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REC Market Update

by James Scarrow, in Washington

State programs to promote the development of renewable energy continue to multiply and evolve, presenting challenges, opportunities and some unexpected consequences for the US power market.

Background

At last count, 20 states and the District of Columbia have established renewable portfolio standards — called "RPS" — requiring electric utilities to supply a specified minimum percentage of their electricity from renewable fuels, such as wind, biomass and small-scale hydropower.

Although each state RPS program is unique, each program addresses six core issues. They are: what qualifies as a renewable fuel, the goal (frequently expressed as a percentage of the state's total retail load), a phase-in schedule, the manner in which electricity retailers are allocated responsibility for achieving the goal, whether a utility that does not want to generate electricity from renewable fuels can satisfy its obligations by purchasing "renewable energy credits" from other, renewable generators, and the penalties for noncompliance and alternative methods for achieving compliance, such as making payments to a state's renewable energy trust fund.

Some states have tiered RPS programs in which certain types of renewable resources are valued more than others, or in which the program has / continued page 2

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WIND DEVELOPERS will not be able to get private letter rulings from the Internal Revenue Service about tax issues in transactions that are structured as "partnership flips." The IRS has placed a hold on any further rulings in such transactions.

Wind farms in the United States qualify potentially for large tax subsidies. Most wind developers are not in a position to use the subsidies and, therefore, arrange with an institutional investor who can use them to come into the project as a part owner. The project is owned by a partnership or limited liability company. The developer and the investor are partners. Tax benefits, taxable income / continued page 3

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specific goals for certain types of renewable resources, such as solar energy.

The Union of Concerned Scientists estimates that RPS laws will support approximately 31,000 megawatts of new renewable power by 2017. The RPS standards in California, Texas, New York, New Jersey and Pennsylvania make them the five largest markets for new renewable energy growth.

Of the 20 states with some form of RPS program, seven (plus the District of Columbia) adopted their programs since 2004. These are Delaware, Hawaii, Maryland, Montana, New York, Pennsylvania and Rhode Island. In addition to the new state RPS programs, a number of states with existing RPS programs have been ratcheting up their program goals.

On April 12, 2006, the New Jersey Board of Public Utilities approved an increase in the state's goal for "class I" resources (which include solar, wind, sustainable biomass, landfill methane and certain fuel cells) to 22.5% by 2021, up from the previous requirement of 4% by 2008. On March 17, 2006, Wisconsin Governor Jim Doyal signed into law an increase in Wisconsin's RPS requirement such that, by 2015, 10% of the state's electricity will be generated from renewable sources. (The prior requirement, enacted in 1999, required that 2.2% of the state's energy be from renewables by 2011.) In August 2005, Texas increased the goal of its RPS program from 2,880 megawatts by 2009 to 5,880 megawatts by 2015. In June 2005, Nevada raised its goal to 20% of sales by 2015, up from 15% by 2013.

	State	Goal	Tradable RECs?
1	Arizona	1.1% by 2007	no
2	California	20% by 2017	no
3	Colorado	10% by 1015	planned
4	Connecticut	6% by 2009	yes
5	Delaware	10% by 2019	planned
6	District of Columbia	11% by 2022	yes
7	Hawaii	20% by 2020	no
8	Iowa	2% by 2000	no
9	Maine	30% by 2000	yes
10	Maryland	7.5% by 2019	yes
11	Massachusetts	4% by 2009	yes
12	Minnesota	19% by 2015	yes
13	Montana	15% by 2015	planned
14	Nevada	20% by 2015	yes
15	New Jersey	22.5% by 2021	yes
16	New Mexico	10% by 2011	yes
17	New York	24% by 2013	no
18	Pennsylvania	8% by 2020	planned
19	Rhode Island	16% by 2019	yes
20	Texas	5,880 mw by 2015	yes
21	Wisconsin	2.2% by 2011	yes

Renewable Energy Credits

Renewable energy credits — called "RECs" — are a mechanism that can be used in some states to comply with the RPS requirements, and they are potentially an additional source of revenue for independent generators in such states.

Fifteen states currently use, or are intending to phase in, REC trading programs. Under these programs, a generator of renewable electricity earns one credit for each megawatt hour of electricity that is generated. RECs can then be bought, sold or accumulated and used to achieve compliance in that same year or to meet future year compliance requirements. The rules for earning and transferring RECs vary from state to state, but the building blocks of a REC program are certification and distribution of the RECs by the administering authority to generators, a tracking system and a sunset date at which time the REC expires unless used.

Through state REC programs, the renewable attributes of energy are unbundled from the electricity commodity. This has several important implications. First, because RECs are credits rather than physical commodities, the transfer of a REC from a seller to a buyer does not occur over transmission lines but rather as an accounting entry. Second, renewable electricity generators can, in theory, have two separate revenue streams — one from the sale of commodity electricity and one from the sale of RECs — allowing generators to seek the maximum sales price for each individual stream. (In practice, various states have proceedings underway to decide who owns the RECs in cases where the electricity is sold by an independent generator to a utility. Utilities argue the RECs convey with the electricity.) Third, the market forces can be harnessed to help ensure that a state's RPS goals will be achieved in an economically-efficient manner.

In order to ensure that an individual REC is not used more than once to meet RPS compliance requirements, it is necessary to have a REC tracking system. REC tracking systems give unique identification numbers to each unit of renewable energy generated, which allows the RECs to be tracked from generator to subsequent owners until the REC is used by a utility for compliance. There are now five REC tracking systems in operation or planned. They cover 1) Texas (managed by the Electric Reliability Council of Texas, also called ERCOT), 2) 11 western states (managed by the Western Renewable Energy Generation Information System and expected to launch in 2007), 3) the states in the New England power pool, 4) the mid-western states (to be managed by the Midwest Renewable Energy Tracking System) and 5) for the states within the "PJM" region (including Pennsylvania, New Jersey, Maryland, Virginia and Delaware) (managed by the PJM Generation Attribute Tracking System).

According to a 2005 study by Ed Holt & Associates, the 2004 market for RECs was about 10 million megawatt hours. This year, that number will be closer to 15 million.

REC Prices

The markets for RECs vary from state to state and are driven by the specific regulatory requirements of the respective RPS programs and the laws of supply and demand. While some states have experienced relatively stable REC pricing, others have seen drastic fluctuations.

The most dramatic price swings have occurred in the Connecticut REC market. Connecticut belongs to the New England Power Pool (NEPOOL), along with Massachusetts, Maine, New Hampshire, Rhode Island and Vermont. Of these six states, four — Connecticut, Maine, Massachusetts and Rhode Island — have RPS programs that allow utilities to satisfy their RPS requirements by purchasing RECs from generators anywhere within NEPOOL, including generators located in New Hampshire and Vermont, which do not have RPS programs. In 2003, the Connecticut legislature increased the state's requirement for the use of renewable energy. Connecticut REC prices promptly spiked from $1 to $40. At the time, experts anticipated that the demand for Connecticut RECs would continue to outpace supply by as much as 50%, presumably resulting in stable or escalating prices. Instead, the opposite happened because of an oversight by such experts on how class I RECs were defined under the Connecticut RPS regulations. */ continued page 4*

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and cash are allocated largely to the investor until a "flip date," after which the interest of the investor flips down to single digits and the developer has an option to buy out the investor. The "flip date" is usually the later of when the tax benefits have run or the investor reaches a target return.

The IRS issued two identical private letter rulings in November in a transaction involving a partnership flip structure. The rulings were favorable. (The rulings were made public in late February.)

However, in early May, the agency placed a hold on any further rulings. It appears that what prompted the hold were two new ruling requests — one where the investor was being guaranteed a minimum return and the other where the amount the investor planned to pay to buy into the deal was contingent on tax benefits. The IRS is assessing whether the investor in such situations is in substance merely a lender or bare purchaser of tax benefits. It is also considering whether to issue guidelines about what it will require before ruling in wind deals involving partnership flips in the future.

It is too early to assess the market reaction. Wind deals have been done traditionally in the US on the basis of tax opinions from outside counsel rather than rulings. Therefore, the reaction at most will probably be to turn slightly more conservative. Tax counsel will pay closer attention to the "ownership sticks" that the investor has so that he or she is well armed if the transaction is ever examined by the IRS on audit.

A TAX RECONCILIATION BILL that President Bush signed into law on May 17 makes a number of changes in US tax laws that will affect the project finance community.

The bill will require every federal, state and local government agency in the United States making payments for "property or services" to withhold 3% of the gross */ continued page 5*

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Specifically, class I renewable resources were defined in the regulations to include eligible biomass facilities constructed on or after July 1, 1998; however, an eligible biomass facility constructed before July 1, 1998 can also qualify as a class I renewable resource if the facility was re-tooled to incorporate certain emission control technologies. As a consequence, when a number of re-tooled biomass facilities in Maine and elsewhere in New England came on line in 2005, the Connecticut REC market was flooded and REC prices crashed from approximately $35 to $40/mWh in June 2005 to $5 to $6/mWh in November 2005. The price of Connecticut RECs today is about $7/mWh.

In contrast to the dramatic swings in Connecticut REC prices, in neighboring Massachusetts, REC prices have continued to bump up against the RPS program's alternative compliance payment price of $50 per megawatt — that is, the payment a utility can make into the state's renewable energy trust fund as an alternative method of achieving RPS compliance. The consistently high price of RECs in Massachusetts may be due in part to the challenges of permitting new projects in the state, such as the proposed Cape Wind project off Cape Cod, but are primarily due to the state's relatively narrow definition of what qualifies as "renewable energy."

Massachusetts officials appear mindful of the depressing effect that a broadening of the definition of qualifying renewable resources could have on REC prices. Thus, in October 2005, the Massachusetts office of consumer and regulatory affairs and business regulation issued a policy statement clarifying that, in contrast to the Connecticut RPS program, re-tooled biomass facilities would be qualified to produce Massachusetts RECs only to the extent that the energy produced by the re-tooled facility represented an increase over its historic generation rate and not for each megawatt of energy produced by such re-tooled facility. By making this clarification, Massachusetts in effect supported the prices of its own RECs while adding continued downward pressure on the price of Connecticut RECs because re-tooled biomass facilities located in New England can qualify for Connecticut RECs but not Massachusetts RECs.

State	2006 REC Price *(per mWh)*
Connecticut (Class I)	$7.75
Maryland (Class I)	$2
Massachusetts	$53.25
New Jersey (Class I)	$8
Texas	$10
New Jersey	$49
Texas	$12

Source: Evolution Markets LLC (prices on April 19, 2006)

In Texas, REC prices have not experienced the wild swings seen in Connecticut, but they have not been as robust as many had predicted. Under the Texas RPS program, each electricity retailer in Texas is allocated a specific number of megawatt-hours of renewable energy for which it is responsible, based on the retailer's share of the statewide electricity retail market. The allocations were originally made assuming a capacity conversion factor of 35%. (The capacity conversion factor represents the actual output from a facility relative to its maximum potential output over the same period of time. Because of the intermittent nature of wind, a capacity factor of 35% for a wind farm may be typical, whereas a gas–fired plant might have a capacity of 90%.) For example, the statewide RPS requirement of 1,400 megawatts of new renewables capacity for calendar year 2002 translated into 1,226,400 mWhs of load that were required to be supplied with qualified renewable energy for that year (*i.e.*, 400 mws x 8,760 hours/year x 35%). REC prices in Texas have hovered in the $11 to $14 range for the past few years even though Texas significantly increased its RPS goals in 2005. In conversations with the *NewsWire*, people who are active in Texas renewables expressed some disappointment that prices have not risen. One reason cited for depressed Texas REC prices is ERCOT's downward adjustment of the capacity conversion factor from the original 35% to 27.9%. The effect of this adjustment has been a 20% decrease in the megawatt hours of RECs that utilities would otherwise have to buy for any given RPS annual requirement.

REC Ownership

Where the power purchase contract is otherwise silent on the issue, disputes have arisen over whether utilities that purchase electricity through long-term contracts are entitled to the RECs associated with that electricity.

Under PURPA (the acronym for the "Public Utility Regulatory Policies Act of 1978"), utilities are required to buy power from two types of independent power plants (so-called "qualifying facilities" or "QFs") at the "avoided cost" the utility would have to pay to generate the electricity itself. Most power purchase agreements between utilities and independent power producers were entered before enactment of state RPS programs and, therefore, do not address the question whether the power purchaser from a QF is entitled to any RECs associated with the electricity being sold.

States that have determined that RECs convey to power purchaser for existing and (where indicated) new QF contracts

Connecticut (existing), Colorado (existing), Maine (existing), Minnesota (existing), North Dakota(existing and new, with compensation), New Jersey (existing), New Mexico (existing and new), Nevada (existing), Texas(existing), Wisconsin(existing).

States that have determined that RECs are retained by the QF for new contracts

Colorado, Nevada, Oregon, Rhode Island, Texas and Utah.

States with ongoing proceedings

Arizona and Pennsylvania.

Source: Ed Holt & Associates, Inc.

A recent study by Ed Holt & Associates identified 16 states in which QF REC ownership had been addressed by states. In each of these states, other than New Mexico, the determination of REC ownership was determined by regulation rather than legislation. In some states, the determination of REC ownership has hinged on whether the underlying power purchase agreement pre-dated a specified regulatory determination or regulation in that state. States have consistently awarded REC ownership to the utility power purchaser in the case of pre-existing contracts. However, several states have awarded RECS for new contracts to the QF even if the contract was silent on REC ownership. / continued page 6

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amount of such payments starting in 2011. Thus, for example, payments by federal military bases or municipal utilities for electricity or implementation of energy savings ideas will require withholding.

There are a few exemptions from withholding.

Municipalities that make less than $100 million in payments for "property or services" annually will not have to withhold. Withholding also does not apply to payments of interest, for real property, to another government agency, tax-exempt entity or foreign government, or under contracts with the federal government that are confidential because of national security concerns or the needs of law enforcement or foreign counter-intelligence.

Some Republicans in Congress have already called for repeal of the provision. However, Congress adopted it after a Government Accountability Office report disclosed that some government contractors are failing to pay taxes. Also, Congress used it to plug a $7 billion gap in revenue that it had to fill in order to comply with budget targets.

The revenue estimators in Congress assumed that the provision would produce mainly a timing benefit. The government will collect taxes through withholding a little earlier in time than it would otherwise. Most of the revenue increase would come in the first year: 2011.

The bill also imposes a large excise tax on tax-exempt entities, Indian tribes and pension trusts that are parties to some transactions that must be reported to the IRS as potential corporate tax shelters.

The government will start collecting the excise tax immediately (in tax years ending after May 17, 2006). The tax is retroactive in the sense that it applies to potential corporate tax shelter transactions that have already closed. If tax-exempt entities, Indian tribes and pension trusts remain parties in the / continued page 7

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Prospects for Long-Term REC Contracts

REC purchase agreements have held out the possibility of providing a second potential revenue stream for renewable energy projects. However, to date, creditworthy REC purchasers have been reluctant to enter into REC purchase agreements for terms longer than five years. As a result, the revenue streams from REC sales have generally not been able to support long-term financings, which can have 10- to 15-year terms.

One of the reasons that long-term REC purchase agreements have been rare is because of the way electricity markets have been restructured. In many restructured markets, such as the New Jersey market, electricity distribution companies bid out their basic generation services through an auction process. Through this process, the winning bidder provides generation services — including compliance with New Jersey RPS requirements — for a specified portion of the overall load and typically for a period not exceeding three years. Because the winning bidders provide those services for a relatively short period, they are unlikely to enter into long-term REC purchase agreements.

The price volatility seen in markets such as Connecticut, coupled with the regulatory uncertainty inherent in the rapidly evolving patchwork of RPS programs, has further dampened enthusiasm for long-term REC contracts.

According to Andrew Kolchins, director of environmental markets at Evolution Markets LLC, while a limited number of long-term REC contracts have been entered to date, hedge funds and other potential investors have been showing increased interest in taking speculative REC positions. Such interest may signal the next step in the maturing of REC markets.

> Hedge funds and other potential investors have been showing increased interest in taking speculative REC positions.

"White Tags": the New Certificate

Even as the REC markets experience some growing pains, states continue to push forward with new market-based innovations to encourage sustainable energy projects.

So-called "white tags" are a new form of energy certificate in which each "tag" represents one mWh of energy savings measured against a specified baseline. The idea is to encourage capital expenditures on energy efficiency projects, with the resulting white tags being fungible with RECs as an alternative way to satisfy RPS requirements. White tags can be sold in a similar manner as RECs and reward those who have instituted energy efficiency improvements as demonstrated through established criteria. Three states have included white tags as part of their RPS programs — Connecticut, Nevada and Pennsylvania. In 2007, the Connecticut program will be the first one to go on line. It is expected that white tags will fetch the same price in the market as RECs, since a single white tag will "buy" the same amount of RPS compliance as a single REC.

Issues to Watch

As regional REC tracking systems establish themselves, planning is proceeding in earnest on how the various tracking systems might be harmonized to prevent double counting and create a "common currency" for renewables. The effort is being led by the North American Association of Issuing Bodies, a voluntary association of certificate tracking systems, regulators and other interested parties.

Another development to keep an eye on, according to Ed Holt, president of Holt & Associates, is the way in which state and federal governments will resolve potential conflicts between the objectives of REC programs and air emission cap-and-trade programs. Specifically, how will states seek to harmonize REC tracking systems and the separate tracking systems currently in place for air certain emissions cap and trade programs? Holt notes that absent coordination between REC and emissions programs, the development of renewable energy generation may not result in their full "advertised" environmental benefits since these projects will not reduce the emission caps under clean air programs and the price of emission credits will be unaffected or even reduced by the expansion of renewable energy resources. ◎

FERC Ruling Frustrates Wind Developers

by Adam Wenner, in Washington

Wind farm owners and other independent power suppliers in the United States are troubled by a ruling by the Federal Energy Regulatory Commission in late February that let a utility charge a toll for allowing electricity from a wind farm to gain access to the regional grid. The electricity had to travel first over distribution lines belonging to the utility to reach the grid.

