The value of the new debt is its "issue price."

While the issue price of the new debt is generally equal to its principal balance, there are at least three situations where this is not the case. First, if the old debt is considered by the tax rules to be "publicly traded," then the issue price of the new debt is the fair value of the old debt and not the principal balance of the new debt. Second, if the new debt is considered "publicly traded," then the issue price of the new debt is the fair value of the new debt and not its principal balance. Third, even if both the old debt and the new debt are not publicly traded, the issue price of the new debt might be less than its principal balance if the new debt has an interest rate that is below the lowest "applicable federal rate" (currently around 4%) in effect in the three months preceding the restructuring.

The key is to avoid a "significant modification" of the loan terms.

The tax definition of "publicly traded" sets a far lower threshold than the commonly understood meaning of this term. Debt is publicly traded under this rule if it is either "exchange listed property," which is property listed on a national securities exchange or certain interdealer quotation systems registered by the US Securities and Exchange Commission, or "market traded property" which is property traded on certain boards of trade or on an "interbank market." An interbank market means an informal market consisting of a group of banks or other financial services companies holding themselves out to the general public as being willing to purchase, sell or otherwise enter into certain transactions. Some project finance loans might fall within this category as one can find a bank or other finance company willing to purchase or sell many types of debt paper. Debt is also publicly traded if it appears on a "quotation medium." A quotation medium means a system of general circulation that provides a reasonable basis to determine fair market value by disseminating either recent price quotations of one or more identified brokers, dealers or traders or actual prices. Lastly, debt is publicly traded if price quotes are readily available from brokers, traders or dealers. Like a number of the former categories, it is possible to obtain a quote on virtually any debt paper in the market increasing the risk that project finance debt call fall within this category.

A simple example illustrates how the project company should compute the amount of tax it owes when it restructures its debt in a significant way and causes a debt for debt exchange: Project company has $1 million of debt outstanding that pays interest at 10% annually. As part of a workout with its lender, the interest rate is increased to 12% annually in exchange for the lender agreeing to lower the required debt service coverage ratios. The outstanding principal balance remains at $1 million. The change to the interest rate is a significant modification because it exceeds 25 basis points. Therefore, the project company is considered to have paid off the old debt by issuing new debt. Assume the project lender then sells 50% of the debt for 80¢ on the dollar. If the new debt is "publicly traded," then the project company will owe tax on $200,000 of cancelled debt. The new debt is valued at $800,000, even though the principal balance is $1 million. The project company has paid off a $1 million debt by paying $800,000. If the new debt is not "publicly traded," then the project company owes no tax and a far more sensible result is reached. It paid off debt of $1 million with a new note with a face value of $1 million.

As is obvious from this example, borrowers with publicly-traded debt are significantly disadvantaged by this rule. Indeed, the project company is economically worse off after the restructuring — it owes the same $1 million except now it must repay the debt at a higher rate of interest. The tax result adds insult to injury as the project company now owes tax on $200,000 of cancelled debt. The project owners will get this $200,000 back from the government sometime in the future as they pay down the principal balance of the loan. The tax rules allow the project owners to amortize the $200,000 as a tax deduction over the life of the note. The project owner, however, loses the time value of money as it pays current tax in exchange for a deferred tax deduction.

Debt-for-Equity Swaps

Prior to 2004, a project lender was able to convert its project debt into an equity stake in the project company without causing any tax consequences to the project company and its owners. This technique was often used to avoid the unfavorable tax results that could result from modifying project debt. Lenders could structure the equity interest as a preferred interest that had many of the protections and advantages of project debt while at the same time avoiding tax penalties to the project company. / continued page 20

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The Bombay High Court dismissed a writ filed by Vodafone challenging the tax assessment. Vodafone plans to appeal to the Supreme Court.

In a separate matter, a division bench of the Bombay High Court ruled in December that UK law firm Clifford Chance is not liable for taxes in India on fees that it earned for working on four power projects in the country, except to the extent the work was done in India. The firm kept records tracking what work was done in India as opposed to in London.

The Indian government claimed the right to tax a larger share of the firm's earnings on grounds that they related to projects in India. The court said the services had to be both rendered in India and utilized in India to be taxable there.

TWO STATE TAX CREDITS that a company received for building a plant in Michigan and hiring local workers do not have to be reported as income, the IRS said.

One of the credits was refundable to the extent the company failed to have enough tax liability in Michigan to use it. The IRS said any refunds would have to be reported as income, but the fact that the credit is potentially refundable does not make the credit itself taxable. The agency said the company will end up with a smaller deduction at the federal level for state taxes paid because of the credits. It made the comments in an internal memo sent to an IRS field office in late November. The memo is FAA 20085201F.

CREBs can be issued to finance electric generating equipment at a landfill, even though the landfill benefited in the past from tax credits for producing landfill gas, the IRS said.

CREBs are bonds that a municipal utility, electric cooperative or Indian tribe can issue to borrow to pay for new generating equipment that uses renewable energy. No interest is paid on the loan. The lender can / continued page 21

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Congress changed this rule in 2004. Since then, if a project company converts its debt into an equity stake, the project company will owe tax if the value of the equity stake is less than the principal balance of the loan. When it enacted this rule, Congress left open the critical question as to how to value the equity stake in a project.

The IRS recently issued proposed regulations that addressed this question. The IRS said that if certain rules are followed, the equity stake could be valued using a "liquidation value" approach. This approach values the equity stake as the amount of cash the lender would receive if the project company immediately sold all its assets in the open market and distributed the cash to the lender. The liquidation value, then, is the starting capital account that the lender is given when it receives its equity interest in the project company. Allowing the project to value the lender's equity stake at liquidation value is usually advantageous. Without this approach, the project company might be forced to reduce the value assigned to the lender's equity stake by a minority or illiquidity discount. The liquidation approach should enable the project company to increase the value given to the lender's equity stake and reduce the amount of its tax bill.

A project company can take advantage of the liquidation value approach only if it follows a number of rules. First, the project company must maintain capital accounts in accordance with the tax regulations. Second, all parties to the exchange must use the same valuation number for all tax purposes. Third, the exchange must be done at arm's length. Lastly, there can be no plan for the project to redeem or buy the lender's interest and avoid tax on cancelled debt.

A borrower might also be taxed when a lender converts a loan into an equity position in a project.

While these proposed regulations are generally favorable to the project company, they create some tax difficulties to the lender. In a debt workout, the lender is most concerned with getting an immediate tax loss for the decline in value of its investment. If an economic decline cannot be matched with an immediate tax benefit (tax writeoff), the economic pain to the lender is increased. The lender must then defer the tax benefit associated with the current economic decline. The proposed regulations do not allow the lender to take the tax writeoff when it exchanges its debt interest for an equity stake in the project; it must defer the tax loss until it sells the equity stake in the project company. This result may make it more difficult to get lenders to agree to debt-for-equity swaps in project debt workouts.

Possible Approaches for Troubled Projects

The primary tax concern for project owners during a workout will be avoiding or minimizing a tax penalty associated with a restructuring. While each workout negotiation will be different, the project owners have a variety of approaches for dealing with this tax problem.

In the case where the principal balance of the note remains unchanged during the workout, but there are changes to the terms of the debt, the project owners might attempt to keep the changes below the "significant" threshold described in the IRS regulations.

In situations where the changes necessitated by the workout are too pervasive to remain below the "significant" threshold, the project owners will need to determine the likelihood that the debt will be considered "publicly traded." If the debt is widely held among a syndicate of lenders, the risk of it being publicly traded is increased. Whether or not the debt is publicly traded, once the debt is changed in a significant way, the project owners should determine how much tax is owed on account of this change. The tax is calculated by reference to the "issue price" of the restructured debt. The difference between the issue price of the new debt and the outstanding balance on the old debt will generally equal the amount of income upon which tax will be owed.

If the new project debt is publicly traded, then the issue price will be its fair value. The fair value of the debt of a troubled project company is likely to be below the face value of the old debt resulting in a potential tax liability to the project owners. If the project debt is not publicly traded, then the project company should be able to avoid tax if the principal balance of the debt is not reduced and the interest rate is at least as high as the three month applicable federal rate.

In the situation where a project company has restructured its debt, it can try to eliminate or reduce its tax liability by making use of the insolvency or real estate exceptions. To claim the insolvency exception, each project owner (and not the project company) must demonstrate its insolvency. A project owner is insolvent if its pre-workout liabilities exceed the fair value of all its assets. Ordinarily, there will be no objective measure of the fair value of the project owner's assets and therefore no way to measure if it is insolvent. Project owners that intend to rely on the insolvency exception should consider hiring an expert to value its assets before the restructuring. The real estate exception requires a detailed review of the assets of the project to see if any of them qualify as "real estate" under a set of detailed tax rules.

When project owners cannot otherwise use any of the exceptions to avoid tax, they should consider swapping the lender's debt for an equity stake in the project. In order to avoid tax on this exchange, the lender's starting capital account must equal the principal balance of the project debt immediately before the swap. The equity stake can then be structured to offer the lender a preferred return or other form of guaranteed payments to enable it to achieve an economic return similar to had it restructured the project debt. This last technique is obviously only possible in close cooperation with the lender and requires identifying and working toward this solution at an early stage.

A final approach worth considering in appropriate circumstances is for the lender to contribute its note to a joint venture between the lender and the project company. As long as the project company holds less than 50% of the economics of this joint venture, no tax should result from the transfer. The borrower and the lender can then attempt to structure the lender's return in a way that resembles the economic position it would have achieved had it simply restructured the note. ◎

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claim federal tax credits instead. The acronym stands for "clean renewable energy bonds." Anyone wanting to use the bonds must get an allocation of bond authority from the US Treasury Department. Congress authorized another $800 million in CREBs in October.

Congress provided tax credits to landfill gas producers in the past as an inducement to produce the gas. It provides separate production tax credits currently to power companies as an incentive to use landfill gas and other forms of renewable energy to generate electricity. However, Congress considers it double dipping for the same project to benefit from both types of tax credits. Thus, production tax credits cannot be claimed by an electricity generator to the extent he uses landfill gas from wells whose output qualified in the past for the gas producer credits.

An electric cooperative plans to use such gas in generators it is installing at an existing landfill.

Congress created CREBs to give municipal utilities, coops and Indian tribes a tax subsidy on power plants that would have qualified for production tax credits had they been privately owned.

The IRS told the coop in a private ruling that the bonds can be used to finance the *type* of project that would have qualified for production tax credits if it had been privately owned.

It said there is no need to inquire further into details about whether the project would have qualified in fact for production tax credits in private hands. The ruling is PLR 200844008. The agency made it public in November.

A RURAL ELECTRIC COOPERATIVE got the green light to buy electricity and gas customers from an investor-owned utility.

The cooperative turned the new customers into "members" in the cooperative. The IRS ruled privately in a ruling released in December that the coop will retain its status as a tax-exempt entity, notwithstanding that / *continued page 23*

How the Global Credit Crisis is Affecting Project Finance in the Gulf Arab States

by Richard Keenan, in Dubai

How different the project finance landscape looks now in the six Arab states that make up the Gulf Cooperation Council — Kuwait, Qatar, Bahrain, Oman, the United Arab Emirates and Saudi Arabia.

Only eighteen months ago, the project finance market was awash with liquidity. There seemed to be no end to the appetite among commercial banks to lend money to large power and water and oil and gas projects in the Middle East.

Lenders were happy to reach financial close with very significant commitments on their books, comfortable in the knowledge that there would be very strong interest from banks wanting to take on syndicated loans. Many large projects were oversubscribed in the syndication market by more than half the required commitment. Law firms were being invited to pitch for sponsor legal roles on the understanding they would prepare "covenant light" packages that had become the buzz words in the project finance market.

Today, the markets are still reeling from the events of the last few months and no one really knows what the long term implications of the current credit crisis will be. However, one thing is clear: the project finance markets are unlikely to return to the heady days of 2005 to 2007 any time soon.

What makes the implications of the global financial crisis so interesting from a Middle Eastern perspective is the massive amount of infrastructure, particularly in the power and water sector, that needs to be developed over the next 10 years. It is estimated that the power and water sector in the six GCC states will require about $50 billion of investment in new power generation capacity and $20 billion of investment in water desalination by 2015.

It is possible that some of this demand may subside with the current economic downturn and, in particular, the fall in the price of oil. However, so far the governments of the GCC have given every indication that their plans for urban and industrial development will go ahead despite the economic gloom. Some of the more ambitious projects such as the King Abdullah Economic City and the other proposed economic cities in the Kingdom of Saudi Arabia may not proceed at the pace originally planned. In any event, according to recent reports published in industry journals, much of this increased demand for energy and infrastructure capacity is required to service development that is currently under way.

This article explores some of the likely implications of the global financial crisis for the project finance market in the GCC and how GCC projects are likely to be funded over the next few years.

Enhanced Government Participation

One of the consequences of the current state of the credit markets is likely to be an enhancement of the role played by governments in the development and financing of projects throughout the GCC.

Thanks to the recently ended commodities boom, most of the GCC governments and ruling families are in an enviable position in comparison to the governments of western economies in terms of available cash reserves to draw on if need be to fund the development of domestic energy and infrastructure projects.

It is likely that we will see governments take on a greater level of participation in projects than has typically been the case in the past, either through larger equity participations or through increased government funding. Debt-to-equity ratios in the independent power and water sector in the GCC have been typically 80:20 and an average of 70:30 in the refining, LNG and petrochemical sectors. Some commentators expect that debt-to-equity ratios in the power sector will fall to 70:30 and as low as 50:50 in other sectors such as LNG, refining and petrochemicals. Given the significantly reduced capacity of international commercial banks to participate in these projects, governments and sponsors may have to increase their equity stakes. Most of the equity slack may have to be taken up by governments.

Government participation in projects may also come through equity investments by sovereign wealth funds. The Abu Dhabi government's investment arm, Mubadala Development Company, recently announced that it has formed a joint venture with France's Veolia Water that will focus on investments in water and wastewater, power transmission and distribution, and district cooling infrastructure.

In the Kingdom of Saudi Arabia, it is anticipated that the

Public Investment Fund and the Saudi Industrial Development Fund will provide greater levels of funding than they have in past projects. Both of these funds are affiliated with the Ministry of Finance, and their functions include the provision of finance to projects in the Kingdom, provided that certain criteria are met.

The Abu Dhabi government is currently proceeding with two projects, the Shuweihat independent water and power project and the second Abu Dhabi wastewater treatment project, with the intention of financing development of these projects in the short term through a bridge loan and securing long term finance sometime in 2009 when hopefully market conditions will have improved. If a long term financing commitment cannot be secured by an agreed date, then the Abu Dhabi government will have the option of buying out the sponsors' interest in the projects and proceeding without foreign sponsor and lender participation.

Unless there is a dramatic improvement in the project finance market in the short term, it is possible that this model will be adopted by some of the other GCC tendering authorities. This approach gives governments flexibility in a very challenging market. It allows them to proceed with development of projects, harness whatever appetite there is in the private sector to participate and, as a last resort, draw on government cash reserves if need be to complete infrastructure critical to meeting rapidly escalating demand for power, water and wastewater infrastructure. Governments, sponsors and lenders in the GCC region will be closely following the outcome of negotiations currently taking place in relation to these projects.

There is a current trend towards development of smaller projects in the GCC without project finance using design, build and operate structures or to use common industry speak, "DBO" structures. Under a DBO structure, the responsibility for providing finance lies with the public authority, as does ownership of the facility. There is likely to be an increase in the procurement of smaller infrastructure projects using the DBO model, particularly in certain sectors such as the water desalination and wastewater sector. However, it remains to be seen whether governments in the GCC will be prepared to procure larger projects, such as independent water and power projects, using DBO structures and thereby tie up sovereign funds that could be invested more profitably elsewhere.

Both the Shuweihat model and the / continued page 24

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coops have been thought of historically as *voluntary* membership businesses.

Coops usually operate on a non-profit basis. They are exempted from federal income taxes as long as at least 85% of income each year comes from members for the sole purpose of paying expenses. Any leftover coop revenues are supposed to be distributed to members based on the amount of business that each member does with the coop. The coop in this case plans to group the customers into two separate divisions — one for gas and one for electricity — and use the separate divisions to price services separately to its electricity and gas customers. The IRS said the separate divisions are okay. The ruling is PLR 200849016

MINOR MEMOS. The IRS confirmed that changes in how the California Independent System Operator — the independent operator of the state electricity grid — manages grid congestion will not cause transmission lines transferred to the ISO by municipal utilities in California to be considered put to "private business use." Any such use could cause the municipal utilities to lose the tax exemptions on bonds they issued to finance their transmission lines. The ISO has moved to a nodal system. Users of the grid hold congestion revenue rights that may require them to pay money to the ISO or receive money depending on whether they are contributing or helping to relieve congestion by where on the grid they choose to send or receive electricity. This is the third private ruling the IRS has issued to address changes in California ISO policies. The agency made the latest ruling public in late December. It is PLR 200850003 . . . . Lenders are required to report any debts they cancel to the IRS on Form 1099-C. Any amount owed that has not been paid within 36 months of the due date is assumed to have been cancelled and must be reported unless the lender can show that it is making a significant effort to collect. This "36-month" rule / continued page 25

Gulf Credit Squeeze

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DBO approach allow cash-rich governments the flexibility of building now and privatizing later at a time when there is more liquidity in the private sector.

Given the dependence of the GCC over the last 10 years on the expertise of foreign developers and international bank debt to fund projects, it is unlikely that we are going to see GCC governments fund large infrastructure and energy projects entirely on their own, notwithstanding the severity of the current global downturn. However, it is highly likely that the present economic conditions will necessitate a much greater level of investment from governments if they are to realize their ambitious development plans within the time frames they have proposed.

The Arab oil exporting countries along the Persian Gulf are feeling the credit squeeze.

Increased ECA Participation

There is little doubt that one of the ramifications of the current credit crisis will be a greater participation of export credit agencies in the financing of projects throughout the GCC. ECA presence in the GCC has steadily grown over the last 10 years. ECAs are playing an increasingly significant role in the funding of projects that has included the provision of loan guarantees to international banks, direct loans and advisory services to project sponsors.

The ECAs are not exposed to the problems that currently plague international banks, and many of them have no shortage of liquidity.