Surprisingly, FERC held that it does not have jurisdiction over the "distribution" portion of the interconnection arrangement. The result is surprising because neither the wind farm owners nor the utility asked for such a ruling.

The courts are expected to overrule FERC — if the case gets that far. The developer of the wind farm has asked FERC for a rehearing.

Line Drawing

The Federal Power Act divides jurisdiction over the different aspects of the electricity business between federal and state regulators. FERC has exclusive jurisdiction to regulate the sale of electricity at wholesale in interstate commerce and transmission in interstate commerce. State commissions regulate retail power sales and distribution services.

FERC has long recognized that when a generator interconnects with a utility for the purpose of selling power at wholesale, if the power enters the interstate grid, then the interconnection arrangement is part of the transmission service provided by the interconnecting utility. Based on this understanding, FERC adopted various / continued page 8

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deals, they will be hit with the excise tax. It is too late to avoid for the tax for 2006.

The excise tax will be collected for being a party in three kinds of transactions. The three are so-called "listed transactions" that the IRS has put the public on notice it considers corporate tax shelters, to other transactions in which an adviser to the deal has insisted that the tax structure be kept confidential, and to transactions in which the fees paid by any of the participants are tied to the tax benefits that the participant receives from the transaction.

The excise tax will be collected annually.

It is 35% of the net income or 75% of the gross proceeds received by the tax-exempt entity, Indian tribe or pension trust each year — whichever tax amount is greater. The tax increases to the greater of *100%* of net income or 75% of gross proceeds if the tax-exempt entity, Indian tribe or pension trust "knew, or had reason to know" that the transaction would attract an excise tax when it became a party to the deal.

It is not clear what it means to be a "party" to such a transaction. Existing IRS regulations already require "participants" in such transactions to report them to the IRS. A person is generally not considered a participant unless he or she reports any tax benefits from the deal on a tax return.

The manager of the tax-exempt entity, Indian tribe or pension trust who approved its participation in the deal will also have to pay a separate $20,000 tax imposed directly on him or her.

Taxable companies that participate in the deal will have to notify the tax-exempt entities that are parties to it in writing of their potential peril.

Private equity funds and hedge funds with tax-exempt entities or pension trusts as investors should be careful about investing in the transactions that Congress has targeted with the excise tax. / continued page 9

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orders starting with Order No. 2003 that establish standardized interconnection agreements and procedures for generators that sell power into the interstate grid. In a series of cases decided in the last five decades, the US Supreme Court has determined that power sales that enter or affect the interconnected utility transmission grid are "in interstate commerce" and, therefore, are regulated by FERC. It is well established that transmission and wholesale power sales in the continental US flow into the interconnected grid — except for sales in the ERCOT region of Texas — and, therefore, are "interstate commerce" that should be regulated by FERC rather than the state commissions.

It is also well established by Supreme Court decisions that the "transmission function" begins at the point the electricity leaves the generator's power plant. In other words, irrespective of the voltage level or function of the system to which the generator is connected, the transmission function "extends from the generator, where generation is complete . . . to the point where the function of conveyance in bulk over a distance . . . is completed and the process of subdividing the energy to serve ultimate consumers, which is the characteristic of local distribution, is begun."

These court decisions have recognized that, although from a scientific or engineering perspective, the transmission function continues all the way to the retail load, the exclusion of federal jurisdiction over local distribution facilities was a political decision, intended to preserve the authority of state regulators to regulate the retail function. As a result, the courts have established that where a generator is involved, FERC-jurisdictional transmission starts at the generator and extends to the point where the power reenters the local distribution grid, where it is delivered to end users.

Under this straightforward test, it would seem obvious that so long as the power from a generator reaches the interstate grid, the interconnection between the generator and the utility grid is a "transmission facility" subject to exclusive FERC jurisdiction. It would also seem clear that whether the interconnection is made to a high-voltage "transmission" line or to a low-voltage "distribution" line, so long as the power generated flows out and onto the interstate grid, the interconnection is "transmission in interstate commerce" and is FERC-jurisdictional.

A ruling by the Federal Energy Regulatory Commission let a utility charge a toll for allowing a wind developer to have access to the grid for his electricity.

However, FERC seemed to forget these principles in a decision in late February involving the filing of an interconnection agreement between PJM — the regional grid operator for the mid-Atlantic and some midwestern states — and a wind farm that GSG plans to build in Lee County, Illinois. The GSG project will interconnect to the distribution facilities of Commonwealth Edison. Since ComEd is a member of the PJM grid, and the power generated by the wind project will be sold into the PJM wholesale market, PJM filed interconnection agreements for the GSG project with FERC. PJM's open access transmission tariff expressly provides for interconnection where the generator uses distribution facilities to deliver energy into the PJM transmission grid, and the interconnection agreements were accordingly filed pursuant to the tariff.

A dispute arose between GSG and ComEd in that ComEd proposed to charge a "wholesale distribution charge" to compensate ComEd for the use of its distribution lines over which power from the wind project would flow before entering the PJM high-voltage transmission system.

GSG objected to the charge, noting that the interconnection studies showed that by injecting power into the distribution grid, the wind project would reduce the need for future transmission facilities and reduce generation losses incurred in serving ComEd's load.

On February 22, FERC, to both parties' surprise, ruled that it lacked jurisdiction over the interconnection agreements and dismissed the case. Ignoring decades of precedent, FERC ruled that it has jurisdiction over a distribution-level interconnection only if, prior to the request for interconnection being made, some other generator is already connected to the distribution facilities, and that generator (or some other seller) is engaged in making wholesale sales over the distribution facilities. If these conditions are not satisfied, then the state commission, and not FERC, will establish the rate, term and conditions of the interconnection. FERC held that in this case those conditions were not satisfied and dismissed the interconnection filing.

Moreover, according to FERC, even if there is an existing interconnection and wholesale sale on the affected distribution facilities, if the generator is a "qualifying facility" or "QF" that sells all of its output to the utility that owns the distribution facilities, FERC still does not have jurisdiction. According to FERC, in this situation, there is no preexisting FERC transmission service involved when a QF sells its output to the interconnected utility and, therefore, the distribution facilities are not FERC jurisdictional.

Backlash

The American Wind Energy Association identified 72 projects in the interconnection queue that are connected at the 69k level or below in a filing protesting the FERC approach in the GSG case. Under FERC's ruling, a state commission would be free to ignore FERC-approved queue policies, as well as long-debated interconnection standards, for interconnections that do not satisfy the standards for FERC jurisdiction. Instead of "preventing balkanization of the interstate power market" — a goal that FERC cited in adopting its uniform open access transmission tariff in Order No. 888 — FERC's policy, if not overturned, will require generators that find it necessary to interconnect at the distribution level potentially to deal with 47 different state policies for interconnection. (The ERCOT region of Texas has already established its own approach to interconnection.)

GSG has applied for a rehearing of the FERC's decision. If FERC fails to change its position, and if the case is appealed, the courts are very likely to overturn FERC's determination and rule that all interconnections involv- / continued page 10

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However, if they do so, it should not ordinarily cause an excise tax to be imposed on their investors, "absent facts or circumstances that indicate that the purpose of the tax-exempt entity's investment in the . . . fund was specifically to participate in such a transaction."

The tax reconciliation bill also extends for another two years through 2010 a special low US tax rate for corporate dividends and capital gains. The rate is 15%. It applies only to dividends and capital gains received by individuals and not corporations.

The bill will make it slightly more difficult for companies in energy and other infrastructure businesses to take advantage of a tax deduction that rewards "domestic manufacturing." Companies engaged in domestic manufacturing in the United States pay tax currently on only 97% of their domestic manufacturing income. In other words, they can deduct 3% of such income. The taxable percentage will drop to 94% in 2007 and to 91% in 2010. Generating electricity is considered manufacturing. However, transmitting or distributing electricity is not. The amount of deduction a company is allowed each year is limited to 50% of the wages it reports on IRS Form W-2 that it paid its employees. The bill tightens the wage cap by limiting it to wages tied to domestic manufacturing. Thus, for example, utilities will have to allocate wages between their generation businesses and their transmission and distribution businesses.

The bill extends a special rule that allows US banks and other lenders to avoid immediate US taxes on interest their offshore subsidiaries earn from making loans outside the United States. The United States ordinarily looks through offshore subsidiaries of US multinational corporations and taxes them on any dividends, interest or other passive income it sees being earned by the subsidiaries — without waiting for the income to be repatriated to the United States. However, there is an exception from this princi- / continued page 11

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ing power sales to the interstate grid — regardless of the voltage level of the facilities to which the generator interconnects — are subject to FERC jurisdiction. Order No. 2003 focused on "dual use" distribution facilities, facilities used for both wholesale sales and retail sales, and correctly held that FERC has jurisdiction over, for example, wholesale sales that take place on the distribution system, while the state commission retains jurisdiction over the use of the distribution system for retail sale and retail distribution or wheeling service.

The basic problem with FERC's approach is that it — and Order No. 2003, which it cites as precedent — rely on the existing use of the distribution system to establish whether or not the new interconnection is FERC-jurisdictional.

There is no basis in the Federal Power Act or in prior court decisions interpreting the Federal Power Act for this "preexisting use" test. Rather, the test is whether the interconnection service that is or will be provided by the utility that owns the distribution system will constitute "transmission in interstate commerce." As already noted, "transmission" begins when generation is complete, irrespective of the voltage level, and continues to the point after the step-down process, where the power is "distributed" to end users. If the service that the interconnecting utility will provide is "transmission in interstate commerce," then, whether or not there is any preexisting use, when the requested interconnection service commences, that service will be FERC jurisdictional.

In the meantime, FERC's decision has already created uncertainty for projects in the queue and for projects that have assumed that FERC's well-established and uniform standards for interconnection would apply to their interconnection. ◎

The American Wind Energy Association has identified 72 projects that could be affected by the ruling.

Energy Department Wrestles with Loan Guarantee Details

by Luis Torres, in Washington

The US Department of Energy is moving to implement a loan guarantee program for energy projects that employ new technologies. The loan guarantees were authorized in the Energy Policy Act last August. The agency is just getting around to establishing an office to implement the program.

The guarantees are supposed to help such projects as coal-to-liquids plants, IGCC (integrated-gasification combined-cycle) power plants and other large coal and biomass gasification facilities.

Guidelines explaining the ground rules for the program and inviting applications are still months away, although the agency says the guidelines should be ready by October.

In the meantime, energy officials are wrestling with at least 10 significant issues relating to the loan guarantees.

Congress has failed so far to appropriate any money for the loan guarantee program. Congress spends money in a two-step process by first "authorizing" the spending, which it did last August, and then following up with a formal "appropriation," which it has so far failed to do. The first guarantees are expected to be of the "self pay" variety where project developers whose loans are guaranteed will have to reimburse the US government for the cost of the guarantee program.

Background

Title 17 of the Energy Policy Act authorized the US Department of Energy to guarantee repayment of loans to projects that use innovative technologies to avoid, reduce or sequester pollutants. Energy projects in the following categories are eligible potentially for guarantees: renewables, fossil fuels, nuclear energy, hydrogen fuel cell technologies, carbon capture and sequestration, efficient electrical and end-use technologies, facilities for fuel efficient vehicles, pollution control and oil refinery projects.

The guarantees can cover up to 80% of project cost. There is no limit on the dollar amount of guarantee for a single project, but the loan being guaranteed cannot extend longer than 30 years or 90% of the projected useful life of the facility being financed.The loan guarantee program has no time limit. Therefore, once the program gets going, it will continue indefinitely until Congress or the Department of Energy decides the program has outlived its usefulness.

Implementation Issues

US energy officials are still debating whether to get the program started by issuing guidelines or by writing more formal regulations. The Energy Policy Act requires regulations be issued on at least two subjects: how the agency will deal with defaults and what recordkeeping will be required by borrowers. Regulations take longer to write because the proposed text must be put out first for public comment. If the department waits to implement the guarantee program through formal regulations, then a delay of at least another year is expected before the first guarantees will be available. Energy officials say the program could be up and running by the fall if the department relies on a simpler set of guidelines. .

The new guarantees will have the same basic structure as private-sector guarantees where the guarantor promises to repay an underlying loan if the borrower defaults. However, Congress left all the details to the Department of Energy to determine. The department is wrestling with the following issues.

Technological Risk. The guarantees will be available only for projects that "employ new or significantly improved technologies compared to commercial technologies in service in the US." This means by definition that the projects will have significant technological risk. Commercial lenders do not usually lend to projects that use / continued page 12

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ple for "active financing income," or income earned by banks and other lenders in the regular course of business. It is not treated as passive income. The exception was scheduled to expire at the end of 2006. The bill extends it for another two years through 2008.

The bill will also make it easier for US companies to avoid immediate US taxes in the future on some income earned outside the United States. Affected companies are ones with offshore holding companies that, in turn, own other subsidiaries that are treated as corporations for US tax purposes. The US normally looks through offshore holding companies and taxes the US parent on any dividends, interest or other passive income it sees earned anywhere in the offshore ownership chain. The bill makes an exception. For the next three years, the US will not treat as "subpart F income" — subject to immediate tax in the US — any dividends, interest, rents or royalties that one subsidiary treated as a corporation pays to another subsidiary in the offshore ownership chain. However, the subsidiary receiving the amounts must have a large enough interest in the one paying them for the two subsidiaries to be considered related parties. There was already an exception in the tax code for dividends and interest paid between related parties, but both the offshore holding company and the payor had to be in the same country.

It is hard to see how anyone could rely on such a temporary provision for purposes of planning. It applies only for the period 2006 through 2008. Congress could decide to extend it.

LANDFILL GAS AND SYNFUEL producers may be out of luck, but they have not given up.

The US government rewards companies that produce landfill gas, other "gas from biomass" and synthetic fuel made from coal with credits. The credits used to be called section 29 credits. They / continued page 13

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unproven technologies. One reason for the guarantees is to encourage such lending. However, the government will have to decide where to draw the line. Energy officials are wrestling with the extent to which the government will guarantee demonstration and pilot projects where the technology has not been tested on a commercial scale.

Technical Requirements. Projects that receive guarantees are required to "reduce, avoid or sequester air pollutants or man-made greenhouse gas emissions," and must also meet any applicable federal or state emission requirements. There are also additional technical hurdles for IGCC plants and certain other gasification projects. The Department of Energy must decide how to evaluate applications for loan guarantees for compliance with these requirements as well as to ensure ongoing compliance and what to do after a guarantee has already been issued if the borrower fails to follow through on its promises.

Completion Risk. Another issue for the department is whether to take completion risk. A project will not generate any revenues until is completed. In conventional project financing, completion risk is managed by having the project company enter into a "turnkey" construction contract with an experienced contractor who would provide liquidated damages if the contractor fails to complete the project by a certain date, but sometimes "turnkey" terms are not available, especially for projects using unproven technologies. Even when "turnkey" terms are available, there is the issue whether the damages to be paid by the contractor are enough to cover the project's operating costs and debt service until any problems with the project can be cured.

In addition to having the contractor share the burden of completion risk, project financiers usually have the project sponsors provide completion support to the project, whether in the form of completion guarantees or funding commitments. Solid sponsors, such as large mining companies or global power companies with strong balance sheets and substantial non-project assets, may not object to providing some level of completion support, but it will be difficult to obtain sponsor support from smaller sponsors.

US energy officials are wrestling with at least 10 significant issues as they try to implement the federal loan guarantees that Congress authorized last August.

Cost overruns are also a factor that bears on completion risk. Any guidelines implementing the loan guarantee program will have to address how the government will insist cost overruns be handled as a condition to receiving a guarantee. For example, will cost overruns be funded through the guaranteed debt, subordinated or shareholder debt, equity contributions or a combination of the foregoing? Will the Department of Energy accept other alternatives to mitigate the risk of cost overruns such as cash reserves during the construction period? These questions remain unanswered.

Sponsor Equity Contribution. The Energy Policy Act limits guarantees to 80% of project cost. It does not address whether the remaining 20% of the project cost must be covered by sponsor equity or whether part of it can also be covered by other (perhaps subordinated) debt. The Department of Energy is expected to require at least a minimum amount of sponsor equity. It will also have to decide on the required schedule of equity contributions as well as what assurances it will require from sponsors to ensure that such contributions are made.

Project Viability. The Energy Policy Act directs the Department of Energy only to guarantee projects for which "there is a reasonable prospect of repayment of the principal and interest," but does not address what will have to be shown to prove financial viability. Among the topics the guidelines are expected to address are whether a project must have in place an offtake agreement with a creditworthy offtaker (such as a take-or-pay contract that guarantees a minimum level of cash flow for the project) or whether it is enough to show that a project can survive on a merchant basis because there is a reliable market for the project's output large enough to ensure sufficient and continuous cash flow.

Lender Risk. Another issue with which energy officials are wrestling is whether to make the lender share part of the repayment risk as a way of ensuring that lenders have some skin in the game. Although the department is authorized to guarantee as much as 100% of principal and interest on a loan, it may decide to adopt a partial credit guarantee structure that caps government participation to a percentage of the loan being guaranteed or an aggregate dollar amount or both.

Financing of Fees. From a more detailed financing perspective, another set of questions that remains to be answered is whether payment of fees will be included in the guaranteed package. Banks traditionally charge a front-end or facility fee as well as a commitment fee in their lending transactions. The government itself is also likely to charge its own front-end fee as part of the "self pay" requirements for the program. Will payment of these fees be part of the financing package? Calculation of the "self pay" fee is also an issue and whether the fee should be structured as an origination, front-end fee or an annual fee, or both, with a portion of the fee paid on or around the date the guarantee commitment is issued and with another portion paid throughout the term of the guarantee agreement.

Permitting Risks. Project developers and financiers usually divide permits into two broad categories: construction permits and operating permits. As a general rule, all permits required for the construction of a project are a condition precedent to the closing of a project financing, but many permits are subject to appeal periods that may run 30 to 60 days or longer. Other permits are granted subject to the project meeting certain milestones or may affect the economics of a project (for example, a permit that effectively restricts the output of a project). The government as a guarantor of a project will have to assess on a case-by-case basis the risk that some of the permits needed for construction or operation may be denied.

A related question tied to permits is whether to require all projects that qualify for Energy Policy / continued page 14

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were relabeled section 45K credits in August last year.

The credits are currently $1.17 an mmBtu. The amount is adjusted each year for inflation. They can only be claimed on the output from facilities that went into service by June 1998, and then only through 2007.

The problem is the credits phase out if oil prices return to levels reached during the Arab oil embargo of the 1970's. Credits would have phased out last year if the average wellhead price for domestic crude oil had reached $66.79 a barrel, and the credits would have suffered a "haircut" — a reduction but not a full phaseout — if the average wellhead price had been above $53.20 a barrel.

The IRS said in April that the average wellhead price last year was $50.26 a barrel, just below the start of the phaseout range.

Oil prices are higher this year.

Two coalitions of synfuel producers tried to persuade Congress to include language in the tax reconciliation bill that President Bush signed on May 17 to link whether the credits phase out not to current oil prices but to prices the year before. In other words, whether credits phase out in 2006 would depend on oil prices in 2005. The proposal was also to freeze the amount of the credit at the 2005 level of $1.13 an mmBtu and not make any more inflation adjustments.

The proposal passed the Senate, but was dropped in the final negotiations with the House over what would remain in the tax reconciliation bill. A number of large synfuel plants have now shut down after failure to get a legislative fix. In the hectic last few days of the negotiations, the synfuel coalitions offered to forego any tax credits in 2007 in exchange for an assurance they would receive credits during 2006.

Congress may still pass a "trailer" bill this summer to extend a number of expiring tax incentives. The synfuel coalitions have not given up hope of getting / continued page 15

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Act guarantees to comply with the review requirements of the National Environmental Policy Act. Such a review takes time. Certain projects where federal funding is involved are subject to NEPA review. Some states also have similar requirements. A NEPA review or similar state review is also a precondition to obtain certain permits.

Policy and Other Considerations. The Energy Policy Act does not address what types of projects should be given priority over others. For example, will there be a ranking of projects based on how environmentally clean they are? Will renewable energy projects be preferred over production facilities for fuel-efficient vehicles because of the economic and social implications of developing the country's ethanol industry (for example, replacing foreign sources of oil with domestic energy sources and creating jobs in rural America)? Will coal projects be given priority? These policy questions remain unanswered.

The Energy Policy Act authorized hundreds of millions of dollars in tax subsidies for many of the same projects that qualify potentially for loan guarantees. The dollar amount of such subsidies is limited. The Internal Revenue Service announced plans for how to allocate the scarce tax subsidies and how it intends to rank projects that apply for them. It is not clear whether the Department of Energy will do the same thing. There is no limit on the potential dollar amount of self-pay loan guarantees. However, there could be a limit to the extent the agency funds the program out of appropriations. ◎

Implications of CO2 Emissions Limits for the US Power Industry

The United States is expected to have to take action to limit carbon emissions that contribute to global warming. A number of states are moving to limit such emissions on their own without waiting for the Bush administration to act. Some individual companies are under pressure from shareholders to disclose the expected future costs of carbon controls in their annual reports. The following are excerpts from a conference call that Hugh Wynne, US utilities analyst for the independent research house Sanford C. Bernstein & Company, LLC, held on April 13 for investors interested in the US power sector. The transcript is reprinted with permission from Bernstein & Company.

Likelihood of US Controls

MR. WYNNE: We believe there is an increasingly large probability — maybe 30%, maybe 50% — that emissions limits will be imposed at a national level in the United States within the next five years.

Our reasons for this conclusion are the following. First, a group of states in the northeast has already committed to limiting emissions. The group includes the New England states, New York, New Jersey, Delaware and Maryland, which together account for about an eighth of the population of the country. Second, California has already taken steps to limit carbon dioxide or "CO_2" emissions from new automobiles sold in the state. In 2005, Governor Schwarzenegger issued an executive order setting limits on CO_2 emissions statewide. There is legislation pending before the state assembly to make the emissions targets in the executive order legally binding. CO_2 emissions limits in California would affect another eighth of the US population. Thus, these two state-level initiatives alone are expected to affect a quarter of the United States.

At the federal level, it is noteworthy that both the leading Republican and Democratic candidates for the presidential nominations in 2008, McCain and Giuliani on the Republican side and Clinton on the Democratic side, all favor limits on greenhouse gas emissions. The Senate has also begun taking action. Last year, the Senate passed a nonbinding sense-of-the-Senate resolution supporting a national program of mandatory, market-based limits on emissions of greenhouse gases. Over the following 12 months, the Senate Energy Committee did extensive research on how to implement a program of emissions controls. It has published the results of some of that research in a "white paper" that can be downloaded from the Senate Energy Committee's website. That white paper is called "Design Elements of a Mandatory Market-Based Greenhouse Gas Regulatory System," and it goes into remarkable detail about just how such a system could be structured.

If a national program of emissions controls is put in place, our view is that it is likely to be an economy-wide one and will not single out individual sectors. While the power sector accounts for about 40% of greenhouse gas emissions, other sectors, including transportation and industry, are also important contributors, and it will be more efficient economically if those sectors are also covered by any emissions limits.

We believe that policy makers are likely to favor emissions caps rather than looking to reduce the emissions intensity of economic activity as proposed by the Bush administration, because the objective ultimately is to limit atmospheric concentration of greenhouse gases and that can only be achieved by capping and then reducing the CO_2 output of the country.

It is highly likely that a large portion of the emissions allowances will be sold, possibly through an auction — much like access to the radio spectrum is auctioned — rather than be granted to emitters as has been done in the European Union. The reason we think that a sale of allowances is more probable than a grant is that governments at both the state and federal levels are keen to maximize their fiscal revenues. Other objectives include avoiding windfall profits by the emitters of greenhouse gases and raising resources with which to fund programs to protect consumers from energy price increases as well as to foment technologies that limit the output of greenhouse gases.

Finally, I think it is likely that to protect affected industries, we may find that any emissions control program put in place includes a safety valve that allows the government to issue additional allowances if the price of allowances exceeds a certain level. The idea is to cap the cost to producers and consumers of CO_2 emissions limits.

Impact by Fuel

Figure 1 (page 16) shows the average US coal-fired power plant emits about a ton of CO_2 per megawatt hour produced. A gas-fired power plant emits a little over half a ton.

One can take the estimated cost of emissions allowances and multiply them by these factors to estimate the increase in the cost of producing electricity at coal- and gas-fired power plants. The range of cost estimates runs from about \$8 to \$28 per ton of CO_2 emissions, \$28 being the dollar cost per short ton of CO_2 at which emissions allowances currently trade in the European Union. The lower estimate of \$8 corresponds to studies and analytical work done in the United States about the cost of complying with a / continued page 16

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relief in the trailer bill, but they would have to overcome seemingly steadfast opposition from Bill Thomas (R.-California), the chairman of House tax-writing committee. Lobbyists for the coalitions say that, at some point, the offer to forego tax credits in 2007 will be withdrawn if the talks drag on because there will be too few months left in 2006 to make the offer worthwhile.

WIND CREDITS remain unchanged at 1.9¢ a kilowatt hour during 2006, the IRS said in mid-April.

It also said the average price at which wind electricity is sold under contract in the United States took a dramatic plunge last year. The average price for such contract sales in 2004 was 4.85¢ a kilowatt hour. In 2005, the average price dropped to 2.89¢ a kilowatt hour.

Tax credits may be claimed during 2006 at the same 1.9¢ rate for electricity from geothermal steam or fluid, "closed-loop" biomass and sunlight. "Closed-loop" biomass means plants grown exclusively for use as fuel in power plants.

The only solar projects that qualify are ones that went into service by December 2005. Other projects have until December 2007 to be put in service.

The IRS said the tax credit for other types of renewable electricity during 2006 will be 1¢ a kilowatt hour. This is a slight increase in the credit amount for such projects from the year before. Credits may be claimed at the 1¢ rate on electricity generated from "open-loop" biomass, landfill gas and municipal solid waste and on the incremental electricity generated by adding turbines to existing hydroelectric dams.

The credits are called "production tax credits." They are claimed by the owner of the power plant and run for 10 years after the plant is first put into service. Congress has extended the deadline to put eligible projects in service several times in the past, and there is hope that it will do so again. The / continued page 17

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program such as one proposed by two influential US senators, John McCain (R.-Arizona) and Joseph Lieberman (D.-Connecticut). The reason for the difference is the less onerous emissions limits that are being proposed in Congress compared to those adopted in Europe.

Thus, to complete the picture, given an allowance price of $8 per ton of CO_2, the cost of generating electricity at a coal-fired power plant should rise about $8 per megawatt hour. The cost of generation at a gas-fired power plant should rise by approximately half that or $5 per megawatt hour.

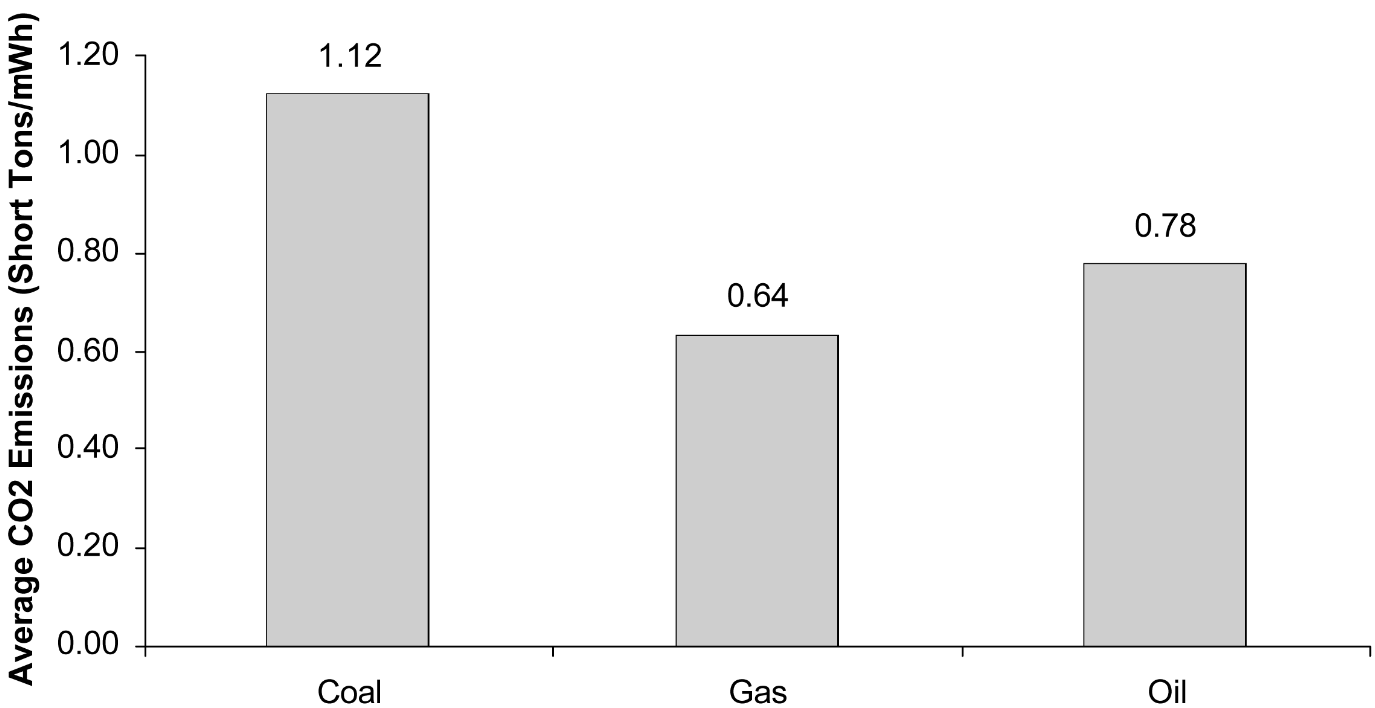
CO_2 emissions limits have important implications for the profitability of different types of power generators. In markets where gas-fired generators are the marginal or price-setting units, their cost of compliance with the CO_2 emissions program will be reflected in the price of power. That would be true, for example, in markets like New England, New York, the mid-Atlantic states and Texas. In markets where coal-fired generators are the marginal or price-setting units, such as the midwest, their cost of compliance will again be reflected in the cost of power.

Because of the differential in the CO_2 emissions of gas plants versus coal plants, power prices will likely rise more in coal dependent markets than they will in gas dependent markets. The implication is that coal-fired generators operating in markets that rely primarily on gas-fired generation, such as Texas or New England, may find their margins squeezed. If their cost of generation were to go up by $8, while the marginal producer sees his cost of generation go up by only $4, then the likelihood is that prices will rise by less than the operating cost of the coal plant, and its margin will be therefore be reduced.

Conversely, the obvious beneficiaries of any program such as this would be the nuclear power plants with no CO_2 emissions that are operating in coal-fired markets, where the increase in the cost of generation will be the greatest, let's

Figure 1

Average CO_2 Emissions in Tons per mWh



Source: Bernstein and Platts

say $8 per megawatt hour. That increase in the cost should drive a similar increase in price that would basically add directly to profit for nuclear generators.

In gas-fired markets such as Texas or New England, that cost and price increase would be less, let's say $4 or $5, but the impact would be the same, adding directly to profit for nuclear generators without any increase in their operating costs whatsoever.

The primary beneficiary we believe would be Exelon, which operates a large nuclear fleet in Illinois, where its competitors are coal-fired power plants. Those plants would face the full cost implications of an $8 per ton allowance price, driving up the price of power in that market and driving up the margins of Exelon by a commensurate amount. We estimate the increase in Exelon's EBITDA (earnings before interest, taxes, depreciation and amortization) from an $8-per-ton allowance price at 40%. There is no cost associated with that to Exelon, so that EBITDA increase should flow through to pre-tax profits.

Smaller but still very significant earnings gains could be expected at companies like Constellation, First Energy, Dominion, PP&L, Entergy and PSEG.

Their gains are less in part because these companies have smaller nuclear fleets, but also because those nuclear fleets are located in regions where gas-fired generators set the price of power and, therefore, the expectation would be that power prices would rise by less.

At risk on the other hand, are companies like TXU, Xcel, Reliant, Northeast Utilities — although its generating fleet is up for sale — Dynegy and NRG. In cases such as TXU and NRG, what we are talking about are the potential pressures on profitability created by operating coal-fired power plants at higher cost in markets where gas is setting the price of power.

Effect on Valuations

Let me move on to the second section of the presentation. Why worry about CO_2 emissions limits now? What are the developments in state and federal policy that lead us to believe that this is becoming an increasingly likely initiative on a national level?

The northeast has already agreed to caps. The first state to enact CO_2 emissions limits was Massachusetts in June 2002. Those limits took effect on January 1 of this year with respect to coal-fired power plants. In / continued page 18

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two senior members of the Senate tax-writing committee — Senator Charles Grassley (R.-Iowa) and Max Baucus (D.-Montana) — said in March that they want to extend the deadline by another three years through 2010.

The credits will phase out if the average contract price for electricity reaches a high enough level that the tax subsidy is no longer needed. The IRS said a phaseout will start in 2006 if the average electricity prices reaches 10.38¢ a kilowatt hour. Separate average contract prices are computed for electricity sales from each type of renewable "fuel." The phaseout would occur as the average contract price moves across range of another 3¢ above the start of the phaseout range.

Only sales under post-1989 contracts are taken into account. Spot sales through power pools are ignored.

CLEAN RENEWABLE ENERGY BOND allocations should be made in September, the IRS said.

The agency is sifting through the more than 700 applications it received for $800 million in total bond authority. The deadline to apply was April 26.

Clean renewable energy bonds are bonds that state and local governments, municipal utilities, electric cooperatives, US territories and possessions and Indian tribes can issue to finance new wind farms and other alternative energy facilities that they will own. No interest has to be paid on the bonds. The bondholders receive federal tax credits instead. Bonds can only be issued for projects that would have qualified for production tax credits if they were privately owned.

The IRS plans to allocate the bond authority to the project that asked for the smallest dollar amount of bond authority first, then to the next smallest request and so on until all the bond authority is used up.

The IRS had still not added up the total dollar value of the requests as the NewsWire went to press. It had / continued page 19

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December last year, several states in the northeast — New York, New Jersey, Delaware, Connecticut, New Hampshire, Vermont and Maine — committed to limit their emissions of greenhouse gases under a regional initiative called the "Regional Greenhouse Gas Initiative" or "RGGI." That initiative would cap greenhouse gas emissions at current levels from 2009 to 2014 and then cut them by 10% by 2019. In April of this year, Maryland passed legislation requiring that state to join RGGI in 2007. These initiatives have committed states to cap CO_2 emissions in a region that encompasses an eighth of the US population.

In California by state law, greenhouse gas emissions from automobiles sold in the state are to be regulated commencing in 2009. The law mandates emissions cuts of 22% by 2012. The state public utilities commission, moreover, already requires utilities evaluating different types of power plants to add a carbon adder of $8 per megawatt hour when evaluating the economics of coal-fired power plants. The governor of the state, Arnold Schwarzenegger, in June of last year signed an executive order capping greenhouse gas emissions at 2000 levels. The executive order does not have the force of law. In April, a bill was introduced in the state Assembly that would make the governor's emissions targets mandatory ones statewide. If that law is enacted and California adopts mandatory CO_2 emissions limits, another eighth of the country's population would be affected.