The Japanese Bank for International Cooperation has the largest capacity among ECAs for direct lending. JBIC has played a key role in financing a number of major projects in the region, including a $2.5 billion loan in connection with the Rabigh petrochemicals project in the Kingdom of Saudi Arabia and a $1.3 billion loan to the sponsors of the Fujairah F2 independent water and power project. Other ECAs that are playing an increasing role in financing projects in the GCC through direct loans are the Export-Import Bank of Korea and Export Development Canada.

As well as providing an alternative source of funding, ECAs also offer more stable pricing for long-term finance. Although the formulations used by ECAs for setting interest rates and risk premiums vary depending on the relevant ECA's policy and the type of product, many of the ECAs, including JBIC, set their interest rates and risk premiums by reference to OECD guidelines.

The provision of insurance covered by ECAs is also likely to increase significantly. Those commercial banks that are still in the market for underwriting deals are going to become very selective in terms of the transactions they underwrite. Any transaction that can over offer ECA covered tranches is always likely to be more attractive to commercial banks in jurisdictions or regions where political risk is a material issue.

The implementation of the Basel II rules on banking, which determine capital adequacy requirements for bank exposure to various types of transactions, including project finance, could also result in an increased demand for ECA cover in projects. The inclusion of an ECA-covered tranche in a project finance transaction will reduce the covered commercial banks' obligations to put aside capital to satisfy the more stringent capital adequacy requirements of Basel II and other capital adequacy requirements recently implemented by central banks throughout the world in response to the global financial meltdown.

Continuing Role for Commercial Banks

Foreign commercial banks will continue to play an integral role in the financing of projects in the GCC. However, the commercial banks with liquidity available to lend to projects in the short term are likely to be fewer in number and the size of commitments these banks will be willing to take on will be significantly reduced. The syndication market is closed, and the view of most bankers is that any project financings that do go ahead in 2009 will be done as club deals. Commercial banks are now certain to take a far more cautious approach to underwriting transactions. Projects structured on the Abu Dhabi, Omani, Qatari and Saudi models are likely to be favored by commercial banks.

The cost of borrowing is clearly a significant issue at present and most commentators appear to share the view that, notwithstanding the recent drastic measures taken by central banks to cut interest rates, the cost of inter-bank borrowing will remain elevated at least in the short term. Pricing for long-term project finance debt is likely to be more than double the margins seen in 2007. High borrowing costs could lead sponsors and governments to look for alternative sources of funding.

During the last few years, tenors in some energy projects were pushed out to 15 years, and it was quite common for tenors in the power sector to extend beyond 20 years. The tenor of equity bridge loans extended to seven years on some transactions, three to four years beyond the scheduled date of project completion and often on margins no higher than 30 to 40 basis points. The low cost of borrowing over these extended equity bridge tenors enabled sponsors to maximize their internal rates of return. It remains to be seen whether such lengthy tenors will be obtainable in the near future. The consensus among most banks at present appears to be that maximum tenors for long-term project finance are likely to be 10 to 12 years. Sponsors may find it difficult to negotiate tenors for equity bridge loans that extend beyond project completion dates at margins anywhere near the sort of margins lenders were signing up to in the recent past.

We may also see the re-introduction of cash sweeps to encourage sponsors to refinance deals after a six- to seven-year period.

The last three or four years in the project finance market have been characterized as a sponsor-driven market where financing terms were dictated by sponsors and reluctantly accepted by lenders eager to participate in a highly competitive lending environment. The distinctions between the project finance and the corporate finance models were starting to blur. It really did seem for a while as though some fundamental principles of the traditional project finance model may have changed for good. */ continued page 26*

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applied in the past not only to financial institutions, credit unions and federal agencies, but also to any other company for whom lending money is a significant business. The IRS revised its regulations in November to require reporting under the 36-month rule only by financial institutions, credit unions and federal agencies. The regulations can be found under section 6050P of the US tax code.

— contributed by Keith Martin in Washington.

Gulf Credit Squeeze

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The tables have now of course turned. We are now likely to see a return to lending in accordance with tried and tested principles of project finance that have evolved over the last 30 or so years.

Lender protections such as long life cover ratios, repeating representations on interest payment dates, look forward events of default, and other lender covenants that were once standard market practice, but that have been eroded in recent years, will make a swift comeback. The inclusion of market flex clauses in bank underwriting commitments is now non-negotiable, and banks are paying particular attention to material adverse change provisions and insisting on more subjective and discretionary tests for determining the occurrence of any such event. Commercial banks are also now likely to insist on the provision of completion support by sponsors in any project where there are deficiencies in commercial and project contractual arrangements that have the potential to undermine the banks' interests.

This is not to say, however, that lenders are necessarily likely to have it all their own way now. If GCC governments do end up taking larger equity stakes in projects and retain the option of buying out foreign sponsor interests in projects, lenders may find that, although the shoe is on the other foot, it ends up on the governments' foot. Some of the government tendering authorities in the wealthier members of the GCC may adopt a take-it-or-leave-it approach with lenders. However, whether or not governments will have the luxury of adopting such a negotiating position will depend entirely on the reliance by each country on external debt to fund its projects.

Developers in the Gulf are looking more to export credit agencies. Debt-equity ratios in projects are falling.

Increased Participation of Islamic Banks

So far Islamic financial institutions have been relatively unscathed by the global financial crisis. It would probably be unrealistic to think that this will remain the case. Islamic banks are heavily exposed to real estate and private equity throughout the Middle East and with heavy selling of stocks, commodities and oil in the last few months, these investments are bound to be affected. Many of the Islamic banks have exposure to the property market in the GCC and some of these markets, particularly Dubai, are starting to show signs of being affected by the global economic downturn.

However, the long-term outlook for Islamic finance institutions remains quite positive. Most industry commentators believe that the Islamic banks should survive the economic downturn in considerably better shape than the conventional banks. The intrinsic characteristics of Islamic finance have helped to insulate it from the effects of excess leverage and speculative financial activities. Islamic law prohibits the payment of interest and requires transactions to be linked to tangible assets, which has deterred investment in complex and intangible financial derivatives that have caused such havoc for conventional banks around the world.

Over the last few years in the GCC, we have seen a steady increase in the participation of Islamic banks in project financings. The Islamic tranche for the Shuaibah independent water and power project in the Kingdom of Saudi Arabia that closed in 2005 was $200 million, and the Islamic tranche for the Marafiq independent water and power project, also located in the Kingdom and that closed in 2007, was $600 million. These and other transactions, like the Rabigh petrochemical project, have demonstrated to the market how Islamic finance techniques can be successfully utilized in the context of multi-sourced financings, while remaining consistent with the principles of Islamic law.

This trend is likely to continue with sponsors now looking to the Islamic banks for financing more than ever.

Reduced Size of Projects

One other consequence of the global credit crisis may be a reduction in the size of projects. Over the last 10 years, we have witnessed the evolution of the "mega project," particularly in the power, water, refining and petrochemical sectors. The size and complexity of these projects have meant construction contractors have had to take on enormous project completion risk that they factor into their contract prices. There are also only about five or six construction contractors in the world with balance sheets and resources large enough to undertake these projects. This has meant reduced competition amongst contractors that has contributed, in turn, to the high cost of contracting.

We may now see the cost of construction contracting fall in light of the global economic downturn. However, the extent to which these costs fall in the GCC remains to be seen.

A combination of high construction costs and a significant reduction in the availability of liquidity in the international banking market may lead to a decision by governments to scale back the size of some of these projects.

Trends in Tax Equity for Renewable Energy

Most renewable energy projects in the United States are financed with a "tax equity," a form of equity that is a hybrid on the spectrum between debt and equity. The US government offers large tax incentives for using renewable energy to generate electricity. Most project developers cannot use the incentives directly, so they barter them for capital to build their projects. The tax equity market is in a weak state just like the debt market. Only a handful of institutions remain active investors.

The following is a transcript from a panel discussion in mid-December hosted by Infocast about the state of the market and whether new investors will emerge. The panelists included two arrangers who work on raising tax equity for projects: Phillip Mintun, managing director of Capstar Partners in New York, and Tim MacDonald, president of Meridian Clean Fuels in Boston. They also included four potential new investors: Michael Feldman, a managing director with Goldman Sachs, Joe Donahue, vice president for domestic tax planning at Marriott International, Inc., Darren Van't Hof, a vice president with US Bancorp Community Development Corporation, and Stephen May, vice president for business development and asset acquisitions with PPL Development Company, an affiliate of PPL Corporation. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Phil Mintun, is it possible to get a commitment for tax equity today?

MR. MINTUN: The short answer is yes, but it is increasingly difficult because a number of the tax equity investors that have been in the market over the past two years have either exited or are currently on the sidelines. Some of this is due to consolidation in the financial institutions industry, and some of it is due to temporary issues.

MR. MARTIN: There appear to have been 18 large institutions that invested in the tax equity market in the last two years. How many do you think are still active?

MR. MINTUN: There are four still writing new commitments.

MR. MARTIN: If someone were to sign a term sheet today, when is the earliest he or she could hope to close the transaction?

MR. MINTUN: If no documents have been drafted and no due diligence has been done, then you are probably looking at something toward the end of the first quarter.

MR. MARTIN: Tim MacDonald, do you want to add anything to what Phil Mintun said?

MR. MacDONALD: Our view of the market is that it is very much in flux right now. For the most part, new commitments are difficult to get. I agree with what was just said.

MR. MARTIN: Phil Mintun, how long ahead are equity willing to lock in yields? If an equity quotes you a target yield today of 8.5%, how long will he hold that?

MR. MINTUN: We are seeing a lot of resistance against holding anything past the end of the first quarter.

MR. MARTIN: That's three and a half months. What happens after the three and a half months?

MR. MINTUN: It depends. The yield might move after that until closing or funding based on an index like an appropriate swap rate.

MR. MARTIN: Where it is indexed to a swap rate, say a Bloomberg screen, would the yield gener- */ continued page 28*

Tax Equity

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ally move only up, not down? And would it move up a half point for every full percentage point increase?

MR. MINTUN: It really depends on the transaction and the sensitivity of the investor internal rate of return to some metrics. Typically what you see is a small band above and below the agreed IRR where a change in the underlying index would not lead to a change in the target yield. However, if the index moves beyond the band, then you would see an adjustment. Sometimes there is a half a basis point adjustment in IRR compared to a full basis point change in the underlying index. That is a fairly common approach.

In terms of up and down, the market has typically had both up and down movements, but with a floor on the downside. However, a downward adjustment in IRR is pretty tough to negotiate in today's market.

MR. MARTIN: Tim MacDonald, if investors are unwilling to lock in yields more than one quarter at a time, what does a smaller developer do who needs an equity commitment at the start of construction to fund at the end and repay construction debt?

MR. MacDONALD: I'm not sure you couldn't get someone to lock in at a price. I think our message is that we don't know what that price is in today's marketplace because the situation is fluid. However, in a normal market, there are investors who will agree that this is the price and they are in it for the duration of the commitment.

MR. MINTUN: In a well-functioning market, a benchmark index-type approach can work. One of the problems we have today is the general scarcity of capital means that potential investors are having to fight for capital internally within their organizations. There is no Bloomberg or *Wall Street Journal*-type index that one can look at to measure the internal fight for capital.

MR. MARTIN: Tim MacDonald, when do you see the tax equity market starting to improve? If we have only four investors today, when will it improve, and what will be the catalyst?

MR. MacDONALD: I think we will see new entrants in 2009. The big question is the general state of the economy. There are players today who have tax capacity and for whom yields are starting to look attractive, but if the economy continues to unravel, that changes.

Of the 18 large institutions that supplied tax equity the last two years for renewable energy projects, only four appear still active.

A big part of what happens will turn on whether the credit markets unfreeze and banks resume lending. The hope is the credit markets will start to stabilize after the first of the year and, if that happens, then we would be pretty bullish that by the middle of 2009, the tax equity market will also have come back to life.

MR. MARTIN: Phil Mintun, any predictions on when in 2009 the market will start to turn around?

MR. MINTUN: No predictions, but I agree with Tim that it will take the fundamental return of some stability into the financial markets, and the re-entrance of existing investors or emergence of new investors will be key to bringing some stability back into our market.

Current Yields

MR. MARTIN: Where are yields today? Where would you say the bottom of the market is? I know the actual yield offered for any particular project turns on the market's assessment of the riskiness of that project.

MR. MINTUN: The most common type of deal on the market at the moment is a portfolio of wind farms. There are still some deals that were committed earlier in 2008 that are working toward closing by the year end with yields in the mid- to high 7% range.

For new commitments today, people are looking at yields in the low 8s.

MR. MARTIN: Do the same yields hold for one-off projects? Are these figures just for wind? Would the same yields apply to solar PV? What about geothermal?

MR. MINTUN: I think for geothermal, depending on a number of factors, you are probably in the same ballpark. Maybe Darren Van't Hof can address solar.

MR. MARTIN: Where would you put biomass?

MR. MINTUN: It has not been an active market recently, so I hesitate to answer.

MR. MARTIN: Tim MacDonald, any comments on yields?

MR. MacDONALD: I agree that the wind market appears to be trying to balance in the 8% range, but we see upward pressure on yields coming from the affordable housing market.

MR. MARTIN: Affordable housing is an alternative investment for many potential tax equity investors. Where are yields today in affordable housing?

MR. MacDONALD: They are in the 8% range and trending up.

MR. MARTIN: And the perception of the market is that there is less risk in an affordable housing investment than in a renewable energy project. Is that correct?

MR. MacDONALD: Yes. Generally, tax credits for affordable housing are more predictable because of the way the tax credit is structured. The affordable housing industry also has a very strong track record going back 15 to 20 years.

MR. MARTIN: Is the affordable housing market feeling the same strain as the renewable energy market in raising tax equity?

MR. MacDONALD: Yes, very much so. The housing market has been disrupted by the credit crunch.

MR. MARTIN: The yields you guys have been quoting have been driven largely by bank and insurance company investors. There is potentially a bifurcated market. You have a number of people sitting on the sidelines who probably would invest if the yields were much higher. You have the situation today where banks are offering the yields quoted, but they can't fill out the syndicates, so developers cannot get full financing for projects at these yields. Is that a fair description of the current market?

MR. MINTUN: I think it is. There are less than a handful of people bidding currently on deals. The market has been dominated by financial institutions and, when you get outside of the world of financial institutions and talk to potential investors about joining syndicates, one of the things that you hear frequently is, you're talking to us about an equity investment with a nominal after-tax return in the 7 or 8% range. That doesn't sound like an equity return to us. The counter-argument is it is equity, but the partnership flip structure puts the tax equity investor in a preferred position where he gets his return before the sponsor. In some ways, what the investor has is an instrument with a stated return but a variable time frame.

MR. MARTIN: What is the difference in yields for leveraged versus unleveraged transactions and for PAYGO versus PAPS deals? For the audience's benefit, PAPS means the investor pays the full purchase price to buy an interest in the project or projects at inception. PAYGO means the investor pays over time, usually partly as a percentage of the production tax credits on the electricity output. Leveraged means that there is debt at the level of the tax equity partnership or the project.

Phil Mintun, how do these things affect the yields?

MR. MINTUN: Historically, tax equity investors have not wanted to leverage deals because there is greater downside peril if the project isn't performing. The nice thing about the unleveraged PAPS or partnership flip structure is that the structure allows the performance of the underlying project or portfolio to catch up, if you will, without the stress of a lender trying to foreclose or otherwise exercise remedies. Introducing a lender significantly increases the risk profile of the transaction for the tax equity investor.

Few leveraged deals have been done. Those that have been done have seen a premium on yield of somewhere in the range of 200 to 300 basis points.

With respect to pay-as-you-go structures, the IRS guidelines for partnership flip transactions limit the contingent payments to 25% of total consideration. When those deals were more common, you saw a premium on yield in the 75 basis point range. We have not seen much use of the PAYGO structure in the last year.

MR. MARTIN: Tim MacDonald, developers have a crossover point. As yields go up, at some point the money is just too expensive and the value they are getting for tax benefits is too little. The developers are better off keeping the tax subsidies, carrying them forward for up to 20 years, and using them when they can. Do you have any feel for where that crossover point is in terms of yield? / continued page 30

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MR. MacDONALD: No, we haven't really done that analysis, but keep in mind the following. Monetizing tax benefits is a nice way of raising money for developers who don't have access to other sources of capital. There is a spectrum. For large, utility-owned sponsors who have access to a balance sheet and the capital markets, that analysis makes sense. I would suggest that smaller developers with fewer sources of capital on which to draw would still look at monetizing tax benefits beyond any crossover point at which a utility-backed sponsor might drop out.

MR. MARTIN: Escalating yields are another sign that the tax equity investors are paying less per dollar of tax benefit and a declining fraction of the project cost. What percentage of cost of a wind farm, for example, is covered by tax equity in the current market? What are the percentages for solar, geothermal, and biomass, if you know them?

MR. MINTUN: There is an interplay among a number of factors. One reason that tax equity is covering a declining share of project cost in the wind, geothermal and biomass markets that rely on production tax credits is construction costs have increased. The tax credits are tied to electricity output. The output doesn't change. Therefore, the tax subsidy is smaller as a percentage of project cost.

That factor, combined with the higher yields on the tax equity, makes it very difficult to make these transactions as tax efficient as they could be. The tax equity investor runs out of capital before it can use all of the depreciation being thrown off by the project.

MR. MARTIN: So there are two problems in the current market. The investors are paying a declining percentage of tax subsidy value and then they are finding, because of the way partnership accounting works, they are not even able to absorb 99% of the tax benefits because they paid so little for them.

MR. MINTUN: That's correct.

MR. MARTIN: So, in wind, there used to be a rule of thumb that tax equity would cover 65% of the capital cost. The percentage is probably closer to 50% today, perhaps even lower.

MR. MINTUN: That's about right. It's around 50%, and sometimes lower.

MR. MARTIN: What about geothermal?

MR. MINTUN: Geothermal projects by and large tend to have a little more room to play. You can still get up to in the 60s and even to the 65% level that you indicated.

MR. MARTIN: Why is that? Because there are additional tax benefits in the form of deductions for intangible drilling costs and depletion?

MR. MINTUN: It is due to a number of things, but the underlying project IRRs tend to be a little more robust.

Tax equity is covering a declining share of the cost of wind, geothermal and biomass projects.

Potential New Investors

MR. MARTIN: Let's bring the other panelists into the discussion. Michael Feldman, you heard Phil Mintun describe these tax equity investments as approaching fixed-return investments with a variable time frame as a way of justifying what are essentially bank-driven yields. Does that ring true with you in terms of where yields ought to be on these types of instruments?