It is interesting to see that the electric generating capacity of the states that are moving to limit CO_2 emissions is a much smaller fraction of the total than the population of these states is of the nation's population. The states that have adopted CO_2 emissions limits encompass about a quarter of the nation's population, but they account for only about 14% of US generating capacity. Much of that capacity is in fact gas-fired capacity. These states account for about a fifth of the country's gas-fired capacity, but only about 5% of the nation's coal capacity. Perhaps these states are more comfortable imposing CO_2 emissions limits because they are large importers of power and because the in-state generation that they are regulating is not a heavily-emitting fleet. It is a gas-fired fleet as opposed to a coal-fired fleet.

Carbon controls will increase the cost of generating electricity from coal by at least $8 an mWh. This will produce windfalls for generators who use other fuels in markets dominated by coal.

Federal action is increasingly likely. In April 2005, the federal Energy Information Agency published a study of a proposed CO_2 emissions limit program, proposed by the National Commission on Energy Policy, and concluded that the proposed limits would not materially affect economic growth in the United States. That had an important impact on the debate around CO_2 emissions limits and, in June 2005, the US Senate passed a sense-of-the-Senate resolution stating that global warming has a great deal of scientific evidence supporting it, that evidence indicates that global warming is being aggravated by man-made emissions of greenhouse gases and that something should be done about it.

Rather than simply passing that resolution as a bit of political drama, the Senate Energy Committee has followed through with extensive research and hearings on how to design and implement a program of CO_2 regulation. The committee published a white paper on the subject. Following up on the various hearings that the Senate Energy Committee has had, one of which took place in early April, Senator McCain now plans to re-introduce his McCain-Lieberman "Climate Stewardship Act" that would cap greenhouse gas emissions at 2000 levels. The leading Republican and Democratic candidates for the 2008 nominations all favor restrictions on greenhouse gas emissions.

Thus, taking into account these state-level initiatives and taking into account the level of federal interest in both the executive and the legislative branches of government, we think that the probability of some type of national limit on CO_2 emissions has increased appreciably and now needs to be factored into the valuations of power companies in this country.

The companies that would be most affected by CO_2 emissions limits are taking the possibility of a nationwide cap quite seriously. The largest US power utilities and their lobbying group, the Edison Electric Institute, are already engaged in a dialog with legislators at the federal level about greenhouse gas emissions.

Moreover, a number of the largest utilities have expressed their support; Exelon and Duke are both advocating economy-wide limits on greenhouse gas emissions, supplemented by a system of tradable emissions allowances. Those are the two largest utilities in the United States. Other large utilities, like Edison International and Entergy, have taken similar positions.

Some utilities remain opposed to a mandatory program of emissions limits, such as AEP and Southern, but those utilities are also being very active in designing strategies to cope with a national program of emissions limits were it to be implemented. Most notably, AEP has recently obtained approval from the Ohio Public Utility Commission to recover in its rates the pre-construction cost of an integrated coal-gasification, combined-cycle power plant that the company plans to build in Ohio. The choice of that technology specifically addresses the expected need to contain the emissions of CO_2 from future coal-fired power plants.

Competing Proposals

Next, I would like to analyze the various policy alternatives that have been put forward and try to derive from that analysis an idea of what the future may hold for us by way of the structure of a greenhouse gas emissions program.

The first initiative to consider is the Regional Greenhouse Gas Initiative opted by the states in the northeast. It has several important elements. First, it is a cap-and-trade program similar to those in effect at the federal level for sulfur dioxide and nitrogen oxide emissions. Second, it only covers the power sector. It is not economy wide. Third, it allows member states to sell rather than grant allowances. Fourth, it has a safety valve mechanism of a sort designed to soften spikes in allowance prices.

Greenhouse gas emissions under this / *continued page 20*

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entered about half the data from the applications in the computer and was moving rapidly to enter the rest.

MATCHING POWER CONTRACTS are not "section 197 intangibles" but rather a financial play, the IRS said.

The IRS made the statement in a private letter ruling that it made public in April.

The significance is a company that bought a pair of matching long-term contracts — one a contract to buy a quantity of electricity and the other a contract to resell the same electricity at a higher price — was able to amortize its investment in the power contracts over a faster period than if the contracts had been "section 197 intangibles." An investment in such intangibles must ordinarily be amortized over 15 years. The ruling is PLR 200614001.

During the 1980's, many utilities in the United States signed long-term contracts to buy electricity from owners of so-called independent power plants. The utilities were required to do so by federal law.

By the 1990's, electricity prices had fallen to such an extent that these contracts were no longer economic. Utilities sometimes paid large sums of money to cancel the contracts. However, rather than sell their contracts back to the utilities, some independent generators agreed to reduce the price of electricity somewhat in exchange for being released from the obligation to supply the electricity from a specific power plant. They then locked in a long-term supply of electricity to match what they had to deliver to the utility, but at the lower prices that were then prevailing in the market. This had the effect of locking in a profit margin over time. Both contracts were put in a special-purpose company. The special-purpose company borrowed against the profit margin to turn it immediately into cash.

An investor planning to buy such a special-purpose company went to the IRS last year to ask for a ruling. The trans- / *continued page 21*

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program would be capped at current levels from 2009 to 2014 and cut by 10% through 2019. Each state may allocate its greenhouse gas emissions budget as it sees fit, but the initiative requires that 25% of the allowances be set aside by those states for sale and the proceeds used for the benefit of consumers or to foment low-emissions power sources. There has been a lot of grass roots pressure put on legislators in these states to ensure that the amount of allowances that are sold is maximized in order to maximize the fiscal revenues available for compensation to consumers, to fund new technology initiatives and to prevent a windfall profit from falling into the laps of the very companies that are emitting the greenhouse gases. The final point is that the program is designed so that if the allowance price exceeds $10 a ton, generators may use offsets — credits from programs to capture CO_2 through reforestation or to capture methane through landfill gas capture — to cover up to 20% of their emissions.

Moving on to the McCain-Lieberman "Climate Stewardship Act," the approach is materially different. This is an economy-wide program: the only sectors of the economy that are not covered by McCain-Lieberman are the residential and agricultural sectors. It is similar to RGGI, on the other hand, in that it is a cap-and-trade program. It allows the government to sell rather than grant allowances. Under McCain-Lieberman, greenhouse gas emissions would be capped at 2000 levels for the years 2010 to 2015. The Secretary of Commerce is empowered to determine what share of allowances should be granted to emitters versus what share should be withheld by the government for sale. The proportion may vary year to year. That, in turn, serves the purpose of allowing the government to grant more emissions when the price is high. In addition, the legislation would allow emitters to satisfy up to 15% of their allowance requirements by purchasing allowances from other countries or by obtaining credits for reforestation and other carbon capture projects.

A Senate Energy Committee white paper suggests that carbon controls should be placed on the sellers of hydrocarbon fuels rather than users of the fuels.

There is an important private sector initiative put forward by the National Commission on Energy Policy, which is a group that encompasses electric utilities, labor unions and academics. Its proposal has stimulated a lot of debate in Washington. The program recommended by the National Commission on Energy Policy is also economy wide. It also involves tradable allowances. Unlike RGGI and McCain-Lieberman, it does not seek to cap greenhouse gas emissions but rather to slow their rate of growth. Unlike RGGI and McCain-Lieberman, it skews the allocation of emissions allowances towards grants to emitters rather than encouraging the government to hold allowances back for sale. Finally, it specifically calls for a safety valve to avoid spikes in the price of allowances.

Specifically from 2010 to 2019, emissions targets would be set that would reflect a reduction in the rate of greenhouse gas emissions per dollar of gross domestic product or "GDP." The idea is to reduce the carbon intensity of the economy, but not necessarily to cap the absolute level of greenhouse gas emissions. The effectiveness of that approach in terms of reducing the level of CO_2 concentrations in the atmosphere is questionable. The advantage, of course, is that it would set less stringent limits that favor the utilities that are behind the proposal.

Another important element is that 95% of the emissions allowances would be issued at no cost to emitters. Over time, that would be reduced to 90% of the allowances being issued at no cost to emitters. Again reflecting the provenance of the proposal, this would maximize the profits of the utility sector.

To prevent price spikes, the government would sell unlimited amounts of allowances at a price of $8 per ton. Thus, it would be possible to quantify in advance the maximum price that emitters would incur to acquire emissions allowances and also to quantify the maximum price that consumers would pay as a result of the program.

Finally, the Senate Energy Committee white paper has set out some very thoughtful observations about the structure of an emissions limit program. One of the things that this white paper recommends is an economy-wide approach, but it also suggests that emissions limits be placed on the sellers rather than the consumers of hydrocarbon fuels. The way that would work is that anyone selling a hydrocarbon fuel, whether it is coal or gas or refined petroleum products, would be required to own allowances for CO_2 emissions equivalent to the CO_2 content of their fuels being sold. What would happen, therefore, is that regulation would take place at the upstream points — the coal mines, the gas gathering companies and the refineries. This would be more efficient than trying to regulate emissions at every final emitter's tailpipe or chimney, particularly when a lot of those final emitters are automobiles or residences and the number of such emitters runs into the millions and the administrative difficulty of monitoring and limiting their emissions is exponentially higher. By capturing all sources of emissions, moreover, the upstream approach may stimulate a wider range of emission reduction responses and thus achieve emission reduction targets at a lower cost.

A government auction of allowances is favored over allocations. The reasons for that are to reduce administrative costs, to limit the potential for windfall profits to emitters and, finally and most importantly, to raise government revenues. Government revenues I estimate could be $50 billion to $175 billion annually from the sale of these greenhouse gas emission allowances.

A portion of the proceeds from the sale of allowances would be set aside to provide technology incentives, to protect consumers and possibly also to compensate energy-intensive sectors that would be materially disadvantaged by CO_2 emissions limits. That would include potential compensation to electricity generators.

Taking into account these various initiatives, what can we perhaps foresee in a future program to / continued page 22

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action to purchase the special-purpose company was treated for tax purposes as a direct purchase of the matching power contracts. The special-purpose company did not exist for tax purposes.

The IRS ruled that the investor bought something closer to a "futures contract, foreign currency contract, notional principal contract, or other similar financial contract" rather than a pair of power contracts. The former are not "section 197 intangibles." Power contracts may be such intangibles. The problem with intangibles is the investor would have had to write off his investment over 15 years. The ruling let him write it off more quickly.

Special-purpose companies in this situation are usually saddled with debt. The ruling does not explain what happened to the debt.

The ruling has implications for anyone trying to avoid characterizing revenue from electricity sales outside the United States as "subpart F income."

The United States taxes US companies on any subpart F income earned by their offshore subsidiaries without waiting for the income to be repatriated to the United States. Non-subpart F income would not ordinarily be taxed until it is repatriated. The ruling says, "[T]he contracts at issue require the sale or purchase of electricity, a commodity with respect to which futures contracts are regularly traded on established markets." Gain or loss from the sale of commodities is subpart F income.

STATE TAX INCENTIVES that encourage companies to build wind farms, ethanol plants, factories and other facilities dodged a constitutional challenge.

The US Supreme Court declined in May to rule on whether such incentives violate the commerce clause of the US constitution, which bars states from interfering with interstate commerce. Such incentives / continued page 23

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eliminate emissions of greenhouse gases in the United States?

Importantly, McCain-Lieberman, the National Commission on Energy Policy and the Senate Energy Committee all favor an economy-wide program over a sectoral program. That seems far more likely to me because it is the cheapest and most effective way to achieve emissions targets in the future.

I also think it is more likely that any such program would have emissions caps as proposed by RGGI and McCain-Lieberman as opposed to limits on emissions intensity, as proposed by the National Commission on Energy Policy, simply because limits on emissions intensity do not address the real problem behind global warming, and that is the level of CO_2 concentrations in the atmosphere.

Both RGGI and the white paper produced by the Senate Energy Committee favor the sale as opposed to the granting of emissions allowances. That, I believe, has high probability because of the fiscal benefits to the government. McCain-Lieberman would delegate the decision about how much to sell and how much to grant to the Secretary of Commerce. Only the National Commission on Energy Policy, which includes utilities among its sponsors, favors the outright grant of allowances to emitters, allowing the emitters to enjoy the benefit of any windfall profit from the increase in the price of fossil fuels or electricity.

RGGI and the National Commission on Energy Policy provide for mechanisms to limit spikes in the price of allowances. I think it's likely that something like that will be included in the final program simply because it will create a level of certainty regarding the cost of the program that both consumer and producer groups will find attractive.

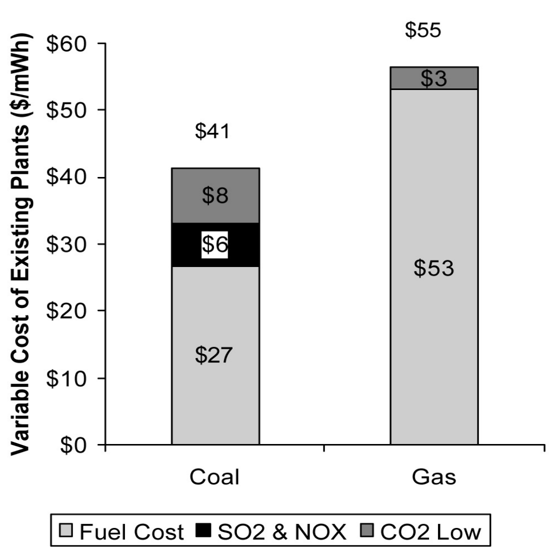
Finally, many of these proposals — RGGI, McCain-Lieberman and the Senate white paper — call for a set aside of the proceeds from the sale of allowances to protect consumers, to promote technology development and to compensate energy-intensive industries.

Implications for Generators

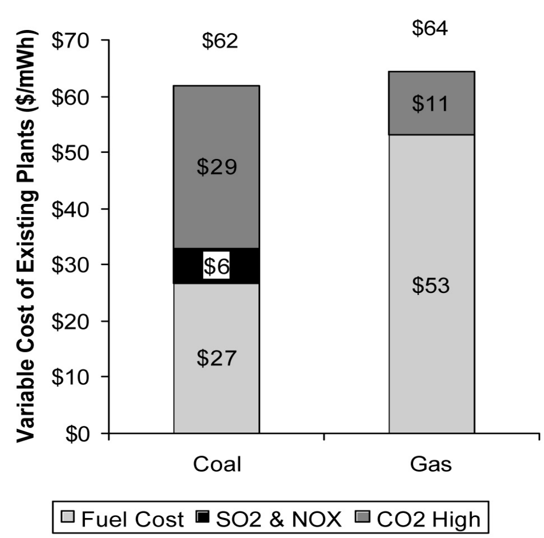
Let me move to the final subject, which is the implications for US generators of limits on CO_2 emissions. The impli-

Figure 2

Plant variable cost with $8/ton CO_2 allowance



Plant variable cost with $28/ton CO_2 allowance



Source: Bernstein, Platts and Bloomberg cations are very much a function, of course, of the price of the allowances. In 2006, the price of CO_2 allowances in the European Union has averaged about $28 per short ton. Estimates and studies done of the cost of compliance in the United States with programs such as that proposed by McCain-Lieberman tend to have much lower prices for CO_2 emissions — about $7 to $9 per ton. We have used $8 therefore to estimate the cost to generators in the United States.

The impact of CO_2 controls in the United States will fall much more heavily on coal-fired generators whose emissions of CO_2 per ton - or per megawatt hour produced — are approximately twice those of gas-fired generators. The advantage that coal enjoys over gas will be eroded. How much it erodes will depend on the price for allowances. The gap will erode but not be eliminated. Figure 2 shows the range of possible erosion in the gap.

We looked at how the generation cost of individual utilities would be affected by CO_2 emissions limits. Our conclusion is that the markets that are going to be most heavily affected by limits on CO_2 emissions will be the midwestern markets of ECAR and MAIN and to a lesser extent the mid-Atlantic market or MAAC, because these are markets where coal-fired generators set the price of power and, therefore, the cost increase per megawatt hour produced will be greatest.

Markets that will be somewhat protected because they are primarily gas dependent markets will be markets like Texas and New England. These are markets where gas-fired generators are the marginal producers and, therefore, the cost increase will be less.

In summary, the implications of a program of CO_2 emissions limits will be, first, an increase in the price of power to reflect a cost increase to the marginal producer in the region of paying for the allowances. Second, there will be a tendency for coal-fired generators in certain markets to see their margins erode. That will be a problem primarily for coal-fired generators that are operating in markets where gas-fired generation is the price setting technology. Third, the greatest gains will be enjoyed by nuclear generators in markets that are heavily coal reliant, such as the midwest and, to a slightly lesser extent, the mid-Atlantic. Gains will also be enjoyed, of course, by nuclear generators in markets that are gas reliant, but those gains will be less per megawatt hour because of the lower CO_2 emissions of gas-fired generators.

We calculated the erosion in gross / *continued page 24*

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might cause a company to put a wind farm, for example, in state X rather than across the border in state Y.

The Supreme Court said that a group of Ohio residents who challenged an investment tax credit that DaimlerChrysler received for building a Jeep factory in Ohio lacked “standing” to challenge the tax credit. It declined to address the merits of their case.

A US appeals court had said earlier that the Ohio tax credit was an unconstitutional attempt by Ohio to redirect interstate commerce.

DaimlerChrysler built a new Jeep factory near an existing plant in Toledo, Ohio in 1998 at a cost of $1.2 billion. The state offered a 13.5% investment tax credit at the time against franchise taxes as an inducement to companies to put “new manufacturing machinery and equipment” in Ohio. The car manufacturer not only claimed the tax credit, but it also received a property tax exemption for 10 years from the two local school districts. The tax benefits were worth $280 million.