MR. FELDMAN: In general, I would say yes. They have many properties of fixed-income investments. In terms of risks, they also share a lot of characteristics of fixed-income, but we also have to be mindful of their operating risks, construction risks, things like wind risk and so forth.

MR. MARTIN: I believe Goldman Sachs had been an investor in these markets, but just not recently, and it is now interested in investing again. What sorts of projects interest you?

MR. FELDMAN: We have solar, wind, and geothermal tax equity positions in our portfolio and would very much like to be in more. We are interested in all of those spaces.

MR. MARTIN: What do you need to see to invest? What sort of yields? What else?

MR. FELDMAN: We are looking for high-quality transactions. We think about pricing within a context of other opportunities in which we can deploy our capital.

MR. MARTIN: What's the comparison? I think you told me before the call you use a risk-adjusted return format. What does that mean?

MR. FELDMAN: We think about it in terms of risk-adjusted returns. Every project is a little different in terms of how risky it is based on its particular nuances, its offtaker, its level of other operating risks and so forth. In terms of what we compare it to, I would say it's a basket of other fixed-income investments.

MR. MARTIN: Have you made any investments since the tax equity market started to struggle in mid-September?

MR. FELDMAN: Not yet, but we are looking at a number of opportunities, and we certainly hope to close some soon.

MR. MARTIN: Joe Donahue, has Marriott invested yet in renewable energy projects? If so, what kinds?

MR. DONAHUE: We were pretty big investors in the synfuel market. The tax credits on those investments expired in 2007. We are just beginning to look at new investments. We have done one solar transaction to date.

Getting back to the earlier question about whether partnership flip positions are debt-like or do they require higher returns, we approach these investments in part as a way to manage our effective tax rate. We don't have a large portfolio of investments where we need to balance different risks and returns. I agree with Phil Mintun that the preferred position the investor has for his return justifies the lower level of return. The tax subsidies come effectively from the government, which is a pretty good credit risk.

We still have to report to our internal investment committee and we are competing with every other hotel or timeshare project that comes up. So we need to meet internal hurdle rates and investing standards. We have had some theoretical discussions about whether we should look at tax equity investments on a risk-adjusted basis, but we haven't gotten a full buy-in yet. That is something that we continue to work on.

MR. MARTIN: Michael Feldman says Goldman Sachs compares these investments to a basket of other fixed-income investments, but you are comparing them to yields that can be earned on a hotel project. Where are those yields at the moment?

MR. DONAHUE: Different hotel projects have different yields. We have internal hurdle rates that we have at least to meet before we can present a project to our investment committee. And once you get in there, you are competing with other deals. A lot of what we have seen initially does not meet the hurdle rate. We continue to try to find transactions that will get us at least to that level.

MR. MARTIN: The one solar deal in which Marriott invested was a utility-scale photovoltaic project. Are there other renewable energy sectors — biomass, geothermal, wind, smaller-scale solar — where you feel you understand the business risks well enough to invest? Obviously you have stepped up to utility-scale photovoltaics.

MR. DONAHUE: We are in the process of learning about the different technologies and markets. As we did with synfuel, if we can get our arms around the operating risks, we can get comfortable with most of the different technologies.

MR. MARTIN: Steve May, there has been speculation about whether utilities can step into the breach and replace the banks and insurance companies that have withdrawn from the tax equity market. Utilities tend to have tax capacity. However, when you and I spoke on a prep call last week, it didn't seem like PPL is ready to make the leap. Where is your company in terms of investing as a tax equity investor?

MR. MAY: We were starting to look at wind tax equity deals last summer and had done a fair amount of due diligence on one particular portfolio of wind projects. However, in September, we basically exited.

We had also looked at investing as true equity in wind farms and came close on a couple of transactions in the last couple years. However, what we were seeing in 2008 was that straight equity was being offered roughly the same yield we were being offered on wind tax equity deals. For that reason, we thought that the risk-return relation for wind tax equity at almost the same yields made sense for us, given that we can fully use the tax benefits. Unfortunately, once the financial credit crisis hit, we exited. We are out of the market for now.

MR. MARTIN: So what is keeping you out of the market is a desire to conserve cash?

MR. MAY: Capital is precious. It is very */ continued page 32*

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expensive to issue debt and equity. For those reasons, we are on hold for now.

MR. MARTIN: But otherwise, you have a tax capacity?

MR. MAY: Yes.

MR. MARTIN: This past summer, the IRS made it possible for utilities to own up to 99% of a project in partnership with a developer, buy all the output and take 99% of the tax benefits. A lot of people wondered whether this might open the door to more utility investment. But if your utility is typical of utilities generally, it sounds like that structure has no special appeal. Or maybe it does have appeal, but this is just a time when you need to conserve cash.

MR. MAY: We had been looking at owning part of a wind project and being 100% of the offtake. I'm on the unregulated side of the business versus the utility regulated side of the business. In some of the deals that we had looked at, we felt constrained not to take more than 50% of the tax subsidies because our affiliate was buying all the output. The fact that the IRS has now relaxed that limit is something that will be useful for us when we get back into the market. It provides flexibility.

MR. MARTIN: What is the credit rating for your holding company? Is it triple B? Single A?

MR. MAY: On the unregulated side of the business, our debt is rated BBB/Baa2, so mid-investment grade. The utility is rated A minus.

MR. MARTIN: The word on the street is that anybody below a single A is having a very difficult time raising capital. Even long-established and stodgy utilities and their regulated affiliates are having trouble. Is it your experience that the credit markets are not really open?

MR. MAY: It is pretty difficult to issue debt or equity today. I think it can be done, but it's expensive. We would prefer not to do that.

MR. MARTIN: Darren Van't Hof, I believe your message is that US Bancorp is open for business. In fact, you are eager to invest in solar projects, especially solar PV. Are you interested in solar PV across the board: residential, big-box stores, utility scale? Where do you draw the line?

There are potential new tax equity investors, but it remains to be seen whether they will invest at yields the developers find attractive.

MR. VAN'T HOF: It is all of those, and we have closed on sale-leasebacks. We have closed on partnership flips. We have done big-box retail. We have done residential. We've not done a utility scale; we are looking at a couple now.

I think unlike what was said earlier, we actually like a leveraged structure. We like to see debt in our transactions if it is structured so that there is a period of standstill to cover our recapture risk.

As far as the bank is concerned, we have a strong tax credit appetite. We have good cash and liquidity positions. We are open for business.

We are not actually doing any wind right now. We are not doing geothermal or biomass. We looked at wind a year ago and it wasn't that appealing. We might look at it again.

MR. MARTIN: You just anticipated my next question. I know you personally work on solar, but you are saying there is no one else in the bank doing wind, geothermal, or biomass at this time?

MR. VAN'T HOF: We have an energy lending group in Denver and it is lending to wind farms. We are still evaluating whether we want to take tax equity positions in projects where the bank is also a lender.

MR. MARTIN: Do you have a preferred structure in the solar deals you work on? You said you do both sale-leasebacks and partnerships.

MR. VAN'T HOF: We defer to the customer. Whatever produces the most benefit for the project.

MR. MARTIN: You heard the discussion earlier about yields in the market and Phil Mintun deflected a question about where solar PV yields are compared to the benchmark rates he quoted for wind. What is your sense about where yields are in the PV market?

MR. VAN'T HOF: It is a risk-adjusted return. We don't really use IRR as our metric for investment. We use a couple other things. Yields are going up.

MR. MARTIN: Michael Feldman, do you feel any constraints on your current ability to invest: a potential lack of tax capacity, a lack of cash or the need to conserve cash?

MR. FELDMAN: No. I would emphasize that we are open for business and are actively looking at transactions.

MR. MARTIN: Where would you put your time first on diligence to make sure it is worth investing more time in a possible deal? Let's say somebody brings you a wind farm or a solar project. What do you look at first?

MR. FELDMAN: It is a series of different items, but the quality of the offtake agreement and its terms are very important, as are warranties and other aspects of operating risk.

MR. MARTIN: Joe Donahue, same question: where would you put your time first? You are in the tax department, so your focus tends to be on tax issues.

MR. DONAHUE: Right. We look first at the financial projections and make sure they meet our hurdle rates and make sense. We put them through our own internal modeling. Then it's what is the technology? Who is the sponsor? We see what kind of expert studies have been done. Then we have a tax person look at the structure to make sure the allocations work. What are the risks? What level of probability are we going to get to on any tax opinion? Are we going to be able to book these benefits or not?

I don't think you ever do one thing first. You just sort of jump in and start looking at a bunch of them. But I think the financial projections are the starting point. We may not get farther than that.

MR. MARTIN: The economic news is so unrelentingly grim these days, and we have read about a slowdown in business travel. I assume a hotel company would also feel some slowdown? Are there any concerns about tax capacity going forward?

MR. DONAHUE: We are a hotel management company, so we should have tax capacity going forward. Although I would encourage everybody to continue to travel and stay in hotels.

MR. MARTIN: Including Ritz-Carltons, which are managed by Marriott.

MR. DONAHUE: Yes, Ritz-Carltons are. We have capacity, although there is always uncertainty about the future. That may constrict cash and other competing investments could look better as the economy weakens and asset values weaken.

MR. MARTIN: Steve May, you come at this from the power company perspective. You are already in the power business. Where do you put your time first if somebody asks you to invest in a renewable energy project?

MR. MAY: We were looking at supplying wind tax equity earlier because we saw the returns in that market that were comparable, but with less risk, to a straight equity deal. Our main business is investing in different technologies as a straight equity investor, so if we had more capital, there are probably better opportunities for higher returns in those types of investments than there are in wind tax equity.

MR. MARTIN: Darren Van't Hof, you are doing solar PV. If you could spend time on just one issue when a potential deal comes in the door to tell whether it is worth going farther, what is it?

MR. VAN'T HOF: The integrator and the sponsor are very important. So is the strength of the offtaker. It depends on how the transaction is structured. If we need a large amount of cash to reach our hurdle rate, clearly we will look a lot more closely at operating risks than if our return is made up largely of tax subsidies that are tied to the project cost.

Potential Legislative Changes

MR. MARTIN: Various ideas are being discussed within the Obama transition team and also on Capitol Hill to revive the tax equity market, and they include such things as making production tax credits and investment tax credits refundable or allowing tax benefits that cannot be used to be carried back for five years — possibly longer — and used to recover taxes that a company paid in the past. Whatever is done would only apply to projects placed in service during a one- or two-year window when the tax equity markets are expected to be struggling. Do you see refundability or extended carrybacks having an appreciable effect on the tax equity market? Will either of these ideas revive the market?

MR. DONAHUE: We have been a taxpayer and expect to be a taxpayer, so we think we can use the tax credits currently anyway. Neither idea would change anything for us.

MR. MARTIN: Would it make you more confident investing, because you don't have to be as accurate about your ability to use the benefits? / *continued page 34*

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MR. DONAHUE: Yes, I think so, although we don't invest up to our full capacity.

MR. MARTIN: Tim MacDonald or Phil Mintun, you have been out in the market trying to raise tax equity. If you had either of these options in your arsenal, do you think it would help?

MR. MacDONALD: I'm not convinced it would make that big a difference. The bigger question is finding a hurdle rate that people like Joe Donahue at Marriott, which has tax capacity, feel provides them with an attractive enough return to invest.

MR. MINTUN: I agree with that. I think it may have some marginal benefit, but I think if people that are considering investing with tax equity in this marketplace have significant questions about their tax positions, they are more likely to exit outright than they are to rely on the ability to claim a refund either from the Treasury directly or by carrying back unused tax benefits. It may make a difference for one or two players. I'm not convinced it will have a huge impact at the margin.

MR. MARTIN: Maybe these answers should not be surprising. There were six ideas batted around by the industry with members of Congress to try to revive the market, and each one tended to focus on a different pool of potential new investors. Refundability looks to the government as the investor of last resort. It probably is of greater interest to developers; it doesn't really expand the pool of private tax equity. It would give developers the ability to get a little cash for tax benefits that otherwise go to waste because they can't use them and haven't been able to do a deal yet.

If depreciation isn't also refundable, but tax credits are, I suppose the developer might securitize the future refund stream. But he will only get a fraction of the tax subsidy he was hoping for otherwise. If the market recovers and somebody has chosen to get refunds of tax credits, but kept the depreciation, do you think it's possible to do a deal around just the depreciation once the market recovers?

MR. DONAHUE: Most of our investors don't value depreciation that highly. They really are driven by the tax credits.

MR. VAN'T HOF: I agree with Tim. Depreciation alone is not terribly attractive to us. Depreciation is discounted on our balance sheet. ◎

Investment Advisers Must Get Prior Approval to Manage Utility Shares

by Bob Shapiro, in Washington

The Federal Energy Regulatory Commission ruled in late November that an investment adviser should have gotten government approval before acquiring and managing more than $10 million in voting shares of several public utilities in customer accounts.

The ruling reflects a broad view of FERC authority over utility acquisitions.

FERC for the first time made clear that an investment firm that manages investments in utilities for third parties and retains the right to vote shares in those utilities can be considered to be a "holding company." Under a relatively new provision of the Federal Power Act, added by the Energy Policy Act of 2005, a "holding company" is required to get FERC approval to acquire more than $10 million in utility securities.

The ruling involved Horizon Asset Management. FERC refused to give Horizon retroactive approval for its purchases of voting shares in several public utilities after concluding the company is technically a utility "holding company." However, because this was a new interpretation of a new law, FERC did not impose any sanctions on Horizon.

FERC made it clear that there may be other investment firms that are similarly situated to Horizon, that FERC may not be so lenient next time, and that these firms have 90 days from the date that the order is published in the *Federal Register* to seek authorization from FERC for their previous acquisitions. That deadline is February 23, 2009.

What Horizon Was Doing

Horizon manages a number of separate investment accounts for unaffiliated entities. Horizon earns management fees, but the entities, called "account holders" for purposes of the FERC order, own the stock. However, Horizon has the exclusive authority to manage the accounts and is delegated by the account holders the right to vote the shares in the accounts, as well as to purchase and sell the securities in the accounts.

Horizon told FERC that it generally defers to an entity known as Institutional Shareholder Services, or "ISS," in exercising its voting rights, but Horizon does retain the right to override the decisions of ISS.

A "holding company" is defined in the Public Utility Holding Company Act of 2005 as a company that "directly or indirectly owns, controls or holds, with the power to vote" 10% or more of the voting securities of a public utility company or a holding company.

Horizon argued that it was not a holding company because the account holders, not Horizon, actually purchased the stock and that Horizon generally deferred on the voting to ISS.

FERC found that the account holders delegated their voting authority to Horizon, and that Horizon retained the authority to vote the shares. Further, Horizon conceded that the account holders own more than 10% of the outstanding voting securities of Aquila, Inc., a public utility company, and Horizon manages those accounts. Therefore, FERC found that Horizon was a holding company, even though it did not acquire utility securities, because it acquired rights to vote those utility securities over the 10% ownership threshold.

Blanket Authorizations

Horizon also sought blanket authorizations or, that is, it wanted FERC to pre-approve, the acquisition of securities of utilities or holding companies for its account holders in the future, subject to a list of conditions. One of the principal conditions was a commitment by Horizon to hold less than 10% of the voting securities of a public utility or holding company in any individual Horizon account, and less than 19.99% of the voting securities of a public utility or holding company collectively by Horizon and any affiliated entity having voting power. FERC granted the blanket authorization for a three-year period, and permitted Horizon to apply for an extension of the blanket authorization at the end of that period, based on the foregoing ceilings on the purchase of utility securities as well as other commitments by Horizon and FERC requirements, which included the following.

First, Horizon must file with FERC, at the same time it files with the US Securities and Exchange Commission, any Schedule 13G filings relevant to the blanket authorizations, and any changes from the Schedule 13G information must be provided to FERC within 45 days after the end of each calendar year. Horizon must also copy FERC with any comments or deficiency letters received from the SEC. A Schedule 13G filing is made with the SEC when a filer acquires 5% or more of a class of securities in the ordinary course of business and not with the intention to effect a change or influence over the control of the issuer.

Second, Horizon agreed not to take action that would require it to make a Schedule 13D filing with the SEC with respect to the securities of a public utility or holding company. A Schedule 13D filing is required when a person acquires 5% or more of a class of securities "with the purpose or effect of changing or influencing the control of the issuer" or if the ownership would be equal to or more than 20% of the class of equity securities.

Third, Horizon is required to retain the records of its transactions relating to public utility securities as required under the Investment Advisors Act.

Fourth, Horizon agreed to include language in its policies and procedures manual, account holder agreements and in its Form ADV, relating to registration of investment advisors under the Investment Advisors Act, that it will not exercise control over any public utility or holding company nor will it withdraw this language without providing FERC with at least 90 days' prior notice.

Fifth, Horizon agreed generally to defer to ISS voting recommendations, to exercise its vote in a manner that is consistent with its fiduciary duties to its shareholders, and to maintain readily auditable records of its voting of shares of public utilities and holding companies.

Sixth, Horizon agreed to file at FERC, for informational purposes, a quarterly report 45 days after the end of each calendar quarter detailing public utility and holding company securities held as of the end of that quarter.

Finally, Horizon must inform the Federal Energy Regulatory Commission within 30 days of any material change in circumstances that would change the facts, policies and procedures relied upon by FERC in granting the blanket authorization.

FERC also dismissed Horizon's request for blanket authorization under another section of the Federal Power Act to undertake the same activities with the same restrictions. Under that section, FERC would have required pre-approval if the activities resulted in a change of control of the public utility or holding company. Since FERC determined that the activities requested would not result in a change of control, blanket authorization under that section was unnecessary.

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Utility Shares

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PUHCA Exemption Filings

FERC issued an order at the same time as the Horizon order to clarify filing requirements for holding companies under Public Utility Holding Company Act of 2005, also known as PUHCA 2005.

Certain holding companies are automatically exempted from PUHCA 2005 because they own only cogeneration facilities and other power plants no more than 80 megawatts in size that use waste and other renewable fuels — called "qualifying facilities" under the Public Utility Regulatory Policies Act — exempt wholesale generators (generating facilities selling exclusively at wholesale) or foreign utility companies or "FUCOs" (entities that reside and sell power only overseas).