A group of Toledo homeowners and small business people challenged the tax benefits at the urging of Ralph Nader. A US appeals court struck down the investment tax credit, but let the property tax exemption stand. The court suggested that direct subsidies like government grants are permitted under the US constitution, but tax credits are not because they involve a state’s use of its taxing power in an effort to redirect interstate commerce. The appeals court had no problem with the property tax exemption.

The auto maker appealed to the US Supreme Court. The court declined to rule on procedural grounds that had the effect of setting aside the appeals court decision. The case is *DaimlerChrysler Corporation v. Cuno*.

Ohio no longer offers the tax credit and is in the process of phasing out its franchise tax.

ETHANOL CREDITS cannot / *continued page 25*

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margin that will be suffered by coal-fired generators that are competing in markets where gas sets the price of power. We then calculated the expected gross margin gains likely to be enjoyed by nuclear generators in markets where gas or coal is setting the price of power. Figure 3 shows the combination of the two. It shows the expected net effect on gross margins of unregulated generators in this country.

The biggest beneficiaries will be companies like Exelon, operating nuclear fleets in coal-fired markets, and to a lesser extent companies like Constellation, First Energy, Dominion, PP&L, Entergy and PSEG, operating nuclear fleets in gas-fired markets. The biggest profit erosion will likely occur at coal-fired generators operating in markets where gas sets the price of power, as would be the case, for example, with NRG in Texas.

Questions

AUDIENCE MEMBER: Duke has said it prefers a carbon tax because a tax would more fairly spread the cost of controls across all industries. What do you think of a tax versus a cap-and-trade system?

MR. WYNNE: The benefit of a cap-and-trade system is that to the extent a company can comply with the emissions reductions at a low cost, its compliance will benefit other emitters whose cost to reduce emissions would be much higher. The point is to find the cheapest way for the economy as a whole to comply.

The concept is that if I am operating an extremely inefficient coal-fired power plant with a very high heat rate, and thus producing very high emissions of CO_2 per megawatt hour, by shutting that plant down, I can reduce CO_2 emissions at a cost to the economy that would be a great deal less than would be the cost to a highly-efficient facility with much lower allowances.

The classic example of how this has worked is what has occurred under the Kyoto treaty where the collapse of highly inefficient manufacturing industries and power plants in the former eastern bloc countries has meant that CO_2 emissions in Europe have declined dramatically.

Those countries have been able to sell allowances for CO_2 emissions that they are no longer using to western Europe where the cost of achieving similar emissions reductions would be much greater because western European countries are much more energy efficient — they are much cleaner in terms of the operation of their manufacturing industry and their generating stations.

Figure 3

Gain/Loss in Generation Gross Margin With Allowances at $8/Ton

	% of EBITDA
Exelon	40%
Constellation Energy Group	12%
FirstEnergy	7%
Dominion Resources	6%
PPL	6%
Entergy	5%
Public Service Enterprise Group	4%
FPL Group	1%
UGI	0%
Cinergy	0%
Edison International	0%
PEPCO Holdings	0%
Ameren	0%
American Electric Power	0%
DPL	0%
WPS Resources	0%
Energy East	0%
Sempra Energy	-1%
Allegheny Energy	-1%
AES	-1%
Mirant	-2%
TXU	-2%
Xcel Energy	-3%
Reliant Energy	-4%
Northeast Utilities	-6%
Dynegy	-8%
NRG Energy	-24%

Source: Platts and POWERdat and Bernstein analysis.

It is basically that efficiency that I think a cap-and-trade program would enable the country to achieve, particularly a cap-and-trade program that is economy wide and that captures all sectors. The efficiency would be lost in a program that would just tax everybody uniformly.

AUDIENCE MEMBER: I had a question about the regional tensions that come from state action. If you take out Maryland, the states in the RGGI greenhouse gas initiative have almost no coal capacity. Assuming Ohio and West Virginia are not likely to join the initiative, it seems to me that in the absence of some federal action, the initiative will actually benefit companies with coal-fired power plants because it will increase electricity prices in the markets to which they export without imposing any costs on them.

MR. WYNNE: That's an interesting point. I think the only flaw in the argument is that a lot of the imports that the RGGI states and California depend on come from hydroelectric sources. The reason California gets away with producing so much less than it consumes is because it imports from Washington and Oregon and the huge hydroelectric resources of that region. One of the reasons that New England gets away with producing less than it consumes is because its importing from Hydro Quebec. The importation of coal-fired power into New England is somewhat constrained by transmission limits. That's less true in California where coal-fired generators in Arizona, for example, are able to export into Southern California. But as a matter of logic, your point is perfectly valid.

AUDIENCE MEMBER: I was wondering what you see happening to coal prices and do you see a difference between coal from the Power River Basin versus Appalachia?

MY WYNNE:The emissions of CO_2 per megawatt hour are going to be more when using coals that have low heat content per ton because the megawatt hours produced are a function of the heat content. So if you are getting less heat content out of a coal, which is the case with Power River Basin coal, then you will be putting up more CO_2 into the atmosphere per mWh.

I think a limit on CO_2 emissions would tend to favor high heat content coals because they have more energy per ton of CO_2 emitted. These would be Appalachian coals.

As to the price of coal in general, it is not clear to me that coal will be materially adversely affected as a fuel unless the estimates of $8-per-ton allowance prices are grossly wrong and, in fact, the allowance prices are at / continued page 26

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be claimed by a company that hires out the actual work of producing the ethanol to a factory under a contract manufacturing or tolling arrangement, the IRS said.

The US government offers small ethanol producers tax credits of 10¢ a gallon on the ethanol they produce. A "small" producer is someone with a capacity to produce no more than 30 million gallons a year. Credits can only be claimed on the first 15 million gallons that such a person produces each year.

A company claimed small producer credits in the following situation. It buys hydrous ethanol outside the United States and then contracts with a factory to convert it into anhydrous ethanol before importing the ethanol into the United States. The company argued that it was the "producer" of the ethanol because it owned the ethanol while it was being converted by the factory to an anhydrous state. This is no different than where a US toy manufacturer hires out the actual sewing of its dolls to a factory on mainland China.

The IRS national office ruled in a "technical advice memorandum" that no tax credits are allowed in this case because the US company is not producing ethanol but merely purchasing ethanol and having it further processed. A "technical advice memorandum" is a ruling by the IRS national office to settle a dispute between a taxpayer and an IRS field agent that came up on audit. The IRS made the ruling public in April.

Interestingly, the IRS did not try to disallow credits on grounds that the ethanol production was outside the United States. The ruling is TAM 200613032.

SHAREHOLDER DEBT passed muster in court.

Several members of the family that owns a small manufacturing company made advances to the company periodically to cover working capital requirements. These advances were eventually documented as / continued page 27

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the European level or higher. The reason I say that is because if you have a coal-fired power plant whose operating cost in the absence of CO_2 emissions allowances is something like $35 today, including the coal price and the cost of emissions by way of NOx and So2 emissions, that's still meaningfully lower than the cost of power from your average combined-cycle gas turbine plant, which may be in the range of $55. To make that gap close, we would need to have, I estimate, an emissions allowance price of about $40. We start with a $20 gap. At $40 per ton of CO_2, the cost of gas-fired generation would go up by about half that amount or about $20. The cost of coal-fired generation would go up by about $40, and the $20 gap would go away. You need some combination of very high CO_2 emissions allowance prices or significantly lower gas prices to close the competitive gap between coal and gas.

Therefore, I think that coal will remain the most economic fuel for the thermal generators in the country and, in the short run, I don't think that the demand for coal should be materially diminished among utilities.

In the long run, clearly the impact is going to be to try to maximize the generation of electricity from sources that don't emit CO_2 — therefore, from renewable sources like wind plants and hydro, but more importantly nuclear sources. To the extent that the generating fleet over a period of decades trends more and more nuclear, then the potential for coal production to grow should be diminished. ◎

Toll Road Roundtable

*Two recent high-profile privatizations of roads in the United States — the 7.7-mile Chicago Skyway and the 157-mile Indiana turnpike — are attracting the attention of both state governments interested in finding new ways to raise money to build roads and institutional investors looking for new places to deploy capital. P3**Americas**.com and Chadbourne hosted a roundtable discussion in New York in late February about the market outlook. The panelists were Greg Carey, a managing director at Goldman Sachs, Frank Sacr, a managing director at Société Générale in New York, Michael Kulper, a vice president of Transurban North America, Cherian George, a senior director at Fitch Ratings, Jack Bennett, senior program analyst for finance in the policy office at the US Department of Transportation, and Trent Vichie, a senior vice president at Macquarie Securities (USA). Richard Kenton, a managing director of P3**Americas**, made the introductions, and Doug Fried, a partner in the Chadbourne New York office, acted as moderator.*

Potential Market Size

MR. FRIED: How large is this potential market and what sort of deal flow can we expect over the next year or two?

MR. CAREY: The use of project finance and public-private partnerships — called PPPs — in the toll road industry is a process of evolution. There has been an evolution in structures, whether it is design-build contracts, 63-20 corporations or not-for-profit entities. The evolution has been driven by the need for delivery of capital. Texas, for example, is talking about an $85 billion shortfall in funding over the next 20 years. The question is how quickly are people drinking the Kool-Aid and saying PPP will happen? The answer is that because of the Indiana and Chicago deals and a few other transactions, project finance and PPP are alternatives at which everyone now must look.

We are entering a phase where two to four bigger deals will be announced each year for the next couple of years. Indiana proves that Chicago was not a one-shot deal. At a workshop a couple of weeks ago in Texas, 400 people showed up for five greenfield procurements that are much more difficult to pull off than the Chicago and Indiana privatizations. Every deal will be different; all politics are local. I think the activity and the interest in this marketplace are well deserved, and there will be growth in this type of delivery method.

MR. SACR: There is no doubt that we will see many projects each year over the next three to four years. Many US cities and states have budget deficits and are trying to find ways not only to use existing infrastructure, but also to build new infrastructure.

We are at the start of the cycle. It is a cycle we have seen in play in Europe and Australia. We will see whether the US model replicates what we have seen elsewhere.

MR. KULPER: Let me present the cautionary view, which is where I typically go. Chicago and Indiana demonstrated that there is tremendous latent value in the assets that already exist in this market. Given the value of those assets and the budget needs, which are pretty universal across jurisdictions, some more assets will shake loose. One to three transactions a year is about the pace at which the market for privatizations is going to develop.

The greenfield side of the market is a very different story. Over the last 10 years, probably no more than a half dozen greenfield projects have closed in this marketplace. I am not sure that relates specifically to the financing delivery method. It relates more to the inherent difficulty of getting such projects done and the difficulty of working through environmental processes and regulatory approvals. A lot of new laws have been enacted recently in an effort to expedite things, but everybody still has his or her training wheels on. The legislation is a necessary condition, but not a sufficient one for getting these projects done. The pace of greenfield development will continue to be slow. We hope to close the Capital Beltway project later this year, which I think will be the first greenfield to achieve financial closing in about five years.

The market is probably a couple of privatizations a year, and if we are lucky, one, maybe two, greenfields a year. The US is a large marketplace, but it is still an emerging market where no more than four or five deals are going to happen in even the best year. There are more than four or five competitors in each of the relevant spaces, so there will be a lot of tears and frustration. The level of interest is still well ahead of the pace of the development. I think people must take a long-term, five- to 10-year view of this market, because while the market has sufficient opportunity in the long term, it is not there yet.

MR. FRIED: So you think four to five deals in a year in total will not always be the high water mark?

MR. KULPER: Yes. There is a clear need for more roads. There is clearly a funding shortfall, and there are serious congestion problems in many urban areas that will create pressure to do deals. However, in many cases the problems are just being identified and the process of moving from understanding a problem to solving a problem, with all of the approvals — including environmental — that need to happen in between, is a five- to 10-year process.

MR. FRIED: How about the size of the deals; are they all going to be mega deals like Chicago and Indiana or will some be smaller?

MR. KULPER: I actually think the US deals to date have not been as large as they will ultimately be.

On the greenfield side, the next step is */ continued page 28*

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loans. The company paid out 10% annual interest on them. There was no fixed maturity date when the loans had to be repaid and no formal repayment schedule. Repayment was subordinated to the obligation the company had to its outside bank to repay loans from it. The shareholders liked the arrangement because unlike most corporate earnings that are taxed twice — once to the corporation and again to the shareholders when the earnings are distributed as dividends — these earnings were taxed only once. The company deducted the earnings that were paid to the shareholders as interest. Only the shareholders paid tax on them.

The IRS disallowed the interest deductions arguing that the "loans" were really shareholder equity in the company. The company did not pay any dividends during the tax years in question. All the shareholders received from the company were the regular interest payments.

A US appeals court said the shareholder loans were real debt. The court released its decision in mid-April. The case is *Indmar Products Co. v. Commissioner*.

The court acknowledged that it is sometimes hard to draw lines between debt and equity, and said it uses a list of 11 factors when trying to decide which label to apply. However, it said the factors distill to a simple test that "the more a stockholder advance resembles an arm's-length transaction, the more likely it is to be treated as debt."

The court found helpful to debt classification in this case the fact that the loans bore a fixed rate of interest, and the rate was consistent with market rates at the time. It said lack of a maturity date or repayment schedule was not important since these were "demand loans" that were to be repaid upon demand of the persons making the loans. It was helpful that the funds were used for working capital needs rather than to purchase capital equipment. The court said the */ continued page 29*

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to move from the $500 million to $1 billion projects to the $5 billion projects, which this market is not yet ready to do. On the privatization side, I think there are assets that are significantly larger, and you will see those deals happen.

MR. VICHIE: I think greenfield projects will be all over the chart. There will be $5 billion deals that will be hard for the market to accept, but you may see them as soon as one or two years from now, but no later than five years. Greenfield projects will come in a broad range of sizes.

Governments in Europe and Australia were driven 20 years ago to bring in private capital to finance highway projects. Budget problems are forcing US states to consider the same thing.

MR. GEORGE: You are not going to be surprised to find that I take the more cautionary view, but I am not going to be too negative.

There is a large potential for privatizations to improve infrastructure and significantly accelerate its delivery. In terms of the size of the market, it will depend largely on the perceived success of the deals that are done. Ultimately, the public will decide whether this move makes sense. It is important to make sure that the projects, from a public policy and from a governmental standpoint, are good projects and that people see long-term value. The perception today is that everything is good, but that has the potential to change in the future.

MR. BENNETT: Congress and the administration are betting that there will be an increase in the number of PPPs. The surface transportation reauthorization bill that President Bush signed in August 2005 provided several significant tools to encourage PPPs. The bill authorizes $15 billion in tax-exempt private activity bonds for qualified surface and freight transfer facilities. Additional provisions allow tolling of interstate highways, increased flexibility for design-build arrangements, streamlining of the environmental process, and improvements to the TIFIA and state infrastructure banks programs.

The government is proposing in the 2007 budget a pilot program of $100 million to provide funds for up to five states to test alternatives to the gas tax. This would be both for financing and to encourage addressing congestion and efficient use of facilities.

MR. VICHIE: One of the most telling statistics about the market is that, in the last 20 years, you have had a 78% increase in miles traveled while the amount of lane miles added has been 4%. The other obviously telling factor is that governments lack the money to deliver new lane miles.

There is increasing acceptance by government officials that the only way to get new roads built is to allow them to be tolled. Then it comes down to a question of what the delivery method will be. There is a lot of demand among private investors, and that will help drive things.

I also agree with Cherian George that how rapidly the market develops will depend on the perceived success of existing projects. For example, the perceived political success of the Skyway and Indiana is absolutely critical. If those projects proceed well, it will embolden politicians in other states to consider the same delivery method. If those deals are perceived as bad deals, then that will make it a lot harder.

MR. CAREY: We are really in a critical period today where the success of just a few projects is very, very important. Politically, it is a lot easier today to do a greenfield procurement for a new road than to take the much greater step of leasing — we don't use the word "sell" — an asset for a long period of time. Indiana is the prime example of using a lease to fund a shortfall.

Privatization v. New Build

MR. FRIED: What is your view on the two different types of markets that are emerging — privatization of existing assets and greenfield development of new projects — and where do you think the focus will be in the future?

MR. VICHIE: You will continue to see a mix of both types of projects. States like Texas have very ambitious plans of building a lot of new roads, but you are also hopefully going to see a few more existing assets shake loose in the next few years, and there is potential for some really good deals to happen. There are existing assets that can be leased, allowing state assets to be redeployed in areas where the need is greatest.

MR. CAREY: We will have to see in the next year or so what happens with the greenfield projects that are already underway. Greenfields are more difficult than privatizations. How do you bid with the construction issues? Privatizing an existing asset is a lot easier. The bidding is a lot easier. It is the quantification of traffic growth rate, toll rate and capture rates in the future. We need a couple of successes with greenfields to determine whether more will move forward or whether the market will be largely privatizations that pay for state construction of new facilities.

MR. FRIED: So what's happening in Texas and Virginia is really instrumental for the industry going forward?

MR. CAREY: Texas and Virginia and Florida with its Miami port tunnel project. I think it is going to be very, very important that these and other greenfields get done and that they get done right.

MR. SACR: We see a couple of drivers that either enhance the market or constrain it. One of the drivers for greenfield projects is construction risk. How is construction risk allocated, particularly between the banks and the construction contractors? With the size of some of the projects that we expect to see, the ability and the appetite of the construction contractors to absorb construction risks will be a big issue in how rapidly the greenfield market develops. Lenders may be used to seeing different allocations in other areas.

State and Regional Markets

MR. FRIED: Which states or regions will provide the most opportunity in the short term and the long term?