However, there are other categories of holding companies that are eligible for exemption or waivers only by filing an exemption notification at FERC. These include entities that would be considered utility holding companies but for the fact that they are purely passive investors, investors in public utilities that have no captive customers and are not affiliated with a utility that has captive customers, electric cooperatives, single state holding company systems, investors in transmission-only companies, and holding companies that own generation facilities of 100 megawatts or less and use the power fundamentally for their own loads or for end uses by affiliates. There are also holding companies that can obtain a waiver or exemption by seeking and obtaining a declaratory order from FERC if they are not otherwise eligible to file an exemption notification.

For those companies that filed for exemption or waivers from the PUHCA 2005 requirements or received a declaratory order, FERC determined that these entities not only have to notify FERC of any material changes in fact that may affect their exemptions or waivers, but also have to notify FERC if the company becomes a holding company with respect to an additional public utility or holding company.

This means that if a company acquires 10% or more of the voting securities of an additional public utility or holding company, that information must be reported, whether or not there has been any change to the facts on which the original exemption or waiver was granted. For those companies that should have provided this information because they have become holding companies for an additional public utility or holding company following the granting of an earlier exemption or waiver, FERC has given them until January 9, 2009 — 45 days from the date the new order was published in the *Federal Register* — to provide the information. ◎

California Plans a Carbon Diet

by Heather Mehta, Briana Kobor and Dr. Robert Weisenmiller, with MRW & Associates, Inc. in Oakland, California

Anyone who thinks that putting a program in place to cap carbon emissions in the United States will be easy should take a look at what is happening in California. The state became the first in the nation to adopt mandatory carbon controls in 2006. It is still struggling to put the regulatory framework in place to implement its program.

Carbon controls are widely expected to be adopted at the federal level by 2010. The California experience shows that developing the regulatory structure to implement controls will likely take years and will be fraught with challenges as the detailed regulations are developed.

The California law that controls emissions is called AB 32. It requires California to limit greenhouse gas emissions to 1990 levels by 2020. In December, more than two years after AB 32 became law, California took a significant step toward fulfilling the goal of AB 32 when the California Air Resources Board — called CARB — unanimously approved a so-called scoping plan that lays out how California will reduce its greenhouse gas emissions to reach the 2020 target. The plan is available on the CARB website at <http://www.arb.ca.gov/cc/scopingplan/document/psp.pdf>.

California Data

California emits roughly 2% of worldwide greenhouse gas emissions, making the state the 15th largest emitter on the planet. However, the California economy is less carbon intensive than the national average. California represents about 13% of the US economy, but state greenhouse gas emissions account for only 7% of total US emissions.

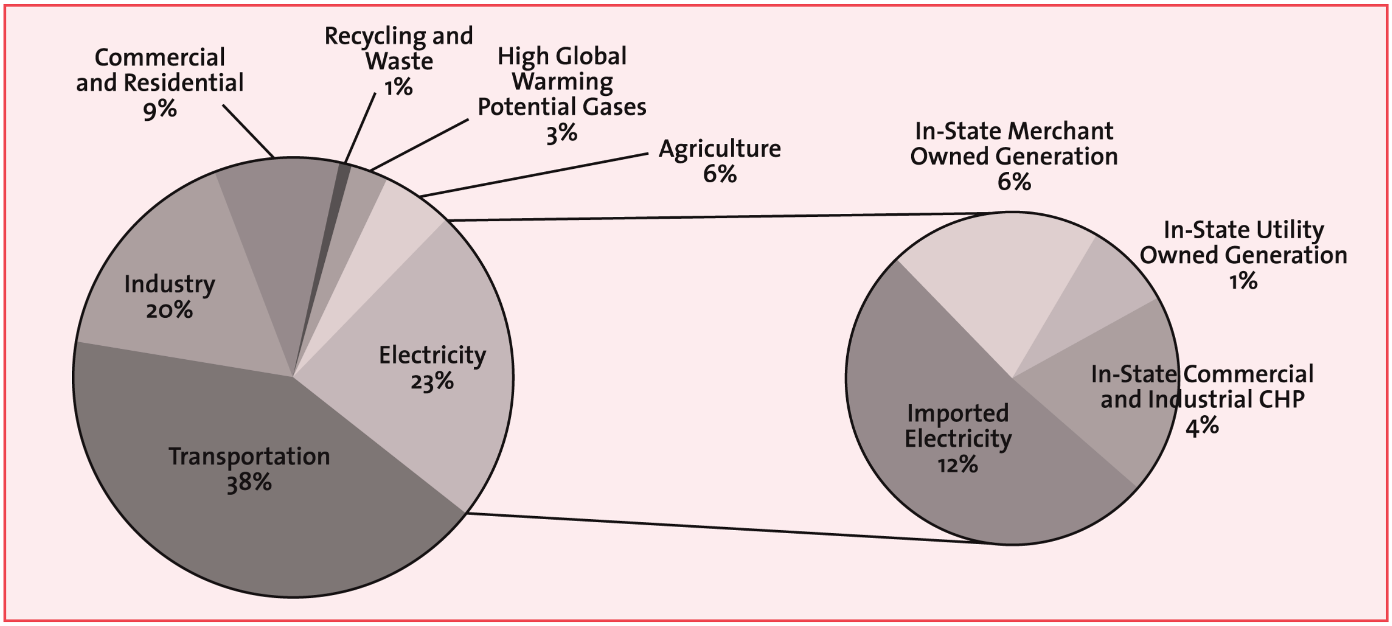
The California transportation sector is the largest single source of emissions, constituting 38% of statewide emissions.

Electricity is the second largest emitting sector with 23% of statewide emissions. The pie charts show average emissions during the period 2002 to 2004 in California by sector. California imports about a quarter of its electricity. However, because a good portion of imported power comes from coal-fired generation, imported power accounts for more than half of the emissions from the electricity sector.

The California emissions profile is different than the profile for the United States as a whole in one important respect: in-state electricity generation is responsible for 11% of California emissions, while on the national level, electricity generation is responsible for 40% of emissions, the largest of any sector.

There are two main reasons for this. First, California has aggressively pursued energy efficiency programs for many years. As a result, per-capita energy use in California has remained relatively flat since the 1970s while national per-capita energy use has risen dramatically. In 2005, national per-capita energy use was nearly twice that of California. Second, California is less dependent on coal for electricity generation with more hydro, renewables and natural gas in its power resource mix than the rest of the nation. Any national policy to reduce greenhouse gas emissions should affect national electricity markets more than the market in California.

Greenhouse Gas Emissions in California (Annual Average During 2002 to 2004)



Legal Framework

California has been moving to limit greenhouse gas emissions since 2002. The state legislature voted that year to require the state to adopt regulations to reduce emissions in the transportation sector, the state's single largest source of emissions.

Meanwhile, Governor Arnold Schwarzenegger issued an executive order in 2005 that called for statewide emissions to be reduced to 2000 levels by 2010, 1990 levels by 2020 and 80% below 1990 levels by 2050. These goals were partially codified a year later in AB 32, which adopted the 2020 target and delegated implementation primarily to CARB.

Following the passage of AB 32, the California Environmental Quality Act — called CEQA — emerged as another policy front with climate change implications. Attorney General Jerry Brown and environmental groups filed lawsuits forcing the consideration of greenhouse gas emissions when land use permitting and planning take place.

In response, the state Senate passed legislation (SB 97) in 2007 requiring clear guidelines be implemented for taking greenhouse gas emissions in account under CEQA by January 1, 2010. Another bill enacted in September 2008 requires streamlining the CEQA process and adoption of strategies for sustainable communities by addressing transportation and housing.

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California

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The implementation details of AB 32 and these other laws will be developed in the months and years ahead.

The various laws leave no doubt that consideration of greenhouse gas emissions and their climate change implications is being built into every major policy decision in California. For example, the California Public Utilities Commission considered the emissions implications of the Sunrise transmission project in its recent decision approving the San Diego area transmission line. The California Energy Commission has opened an investigation into how best to incorporate consideration of greenhouse gas emissions impacts in its power plant siting cases.

The Scoping Plan

California emissions will be capped at 427 million metric tons of CO2-equivalent emissions (MMt) in 2020. Such a cap will require a reduction of 169 MMt, or roughly 30%, from projected business-as-usual emissions in 2020. This reflects an overall reduction of roughly 10% from recent emission levels.

Status of AB 32 Implementation at CARB

- ☑ **Adopt list of discrete early action measures to be implemented before January 1, 2010.**
- ☑ **Establish 2020 emissions cap by January 1, 2008.**
- ☑ **Adopt mandatory reporting rules for significant emission sources by January 1, 2008.**
- ☑ **Adopt scoping plan indicating how emissions reductions will be achieved via regulations, market mechanisms and other actions by January 1, 2009.**
- ☐ **Implement early action measures by January 1, 2010.**
- ☐ **Adopt emission limits and reduction measures in regulations by January 1, 2011.**
- ☐ **Begin operation of reduction measures, including cap-and-trade, by January 1, 2012.**
- ☐ **Achieve reduction to 1990 emissions level by 2020.**

CARB adopted its proposed scoping plan on December 11, 2008. The plan describes California's strategy for meeting the emission reduction target. While the focus of this article is primarily on the electricity sector, the scoping plan includes measures for greenhouse gas reduction in other sectors, including separate measures directed at the transportation sector, creation of public goods charges and water use fees, and fees on gases with high global warming potential.

The strategy for reducing emissions from the power sector has several parts. The state will try to generate 33% of its electricity from renewable energy by 2020. It will expand existing energy efficiency programs and strengthen appliance standards. It will set a goal for increased use of combined heat and power technologies. It will link its cap-and-trade program with the Western Climate Initiative or WCI (see sidebar) to create a regional market for GHG emissions. The CPUC has already adopted some of these goals for the investor-owned utilities, but the scoping plan extends them to the municipal utilities as well.

The actual reduction measures aimed at the electricity sector embrace both command-and-control and market-based strategies for emissions reductions. To some extent, the command-and-control requirements for renewable energy, enhanced energy efficiency and combined heat and power are analogous to the tried approach of requiring the best available control technologies. However, a full command-and-control approach would lead to a struggle with the appropriate role for the market. "If there's anything we know from history, we need a price signal to mobilize market forces," said CARB member Daniel Sperling. "That means a carbon tax or cap-and-trade." Given California's disastrous experience with power market restructuring, there is a concern in many corners that a cap-and-trade program will lead to creative carbon market manipulation schemes to transfer money but not necessarily achieve real greenhouse gas emissions reductions. Chair Mary Nichols said: "Whenever someone says something is simple and easy, you should always hold onto your wallet."

A cap-and-trade program is scheduled to come into effect for electricity and large industrial sources in 2012. Smaller industrial, residential, commercial and transportation sectors will follow in 2015. The scoping plan states that the cap-and-trade program will be used to meet 20% of the overall emission reduction goal and will regulate 80% of California emissions sources. CARB had initially indicated that it would pursue only the cap-and-trade program, giving less focus to consideration of a carbon tax policy. However, in the public meeting approving the scoping plan, several CARB members said a carbon tax is still a possibility if concerns arise over cap-and-trade implementation.

Issues for the Power Sector

The scoping plan is merely an overview of program strategies. The details are expected to take another two years to fill in. There are five big issues of concern to power companies.

One is what share of reductions will have to come from power plants. The scoping plan envisions that the electricity sector will contribute at least 40% of total reductions even though the electricity sector accounts for only 23% of statewide emissions. At the same time, CARB wants to reduce emissions in the transportation sector by promoting electrification of different forms of transportation (*e.g.* plug-in hybrid electric vehicles, electric forklifts, and truck stop electrification). Thus, the power sector is being asked to shoulder a substantial burden for the state efforts to reduce transportation emissions. The CPUC and the CEC encouraged CARB to allocate extra allowances to the electricity sector in recognition that transportation-specific electrification measures could lead to higher emissions in the power sector.

Another issue for power companies is the point of regulation. California faces special challenges in reducing emissions from the electricity sector because of the quantity of imported electricity generated from coal. In addition, California must anticipate legal challenges to its regulations from out-of-state owners of coal generation and coal producers on the grounds that these regulations may violate the interstate commerce clause of the US constitution.

Three basic approaches to the point of regulation were considered by CARB before issuing the scoping plan: a source-based approach, a load-based approach, and a first-jurisdictional-deliverer approach. The state is expected to adopt a first-jurisdictional-deliverer approach.

Under a source-based approach, the point of regulation is the generator. A key drawback to the source-based approach was that California has no legal jurisdiction to regulate emissions of out-of-state generators. An alternative would have been to follow a load-based approach, which would have regulated the load-serving entities that generate or buy electricity for delivery to their customers. While a load-based approach would account for out-of-state generation, it would have involved complex accounting and less direct reduction incentives than a source-based approach. The first-jurisdictional-deliverer approach is a middle ground. Under the first-jurisdictional-deliverer approach, the responsibility for compliance is assigned to the entity that owns the electricity as it is delivered into the California grid. The first-jurisdictional-deliverer of in-state electricity would be the generator. For a majority of imported power, the "deliverer" is the importer: an investor-owned or public utility or wholesale power marketer.

A third issue is how allowances will be distributed under the cap-and-trade program. The distribution scheme has the potential to confer a competitive advantage on particular businesses. Full administrative allocation has the potential to generate windfall profits for some entities while full auction could create a large financial burden of compliance.

The scoping plan calls a 100% auction of allowances "a worthwhile goal," although there must be a transition to such a system. The WCI has recommended that a minimum of 10% of allowances be auctioned in the first compliance period, gradually increasing to an auction of at least 25% of allowances in 2020. The CEC and the CPUC want a much swifter transition. They are calling for 20% of allowances to be auctioned in 2012 increasing by another 20% each year thereafter until a 100% auction is reached in 2016.

The fourth big policy issue is offsets. CARB is considering whether to allow companies to use offsets to meet their emission reduction obligations. Offsets are emission reductions from uncapped sources beyond those required by direct regulations – for example, manure management or methane capture at landfills. Without any offsets, or with insufficient offsets, emitters will have to meet their obligations through direct emission cuts or through the purchase of allowances in the marketplace.

The WCI is recommending that states may use offsets for as much as 49% of reductions over the lifetime of the program without any rules on when polluters can use the offsets. In contrast, CARB will limit the use of offsets to each three-year compliance period. Thus far, CARB has determined that it will limit offsets to account for less than half of emission reductions, but has not finalized an offset percentage.

CARB identified two important purposes for offsets in the California program. First, offsets could potentially offer lower-cost emission reduction options for companies whose emissions are capped. This flexibility in / *continued page 40*

Key Players

California Air Resources Board (CARB) — CARB is the lead agency for implementing California's greenhouse gas policy. The board is a department within the California Environmental Protection Agency and has 11 members appointed by the governors, half representing scientific expertise and the other half representing regional districts within California. CARB's mission is to reduce air pollution while considering the state's economic well-being. AB 32 requires CARB to consult with the California Energy Commission and California Public Utilities Commission about any emission reduction measures that apply to electricity and natural gas.

Climate Action Team (CAT) -— CAT is an advisory team that was established by the governor through an executive order. The team is led by the California Environmental Protection Agency with representation from various state agencies. The agencies represented are the Business, Transportation and Housing Agency, the Department of Food and Agriculture, the Resources Agency, the Air Resources Board, the California Energy Commission and the California Public Utilities Commission. CAT serves as in an important advisory position to CARB. It played a key role in developing the scoping plan. It also formed the California Climate Action Registry, a voluntary emissions reporting scheme.

California Energy Commission and the California Public Utilities Commission (CEC and CPUC) — The CEC and CPUC are the two state agencies with primary responsibility for regulating the electricity and natural gas sector. Both agencies made recommendations to CARB in an October 2008 report that were relied on by CARB in development of its scoping plan.

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meeting emission reduction goals is critical in the view of energy companies such as the investor-owned utilities. Second, offsets could achieve reductions from "uncapped" sources. The geographic scope of allowed offsets, including whether out-of-state or international offsets would be acceptable, is still undetermined.

Some parties to the CARB proceeding argue that CARB should not permit any offsets and other parties believe offsets should be limited to a very small percentage of the emission reduction targets. Opponents of offsets cite a number of reasons for supporting limitation or exclusion, including that limiting offsets will encourage investments in green energy and clean technology and will ensure the allowance market is robust by increasing demand for allowances.

The last big policy issue is contract "shuffling." Many greenhouse gas emissions attributed to the supply of electricity in California are emissions from power plants in other states. California does not have the authority to regulate emissions from these plants, but it does have jurisdiction over entities that purchase power from these generators. This situation has led to some concerns over what has become known as contract shuffling.

Buyers of imported power could try to replace contracts for coal-fired power with contracts for hydro, wind or other carbon-neutral sources of power. If the sellers of power to California shuffle the allocation of types of power in their portfolios, then they could continue to offer the same coal-fired power to customers in other states. Carbon emissions in the region as a whole will not have changed. Cap-and-trade implementation in other states and provinces who have signed on to the WCI will help to ease this concern; however, under the current program, several western states will remain unregulated.

Potential Winners and Losers

When the dust settles, California could come out a winner or a loser. As a trailblazer for emissions controls, California should have a first-mover advantage in attracting clean technology businesses to the state. Where California could be the loser is if other neighboring states or even other US states opt not to adopt similar policies, and California simply becomes a high-cost state for both residents and businesses.

How state regulators react to the inevitable implementation delays and problems will also determine California's success. California cannot afford to be on the bleeding edge of regulatory innovation again.

CARB is pinning substantial hope on renewable energy being able to deliver a significant amount of zero-emissions electricity to meet electricity demand. Of the 169 MMt in emission reductions required under the scoping plan, 21 MMt are expected to come from an increase in the amount of electricity generated from renewable energy. While not yet codified into law, the emphasis on a 33% percent renewable standard indicates that California remains serious about spurring new renewable development within its borders.

The concept of a 33% renewable standard has been discussed for several years now and was the subject of a November 2008 executive order signed by Governor Schwarzenegger. However, California is not on track to achieve even the current, legislatively-mandated target of 20% renewables by 2010. California renewable generation accounted for only 12% of retail electricity deliveries in 2007, roughly the same amount as when the standard of 20% by 2010 was made law. The CEC reports that the primary reason for this failure is insufficient transmission infrastructure. Over the past few years, utilities have signed contracts for renewable generation, but the interconnection queue to connect new generating facilities to the inadequate grid has been clogged, preventing timely connection.

CARB is also relying heavily on enhanced energy efficiency. California has a record of success with energy efficiency that stretches over three decades. CARB, the CEC and CPUC have established very aggressive energy efficiency goals that may prove difficult to reach. For example, in September, the CPUC adopted the state's first long-term energy efficiency strategic plan calling for, among other goals, that all new residential home construction be zero net energy by 2020 and all new commercial buildings be zero net energy by 2030. The investor-owned utilities could benefit from the heavy emphasis on energy efficiency given the substantial incentives already in place for the utilities to achieve energy efficiency targets, but they will be challenged to meet these new goals.

Another potential winner may be combined heat and power, or cogeneration, which has languished in California for the past two decades. The scoping plan set a target of adding 4,000 megawatts of cogeneration */ continued page 42*

Western Climate Initiative (WCI) — The WCI is a collaboration of seven western states and four Canadian provinces that was formed in 2007 to develop a regional climate change strategy, including a cap-and-trade program. The WCI set a goal of reducing regional greenhouse gas emissions to 15% below 2005 levels by 2020. This goal is quantitatively similar to the AB 32 target of reducing California emissions to 1990 levels by 2020. California and the WCI are coordinating their policies so that the California program will integrate well into the larger WCI regional program. WCI released its recommendation for cap-and-trade program design in September 2008, and CARB relied on those recommendations in drawing up its scoping plan. Both the WCI program and the CARB program are expected to begin operation in 2012. (WCI member states include California, Arizona, New Mexico, Oregon, Washington, Utah and Montana. Member provinces are British Columbia, Manitoba, Ontario and Quebec. Notably, Nevada, Idaho, Colorado and Wyoming are not members of WCI.)

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capacity by 2020 to offset 30,000 GWhs of electricity demand that would otherwise be met by traditional power sources. In the coming year, the CPUC and CEC will begin new proceedings to address market barriers to increased use of cogeneration, both investor- and municipally-owned utility procurement of cogenerated electricity, eligibility criteria like maximum megawatt capacity to qualify for cogenerator incentives, and a way for cogenerators to sell excess electricity to the grid. Once the CPUC and CEC have addressed these issues through their respective proceedings, CARB plans to evaluate whether additional methods will be necessary for meeting its goal.

In terms of potential losers, the holders of long-term fixed-price contracts may be unable to adapt to the new market. The new emission caps create an obligation for power plant owners that in many cases was not contemplated when long-term power purchase agreements were negotiated. Holders of fixed-price contracts have no means to increase revenues to offset higher costs incurred to reduce emissions. The only alternative for these entities may be to reduce output. This, in turn, could have implications for reliability of the grid.

Owners and operators of coal-fired power plants and other carbon-intensive fuels will see their competitive positions eroded. A number of municipally-owned utilities in southern California, including the Los Angeles Department of Water and Power, rely heavily on out-of-state coal-fired power plants in their resource mixes. These entities have argued passionately that the plan for a cap-and-trade strategy could amount to a wealth transfer from them to investor-owned utilities. LADWP analyzed the scoping plan and concluded that PG&E (which has very low greenhouse gas emissions) would stand to reap $3.2 billion from the sale of allowances while LADWP would pay $2.2 billion a year to purchase allowances. LADWP would rather invest these billions in energy efficiency and renewable generation projects and not, as LADWP has stated, provide a "subsidy" to PG&E for its emission reduction efforts.

Finally, the utility sector may struggle in the face of increasing costs. Utilities will be obligated to purchase more renewable power and implement aggressive energy efficiency measures. The utilities are also likely to require an enhanced and smarter grid system. The utility rate base could be expanded considerably through the addition of smart meters and smart grids with additional distribution, transmission and storage systems. These expenditures, combined with required purchase of allowances and offsets, could substantially increase utility revenue requirements. In addition, the utility sector faces a significant challenge posed by the CARB proposal to reduce emissions in the transportation sector through electrification. This proposal holds the possibility of shifting the burden for emission reductions to the power sector. With large-scale transportation electrification, demand for electricity will increase at the same time the scoping plan calls for decreasing electricity emissions. In the end, utility ratepayers may prove the real losers as utilities raise electricity rates to cover increased costs associated with environmental compliance. ◎

Options for Restructuring Publicly-Traded Debt

by Marc M. Rossell, in New York

We live in turbulent financial times. Even companies with relatively stable financial positions face the prospect of restructuring their liabilities.

The absence of a meaningful credit market to refinance maturing indebtedness, the lack of short-term liquidity, or simply the inability to maintain required financial ratios in loan agreements may generate a need to consider a liability management transaction of some kind.

Companies whose debt securities trade publicly at a discount to par or face value may also want to capture some of the discount by purchasing their own securities with available cash.

Companies with bank debt or debt held privately by a few institutions can often deal with their creditors on a consensual basis without worrying about US securities laws. However, companies with outstanding indebtedness or that wish to issue new indebtedness in the form of bonds or other similar debt constituting "securities" must face a series of other issues arising under the securities laws.

This article outlines some of the securities law considerations companies have to take into account when contemplating an out-of-court restructuring of their publicly-issued debt securities. For this purpose, "publicly-issued" means issued in a public offering or otherwise traded in the institutional capital markets as restricted securities. This article does not include any discussion of equity securities, including convertible debt that is considered equity under the securities laws, nor does it consider issues related to securities issued by a company in a bankruptcy proceeding.

Six Options

Companies with outstanding debt securities can engage in a variety of transactions with holders. The choices depend to some extent on whether or not the company has access to cash.

Where cash is available, either from internal funds, new financing or both, a company can consider an optional redemption, open market purchases or a cash tender offer.

Without cash, the most likely alternative is an exchange offer of new securities for the existing securities.

In the case of either a cash tender offer or an exchange offer, there is often a consent solicitation as well to modify the terms of the existing securities. If only a waiver or amendment of existing terms is required, a stand-alone consent solicitation may be the answer.

Options for Company with Cash

If the agreement governing the indebtedness, typically an indenture, permits the company to redeem the bonds prior to maturity, then an optional redemption of the debt securities can be made. However, many indentures restrict such redemptions in the early years of the bond — the so-called "non-call period" — and in later years the exercise of the redemption feature may be subject to payment of an additional premium which may be unattractive. Some indentures allow redemptions at any time subject to payment of a "make-whole" premium based on the recuperation of the yield through maturity, a price that is usually quite high. Where the bonds are trading at a discount to par value, these options will be particularly unappealing.

Most indentures do not restrict the company from repurchasing its own bonds in the open market. If no such restrictions exist, and assuming there are no other applicable contractual or regulatory prohibitions binding on the company, then cash repurchases in the open market can be made through privately negotiated transactions with individual holders, either directly or through the intermediation of a broker.

Most open market debt repurchases can be structured in a manner to avoid the application of the "tender offer" rules under a US securities law called the Exchange Act, but counsel should be consulted prior to undertaking any such program to ensure that such purchases do not amount to a tender offer. Repurchases that might be recharacterized as a non-compliant tender offer could expose the company to liability and sanctions.

What constitutes a "tender offer"? Neither the US securities laws nor the US Securities and Exchange Commission has defined the term "tender offer," and there is not much case law or SEC commentary on the topic. Eight factors have generally been cited as evidence of a tender offer. Not all of them have to be present. The eight are 1) active and widespread solicitation of holders, 2) solicitation for a substantial percentage of the outstanding debt, 3) the offer is made at a premium over the prevailing market price, 4) the terms of the offer are firm and not negotiable, 5) the offer is contingent on a minimum number of tendered securities, 6) the offer is open only for a limited period, 7) the offeree is subject to pressure to sell the securities, and 8) the public announcement of a purchasing program precedes or accompanies rapid accumulation of the securities.

The best way to avoid inadvertently making a tender offer is to solicit only a limited number of holders, preferably sophisticated investors, stretch the repurchases over a long period of time, without deadlines or other pressures, purchase on separately-negotiated terms and prices from different holders, and consider limiting the total amount of securities purchased in the open market. If both a repurchase program and an overt tender offer are contemplated, the company should consider undertaking them separately and having some period of time elapse between the two events to avoid the repurchases being considered part of the tender offer.

Indentures typically provide that bonds purchased or otherwise held by the company or an affiliate will not be considered to be "outstanding" for purposes of tabulating votes required for taking action under the indenture such as waivers, consents and amendments. Companies and their affiliates (often controlling shareholders) should be conscious of this limitation if there is any intent to influence the outcome of a vote by acquiring outstand- / continued page 44

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ing bonds in the open market or otherwise.

Finally, a company with cash may wish to offer all holders the opportunity to tender their bonds for a cash payment. Cash tender offers for debt securities are regulated by section 14(e) of the Exchange Act. These rules generally prohibit fraudulent and manipulative activity and require that the tender offer be kept open for a minimum of 20 business days from commencement and 10 business days from notice of a change in either the percentage of securities sought, the consideration offered or the dealer's soliciting fee.

Borrowers who need to restructure public debt have six options.

Since it is often impractical to leave a debt tender offer open for such a long period, the SEC has issued a series of "no-action" letters exempting certain tender offers for investment-grade securities from the 20-business-day rule, subject to certain conditions. Pricing formulations vary, but since the "equal treatment" rules for tender offers of equity securities do not apply to non-convertible debt securities, alternative pricing mechanisms such as Dutch auctions and fixed-spread pricing are available. There are also certain structural features to the offer that can be implemented to incentivize holders to tender early, such as "early bird" premiums to holders who tender before a certain date, thus providing greater certainty to the company as to results prior to the expiration of the offer.

The Exchange Act rules do not require the filing of any offering document with the SEC, and there are no specific disclosure requirements that apply. However, an offer-to-purchase document is customarily prepared, and it should be materially accurate and not misleading to avoid liability. If the targeted debt securities are listed or quoted on a securities exchange, then the rules for such exchange must also be reviewed to determine whether any specific disclosure or procedural requirements apply.

Anti-Fraud Liability

Whether the company engages in open market purchases or conducts a cash tender offer, often the most significant legal issue is avoiding liability under the anti-fraud provisions of the securities laws, including Rule 10b-5 under the Exchange Act.

This rule generally prohibits the use of materially misleading statements or omissions in connection with the purchase or sale of a security and otherwise prohibits the use of manipulation or deceptive devices to purchase or sell a security.

The application of Rule 10b-5 in the context of open market debt purchases is not entirely clear. If the company makes statements in the context of a purchase that are materially misleading or inaccurate, then the seller may have a Rule 10b-5 claim.

Where no statements are made but the company has inside information and the purchases are made through a broker, the result is less clear because Rule 10b-5 only imposes liability for omissions where the buyer has a duty to disclose and has failed to do so. Recent decisions have held that companies that are solvent have no fiduciary duties to holders of their debt securities and, thus, assuming current public disclosures by the company are correct, there would be no duty to disclose material non-public information in the context of a debt repurchase. However, not all courts might agree with this position and there are other theories, such as common law fraud, that might be used to infer a duty to disclose even in the absence of a fiduciary duty.

Options for Companies Without Cash

A company may not want to use cash or may otherwise need to make an offering of new securities with different terms to its existing holders.

Most indentures provide that a unanimous consent is required to change fundamental economic terms of the securities (such as maturity, interest rates or mandatory redemption events). Obtaining such consents is often quite difficult. Any exchange of newly-issued debt or equity securities for outstanding debt securities is considered an offer of securities under the Securities Act of 1933 and, thus, it must be registered with the SEC unless an exemption from registration is available. The most common exemptions are the section 3(a)(9) exemption and the so-called "private placement" or section 4(2) exemption. Exchange offers are also considered tender offers and, thus, the Exchange Act rules for tender offers discussed earlier also apply.

Although there is no legal requirement for the company to use the services of an intermediary to solicit exchanges, it is customary in most situations to appoint a dealer-manager of an exchange offer. In that event, due to similar liability concerns that arise in any new offering of securities, dealer-managers customarily perform due diligence on the company and request third-party assurances on whatever offering document is prepared, including auditors' comfort letters and lawyers' negative assurances or "10b-5 letters."

Section 3(a)(9) of the Securities Act allows a company to offer and sell new securities to existing holders of its own securities without registration, subject to certain conditions.

The offering must be made exclusively by exchange with its existing holders. The issuer of the new securities must also be the same issuer as the issuer of the old securities, a requirement that can present structural challenges if there are parent or subsidiary guaranties involved. One of the most problematic requirements of section 3(a)(9) is that the company cannot pay a fee to the dealer-managers to solicit tenders. The SEC has issued a series of no-action letters that permit a financial adviser to undertake certain administrative activities in connection with the exchange, including pre-launch discussions with sophisticated holders of bonds, so long as there is no success fee involved. The restriction on these fee arrangements where active solicitation may be required in an exchange often leads companies to select another form of exchange offer. In a section 3(a)(9) exchange offer, similar to registered exchanges, there is no restriction on general solicitation or advertising, thus allowing unrestricted publicity, and there are no restrictions on the nature of the offerees.

Another exemption available for an exchange offer is the so-called "private placement" exemption under section 4(2) of the Securities Act. With this structure, the offer and sale are made only to accredited investors such as large institutional holders; non-US persons are also often solicited in reliance on Regulation S of the Securities Act under this concurrent exemption. Another important limitation of this exemption is that there can be no general solicitation or advertising, a restriction on publicity that should be taken into account when considering this alternative. However, this exemption does not impose any restrictions on fees for the dealer-manager, so there is more flexibility on that issue.

Because of the limitation on the nature of the offerees, the offering document cannot simply be distributed to all existing holders. Holders must pre-qualify through an eligibility questionnaire before receiving an offering document. In most exchange offers for outstanding debt, there is little if any non-accredited investor participation and, thus, this pre-qualification process mostly affects timing since the offer takes more time to implement.

Another option is a registered exchange offer. A company can file a registration statement on Form S-4 with the SEC to register the offer and sale of the new debt or equity securities to the holders of its existing bonds. Form F-4 must be used if the company is a foreign private issuer.

In a registered exchange offer, there are no structural restrictions or fee limitations as there may be in a section 3(a)(9) exchange and dealer-managers can freely solicit tenders and all holders can participate, including retail investors. However, companies cannot generally use existing "shelf" registration statements to conduct an exchange offer, and the SEC may elect to review the new registration statement, a process that can be lengthy and unpredictable. Companies are also subject to heightened liabilities under the Securities Act for disclosures and omissions in the registration statement and prospectus.

Exit Consents

In order to encourage holders to tender their bonds in an exchange offer or cash tender, and to allow the company to avoid the application of restrictive covenants in the indenture for the bonds that the company is attempting to retire or repurchase, companies often seek "exit consents." This refers to the practice of having tendering holders consent to amendments or waivers of covenants or other terms in the existing indenture as a condition to acceptance of the tender or exchange.

The amendments or waivers that are */ continued page 46*

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sought are typically those that can be adopted or granted with a simple majority vote of bondholders. Holders tendering their bonds for cash or new securities will generally not be concerned about the protections in the existing indenture and those refusing to tender or exchange their bonds will be left with an indenture without the same protections. In addition, if the tender or exchange is successful, non-tendering holders will be left holding bonds with a more limited trading market which is likely to affect trading prices for the old securities adversely; this also acts as an additional incentive to participate in the tender or exchange.

Companies should consider the application of the "new security" doctrine if a consent to an amendment or waiver relates to fundamental terms of the securities.

The SEC has taken the position that consents to amendments to existing debt securities that fundamentally alter the terms of debt securities have the effect of creating a new security, thus requiring analysis of the consent under the Securities Act similar to what occurs in an exchange offer. In addition, in the context of exit consents included as part of an exchange offer relying on the private placement exemption of section 4(2) of the Securities Act, one issue to be addressed is whether or not a consent is valid if not all holders are given an opportunity to consent. Certain New York case law has cast some doubt on this point. Because private placements exclude non-accredited investors, to the extent there are any such holders excluded, consideration needs to be given to restructuring the transaction to accommodate this concern: for example, by undertaking a separate consent solicitation outside of the exchange offer to afford all holders the opportunity to participate.

Tax Implications

The tax implications of debt repurchases and exchange offers should be considered; they are usually disclosed to existing holders in any offering document. Although the application of the tax rules to a particular transaction is often fact specific, certain principles generally apply.

A company repurchasing debt at a discount will generally recognize "cancellation of indebtedness" income in an amount equal to the discount.

In an exchange offer for new securities, the company will generally recognize this income to the extent that the amount owed on the existing debt exceeds the fair market value of the new securities. In the case of new debt securities, if the fair market value of the new securities is less than the outstanding principal amount of the debt, there will likely be original issue discount that the holders of the new debt will be required to treat as income (with a corresponding interest deduction for the company over the life of the new debt). ◎

Overcoming Hurdles to Commercializing Cellulosic Ethanol

by Todd E. Alexander and Lee Gordon, in New York

Although current efforts to produce cellulosic ethanol are frequently referred to as being near fruition, considerable uncertainty remains about the speed with which cellulosic ethanol will become commercially viable. So far, no company has been able to produce cellulosic ethanol in mass quantities at a cost that can compete with starch- or sugar-based ethanol. Moreover, the US Energy Information Administration recently released a report projecting that renewable fuels will not be able to meet the 36 billion gallon federal mandate by 2022. Yet, because cellulosic ethanol has the potential to improve the environmental benefits of using biofuels significantly, efforts to achieve its commercialization continue.

In recent years, these efforts have increasingly been bolstered by incentives provided by the federal government. Given the recent nomination of Tom Vilsack as US Secretary of Agriculture and Steven Chu as US Secretary of Energy, both of whom have been public advocates for the development of cellulosic ethanol, federal support for the industry is expected to continue. Such support must overcome not only the technical hurdles to commercializing cellulosic ethanol, but also the financial and legal hurdles that contribute to the uncertainty surrounding its future.

What is Cellulosic Ethanol?

Cellulosic ethanol is distinguishable from starch- and sugar-based ethanol primarily by the fact that it is produced from feedstocks that are not typically used as foods. Whereas starch- and sugar-based ethanol are produced from feedstocks such as corn and sugarcane, feedstocks that can be used to produce cellulosic ethanol include residual non-food parts of agricultural crops such as corn cobs and sugarcane bagasse, residual parts of forestry and waste products such as wood chips and organic garbage, and non-food crops such as poplar and switchgrass. Such a variety of feedstocks can be utilized because lignocellulose, the material that is processed into cellulosic ethanol, is found in all plants.