MR. KULPER: You must understand that the United States is not a market. Each state is its own market and, within some states, there are different markets. In Texas, for example, Dallas is its own market and / continued page 30

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fact that the company paid no dividends during the period would only have been relevant if the shareholders were charging interest at exorbitant rates. They were not. Not all of the shareholders made loans, but all of the shareholders were members of the same extended family.

The total shareholder loans were less than half the net current assets of the company and only a small fraction of its annual gross receipts.

Indmar treated the advances as short-term debts for state tax purposes in order to avoid a 6% Tennessee tax on dividends and interest on long-term debts. However, it treated the amounts as long-term debts on its financial statements and reports to its outside bank. It justified the reporting position by getting annual waivers from the shareholders who made loans that they would forego repayment of the principal for at least another 12 months.

NUCLEAR POWER PLANT owners qualify potentially for tax credits of 1.8¢ a kilowatt hour on the electricity they produce, but must apply to the US government for an allocation. Tax credits are limited to plants with a total capacity of 6,000 megawatts.

The IRS explained in April how it plans to allocate the credits.

The agency set two deadlines. Projects must apply to the Nuclear Regulatory Commission for construction and operating licenses by December 31, 2007. This deadline will be extended until the NRC has received applications from at least 6,000 megawatts worth of plants. Then projects have another seven years — until January 31, 2014 — to apply for tax credits. The tax credit application must be sent to both the US Department of Energy and the IRS. Applicants will be informed by the end of 2014 whether they were awarded tax credits.

All plants whose appli- / continued page 31

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Houston is its own market, and there are other markets in Texas. This makes it very hard to answer the question in a generalized way.

On the greenfield front, there have been more failures than successes in the last 10 years. There have been examples of developers spending two years and a lot of money on processes that go nowhere. The incumbent developers of projects are quite cautious about this marketplace and are looking to the public sector to provide tangible evidence that it is in fact serious about delivering these projects. Having enabling legislation at the state level, where at last count about half the states have legislation, is a necessary, but not a sufficient condition. Having the expedited federal processes is very helpful, but, again, a necessary, not a sufficient condition. What you need is political will to get things done, and you really have to pick your spots very carefully because you are investing between two and five years and millions of dollars. I don't think you are going to see very many markets develop quickly, and I think people are going to be biased towards sticking with states like Virginia and Texas.

The next series of states and regions that will develop opportunity will be those that have the most need. It will be states and regions where there is a lot of growth, like Florida, and places that have big cities and lots of congestion, like California, New York and New Jersey.

MR. FRIED: Assuming one can get past the political issues in places like California?

MR. KULPER: Politics are interesting. The point at which there is commitment to these kinds of projects is when congestion becomes a political issue. The problems in some parts of California are significant enough, and the budget problems are significant enough, that you are going to see movement within three to seven years.

MR. VICHIE: I absolutely agree with Michael Kulper on that. If you would pick a market, California is one that seems to have the greatest need, but the tough thing about California is that it has really interesting politics. It is hard to get things done there.

There has been a 78% increase in the last 20 years in traffic on US roads while road capacity has increased only 4%.

We are involved in a couple projects in Oregon about which we are pretty hopeful, but they will take a little while. We don't expect anything this year, but maybe next year we will have a successful project to announce and hopefully that will roll things along there.

I think you might see activity in some of the midwestern states. I don't want to point to any one state in particular, but certain states are going to get cash by leveraging their existing facilities that can be used to deliver a whole range of new projects. One of the political drivers of the process will be the creation of new jobs. Politicians think about platforms to run on. If they can create 50,000 to 100,000 jobs with a massive transportation program, kind of like what Mitch Daniels is trying to do in Indiana, then road privatizations to raise financing look attractive. Traditional industries in the rust belt are in transition and political leaders are looking for new ways to create jobs and growth.

MR. GEORGE: To the extent that you have a strong champion of the project and a key position taker, you will see movement. Chicago had a strong champion in the mayor. In Indiana and Texas, you have the governor behind the projects. In Florida, the Florida Department of Transportation is making a big push to get things done in a new way. States where the state department of transportation plays a strong role and can make decisions that go beyond an electoral cycle may see movement because these projects are not going to get done necessarily in four years.

MR. BENNETT: On the question which states will offer the greatest opportunity, the answer is, one, states that have a large portfolio of toll roads, two, high growth states, and, three, states that have lots of congestion. Several candidate states have been mentioned already. There are opportunities in Georgia, Utah, Florida, New York, Oregon and the sleeping giant, California.

MR. FRIED: There seem to be many obstacles to getting this industry going in New York. Would anyone like to comment on that?

MR. CAREY: Look at the recent failure of the west side stadium recently and the failure of Westway. New York is a unique political environment with many different constituencies, whether they be the unions or the legislature. You have the head of the state assembly and the head of the state senate who are just as strong as the governor, and these three key political leaders don't agree. New York has very parochial politics.

MR. KULPER: The politics of these projects are difficult wherever you go. I don't think the politics are any easier in Texas or any other place.

Market Drivers

AUDIENCE MEMBER: Does the initiative in this market come more from government officials or from developers and advisers who are looking for bankable projects?

MR. CAREY: I think that the job of the developers and lenders is to go out and stimulate business delivery methods. I think the speaking circuit we are all on these days is an effort to encourage that. That said, you always need the political champion and the ability to reach agreement on the use of proceeds will either make or break a lot of these projects, especially the large asset sales, where there is fighting over the spoils. You need someone willing to take the heat for the difficult decisions.

MR. VICHIE: The market drivers are a combination of factors. A lot of the market stimulation will come from developers asking state officials whether they have considered other options besides state construction of new roads. Here is what a road map could look like. Another driver is a politician who can effectively sell the idea to the public. Yes, this is a good idea. I can run with this.

Once there are a few good examples in the market, then other politicians will read about it and decide it makes sense in their states, as well. / *continued page 32*

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cations are approved will share in credits. Thus, for example, if plants with a total capacity of 8,000 megawatts are approved, then each will be allowed to claim credits on three fourths of its electricity output. The IRS chose this approach at the request of the nuclear power industry, rather than rank projects and make full awards to plants with the highest rankings until the 6,000-megawatt cap is reached.

The procedures for applications are in Notice 2006-40.

To qualify, a project must use a nuclear reactor design that was first approved for use by the Nuclear Regulatory Commission after 1993.

Construction must begin by January 2014 — *before* the government has informed projects whether they will be allowed tax credits. Construction is considered underway when safety-related concrete is poured for the nuclear reactor building. Each reactor is considered a separate project.

The plant must be put into service no later than 2020.

The tax credits are claimed on the electricity output in the first eight years after a plant is put into service. However, no more than $750 million in total credits must be claimed. The cap is $125 million for each 1,000 in national megawatt limit that the IRS allocates to a project.

Twenty percent of US electricity is supplied currently from nuclear power plants. There are 113 such plants in operation in the United States. It takes approximately nine years to license and build a new plant. Nine companies or consortia are expected to apply in the next two years for licenses to build between 12 and 19 new nuclear reactors. These will be the first new nuclear plants built in the US in several decades.

A CALIFORNIA TAX on limited liability companies has been declared unconstitutional.

Companies need to file refund claims.

California collects an / *continued page 33*

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MR. FRIED: What is a more important driver: budget deficits or highway congestion?

MR. VICHIE: Both. There is clearly a need for construction of new roads. It is also clear that there is not a lot of money, so there are gaps in transportation plans that need to be filled.

AUDIENCE MEMBER: Many of the existing greenfield projects cost less than $500 million. A number of them are in the $10 million to $20 million range. What rules of thumb are there for the institutional equity market to assess whether deals that size are worth the trouble?

MR. CAREY: The amount of time involved and the level of competition are important. The transaction costs may be the same for a small project as for a large project. The design costs may be the same. These are factors in the return on equity. What are the opportunity costs? When you have to bid a deal, you spend up to 10% of your money before a deal gets bid. The bid costs may range from $1 million to $10 million depending on the deal. Is that too much money to be risking on a greenfield project?

In terms of competition, deals will get done if the economics seem to make sense. Competition may ultimately help get the deal done.

MR. VICHIE: If a $10 million or $20 million project still needs 10 years worth of work, developers will not bother with it. On the other hand, if the project has gone through an environmental process and it is just reaching the funding stage and can be closed in six to 12 months, then maybe.

It also comes down to the amount of resources the party has. Some people coming into this market may have only a couple guys on the ground. The smaller projects may not be the best use of their time, but someone with a larger deal team may be able to justify it.

MR. KULPER: The level of competition is important. If you ask four people to show up and bid on a $100 million job, you are going to be disappointed. But for the smaller deals, there are probably situations where you can have a negotiated outcome that makes sense for all parties because developers look at risk as well as reward, and while the rewards may not be so big if you can prepare the deal on an exclusive basis and have it environmentally cleared, there may still be an opportunity to do something because there is less risk.

Investment Grade Ratings

MR. FRIED: Cherian George, at what factors do the rating agencies look when determining whether a project deserves an investment grade rating?

MR. GEORGE: Briefly, it is important that the government maintain flexibility. The decisions that are made today may affect the government's ability to provide for future public needs. It is important to maintain the ability to adjust as times change. The government should also maintain the fair value of the asset. To the extent that the state takes money up front, there is risk that the money might be diverted to other uses. One of the things that has been talked about, in the case of Delaware for example, is the creation of a trust, where the money is kept over a long period of time. That's extremely important because if there is a termination, at least you can look at the trust.

In terms of a concession, an extremely important factor is the long-term track record of the concession holder in doing projects around the world. At the end of the day, these deals are going to have a lot of debt, so there is a balance that must be maintained between financial flexibility — that's cash flow, rate-making flexibility over the life of the deal and liquidity, on the one side, with leverage, on the other.

The market for private roads in the US is still thin — only two to four major deals a year.

The clarity of performance requirements is also important. It should be clear what the basis of performance can be and how any defaults might occur in terms of performance.

Another important factor is complete independence in ratemaking. There should be no ambiguity within the approved toll rate regime. The project should have latitude to do what it needs to do.

Very aggressive traffic and revenue assumptions would clearly be a negative. We do see, particularly with deals like Indiana and Chicago, where nominal GDP per capita has been factored into the equation for setting tolls, so that there is the ability to raise revenues at much higher rates. This is particularly true here in the United States, which economically has much stronger characteristics than almost any other country in the world to generate greater levels of revenues than we have ever seen. But maintaining some conservatism in that respect will be important.

Political risk is something that we know exists. We are sensitive to it in deals and take it into account in the rating.

Another point is unamortized balances. You are looking for the ability in short-term deals to take out the deal as soon as possible. You might have an element of refinancing risk. The debt might be short- or medium-term debt with a bullet payment. Clearly, with 99-year deals and 75-year deals, there is a lot more flexibility about when to refinance. Macquarie demonstrated that with its recent financing of Skyway. Refinancings can be expected to occur a number of times. It's not an issue any of us will have to deal with in our lifetimes, but somebody at some point is going to have to make sure that the amount of leverage on the deal is enough over the life of the concession.

Finally, traffic forecasts are a concern. There is no surefire way to forecast future value and limit the leverage over time, and that is something about which all of us need to be vigilant.

MR. FRIED: How do you analyze traffic forecasts?

MR. GEORGE: The traffic forecasts give us a good sense of the background on the project, the nature of the demand and the economics over time. In terms of the actual numbers, we at Fitch think that the magnitude of volume that these forecasts predict is more important than the actual number. The reason is these models are not designed for financial planning purposes. They are engineering and planning models. To be safe, they err in the opposite direction of how a conservative financial model would err.

What we have seen in our experience */ continued page 34*

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annual fee on limited liability companies doing business in the state. The fee runs from $900 for LLCs with incomes between $250,000 and $500,000 up to $11,790 for LLCs with incomes above $5 million a year. The state makes no attempt to determine how much of the income was earned in California as opposed to other states.

A California superior court ruled in March that this failure to base the fee solely on income earned in the state makes the fee unconstitutional. The commerce clause of the US constitution requires that a state limit any tax to business activities within the state. The court said the LLC "fee" was in reality a form of tax. The state is expected to appeal the decision.

In the meantime, LLCs that have paid the fee should file refund claims. There is a four-year statute of limitations in California on audits and refunds. The four years begin to run on April 15 of each year or, if later, when a tax return was filed. Thus, most LLCs should be able to file refund claims back to 2002. Some may still be able to seek refunds for 2001 taxes depending on when their returns were filed in 2002. The maximum refund for four years of fees is only $59,000, but back interest could double the amount. The case is *Northwest Energetic Services, LLC v. California Franchise Tax Board*. A second LLC fee case, called *Ventus Finance I LLC v. California Franchise Tax Board*, was scheduled for trial on May 8.

LLCs that are registered to do business in the state must also pay a minimum franchise tax of at least $800 each year — in addition to the LLC fee.

Separately, the California State Board of Equalization ruled in March that an out-of-state LLC that owns interests in other LLCs and partnerships in California is itself doing business in California and must pay both the annual LLC fee and minimum franchise tax. The ruling was in a case called *In re International Health Institute LLC*. The */ continued page 35*

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is that while the forecasts have been higher than the actual traffic in the near to medium term, particularly on the long end, they tend to severely underestimate. So there is a lot of value on the back end. That's where I think the debt structure is. Macquarie and Transurban, which do some of these deals, have brought structures to market that reduce the default risk.

I think even the Dulles deal that was done by Bear Stearns last year did that very well where Bear Stearns was able to reduce the default risk by recognizing the growth in long-term value of these deals. The combination is what we look at.

MR. FRIED: So the lenders have to be a little bit more patient at the beginning and allow for longer ramp-up periods and then make it up later?

MR. GEORGE: Absolutely.

MR. SACR: That's actually very helpful, Cherian. The rating agencies have a crucial role to play, particularly in the US market. We talked earlier about toll rates in Australia and Europe. The potential toll rates in the US just swamp everywhere else and the demand, if you count up all the roads, the huge amount of capital and the ability to recycle capital and to have projects rated and distributed into the biggest capital market in the world, these are all reasons for optimism.

I think one of the things we as lenders are looking for from the rating agencies is transparency. It is important to understand the ratings criteria.

MR. CAREY: Let me ask Cherian George a question. We used to have discussions years ago about pricing capacity and the ability to raise tolls even though municipalities obviously prefer not to raise tolls. Please talk about the evolution of raising tolls, the trend of linking toll increases to GDP per capita and where you think the market is going with this.

MR. GEORGE: We tend to think if you raise rates consistently, you should be able to raise them at least at CPI, meaning the real cost to the user remains constant. People's expectations that toll will increase regularly over time should not lead to a reduction in traffic volume. What that would argue for, particularly in a free network that is congested where the toll road has the capacity, is the ability for the toll road to accept growth even at rates higher than inflation. That's where the concept of GDP per capita comes in because it is a sense of economic activity. We don't see any reason why you should not be able to raise rates at or close to GDP per capita, particularly in good times, and also have traffic growth at some level. At least, there should not be any traffic reductions.

Competition among investors for deals has probably tripled since the Chicago Skyway transaction in 2005.

Future Competition

MR. FRIED: Now that people in the industry have had a chance to think about the economics of the Chicago Skyway, including the various assumptions that were made, how much competition would you expect for similar deals in the future?

MR. CAREY: The number of new entrants into the US market, whether foreign or domestic, continues to grow at an outstanding pace. Competition has probably tripled since the Chicago bid. There are many investors interested in this asset class. The ability to invest long-term equity, patient equity as we call it, is phenomenal.

MR. KULPER: There will be vigorous competition for privatization projects. The international toll road concessionaires will continue to show up, and my expectation is that there will be a domestic US industry that grows up over time. A lot of institutions have raised infrastructure funds looking to put money to work, and those guys will show up. Competition for privatizations will be intense.

On the greenfield side, the ideal situation for state departments of transportation is to put projects out for bid. The problem with that is private sector resources are needed in most cases to expedite projects and get them to a position where they are in a position to close. You are going to continue to see a bifurcation between those markets where greenfield projects will be awarded based on qualitative criteria and others where the developer will be a partner with the state department of transportation to move the projects to closing. A perfect example is the hot lane projects that we are doing in Virginia.

MR. FRIED: Do you expect more non-US entities to compete in the US market?

MR. KULPER: Most of the experienced overseas players are already here. The next big stage is going to be the financial guys in the US wanting to play. The difficulty they have is lack of knowledge and experience in dealing with roads.

MR. VICHIE: It seems like every week you read another article and you hear about another Wall Street firm raising a fund to invest in this area. The problem is that successful investing in roads requires a lot of expertise. It requires a lot of bodies on the ground and a lot of people who understand the asset class. The real competition from US financial houses is still a few years away.

MR. FRIED: How important is knowledge of the local market?

MR. VICHIE: It is important, but it is more important to understand the asset class. You can hire locals who can help you navigate the market. That's important, but that is really not what differentiates market participants. What gives someone an edge is understanding the asset class, including how to price the risks involved and how to structure a deal.

Traffic Risk

MR. FRIED: How will developers and lenders in the US get comfortable with traffic risk?

MR. SACR: We are trying to apply to US roads the same rules and lessons that we apply globally. The main differences among bidders in the US are not so much their financing structures, which are more or less of a similar style, but rather their traffic growth assumptions. Everybody has his or her own traffic consultant, and the bank also / continued page 36

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board takes a broad view of what it means to be doing business in the state.

In an unrelated development, a California appeals court held in April that Toys "R" Us could not count as sales income both the principal and interest payments that its treasury department earned from investments in short-term instruments to manage cash flow. The toy company earns most of its income around Christmas. Its treasury department then invests the funds until they are needed to start rebuilding inventory during the summer.

California, like other states, figures out what share of income a multinational company like Toys "R" Us earned in California by looking, among other things, at the share of its total sales that are in California. The company's treasury department is in New Jersey. The appeals court said it could count as sales revenue the interest earned on the investments, but not repayments of principal.