The components of lignocellulose — cellulose, hemicellulose and lignin — contain sugars and carbon that can be converted into ethanol once the lignocellulose has been broken down so that the sugars or carbon can then be separated. This need to break down lignocellulose and separate the sugars or carbon is the primary technical impediment to the commercialization of cellulosic ethanol. Although several processes exist for producing cellulosic ethanol, none of these processes has been proven cost efficient on a commercial scale. Among the most promising current efforts are those focused on processes that break down cellulose and hemicellulose into sugars through the use of enzymes or chemicals (biochemical processes) and those focused on processes that break down the carbon in lignin by gasification (thermochemical processes).

One big advantage of cellulosic ethanol is political: it does not drive up food prices. The feedstocks that can be used to produce cellulosic ethanol are more abundant than those used to produce starch- and sugar-based ethanol. A joint study by the US Department of Agriculture and US Department of Energy found that 1.3 billion tons of biomass feedstock could be used annually in the United States for biofuel production — the vast majority of feedstocks needed for cellulosic ethanol production — with only minor changes in land use and agriculture. In addition, since cellulosic ethanol can be produced from feedstocks that are often residual or waste products, criticisms related to increases in greenhouse gases from indirect land displacement have not been directed at cellulosic ethanol. Also, since several waste-feedstocks used for cellulosic ethanol do not require chemicals and fertilizers to be produced, cellulosic ethanol often has lower lifecycle greenhouse gas emissions than petroleum fuels or starch- and sugar-based ethanol.

Role of the Federal Government

Cellulosic ethanol receives federal support through a combination of incentives, including regulatory mandates, tax credits and depreciation allowances, grants, loan and guarantee arrangements, and biomass crop programs. These federal incentives are contained in several pieces of legislation, such as the Energy Policy Act of 2005, the Energy Independence and Security Act of 2007 and the 2008 Farm Bill.

Among the incentives is the renewable fuel standard or "RFS," a federal mandate that requires increasing volumes of renewable fuels be blended into transportation fuel in the United States each year. The US Environmental Protection Agency, which administers the program, requires each fuel supplier (a fuel refiner or importer) to show each year that it has met the requirements of the RFS through a combination of purchases of renewable fuels and purchases of credits from other suppliers that have made renewable fuel purchases.

The RFS requires fuels produced from non-corn feedstocks that have 50% lower lifecycle greenhouse gas emission than petroleum fuels — called "advanced biofuels" — beginning in 2009 and fuels produced from cellulose, hemicellulose or lignin that have 60% lower lifecycle greenhouse gas emissions than petroleum fuels — called "cellulosic biofuels" — beginning in 2010 form an increasing percentage of the RFS.

As the RFS increases from 11.1 billion gallons in 2008 to 36 billion gallons in 2022, the mandate for advanced biofuels increases from six million gallons in 2009 to 21 billion gallons in 2022 and the mandate for cellulosic biofuels increases from one million gallons in 2010 to 16 billion gallons in 2022. As a result of these increases, by 2022, advanced biofuels are scheduled to represent 58.3% of the RFS, and cellulosic biofuels are scheduled to represent 76.2% of the advanced biofuels, the balance of the RFS being met by earlier generation ethanol and biodiesel fuels.

Tax subsidies are also important. In addition to the general tax credits for renewable fuels, such as the volumetric ethanol excise tax credit and the small ethanol producer tax credit, cellulosic ethanol production is provided with additional tax benefits. Producers of cellulosic biofuels are entitled to a tax credit or $1.01 per gallon on production after 2008, but the amount is reduced by the volumetric ethanol excise tax credit and the small ethanol producer tax credit. Also, a special depreciation allowance for cellulosic ethanol facility property allows for a depreciation deduction for 50% of the cost of a new enzymatic process cellulosic ethanol facility in the year that it is placed in */ continued page 48*

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service. The cellulosic biofuel credit and the depreciation allowance both expire on December 31, 2012.

Grants, loan guarantees and loans may be available through the US Department of Agriculture. The biorefinery assistance program provides loan guarantees of up to $250 million per project to fund the development, construction, and retrofitting of commercial-scale biofuel facilities producing advanced biofuels. The guarantees can cover up to 90% of principal and interest on a loan. They cannot exceed 80% of project costs. The program also provides grants for up to 30% of project costs to assist the development and construction of demonstration-scale biofuel facilities producing advanced biofuels. A separate bioenergy program for advanced biofuels provides up to $300 million in payments to biofuel producers to support the expanded production of advanced biofuels. Also, a repowering assistance program provides up to $35 million in grants to owners of existing biofuel facilities to promote the use of renewable biomass to produce heat or power as a substitute for fossil fuels.

Grants, loan guarantees and loans may also be available through the US Department of Energy. A biomass research and development initiative provides up to $200 million in grants for the development of biomass crops and the development and construction of demonstration-scale biofuel facilities producing advanced biofuels. A separate biorefinery project grants program provides up to $186 million in grants for biomass research and development and demonstration-scale biofuel facilities. Loan guarantees up to $10 billion for renewable energy and energy efficiency are provided under several programs to support loans from private lenders for the construction of advanced biofuel facilities that produce ethanol from cellulosic feedstocks and various other clean energy projects. The cellulosic biofuels production incentive program permits the US Department of Energy to provide incentives through per-gallon payments up to $25 million for cellulosic biofuels facilities until annual production of cellulosic biofuel in the United States reaches one billion gallons or the incentive program expires in December 31, 2014.

Calendar Year	(volume in billions of gallons)				
	RFS	Advanced Biofuels	Advanced Biofuels as a Percentage of RFS	Cellulosic Biofuels	Cellulosic Biofuels as a Percentage of Advanced Biofuels
2009	11.10	0.60	5.4%	—	—
2010	12.95	0.95	7.3%	0.10	10.5%
2012	15.20	2.00	13.2%	0.50	25.0%
2014	18.15	3.75	20.7%	1.75	46.7%
2016	22.25	7.25	32.6%	4.25	58.6%
2018	26.00	11.00	42.3%	7.00	63.6%
2020	30.00	15.00	50.0%	10.50	70.0%
2022	36.00	21.00	58.3%	16.00	76.2%

Impediments to Commercialization

Even though several facilities for commercial cellulosic ethanol production are under construction, the total cost of developing a cellulosic ethanol facility is not well known at present. Without an understanding of the total cost of engineering, constructing and testing a cellulosic ethanol facility, it has been difficult for developers to obtain standard construction schedules, cost commitments and performance guarantees from contractors. Without price, schedule and performance guarantees, it is difficult to raise equity for these projects, and it is nearly impossible to raise debt from private financial institutions. Lenders will be sensitive to any increases in the cost of developing the cellulosic ethanol facility, and although the Department of Agriculture and Department of Energy administer a variety of programs offering loans and guarantees, developers will likely have to assume the risk for some of these increased development costs.

Another cost issue relates to the operating costs of a cellulosic ethanol facility. Until a cellulosic ethanol technology is deployed on a commercial scale, it is impossible to know the full cost of producing ethanol from certain feedstocks. Currently, the high costs of processes for breaking down lignocellulose and separating the sugars and carbon are an impediment to the commercialization. Where operating costs either cannot be reasonably determined, or cannot be shown to decrease from the high costs associated with current processes, it may be difficult for a developer to obtain additional funding to move forward with commercial development. Also, high operating costs put pressure on working capital, which may result in the cellulosic ethanol facility being unable to meet its debt service.

Developers of cellulosic ethanol facilities have found it difficult to commercialize their new technologies due to what has been termed the "valley of death." The valley of death is a period in the development of a new technology when it is susceptible to failure due to the developer's difficulty in raising additional cash to fund its commercialization. During this period, a developer faces an increasing demand on existing cash, as cash is spent on development, and a decreasing ability to raise additional cash, due to the project's lack of demonstrable positive future cash flow. Venture capital investors tend to provide financing to developers once the technology has been shown to be commercially viable, just before the upturn in cash flow is experienced. Private equity investors are typically interested in investing in companies that are already operating and established in the market, rather than developers that have an as-yet unproven technology.

One way of moving a technology through the valley of death is for a developer to enter into a strategic joint venture with an established company. By doing this, the developer can use the cash flow of the established company in order to raise additional cash for commercialization of the new technology. However, using a strategic joint venture requires identifying companies that are willing to accept the risk associated with the new technology and have access to sufficient cash to support additional development costs or can guarantee debt financing for the developer. Several oil companies have invested recently in cellulosic ethanol, including BP in a strategic alliance with Verenium, Suncor in a partnership with Lignol and Royal Dutch Shell with Iogen.

Developers have increasing access to loans and guarantees from the US government. This is another possible route through the valley of death. For example, the Department of Energy has provided funding for nine small-scale projects and four commercial-scale projects, including an additional $76.3 million in POET to develop a cellulosic facility (after an initial $3.7 million investment). Also, the Department of Agriculture recently announced that it will begin providing loan guarantees of up to $250 million under the biorefinery assistance program to support commercial-scale advanced biofuel facilities.

Another possible hurdle to the commercialization is the uncertainty surrounding access to feedstocks. Although the Department of Agriculture administers programs to promote the production of biomass crops, it is unclear whether these programs will convince farmers that a market for biomass crops will develop. Many of these crops may take several years to establish before a marketable crop is available for production, and until such time, it may be difficult to predict whether these crops will be commercially viable. Without knowing whether crops can be produced at commercial yields and prices, and in the absence of a market for biomass crops, it may be difficult for developers of cellulosic ethanol facilities to procure binding feedstock agreements.

In addition, the production and transportation costs for cellulosic ethanol feedstocks (residual non-food parts of agricultural crops, residual parts of forestry and waste products and non-food crops) on a commercial scale are largely unknown. Feedstocks that contain significant amounts of lignocellulose tend to be bulky, which may present difficulties and additional costs in terms of harvesting, collecting, transporting and storing these feedstocks. Much of the marginal land that has been identified as being a major source of feedstocks for cellulosic ethanol production lacks access to populated areas where ethanol would be used, which may further increase transportation costs. Projections of the amount of available feedstocks are based on the assumption that feedstocks can be harvested at increased per-acre yields, which in certain instances would require additional spending on new harvesting / continued page 50

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machinery. Also, the projections do not necessarily take into account the impact that such harvesting may have on continued increases in per-acre yields for agricultural crops, due to the removal of harvest residue that would otherwise fertilize the next year's crops. All of these additional costs will remain difficult to quantify until cellulosic ethanol facilities enter commercial production.

Another risk to large-scale commercial production is what has been termed the "blend wall." Currently, most ethanol-gasoline fuel blends contain no more than 10% ethanol (a fuel known as E10). Blenders stop at 10% because the automakers take the position that using higher percentages of ethanol will void most vehicle warranties. Given that current US consumption of gasoline is estimated at 142 billion gallons a year, absent an increase in the percentage of ethanol that can be blended with gasoline, the total annual market for ethanol in the US is expected to reach the blend wall at a maximum of 14 billion gallons of ethanol. The RFS is scheduled to increase beyond the current blend wall in 2012 and provides an incentive to increase ethanol production even though there may be no one to buy the additional ethanol in practice.

Unless the percentage of ethanol that can be blended with gasoline is increased, through a change in the types of vehicles sold in the US, additional production of commercial cellulosic ethanol will be difficult to absorb into the motor vehicle fuels pool. This concern is heightened by the fact that most, if not all, cost projections for producing cellulosic ethanol using current technology show that the fuel is not cost competitive with starch- and sugar-based ethanol. ◎

Biofuels producers face a potential "blend wall" before the amount of ethanol required in US gasoline increases again in 2012.

Hooking Up: Recent Cases Affecting Grid Interconnection

by Adam Wenner, in Washington

Two major issues for independent power projects, especially wind, geothermal and large-scale solar, are who pays the costs of interconnection and which projects are allowed to use existing interconnection capacity. Renewable energy projects in particular tend to be far from population centers and more expensive to connect to the grid.

In addition, the status of a project in the interconnection queue significantly affects the viability of the project.

The Federal Energy Regulatory Commission, which regulates interconnections in the continental US, other than in the ERCOT area of Texas, has issued several decisions recently that affect generator interconnections.

Midwest ISO

"First come, first served" is now "first ready, first to interconnect" in the Midwest ISO.

To address its backlog of interconnection requests, the Midwest ISO proposed, and FERC accepted in large part, a proposal to revise the interconnection queue process.

The Midwest ISO proposal included 1) a pre-queue phase, 2) a modified feasibility study that permits requests to be routed to a "fast lane" to allow projects in unconstrained areas to proceed without delay, 3) establishing queue positions based on achievement of milestones, which is intended to avoid blocking of queues with non-viable or inactive projects, 4) increasing deposit amounts and changing the timing for making deposits and 5) changing the ability to suspend the transmission utility's construction or installation of interconnection facilities or network upgrades for up to three years for any reason to permit suspension instead only in cases of *force majeure*.

The first phase in the Midwest ISO's proposal is the system planning and analysis phase. It is similar to the current system impact study phase; however, queue position is less important because it can change through the interconnection process.

The next phase is the "definitive planning phase" in which a system impact restudy is performed, if necessary, as well as a facilities study. The fee to enter this phase is approximately double the expected actual cost, with the excess used to cover the facilities study and costs incurred to re-study lower-queued projects if the generator drops out. Unused balances are returned to the customer. Study deposits are $30,000 for projects between 20 and 50 megawatts and $60,000 for projects between 50 and 500 megawatts.

Entering into the definitive planning phase also will require technical data and meeting milestones. Technical data required are 1) a detailed stability model, 2) a definitive point of interconnection, 3) a one-line diagram showing ratings and impedance information for associated electrical equipment, 4) the definitive amount of capacity of the project, 5) either recertification of site control or, if the project has provided a $100,000 deposit in lieu of showing site control, the deposit becomes non-refundable 10 business days after the start of the planning phase and 6) any two of four other items. The four are i) documentation of an application for state or federal permits and a showing that the application is proceeding, ii) approval of the project by a state utility commission, iii) approval from an independent board of directors of the applicant or a similar showing of organizational approval or iv) security equal to the nameplate capacity times the rate for one month of drive-out point-to-point transmission service.

In addition, before the Midwest ISO will start a facilities study, the generator must show that it has achieved one of the following additional milestones: 1) security for the cost of network upgrades as determined in the system planning and analysis review, 2) execution of a power sale agreement or an attestation that the project is included in a state resource adequacy plan or evidence that the generator will qualify as a designated network resource or 3) a demonstration that the turbines have been ordered.

Under the Midwest ISO's prior interconnection procedures, a customer could suspend the effectiveness of an executed interconnection agreement for a total of three years for almost any reason. Under the revised program, suspension would only be permitted based on a *force majeure* event and for a total period of three years. In addition, a customer may have up to six months from completion of the system planning and analysis review to the start of the facilities study to meet the applicable milestones, and may obtain another three months between the completion of the facilities study and the execution of the interconnection agreement. However, a customer must provide security for the cost of its network upgrades in order to avoid harm to lower-queued projects resulting from the suspension.

FERC ruled on the proposal in a ruling called *Midwest Independent Transmission System Operator, Inc.* A request for a rehearing is pending.

California ISO

Interconnection requests totaling more than 105,000 megawatts, including more than 68,000 megawatts of renewable resources, are in the California ISO or CAISO interconnection queue, far exceeding the 50,270 megawatts of peak demand for the CAISO balancing authority area as well as the capacity required for compliance with the California renewable portfolio standard. As in the Midwest ISO, many of these projects drop out, forcing a restudy of lower-queued projects, as upgrades that would have been built by the dropped-out projects are now assigned to the next project in line. These dropouts, as well as suspended in-service dates for projects, are clogging the interconnection queue and imposing cost uncertainty on other projects.

To address these concerns, CAISO filed proposed interconnection queue reforms with the Federal Energy Regulatory Commission in early July.

The CAISO proposed to establish three categories of interconnection requests: a grandfathered group that will be processed under the existing large generator interconnection procedures, an initial generation interconnection process reform tariff called GIPR and a transition cluster group generally subject to the GIPR.

The CAISO filing notes that while clustering of interconnection requests has worked in Tehachapi, it alone cannot address the withdrawal and re-study problems created when projects drop out. CAISO's response is to impose greater financial commitments on generator developers, but in return to provide more cost certainty. FERC approved the CAISO's proposal one week after filing.

The CAISO subsequently filed a GIPR / *continued page 52*

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tariff amendment that would establish substantive changes to the interconnection process. It has three major parts: 1) adopting a clustering approach to process interconnection requests within a cluster window, as opposed to existing project-specific studies, processed in the order of receipt, 2) consolidation of interconnection studies from three into two, called the phase I interconnection study and the phase II interconnection study and 3) a significant increase and acceleration of financial commitments required to participate in the interconnection process.

FERC approved a plan by the Midwest ISO to drop projects from the interconnection queue that fail to keep on track.

Under the FERC's and the CAISO's current large generator interconnection procedures, under which interconnection applications are processed individually, later-queued projects depend on the availability of transmission network upgrades that are scheduled to be constructed on behalf of earlier-queued projects. A significant risk in this approach is that if a higher-queued project is not developed, the network upgrades that were assumed to be in place for the lower-queued project will not be available. As a result, the lower-queued generation project can face a significant and unexpected increase in the cost of interconnection, as it may be required to pay for facilities that were scheduled to be constructed by others.

This risk is one of the fundamental flaws that the CAISO proposal is intended to address. It does this by weeding out speculative projects and requiring increasingly non-refundable security, thereby reducing the likelihood of dropouts that were relied upon to complete their upgrades. Based on this reduced risk of dropouts, the CAISO proposal caps the cost of network upgrades for which a project can be held responsible at the originally-estimated cost, and the costs of the network upgrades to have been developed by the dropout projects are borne by the transmission utilities operated by the CAISO.

The CAISO proposed to use a clustering approach, with two queue cluster windows open each year, during which it will accept interconnection requests. Queue position would cease to have any significance. Following an extra cluster window of October 1, 2009 to January 31, 2010, the cluster windows will be four months long, including April 1 to July 31 and October 1 to January 31.