> *The court said that if principal also counted, a company could cause a huge shift of allocable income outside the state merely by moving its treasury department with a handful of employees across state lines. The case is* Toys "R" Us Inc. v. California Franchise Tax Board.

MICHIGAN declined to take into account the fact that an independent power plant is a "QF" project when assigning a value to it for property tax purposes.

Utilities are required by federal law to buy the electricity from certain power plants called "qualifying facilities." The city of Midland, where the power plant is located, argued that the plant was assigned too low a value for property tax purposes because the assessor failed to take into account the special regulatory status of the plant. A state appeals court disagreed in a decision in late February. The case is *Midland Cogeneration Venture v. City of Midland*.

The property tax asses- / continued page 37

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takes its own view. I am sure that rating agencies take their own views as well.

MR. KULPER: Traffic is an issue with which we all grapple. It is interesting that for both the Chicago and Indiana projects, Macquarie decided to use a foreign firm. Transurban's approach to its projects today has been to rely on very substantial in-house expertise. We view traffic risk as such a critical area that we have a team of eight individuals, and we have a competency in-house that we supplement with locals. We are very active participants in the process.

I think the US industry has relied on traffic studies that are not suited for all the purposes to which they are being put. The studies may have been done for a department of transportation whose motivation is to deliver infrastructure and not necessarily to ensure the sufficiency of the investment. The other primary consumer of traffic studies has been the construction contractors who want to build the roads. There has not been enough investment yet in traffic studies, and the result is the existing studies may lack the rigor and comprehensiveness that the financial community needs.

My guess is there is a high degree of correlation between the amount of time and effort put into traffic forecasts and how much actual traffic usage has varied from the forecasts in the projects that have been done to date, and that this is a key factor in whether projects succeeded or failed.

MR. CAREY: Traffic risk is the $64,000 question. How is the investment going to pay off and how much room do we have at the end to fix it if it doesn't?

MR. FRIED: I think, as Cherian George said, traffic volume often starts out low and then improves on the back end.

MR. VICHIE: The macroeconomics are driven off what is going on in the surrounding area. Having a good understanding of the macroeconomics, certainly when you are looking at a 75-year concession, is absolutely critical because you are ultimately investing based on a cash flow projection.

The question is how much risk is there in a particular project. It may be tougher to get lenders to take traffic risk for projects that have lots of tunneling or development of mountain faces or other construction risks.

Final Thoughts

MR. CAREY: I think private activity bonds will have an effect on the market. The availability of tax-exempt financing will not determine whether projects get done, but they will enhance the potential returns from certain projects. TIFIA [grants] will have the same impact. TIFIA puts additional pseudo equity in greenfield projects. Only one TIFIA deal has been done to date on the private side, and that is the SR 125 project near San Diego.

AUDIENCE MEMBER: Might there be some movement towards the simpler shadow toll or availability payment type deals being done in Canada?

MR. SACR: From a banker's perspective, those deals are very attractive.

MR. CAREY: There are toll transactions that are being done now in Texas where the municipality is taking the risk — one is in Williamson County and there is one supposedly in Collin County. There is an evolution that is just starting, but those deals will be slow in coming.

MR. VICHIE: My view is that you might see a couple here and there, but the majority of the market is going to be real toll deals.

MR. GEORGE: The recent federal highway bill authorized more than $280 billion in public funding for transportation. Shadow tolls are a means in which to bring the private sector in and get more for each public dollar. The United States could move in that direction in the future.

MR. VICHIE: This market is in its infancy. I am hopeful that you will see slow expansion and growth. More successes will

Whether the US toll road market ever truly takes off will depend on perceptions five years from now about the Chicago Skyway, Dulles Greenway and a few other marquee transactions.

mean more projects. Clearly, there is a demand and the private sector is developing quite nicely there to meet that demand. The right factors are here for the market to work. It might be a bit slow, but the market will get there.

MR. BENNETT: We have come a long way in a couple of years and I think if we were to meet again in a couple of years, we will have come a good distance more. We in the federal government are beginning to think about the next reauthorization for the surface transportation bill. A couple of commissions have been set up to look specifically at alternatives for the gas tax. We will also be looking to the states and developers for ideas to include in that reauthorization that would help encourage PPPs.

MR. GEORGE: My comments really focus on the big picture policy issues. In my opinion, the federal government is standing a little bit more on the sidelines of this privatization effort than it should be. There is a need for corridor management. With the Skyway for example, we have the traffic along the corridor, not just the Skyway, and there are other roads that feed into the Skyway. Understanding the impact on the rest of the network is something that I think the federal government should address given that the impact will be beyond just a city or a state. Indiana has an impact on an entire corridor that serves from the east coast to the midwest. Those are areas where the federal government should play a role by encouraging individual states to fall in line with a regional or national program.

MR. KULPER: Let me give the global context. In most of the other developed nations in the world, governments were forced to turn to the private sector for delivery of infrastructure, specifically roads, because they could not afford to provide it themselves. There has been a 20-year plus history of this in Europe and Australia. The US has been fortunate that the public sector has been able to provide this service for a lot longer, but over the last 10 years or so in particular, the US system started to break down because the needs exceeded the system's ability to fund. Out of necessity, the inevitable long-term trend is that the private provision of capital to these assets will continue to grow. In the short term, an irrational exuberance in the marketplace accounts for the demand for these assets exceeding the supply. There will be some winners and losers as this works out. The successful players will be the ones that understand the asset class and have been doing this for a long time. Over the longer term, I think there is a very good business here. */ continued page 38*

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sor used the replacement cost method to value the plant. In other words, he looked at what it would cost to build the same plant today, and then adjusted the amount to reflect wear and tear at the plant.

The court said this was a reasonable approach given that there was no guarantee the utility that buys the output from the plant — Consumers Energy — would agree to let any new owner of the plant keep the contract.

FOREIGN COMPANIES that invest in the United States through joint ventures are chafing at US withholding taxes.

The United States requires partnerships with foreign partners to withhold US income taxes from the share of each such partner's partnership income that is effectively connected with a US business. A partner's share of income may have nothing to do with the cash it is distributed by the partnership. Suppose a partnership earns $100 and uses $90 to repay principal on a loan. The withholding is on each partner's share of the $100.

The withholding taxes are at a 35% rate for foreign partners who are individuals, but can reach as high as 54% for foreign partners who are corporations. The higher rate for corporations is due to additional withholding for "branch profits" taxes.

Any partner who has suffered from overwithholding can get a refund by filing a US tax return. Many choose not to do so.

Meanwhile, US tax withholding is not required on interest that a US borrower pays on "portfolio debt." That is debt that is held by someone — like a private equity fund — that is not in the regular business of lending like a bank would be. However, someone who receives portfolio interest cannot avoid withholding if he or she owns 10% or more of the US borrower.

The US Treasury is working on guidance to address whether this */ continued page 39*

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MR. SACR: I think we see a few different drivers, if you would like, that could constrain or drive the market. We talked about the construction risks. Traffic growth, to the extent it happens, is going to bring a lot more capital into the market. Finally, the transparency of how these projects are being rated is going to be an important factor given the amount of capital that will be required in the US.

MR. CAREY: Returning to the point that Trent Vichie raised earlier, there has been a 4% increase in capacity while traffic miles driven increased by 74%. The last economic development tool most municipalities, cities or states have is transportation, whether it is on the rail side or the highway side. Just like [Garvee] bonds took a long time –- it took some departments of transportation 10 years of talking before they realized it was a drug — once they started using such bonds, they had to continue using them. I think the idea here is that further education and continued success of these transactions will determine whether this is a long-term viable business or not.

MR. FRIED: Over the last few years, we have seen a tremendous increase in the profile of this industry. If a few years ago we had a similar roundtable on the PPP transportation industry in the United States, there would have been only about a dozen of us sitting around a table. Only time will tell what happens over the next few years.

Ethanol from a Lender Perspective

Chadbourne participated in a briefing about the US ethanol market in New York in March hosted by WestLB. The following are edited excerpts from the briefing. The speakers are Tom Murray, managing director and co-head of the loan and debt capital markets group at WestLB, Todd McGreevy, a senior consultant with Muse Stancil, Rohit Chaudhry, a partner in the Chadbourne Washington office, and David Black, president of Americas Strategic Alliances.

MR. MURRAY: Several high-profile individuals like Bill Gates are interested in ethanol development. Gates has invested $84 to $85 million in an ethanol company called Pacific Ethanol. Richard Branson, the founder of Virgin Airlines, is also interested in investing in ethanol.

The main drivers behind the current interest in ethanol are high oil and gasoline prices and the need for ethanol as a replacement for a fuel additive called MTBE. MTBE is being phased out due to its contamination of ground water.

There is significant political support in the United States for ethanol production. George Bush has been promoting ethanol in a series of political events this year. The Energy Policy Act last August set a renewable fuel standard of 7.5 billion gallons a year by 2012. To meet that, we calculate that more than $5 billion will be required for production capacity and several billion more will be needed for support infrastructure.

Now, that being said, the other side of the coin is that there is a fair amount of uncertainty about how this industry will evolve. There are inherent risks such as commodity price mismatch risks between the corn or grain supply and the ethanol output. The large banks and private equity funds are trying to figure out now how to play in the ethanol space.

Some of the open questions that are being asked are: Is ethanol going to be limited to the role of a fuel additive? Will it develop into an economically-viable alternative to gasoline like it has in Brazil? Who in the industry is going to make a profit? Will most of the profit go to the plant owners, the raw material suppliers, the marketers, the transportation providers, technology suppliers or the construction contractors?

Then, finally, what type of plant should one build? Should one build a dry mill, which most of the US plants are? Or should one build a wet mill? Another question a lot of people ask is whether to build in the corn belt or to build a destination plant. Most ethanol plants that have been built to date have been built near the grain source, but many projects under development are destination plants in places like Texas, California and the northeast.

Risks and Possible Mitigants

The first and foremost issue for anyone thinking of providing financing for a plant is the commodity price risk. There is a lack of correlation between the grain supply and the ethanol price. Also, if a significant reduction in oil prices were to occur, it would cause ethanol prices to fall since ethanol is basically a direct substitute for gasoline. Ethanol is profitable currently because oil is expensive. Some of the experts believe the break-even price is somewhere around $25 to $30 a barrel of oil. Oil prices below that figure would make ethanol an uneconomic investment.

There are also legislative risks. The US government allows an excise tax credit, but it will remain in effect only until December 2010. The credit is an indirect subsidy of 51¢ a gallon, provided to the blenders. If the credit is not renewed, it could result in a decrease in the price of ethanol, thereby having a negative impact on the ethanol industry. The US collects duties on ethanol imported from other countries. This helps domestic producers, but there is always a risk that the duty will be suspended.

There are concerns about overcapacity. Many lenders remember the overcapacity in the power sector and how they were caught holding loans to projects that could not repay the loans after prices collapsed. This is a concern on their minds as it relates to ethanol.

Lenders address the risks on the commodity price side by using conservative financial structures that require significant equity and equity-like debt as well as leveraging. There are mandatory cash sweeps that ensure the debt will be repaid in five years, notwithstanding the fact that the useful life of the plant is 20 or 25 years. We are also seeing management services provided by sophisticated players like Cargill and ADM to help mitigate some of the commodity price risk. These mitigants are not enough to allow the capital markets to open to this space.

Some of the other things that are being talked about are tolling contracts with investment-grade counterparties. There are oil and agricultural companies who are talking about providing a contract that would tie the price of grain supply to the ethanol output. That would obviously be a welcome structural change that would open up the debt market to ethanol financing.

There is the potential for vertical integration — of getting the grain supply in ethanol production. We have heard that probably too much land is likely to be required for that to be feasible. However, the concept of grain price subordination to operating and maintenance expenses and debt service is something that may be possible if we have creditworthy suppliers willing to enter into this type of arrangement. We have not seen this yet in the ethanol space. It is something that was implemented early on in merchant power plant financings. / continued page 40

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requirement that an interest recipient not own 10% or more of the borrower is applied at the partner or partnership level in cases where the offshore lender is considered a partnership for US tax purposes. The guidance is expected by year end.

CONSTRUCTION COSTS can sometimes be allocated largely to the part of a project that a company will sell at completion to a third party, even though the company will retain part of the project for itself.

Qwest, the US phone company, had contracts with various companies to bury conduit for holding fiber optics cables along rail beds. The company charged $30,000 to $40,000 a mile. Conduits are tubes through which fiber optics cable is pulled. The customers would own the conduits and fiber cable eventually pulled through them. The jobs involved digging trenches. In addition to burying conduits for its customers, Qwest would also put in conduits that it would keep for its own future use. Qwest allocated the cost of the construction jobs largely to the customer conduits, and assigned to the conduits it kept only the incremental costs of putting additional conduits in the trenches.

The IRS told Qwest it had to average the costs between the two uses — conduits that it sold and those that it kept.

The US Tax Court disagreed in a decision in March. The case is *Anschutz Co. v. Commissioner.*

The court said the incremental cost approach used by Qwest was more consistent with its business plan. The company would not have undertaken the projects without a customer contract.

COAL SUPPLY CONTRACTS were not taxed when transferred as part of a swap of mining properties.

Peabody Natural Resources Company exchanged its gold mining business with Santa Fe Pacific Mining Co. for a coal / continued page 41

Ethanol

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Another option is to integrate the ethanol plant with a co-product plant. This is called a wet mill. In a dry mill, about 85% of the revenue comes from ethanol sales and 60% or more of the operating cost is the cost of grain. That leads to a pretty big mismatch. If you were to integrate a corn fractionation facility or a vital wheat gluten facility into an ethanol project, then your grain cost could effectively be covered by your co-products. The remaining risk could be covered by hedging against ethanol prices. We have not seen that yet as a lender, but many of the large agribusinesses like ADM and Cargill have built these types of facilities. Wet mills are more expensive to build.

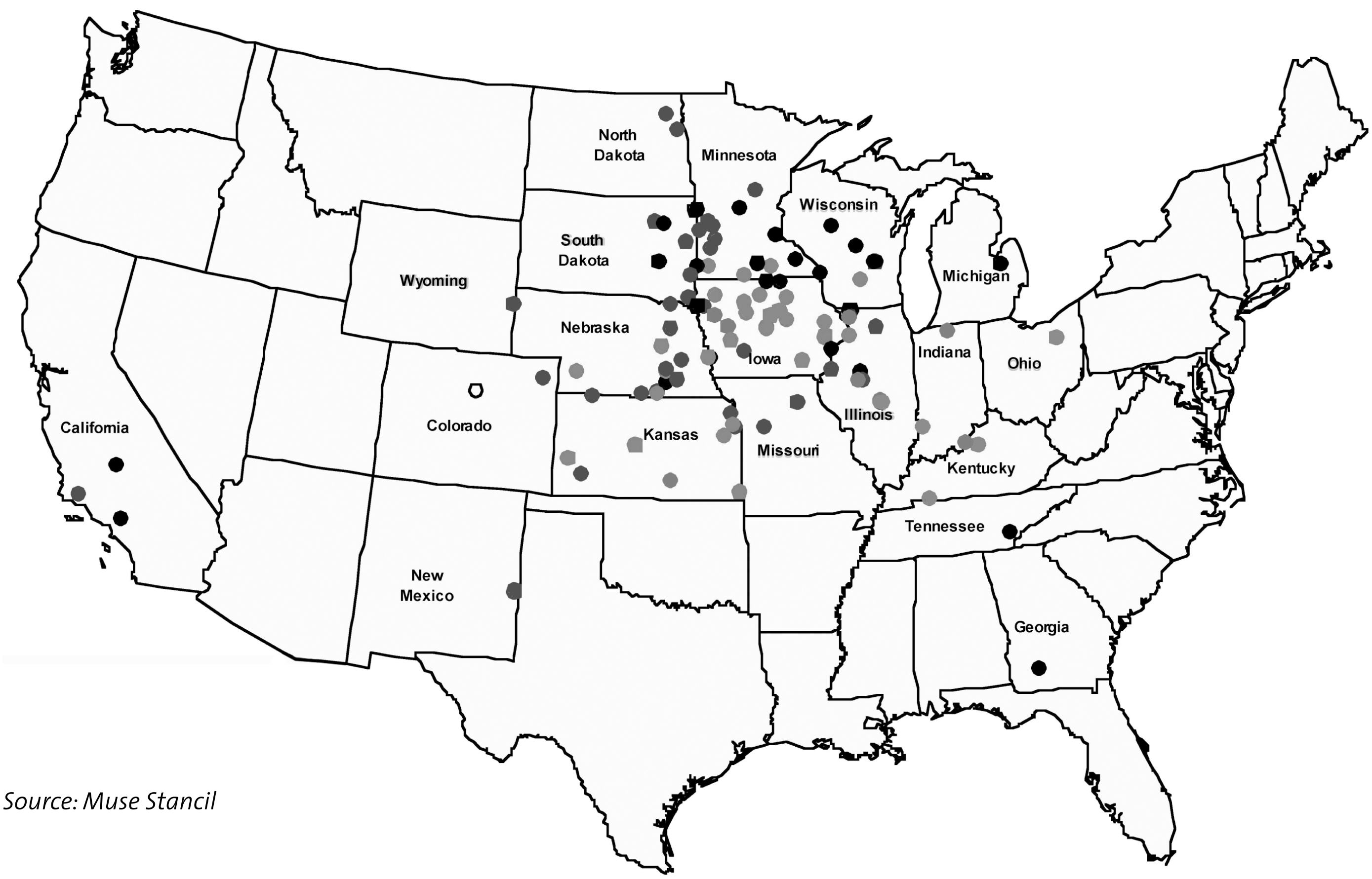
There has been a lot of discussion about producing ethanol from cellulosic and waste material. That would limit the commodity price risk to the output side. Currently, such processes are too expensive. It costs more than $2 a gallon to produce ethanol from cellulosic material.