In order to weed out unviable or premature projects, the CAISO requires higher financial commitments and more data for a project to enter and remain in the queue. All required technical data must be submitted with the interconnection request. Wind developers will no longer have a six-month window to submit their detailed electrical design specifications and other technical data. The request must include a proposed commercial operation date when the entire output of the project will be in service. However, customers may identify proposed phasing, which often occurs in wind energy projects. Further, consistent with the current large generator interconnection procedures, generators would be permitted to delay commercial operation for up to three years without causing the withdrawal of the interconnection request or forfeiture of financial security.

The CAISO proposed to consolidate the three interconnection studies required for large generators — the feasibility study, the system impact study and the facilities study — into two studies: the phase I and phase II interconnection studies. The CAISO proposed to make additional transmission information and technical data available to prospective project developers, so that they can conduct their own preliminary assessments of interconnection requirements, rather than having to undergo a formal interconnection feasibility study upon entering the queue. The deposit required to cover the cost of processing interconnection studies would be increased from $10,000 to $250,000, which would cover both studies. The deposit will become non-refundable over time: $100,000 becoming non-refundable 30 days after the scoping meeting and the full amount becoming non-refundable 30 days after the phase I interconnection study results meeting. Amounts not needed to cover study costs and overhead are refunded after a customer executes a large generator interconnection agreement. The CAISO stated that these increased deposits are intended to insure that developers only seek interconnection for projects with a substantial probability of being completed, with the partial refundability approach designed to provide incentives for developers to withdraw projects as early as possible if they are found not to be viable.

The phase I interconnection study is intended to evaluate the impact of all interconnection requests received during the queue cluster window, preliminarily identify all network upgrades needed to address these requests, preliminarily identify all interconnection facilities required for each interconnection request, assess the requested point of interconnection and potential alternatives, establish maximum cost responsibility for network upgrades assigned to each interconnection request, and provide a good faith of the cost of interconnection facilities associated with each interconnection request.

The phase II interconnection study is intended to update the phase I study to reflect withdrawal of interconnection requests, finalize and assign financing responsibility for network upgrades, provide a plus or minus 20% cost estimate for the customer's interconnection facilities and transmission owner's interconnection facilities, and optimize in-service timing requirements to achieve commercial operation dates.

Under the cluster approach, the network upgrade costs associated with the cluster group are assigned on a pro rata basis to the members of the group, based on the capacity of the generating facility. In contrast to current large generator interconnection procedures, where cost responsibility estimates can change based on decisions made by other interconnection customers, under the CAISO proposal, phase I estimates for a customer's cost responsibility for network upgrades are the maximum that can be assigned to that customer. If the cost of network upgrades increases after the phase I study, those increased costs will be paid by the CAISO transmission companies and passed on to their customers.

The current large generator interconnection procedures provide that the interconnection customer does not have to post security until construction of network upgrades or interconnection facilities begins. In contrast, the CAISO proposal requires an interconnection customer to post security equal to 20% of its total cost responsibility for network upgrades and transmission owner interconnection facilities by 90 days after publication of the final phase I interconnection study report. The remaining 80% must be posted within six months after the conclusion of the phase II interconnection study.

Financial security would become non-refundable over the course of a schedule, with the greater of $500,000 or 50% of the initially posted 20% of projected network upgrade costs becoming non-refundable regardless of the reason for withdrawal.

FERC conditionally approved the CAISO proposal in late September. The case is called *California Independent System Operator Corp*. A rehearing is pending.

Distribution or Network Upgrade?

How interconnection facilities are classified for regulatory purposes determines who has to pay the cost.

The general FERC policy on interconnection facilities is that facilities on the generator's side of the point of interconnection to the transmission grid are "directly assigned" to the generator, who must pay for these facilities with no transmission credits provided. In contrast, facilities added on the transmission provider's side of the point of interconnection are "network upgrades," which the transmission provider (and ultimately its customers) must pay for. The generator must initially fund the cost of network upgrades, but is repaid, with interest, through credits against its transmission charges. If there are no transmission charges, the amounts are refunded over time in cash.

FERC has recognized that there is a third category of interconnections — interconnections to the utility's distribution system, which are on the utility's side of the point of interconnection. The cost of upgrades to the utility's distribution system is borne by the generator on the grounds that these upgrades do not benefit other transmission customers. Under this policy, the determination of whether the utility facilities to which a generator is connected are part of the transmission grid or the distribution system becomes crucial, since it determines who bears the cost of interconnection.

Distribution facilities are generally low voltage, while transmission facilities are higher voltage. However, low voltage facilities can be part of the trans- / continued page 54

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mission grid, while high voltage facilities can be distribution facilities.

In a case involving wind projects in the wind-rich Tehachapi region of California, FERC ruled that the test for transmission versus distribution is made under the five-factor test adopted in a 2001 case called *Mansfield*. The five factors are 1) whether the facilities are radial or they loop back into the transmission system, 2) whether energy flows only in one direction, from the transmission system to the customer over the facilities, or in both directions, from the transmission system to the customer, and from the customer to the transmission system, 3) whether the transmission provider is able to provide transmission service to itself or other transmission customers over the facilities in question, 4) whether the facilities provide benefits to transmission service capability or reliability, and whether the facilities can be relied on for coordinated operation of the grid and 5) whether an outage on the facilities would affect the transmission system.

FERC held that under the *Mansfield* test, the facilities to which the windfarm is connected and that would require upgrades are distribution facilities. It also found that 1) the interconnected facilities are not part of a continuously closed loop and, therefore, are radial, 2) power only flows on the interconnected facilities from the wind farm to the CAISO grid, but not in the opposite direction, 3) CAISO, and not Southern California Edison, is the "transmission provider," and CAISO does not provide service to itself or other customers over the interconnected facilities, 4) the interconnected facilities do not provide any benefits to the CAISO grid and 5) an outage on the interconnected facilities would not affect the reliability of the CAISO grid. As a result, FERC concluded that the upgrades are on a distribution system and not on the transmission grid and that the generator must pay for the upgrades.

The case is *Cabazon Wind Partners, LLC v. Southern California Edison Co*.

New projects with more than 105,000 megawatts of capacity are in line hoping to connect to the California grid.

Extensions to Complete Projects

In another recent FERC ruling, there was no harm, no foul for extensions of the in-service date beyond the three-year safe harbor.

Network upgrades developed in connection with higher-queued projects affect lower-queued projects. As a result, the large generator interconnection procedures distinguish between "material modifications" to an interconnection proposal, which cause the customer to lose its place in the queue, and "non-material modifications," which do not affect the generator's queue position.

The determination of whether a modification is "material" is generally based on whether or not it would harm lower-queued generators. Section 4.4.5 of the large generator interconnection procedures states that extensions of less than three cumulative years in the commercial operation date of a generating facility seeking interconnection are not a "material" change, thus providing a safe harbor for delays in the completion of wind and other generation projects.

The form of large generator interconnection agreement provides, in section 5.16, that a generator may suspend the interconnecting utility's work on network upgrades or utility-owned interconnection facilities for up to three cumulative years, provided that the generator covers the utility's costs that have been incurred prior to the suspension and costs associated with the suspension, such as cancellation costs. This three-year grace period is intended to provide generators flexibility in the development process, but with a finite end-date, so as to avoid undue harm, in the form of delays, to customers that are farther back in the queue and are relaying on network upgrades that are to be developed by the generator seeking the suspension.

In a case involving an interconnection between the 188-megawatt Judith Gap wind farm, located in Montana, and NorthWestern Energy, FERC addressed the question of whether a delay in completion of the project to a date more than three years after the scheduled commercial operation date, was a major modification that would cause Judith Gap's requested interconnection service to go to the end of the queue.

Like many projects, the Judith Gap project consists of two phases, phase I, 135 megawatts, that became operational within the scheduled date of November 15, 2005, and phase II, an additional 53 megawatts, that was delayed beyond the three year date (beyond November 15, 2008). Importantly, all of the interconnection facilities and network upgrades needed to accommodate the full 188 megawatts of capacity have already been constructed and placed in service.

FERC held that the three-year "safe harbor" for delaying the commercial operate date of the generator does not mean that all extensions beyond three years are considered material modifications. Instead, the standard is whether a further delay will harm lower-queued generators. Since all of the interconnection and network upgrade facilities associated with the full 188 megawatts of capacity are in service and available for use by lower-queued generators, FERC found that the additional delay is not a material modification and Judith Gap does not lose its place in the queue for phase II. FERC did not foreclose the possibility that delay in completing a generating project, as opposed to network upgrades, could be a material modification, but held that no harm was imposed in this circumstance.

The case is *Judith Gap Energy LLC*.

Losing the Queue Position

In another case involving NorthWestern and Montgomery Great Falls Energy Partners LP, a proposed 277-megawatt generator in Montana, FERC found that, in contrast to the situation in the *Judith Gap* case, extending the commercial operation date of a generation project would materially affect lower-queued projects. It accordingly upheld NorthWestern's determination that the project must go to the back of the interconnection queue. Had the project maintained its lower-queue position, it could have availed itself of available interconnection capacity and its interconnection costs would have been low. However, its end-of-the-queue position was behind five other projects, which would use up available capacity. As a result, Montgomery's interconnection costs would be approximately $147 million.

NorthWestern had advised Montgomery that while it could not extend the commercial operation date beyond the three-year safe harbor for extensions provided in the FERC rules, and that a further extension would be a material modification because it would harm other projects in line behind Montgomery, it would interconnect 167 megawatts of project capacity — the gas turbine portion of a planned combined-cycle facility — that would be on line by the three-year extension date. However, a new interconnection request would have to be filed for the remaining 110 megawatts.

Montgomery's response was to let the interconnection agreement be cancelled and to submit a new interconnection request. The consequence of those actions was that Montgomery lost its place in the NorthWestern queue, with the effect that its interconnection costs were substantially increased.

The key distinction between this case and the *Judith Gap* case is NorthWestern's unchallenged finding that delay of the Montgomery project *would* harm other projects. In contrast, in *Judith Gap*, the upgrades required for interconnection of the delayed project had already been placed in service, and delaying the startup of the generator (a wind turbine project) did not harm lower-queued customers. FERC's order cited specific examples of how delaying the Montgomery project would "delay or derail" other projects or potentially impose significant additional costs.

It is relevant that the FERC large generator interconnection procedures — the guidebook to interconnection issues and processes — permit a generator that wants to get a definitive answer as to whether a proposed change to its interconnection arrangements to do so. Section 4.4.3 of the form of large generator interconnection agreement permits a generator to request a determination from the interconnecting transmission utility about whether a modification would be a "material modification" — which results in a loss of queue position — or a non-material modification, which permits the generator to maintain its queue position.

The case is *Montgomery Great Falls Energy Partners LP v. NorthWestern Corp*.

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Leapfrogging the Queue

What happens when the transmission system's existing capability to support interconnections without upgrades is sufficient to accommodate higher spots in the interconnection queue, but a higher-queued project is delayed?

FERC held that if a lower-queued project can use the existing interconnection capacity, it is entitled to do so temporarily. However, if and when the higher-queued project does come on line, the lower-queued project must fund the costs of upgrades needed to interconnect the higher-queued project, so that the "first come, first served" policy in effect for non-RTO and ISO utilities is honored.

This approach avoids the risk that the lower-queued project will construct new upgrades that turn out not to be needed if the higher-queued project fails to come on line.

This ruling, first adopted in a 2003 decision involving the Virginia Power transmission system, was followed in an August 2008 case involving the use of existing interconnection capacity by two competing merchant transmission projects. The latest case is *Hudson Transmission Partners, LLC v. New York Independent System Operator, Inc.* A rehearing is pending.

Increases in Capacity

Even a small increase in capacity requires filing an updated large generator interconnection agreement.

A generation facility interconnected to the Midwest ISO transmission system sought to increase its capacity by 0.7 megawatts, from 32.4 megawatts to 33.1 megawatts. The interconnected customer had a pre-Order No. 2003 interconnection agreement, with terms and conditions that differ substantially from those in the standard form of large generator interconnection agreement used since 2003.

Consumers Energy, which owns the interconnected transmission system, argued that since the increase is tiny, it should not be required to file a new interconnection agreement, especially since the increase would not require upgrades, would have no perceptible effect on other plants in the queue, and would be essentially undetectable for operational purposes.

FERC disagreed on the grounds that under Order No. 2003, all new interconnection requests must comply with applicable large generator interconnection procedures, and the Midwest ISO's procedures explicitly provide that *any* increase in generation capacity from an existing customer requires a new interconnection request and a new interconnection agreement conforming to the standard form of large generator interconnection agreement. As a result, it was appropriate to require that a new interconnection agreement be filed. Generators seeking to preserve pre-Order No. 2003 interconnection agreements should take heed of this ruling. The case is *Midwest Independent Transmission System Operator, Inc.*

> Long lines complicate planning. Upgrades that a project ahead in line was expected to pay for might not be made if the project is abandoned.

PJM

There is a cost when a generator asks PJM to accelerate improvements that PJM has already scheduled for its own reasons so that the generator can connect its project to the grid.

PJM plans for the enhancement and expansion of its transmission capability on a regional basis. PJM annually establishes a "baseline" of expansion plans needed to meet system enhancement requirements for firm transmission service, load growth, interconnection requests and other system enhancement factors. If a generation customer seeks to have PJM accelerate the schedule for constructing transmission system upgrades, so that it can use the upgrade to accommodate its own interconnection, PJM policy is that the interconnection customers must pay the costs to accommodate interconnection requests that would not have been incurred under the plan "but for" this new service request.

Previously, the costs for which the interconnection customer was responsible were limited to the time value to advance investment in network upgrades to the date sought by the customer. PJM transmission owners complained that the customers' obligation, as stated, is not synonymous with the "time value of money," and that there are many other costs associated with advancing the date of construction, such as overtime and additional siting and permitting costs. FERC accepted this proposed change to the PJM tariff to include these additional costs of delay. The case is *PJM Transmission Owners*.

Dealing with Federal Utilities

Beware of transmission owners that are not required to synchronize availability of interconnection and transmission services.

The Bonneville Power Administration is not subject to FERC jurisdiction. However, in order to avail itself of the open access transmission tariffs, or OATT, of FERC-regulated utilities, BPA must adopt an OATT similar to the FERC OATT.

In response to a request from a generator seeking both transmission and interconnection, BPA filed a request for FERC to issue a declaratory order on the issue of whether it can require the customer to execute transmission service agreements prior to its offering an interconnection agreement to the customer.

FERC's OATT, as well as the version adopted by BPA, allows a transmission customer to obtain up to five one-year extensions for the commencement of service, provided that it pays a fee equal to a one month charge for the firm transmission service for each year, or fraction of a year, for which an extension is sought. Because BPA is a federal agency, under the National Environmental Policy Act it is required to conduct an environmental review of actions that may significantly affect the environment. Pursuant to that requirement, BPA previously had delayed acting on transmission service requests until it completed its environmental review of a proposed interconnection. However, in mid-2007, BPA changed its practice and offered transmission service 15 days after it delivered an interconnection feasibility study, or if the customer waived the feasibility study, 15 days after it tendered a system impact study, with no delay for the environmental review of the interconnection. This policy can force the generator to begin paying for transmission service before the generator could use it, since the interconnection facilities cannot be constructed prior to the environmental review.

The generating customer argued that FERC should require that the timing of the transmission and interconnection offers should be linked since, under BPA's approach, a customer could be required to pay significant charges for extending the commencement of service even though BPA was not ready to provide transmission service.

FERC rejected that argument, holding that transmission and interconnection are distinct services and that FERC has not required that they be synchronized or linked. FERC noted that, in addition to the option to pay to extend the commencement of transmission service, the generator can sell or assign its rights under its transmission agreement to a third party while awaiting completion of the interconnection. However, it is not necessarily the case that a willing purchaser of temporary transmission service can be found.

In contrast to BPA, investor-owned utilities are not required to conduct a review under the National Environmental Policy Act prior to constructing interconnection or transmission facilities, so that the opportunity for non-synchronized transmission and interconnection service is reduced. However, the risk of non-synchronized availability is not eliminated, and it can pose the risk of significant financial harm to a project that requires both interconnection and transmission services. The case is *US Department of Energy (Bonneville Power Administration)*. A rehearing is pending.

O&M Costs

A 50-megawatt biomass facility owned by Russell Biomass, LLC is seeking interconnection to the Western Massachusetts Electric Company, or WMECO, transmission system that is operated by ISO New England, via a new, 5.1-mile, 115-kV transmission line and a new switching station that will be constructed and paid for by Russell Biomass and conveyed to WMECO upon completion.

WMECO proposed to charge $515,200 annually for operating and maintenance costs for these facilities, based on the ratio of the capital cost of the facilities to WMECO's total transmission investment. Russell Biomass contends that it should be responsible only for the incremental O&M charges directly associated with O&M on the facilities, which it estimates are $48,000 per year, which is / continued page 58

Interconnection

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less than one-tenth of the amount sought by WMECO. WMECO also asserted that Russell Biomass must pay for the WMECO and ISO-New England legal fees associated with negotiating the interconnection agreement and litigating the case.

FERC has set the matter for a hearing and urged the parties to reach a settlement.

Tehachapi

The Tehachapi region of California has the potential for more than 4,500 megawatts of additional wind generation. Since under the California renewable portfolio standard, California utilities are obligated to obtain at least 20% of their power from renewable sources by 2010, there is tremendous interest by utilities and developers in constructing transmission to connect Tehachapi projects with the utility grid.

However, development has been hampered by the remote location and associated high cost of interconnecting to the California ISO grid, as well as the difficulties of coordinating planning and development of transmission involving many different wind developers with different timelines. In addition, standard regulatory policies inhibited development of interconnection. Normally developers must pay for "gen-ties" that are used only to connect generation to the grid and are not part of the integrated transmission system, but the costs and coordination problems made that unviable. Utilities normally are not permitted to include the costs of gen-ties in their transmission cost of service and recover their costs from ratepayers. In addition, under FERC ratemaking policy, a utility normally may only recover the costs of facilities that are "used and useful," and if interconnection facilities turn out not to be used because wind projects failed to materialize, utilities risk non-recovery of 50% of the costs of "abandoned plant."

As a result, Southern California Edison was reluctant to proceed with a gen-tie line without contractual commitments from wind and solar energy project developers.

To solve this problem, the California ISO proposed a program to resolve the dilemma and permit needed development to occur. Under the plan, the CAISO identifies "energy resource areas" that have the potential for development of a significant quantity of "location constrained resources," such as wind, solar and geothermal, that can only be developed where the resource is located. Interconnection lines to energy resource areas, called "multi-user resource trunk lines," would be eligible for favorable rate treatment. Utilities that develop and own trunk line projects would be permitted to recover associated costs in their transmission rates, if these costs are not being recovered from generators. As generating resources are developed and sign up for interconnection service, they would be assigned a pro rata share of the costs of the trunk line, on a going-forward basis, and the utility and its ratepayers would be relieved of this portion of the costs. Since there are tremendous economies of scale in transmission, the costs of a pro rata share of a high voltage line are significantly lower than the costs of a standalone line with lower voltage and transfer capability.

> Even a small increase in capacity at a project may require filing a new interconnection agreement.

In order for interconnection projects to qualify as trunk lines, they must not otherwise be eligible for inclusion in the utilities transmission rate base and must be turned over to the CAISO for operational control. The projects, which must be high-voltage transmission designed to serve multiple-location-constrained resources, must be evaluated and approved by the CAISO in its transmission planning process. To limit potential cost impact on ratepayers, total investment in trunk line projects cannot exceed 15% of the total high voltage transmission plant of participating transmission owners. Finally, to limit the risk of stranded costs that would occur if the generation projects are not developed, construction of a trunk line project may only commence if 25% to 30% of the project's capacity is subscribed, and there must be a "tangible demonstration of additional interest in or support for the project" in the range of an additional 25% to 35% of the trunk line's capacity.

FERC approved the CAISO proposal in April 2007, and construction of portions of the trunk line project proposed by Southern California Edison is now underway.

Incentives for New Transmission Lines

In response to its concern that utilities were not investing sufficient capital in new transmission construction, as part of the Energy Policy Act of 2005, Congress added new section 219 to the Federal Power Act.

This law directs FERC to establish incentive rate opportunities for companies, including traditional utilities and independent transmission companies. In Orders 679 and 679-A, FERC held that to receive incentive rate treatment, an applicant must demonstrate that the transmission project would ensure reliability or reduce congestion and thereby reduce the cost of delivered power. FERC established a rebuttable presumption that a transmission project meets these standards if it has been authorized under a regional planning process that evaluates projects for reliability or congestion or if it has been approved by a state commission or state siting authority.

As proposed by Southern California Edison, the Tehachapi project is a $1.7 billion project broken into 11 segments and consists of more than 200 miles of 500-kV transmission line, approximately 10 miles of 220-kV transmission line and three new substation facilities. The Tehachapi project will ultimately interconnect up to 4,500 megawatts of generating resources, consisting primarily of wind generation, in the Tehachapi area to the Edison transmission system, located in the Tehachapi and Big Creek corridor areas.

After receiving FERC support for the CAISO innovative approach to ratemaking policies to develop the Tehachapi transmission project, Southern California Edison sought FERC authorization for several transmission rate incentives allowed under the FERC rules for that and two other transmission projects. For Tehachapi, Edison sought 1) an additional 150 basis points on its allowed return on equity, 2) authorization to include the costs of construction in its rate base, which is an exception to the general rule that project costs are normally includable in rate base only when they are in-service and 3) a commitment from FERC that if the project is cancelled due to factors beyond Edison's control, then it could recover the costs that it had expended on the Tehachapi project.

FERC granted Edison's request, finding that it satisfied the standards outlined earlier. In addition, FERC held that Edison had demonstrated that there is a nexus between the incentives sought and the investment being made in the transmission project. FERC found that authorizing the inclusion of Tehachapi project costs in rate base would reduce the pressures on Edison's finances caused by investing large sums in transmission projects.

Regarding recovery of costs if the project is not completed, FERC found that because Edison had not received many of the needed federal, state and local approvals for the project, this created increased regulatory risk. FERC also ruled that Edison is entitled to the 150 basis point adder to its allowed return on equity for the costs of the Tehachapi project, based on Edison's overall investment of $2.5 billion in transmission projects, an "unprecedented capital investment program that presents a significant financing challenge" for Edison.

These incentives, along with the FERC authorization to include the costs of the unsubscribed portions of the Tehachapi transmission project in Edison's rate base, provide significant encouragement for Edison to develop the transmission infrastructure needed to interconnect with wind, solar and geothermal facilities for which, under traditional ratemaking policies, the cost of interconnection would have been a perhaps insurmountable obstacle. ◎

Environmental Update

A US appeals court reinstated limits on nitrogen oxides and sulfur dioxide emissions in late December in 28 eastern states and the District of Columbia.

The limits will require power plants in the affected states to reduce NO_X and SO_2 emissions or buy potentially costly allowances to cover them.

The limits — called the "clean air interstate rule" or "CAIR" for short — were issued in final form by the US Environmental Protection Agency in 2005. The limits take effect in two phases in 2009 and 2015 for NO_X and 2010 and 2015 for SO_2.

A court reinstated limits on NOx and SO2 emissions from power plants in 28 eastern US states.

The reinstatement is temporary until EPA can come up with new rules to control both pollutants, but the court set no deadline for the agency to act.

When fully implemented, EPA estimates that NO_X emissions would be reduced by 61% from 2003 levels and that SO2 emissions would be reduced by 45% from 2003 levels.

The same US appeals court that reinstated the clean air interstate rule in late December struck it down in July 2008 after concluding that there were "more than several fatal flaws in the rule." The court issued its latest decision on December 23. The case is called *State of North Carolina v. EPA*.

The United States already regulates SO_2 and NO_X through the acid rain and NO_X budget trading programs. Under the acid rain program, which was developed in 1990, the government distributes allowances to power companies to cover SO_2 emissions from generating facilities and some allowances are also sold each year in public auctions. Facilities that started operating in 1996 or later are not allocated allowances. These facilities must purchase allowances at the government auction or in the market. Each allowance represents the right to emit one ton of SO_2. Companies must have allowances each year to cover their emissions. Anyone who was not given enough allowances by the government to cover his emissions must either take steps to reduce emissions or buy allowances at the government auction or in the market from other companies that reduced emissions thereby freeing up allowances for sale.

It is not clear how a revised clean air interstate rule — if EPA eventually issues one — might affect other air emissions regulatory programs and proposals that assumed that NO_X and SO_2 air emissions would decrease. For example, before the court's latest decision, EPA had already announced that it was dropping an hourly air emissions test (in favor of allowing projected emissions to be averaged over an entire year) when deciding whether a "new source review" is required for major new facilities or major modifications to existing facilities.

In addition, it is unclear how NO_X and SO_2 credits trading markets will react to the uncertainty inherent in a revised CAIR. The risk is to companies that hold on to unused allowances expecting to find some value for them in the future and to anyone making forward purchases of allowances.

Many people expect the Obama administration to issue a plan to revise CAIR shortly after taking office. Carol Browner, the EPA administrator under President Clinton, has been put in charge of energy and climate change policy at the White House.

Mercury

The Obama administration is expected to abandon an effort to reinstate limits the Bush administration proposed on mercury emissions from power plants.

The limits — called the "clean air mercury rule" or "CAMR" for short — would have required a 70% reduction in mercury emissions by 2018. They would have set a nationwide cap on emissions of 38 tons in 2010, dropping to 15 tons in 2018.

The same US appeals court that struck down and later reinstated the clean air interstate rule set aside the mercury rule in February 2008. The Environmental Protection Agency petitioned the US Supreme Court in October to rehear the case. The Supreme Court extended the time to respond to the petition until January 21, 2009, one day after the new Obama administration takes office.

The mercury rule would have applied to coal-fired power plants that sell more than 25 megawatts of output to the electricity grid. It would have set performance standards for new plants and established a cap-and-trade program limiting mercury emissions for both new and existing coal-fired power plants.

The mercury rule has been in the courts since 1992 when the National Resources Defense Council sued the Environmental Protection Agency for not treating power plants as subject to regulation under section 112 of the Clean Air Act, the section that regulates *hazardous* air pollutants. Section 112 requires installation of maximum achievable control technology, or "MACT," at all plants subject to the section. EPA eventually issued a finding in December 2000, as President Clinton was preparing to leave office, that it was appropriate and necessary to regulate mercury from coal and oil-fired power plants as a hazardous pollutant.

Once a source category is listed under section 112, then the Environmental Protection Agency has three years to propose a hazardous pollutant standard. The Bush administration felt that regulating mercury under section 112 would cripple the coal-fired power industry. It removed coal and oil-fired power plants from the section 112 list and proposed using a cap-and-trade approach under section 111 of the Clean Air Act to regulate mercury. The environmental community views regulations adopted under section 111 as weaker than any regulation imposed under section 112.

The appeals court struck down the Bush administration's cap-and-trade program for mercury in February because the government failed to follow the required administrative process for any delisting under section 112. The court threw out the Bush mercury rule in its entirety. It did not ask EPA to take any further action. This now leaves EPA with two options in theory. One is to try properly to delist oil- and coal-fired power plants. The other is to press forward with requiring owners of such power plants to install the maximum achievable control technology to limit emissions.

EPA has not developed a federal mercury MACT. In 2004, it proposed MACT for coal-fired power plants at a level of 2 lb/TBtu (bituminous fired) and 5.8 lb/TBtu (subituminous fired). For comparison, Virginia issued a permit to construct a coal-fired power plant in June 2008 that included a mercury limit of 0.09 lb/TBtu. Environmentalists are challenging the Virginia permit limit as too generous.

MACT

A federal district ruled in early December that Duke Energy must do a MACT analysis for the Cliffside power plant that the company has under construction in North Carolina. Duke is appealing. The case is *Southern Environmental Law Center, et al. v. Duke Energy Carolinas*.

Duke received an air emissions permit from the North Carolina Department of Environmental and Natural Resources in January 2008 to construct a new coal-fired power plant. Construction began shortly after the permit was issued (on January 30, 2008 according to Duke, but on February 9, 2008 according to environmentalists).

The clean air mercury rule was struck down by a court on February 8, 2008. Environmental groups challenged the Duke permit, arguing that because there was no clean air mercury rule when construction of the plant got underway, the plant should have been considered on the section 112 list of plants that can only be built if they install maximum achievable control technology to reduce mercury emissions.

The federal district court that heard the case declined to stop construction. However, it ordered Duke to submit a full mercury-control assessment to state environmental regulators. Previously, Duke had agreed to provide a MACT-like assessment on a voluntary basis, but resisted a formal MACT determination with public review.

North Carolina has no blanket policy of reviewing new coal-fired power plants for MACT controls. Duke asked the state to make such a determination in / continued page 62

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its case soon after the federal district court ruling. The state environmental department issued a "notice of intent to disapprove" Duke's request on December 17.

Duke also applied to modify its air emissions permits with respect to hazardous air pollutants. Under the modification, the Cliffside plant would be considered a minor air emissions source emitting less than 10 tons per year for any single hazardous air pollutant and less than 25 tons per year for any combination of such pollutants. The environmental groups who challenged the original permit are skeptical that the facility could be considered a minor source. Written comments regarding the modification are due on January 22.

The lesson from the Duke case is that air emissions permits to construct coal-fired power plants that do not reflect MACT for mercury may be challenged. The Natural Resources Defense Council said in a press release last February 28 that the ruling may affect coal-fired plants in 13 states.

Greenhouse Gas Regulation

The Environmental Protection Agency issued a memo in mid-December rejecting a finding by a permit appeals board that it should have considered whether to require a developer who plans to build a power plant in Utah that will burn waste coal as fuel to install best achievable control technology to control carbon dioxide emissions.

The Environmental Appeals Board made the finding in mid-November.

The power project is one being constructed by Deseret Power near Bonanza, Utah. An EPA regional office issued a so-called PSD permit allowing the developer to start construction. PSD stands for "prevention of significant deterioration." A PSD permit is the kind of permit issued to developers with projects that are considered major stationary sources in attainment areas.

The EPA regional office issued the PSD permit in August 2007. The Sierra Club then challenged the permit, in part, based on the failure by the EPA regional office to consider whether to impose BACT for CO_2 emissions. The Sierra Club argued that the US Supreme Court decision in the case *Massachusetts v. EPA* that greenhouse gases are pollutants requires EPA to take action to control CO_2 emissions. The Clean Air Act prohibits construction of major new emitting facilities (or major modifications to existing facilities) unless the owners install best achievable control technology for each "pollutant subject to regulation." The EPA regional office that issued the permit argued that while companies are required to monitor and report CO_2 emissions, they are only required to install best achievable control technology to control "pollutants subject to regulation," which, in its view, means only those pollutants that are regulated currently. The federal government has not issued any limits yet on CO_2 emissions.

"One-pass" facilities that do not reuse cooling water may be required to install expensive pollution control devices, depending on how the US Supreme Court decides a pending case.

The Environmental Appeals Board said the following when it sent the permit back to the EPA regional office:

> In remanding this permit to the Region for reconsideration of its conclusions regarding the application of BACT to limit CO2 emissions, the Board recognizes that this is an issue of national scope that has implications far beyond this individual permit proceeding, The Board suggests that the Region consider whether interested persons, as well as the Agency, would be better served by the Agency addressing the interpretation of the phrase "subject to regulation under this Act" in the context of an action of nationwide scope rather than through this specific permitting proceeding.

The EPA administrator released a memo on December 18, 2008 rejecting the appeals board finding. The memo said the government is not required to consider CO_2 emissions when issuing air emissions permits under the PSD program. Environmentalists fear that this interpretation, if allowed to stand, will lead to a rush to permit new coal-fired power plants without consideration of CO_2 emissions before the new administration takes office. Thus, it seems clear that any new air emissions permit issued under the PSD program without CO_2 controls will draw legal challenges.

IFC Standards

The International Finance Corporation is expected to publish final environmental, health and safety guidelines for thermal power plants financed by the IFC — an arm of the World Bank — early in 2009. The public comment period ended on May 11. No major changes are expected from the guidelines the IFC proposed earlier.

The guidelines apply to power plants with a total heat input capacity of greater than 50 megawatts and that use gas, liquid and solid fuels or biomass for fuel. The guidelines describe issues associated with the environment (air emissions, aquatic habitat alteration, effluents, wastes, hazardous materials and oil and noise) and provide recommendations to reduce environmental impacts associated with these facilities.

They are important because they establish benchmarks that commercial banks also tend to follow. They supplement guidelines that the IFC issued earlier for wind farms and geothermal projects.

Cooling Water

The US Supreme Court heard arguments in three consolidated cases in early December on whether the government is allowed under the Clean Water Act to compare costs to benefits when determining the best technology available to control water pollution associated with existing cooling water intake structures.

Many of the questions asked by the Supreme Court justices focused on how such cost comparisons can be made — for example, what is the value of a fish?

The decision has potentially huge economic consequences for so-called "one-pass" facilities that withdraw water for cooling purposes and discharge it directly back into a body of water without any recirculation. An example of a one-pass facility is an older power plant without a closed-cycle system, like a cooling tower, to recirculate water it uses for cooling. A decision that cost-benefit comparisons are not allowed could require costly upgrades to existing power plants. Estimates of the total cost run as high as $585 million.

The consolidated cases are *Entergy Corp. v. Riverkeeper*, *PSEG Fossil v. Riverkeeper* and *Utility Water Act Group v. Riverkeeper*.

Existing cooling water intake structures are regulated under section 316 of the Clean Water Act. That section requires "effluent limitations that will assure protection and propagation of balanced, indigenous population of shellfish, fish, and wildlife." Current EPA regulations require facilities with existing cooling intake structures to use best technology available or its equivalent to reduce any adverse environmental impacts.

A federal appeals court ordered EPA in January 2007 to reconsider several provisions of its existing regulations on cooling water intake structures at existing facilities in a case called *Riverkeeper, Inc. v. EPA*. The *Riverkeeper* court found that EPA improperly rejected selection of closed-cycle cooling as the best technology available, in part because the court could not determine whether EPA had properly weighed cooling tower costs and benefits when drafting the regulations. In essence, this means that future regulations could require existing facilities install cooling towers or achieve an equivalent reduced level of environmental impact.

A decision by the Supreme Court is anticipated in the spring of 2009.

Carbon Capture and Storage

The Environmental Protection Agency is moving to adopt regulations for carbon sequestration under ground. The comment period for these proposed rules for underground storage of carbon on a long-term basis closed in December.

The government currently regulates five classes of injection wells (including several subtypes of wells within these classes). Government standards for the various wells vary according to the type of material injected and the depth of injection under ground. For example, hazardous substance injection is falls under class I. Carbon sequestration falls under a new class of under- */ continued page 64*

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ground injection control wells called class VI.

EPA proposed rules for carbon sequestration in July 2008. Its proposed rules include requirements for well location, construction, testing, monitoring and closure. Critics charge that EPA did not provide useful guidance with respect to liability under the Resource Conservation and Recovery Act (RCRA) or the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA).

RCRA applies to hazardous waste from generation to disposal. It is unclear whether hazardous waste will be generated from operation of these proposed wells. According to the proposal, EPA cannot provide a blanket determination that impurities in the carbon dioxide injection stream are considered hazardous.

CERCLA provides a mechanism for the government and private parties to recover the costs of environmental cleanup of hazardous substances. Although CO_2 itself is not considered a hazardous substance (or waste), impurities in the CO_2 may be hazardous. The amounts of any impurities in the CO_2 will be dictated by factors such as fuel source composition (for example, coal type) and pollutant removal technologies. Although the proposed rules note that the injection of hazardous substances would be regulated under existing class I regulations (as opposed to class VI regulations), EPA did not address whether liability under CERCLA would be created by disposing of a hazardous substance (in the form of CO_2 with impurities). Its proposal notes that

> the CO2 stream may ... react with groundwater to produce listed hazardous substances such as sulfuric acid. Thus, whether or not there is a "hazardous substance" that may result in CERCLA liability from a sequestration facility depends entirely on the make-up of the specific CO2 stream and of the environmental media (e.g., soil, groundwater) in which it is stored. CERCLA exempts from liability certain "federally permitted releases" including releases in compliance with a [disposal] permit under the [Safe Water Drinking Act].

EPA acknowledged that hazardous substances may be created as a result of the injection process, but failed to address the ramifications of these hazardous substances. If hazardous substances and waste are generated as a result of CO_2 injection, then RCRA and CERCLA may be triggered.

Until these issues are addressed, investors may be hesitant to fund sequestration projects considering the unknowns associated with RCRA or CERCLA liability and the potential new avenues for citizens to challenge carbon sequestration facilities (citizen suits under RCRA for imminent and substantial harms). The comment period closed on December 24.

— contributed by Sue Cowell in Washington

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