As for possible mitigants of the legislative risks, it is important to note that ethanol plants are profitable on a standalone basis given current oil prices, even without any government support. However, if oil were to drop below $25 a barrel, then additional support would be needed from the government.

We, as a lender, are not too concerned about the overcapacity risk in the short and medium term. We think that the contractors and technology providers serving the sector have too limited a capacity to make overbuilding possible. However, in the long run, overcapacity is a concern and will require vigilance to investors and lenders to prevent.

Figure 1

Currently Operating US Ethanol Plants



Source: Muse Stancil

Trends

I think one trend that we will see is consolidation of the industry. Many plants today are owned by small farmer cooperatives and small developers. We expect pure ethanol companies with larger size and more scope to move into the market. Also, the large agricultural concerns and oil companies may decide to roll up ethanol plants in an ethanol subsidiary.

We think the move from use of grain to less valuable materials, including cellulose materials and waste, as a feedstock is still probably five to 10 years away because of the technological advances that are needed to make use of alternate feedstock economically viable. However, it is important to note that the current generation of grain-based plants can be converted to consume cellulosic feedstock with only minor modifications. All the money pouring into grain-based plants today is not money that will be lost if we develop technology to produce ethanol from cellulose material.

One question on a lot of people's minds is whether ethanol can become a competitive alternative to gasoline. It is a viable alternative in Brazil where ethanol represents more than 50% of vehicle fuel. There are already service stations in the midwest that provide E85, which is a blend of 85% ethanol with 15% gasoline, and we have flex fuel vehicles that can consume anywhere from zero to 100% ethanol and anywhere in between.

What is required for long-term success of the ethanol industry is continued high oil prices, which would drive the necessary investment in research and needed infrastructure, or continued temporary government support to accelerate the pace of technological advances. Keep in mind that the excise tax credit runs to the end of 2010. That is another four and a half years to enjoy the benefits of the government support.

Finally, and on a somewhat controversial note, many supporters of the ethanol industry argue that the true price of oil is actually higher than the $70 being charged today on world markets. That's because the price does not take into account the vast amount of money the US government spends to secure a steady supply of oil from places such as the Middle East. If you taken into account this cost of securing the supply, then the true cost of oil is closer to $200 a barrel. If we could take some of that money and use it instead to advance ethanol, it would go a long way toward the energy independence that we are seeking.

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mine in New Mexico and two long-term contracts to supply coal from the mine to Tucson Electric Power Company and Western Fuels.

Ordinarily when two companies exchange properties, the exchange triggers an income tax. Each company must compare the fair market value of what it received to the "tax basis" it had in the property it exchanged. The difference is taxable gain.

However, no tax is triggered if the properties being swapped are of a "like kind." The IRS does not allow like-kind treatment for exchanges of most contracts. Peabody argued that it was exchanging real property — one mine for another — and the coal supply contracts were a kind of real property right tied to the mine.

The US Tax Court agreed in early May. The court said the key was New Mexico law treats the supply contracts as a "servitude," or right to receive the coal dug out of the mine for the full terms of the contracts. The contracts burden what any owner can do with the mine. The case is *Peabody Natural Resources Company v. Commissioner.*

"DISREGARDED ENTITIES" may become harder to arrange outside the United States.

The US Treasury Department is considering a proposal not to allow US companies to treat their offshore subsidiaries as "disregarded entities" for US tax purposes in cases where the subsidiaries are separate business units. The IRS currently lets US companies choose how to classify most subsidiaries as transparent or as separate corporations. A subsidiary that a US company chooses to treat as transparent and that has a single owner is treated as if it is does not exist; it is "disregarded."

Perhaps counterintuitively, the ability to treat offshore subsidiaries as transparent makes it easier to prevent offshore earnings from being taxed immediately in the United States. US tax can be delayed by keeping the earnings offshore.

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Market Outlook

MR. McGREEVEY: My topic this morning is the "Ethanol Market Outlook 2006 and Beyond." Ethanol has been part of the US fuel supply for decades. It has been used as an octane and volume extender, primarily in the midwest where the bulk of the corn supply is located. In the early 1990s, it also found a new niche as an oxygenate for reformulated gasoline.

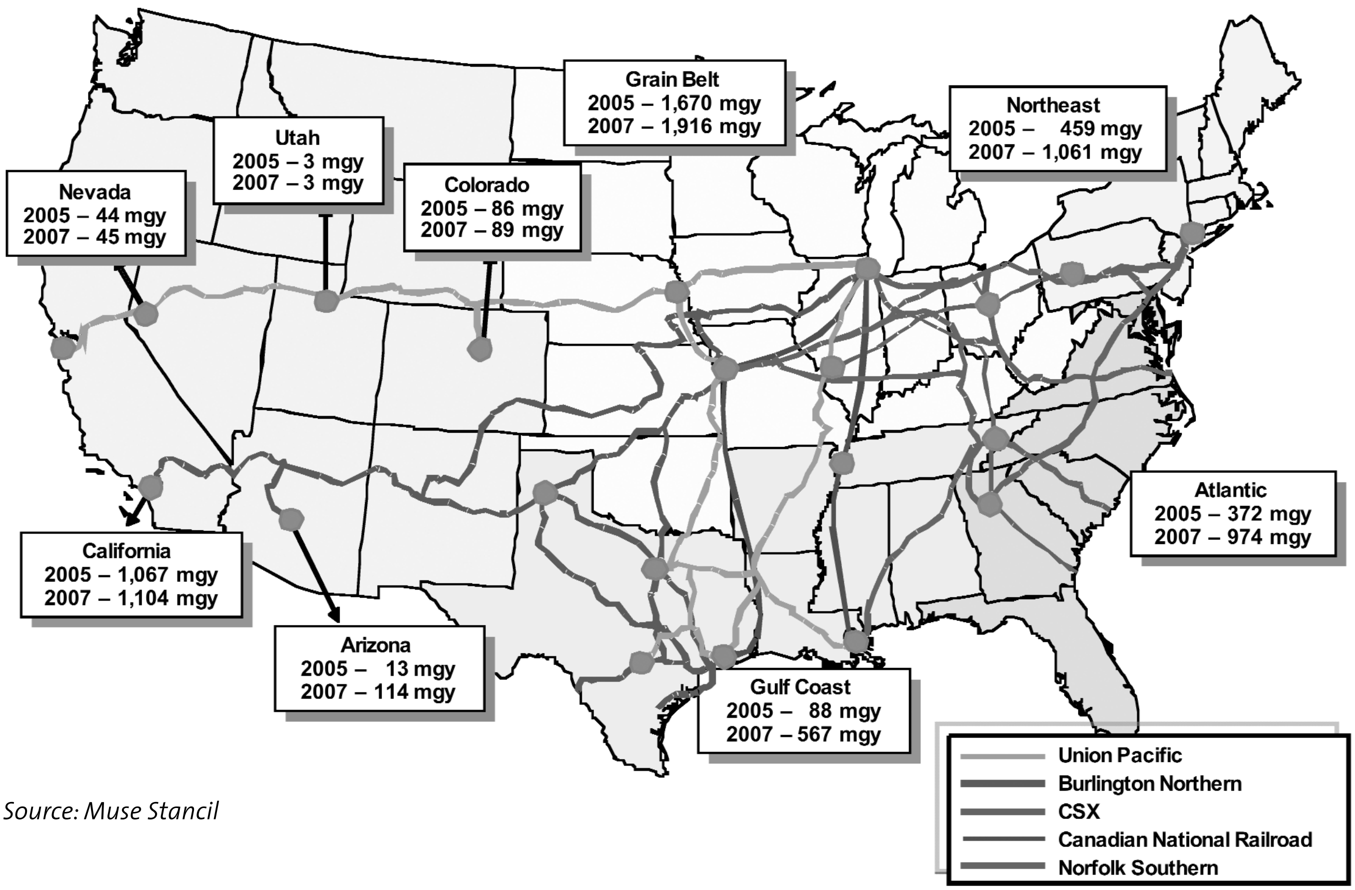
The US ethanol industry has been in a tremendous upward swing, essentially since 2000, due mainly to the decline in use of MTBE because of the groundwater contamination issues about which Tom spoke and the recent run-up in prices in global fuel markets. There are 96 ethanol plants in operation in the United States. Total aggregate capacity in the United States is 4.3 billion gallons. we are running virtually neck and neck with Brazil for the title of world's leading ethanol producer.

The Energy Policy Act last August will create significant new demand for ethanol for two reasons. The first is a renewable fuel standard in the bill. It calls for a stepped-up level of ethanol blending beginning in 2006 at four billion gallons a year, ultimately rising to 7.5 billion gallons a year by 2012. This means that the ethanol output must double in size over the next five to six years. The same legislation will also hasten the departure of MTBE from the gasoline pool because the legislation did not provide for any protection for MTBE producers or lenders for liability for groundwater contamination.

Another provision that is ethanol related in the energy bill is the removal of the oxygenate requirement in reformu-

Figure 2

Major Ethanol Demand Centers and Transportation Routes



Source: Muse Stancil

lated gasoline. There has been speculation that this might limit the amount of ethanol blending. However, it is our opinion that removal of the oxygenate requirement will not lead to a reduction in the amount of ethanol blending. However, it could cause some shifting in where ethanol is blended. A good portion of the reformulated gasoline that requires oxygen is consumed today along the Atlantic seaboard and in California. We believe that there could be some shifting of ethanol back to the midwest closer to where most ethanol is produced.

The US Environmental Protection Agency has not yet issued rules to implement the renewable fuel standard. How it will be implemented remains unclear.

Figure 1 (page 40) is a map that shows where all the ethanol plants are located currently. Most are in the upper midwest. However, a number of plants are beginning to appear on the periphery; Tom called these "destination plants."

Ethanol, has been limited historically to an extent by a lack of infrastructure for blending. The blending infrastructure is now being added at a very rapid pace, particularly in the northeast, as MTBE is phased out. We believe MTBE will completely exit the gasoline pool by the end of 2006 due to previously-mentioned liability concerns.

Another significant demand driver for ethanol is the organic demand growth for gasoline, which historically has averaged close to 2% a year and should continue to grow at a rate of between 1.5% to 2% a year in the future. The recent run-up in gasoline prices is not restraining the growth in gasoline demand, and so we believe that the market will continue to absorb the price increases and grow at close to its historic growth rate. Demand growth of 1.5% to 2 is the equivalent of approximately adding one large refinery every year in the US and, as most of you know, not a single new refinery has been constructed in this country in more than 30 years.

The primary mode of transportation today for long-haul deliveries is by rail. Truck deliveries are more expensive and are primarily used for short-haul deliveries from a central translocation facility to the final terminal where the ethanol is blended. Water-borne transport would be more economical; however, very few ethanol plants are near enough to large rivers to enjoy the benefits of water-borne transportation.

Figure 2 is a rail map, and it shows / *continued page 44*

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Robert Dilworth, a senior Treasury lawyer, said at a Washington luncheon in late April that the proposal is under "active study." The Congressional Joint Tax Committee recommended last year that Congress could make such a change as a "revenue raiser" in a future tax bill to help pay for other tax cuts that Republicans in Congress want to make. It estimated the change would increase US tax collections over the next 10 years by $1.2 billion in total.

Congress has had an opportunity in at least three tax bills since then to adopt the proposal, but has not done so.

MINOR MEMOS. The US Treasury Department told a congressman from North Carolina in March that it lacks authority to bar biodiesel tax credits for fuel blends that use biodiesel made from palm oil. Some US producers are angry that palm oil qualifies. Most palm oil is imported . . . . A court in Washington, DC told that the city in March that it cannot collect unincorporated business taxes from partnerships doing business in the city to the extent the tax falls on partners who live outside the city. Congress barred the District from imposing taxes on the "personal incomes" of nonresidents. The city is expected to appeal. The unincorporated business tax brings the city $100 million a year in revenue — most of it from real estate partnerships.

— contributed by Keith Martin in Washington.

Ethanol

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that the eastern half of the country is far more connected by rail than the western half. It means that ethanol producers located on the eastern side of the corn belt have many more options in terms of where they can deliver their ethanol. That said, the west is a more mature market. It has had ethanol blending since 2004. The eastern side of the country still has a number of markets that are blending MTBE. We believe demand growth in the east could be as much as a 1.5 billion gallons a year in the next couple of years.

I turn now to trends. Figure 3 (page 44) is our forecast of ethanol prices. The ethanol market will become increasingly competitive over time. In order to remain competitive, producers will have to do everything they can to lower costs, and they can do that through a variety of means. One way is by reducing transportation costs. Tom touched on destination plants. Ethanol producers are also improving yields to squeeze more ethanol out of a bushel of corn. Five years ago, the average yield was about 2.5 gallons per bushel. Today, it is more than 2.7 gallons, and there are plants that are yielding close to three gallons per bushel.

Another area where producers are looking to save costs is by finding ways to replace natural gas with other fuel. There are a number of alternative fuel sources that include renewable fuel such as wood chips, distillers grains, or in the case of at least one plant we know of in west Texas, where the owners intend to use cow manure as their primary fuel. In the more distant future, producers will be switching to cellulosic feedstocks like switch grass, corn stover, and other wood products. However, the technology is still in its

Figure 3

Ethanol Price Forecast — Real Prices

		2005*	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
New York												
Conventional Gasoline	¢/G	155.69	153.61	130.61	109.51	109.42	109.33	109.25	109.16	109.08	109.00	108.91
Premium Gasoline	¢/G	174.43	162.01	137.69	116.16	116.04	115.91	115.79	115.66	115.54	115.42	115.30
RFG	¢/G	159.13	157.30	133.95	112.54	112.45	112.36	112.27	112.19	112.10	112.02	111.93
Ethanol	¢/G	170.04	193.27	176.60	162.16	162.06	161.95	161.85	161.75	161.64	161.54	161.44
Chicago												
Conventional Gasoline	¢/G	159.39	155.36	132.34	111.22	111.12	111.02	110.91	110.81	110.71	110.61	110.51
Premium Gasoline	¢/G	166.33	161.46	137.14	115.62	115.50	115.38	115.26	115.14	115.03	114.91	114.79
RFG	¢/G	165.22	157.55	134.60	113.46	113.34	113.21	113.08	112.96	112.84	112.72	112.59
Ethanol	¢/G	172.02	190.27	173.63	159.22	159.14	159.07	158.99	158.92	158.85	158.77	158.70
Los Angeles												
Conventional Gasoline	¢/G	174.25	162.11	139.02	117.84	117.67	117.50	117.34	117.17	117.01	116.85	116.69
Premium Gasoline	¢/G	185.98	170.21	145.80	124.20	124.00	123.79	123.59	123.39	123.19	122.99	122.80
CARB (California RFG)	¢/G	176.60	167.61	144.47	123.23	123.01	122.79	122.57	122.35	122.14	121.93	121.72
Ethanol	¢/G	175.84	195.27	178.58	164.12	164.00	163.87	163.75	163.63	163.51	163.39	163.27
U.S. Gulf Coast												
Conventional Gasoline	¢/G	159.62	150.61	128.13	107.55	107.48	107.41	107.35	107.28	107.21	107.15	107.09
Premium Gasoline	¢/G	170.06	157.46	133.68	112.44	112.35	112.26	112.17	112.08	111.99	111.91	111.82
RFG	¢/G	159.93	156.30	132.96	111.56	111.48	111.40	111.32	111.24	111.17	111.09	111.02
Ethanol	¢/G	176.52	189.27	172.63	158.22	158.14	158.07	157.99	157.92	157.85	157.77	157.70
WTI - Cushing	$/B	56.44	55.00	47.50	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00

* 2005 are actual prices

Source: Muse Stancil

infancy, and we do not expect to see much impact from it for another 10 years.

Financing Challenges

MR. CHAUDHRY: Let me give everyone an idea of the number of transactions in the market. In 2005 alone, approximately 30 to 40 projects either commenced construction or commenced operations. There are probably more than 100 projects currently under development. Clearly all 100 of these will not end up getting financed.

My focus this morning is on some of the hurdles that producers must overcome to get financing.

One is a lack of a deep-pocket sponsor. This is both an opportunity and a barrier. It creates opportunities for private equity firms. A recent trend is the large number of private equity firms that are chasing some of the existing ethanol opportunities. However, a lack of deep pockets makes it more difficult to get financing for a number of reasons. If you have a deep-pocket sponsor, some risks in the deal that cannot be allocated to third parties can be addressed by contingent equity support from a creditworthy sponsor. That option is not available when there is no deep pocket. Private equity firms are usually unwilling to provide contingent equity support to address project-related issues. As a general matter, banks derive some level of comfort knowing that a creditworthy sponsor is standing behind a project. The absence of that, in the ethanol sector, makes financing that much harder. It is not an insurmountable issue, but something to keep in mind.

Also, a sponsor without deep pockets must raise its entire capital structure in the market — senior debt, subordinated debt and equity. While this has been done successfully by developers in the ethanol sector, it takes longer to close the deal and can lead to complicated intercreditor discussions.

The financing for ethanol projects came in the past largely from agricultural banks. Today, it is coming increasingly from New York banks, institutional investors and the capital markets. At the same time, the projects are becoming bigger. There are more 100-million and 120-million gallon facilities compared to the 30-, 40- and 50-million gallon facilities that existed earlier. Those still exist, but there's a trend towards bigger facilities. There is also a trend toward developers combining two or more facilities in one financing package, resulting in larger financings. As the financing sizes have increased, there has been a natural migration from agricultural banks to Wall Street financings.

Ethanol producers will have to figure out ways to cut costs to remain competitive as more and more companies crowd into the market. A major cost is transportation.

Generally, there are higher hurdles to clear to obtain financing from Wall Street sources than from agricultural banks.

Another recent trend is the shallow construction market. There are just not enough contractors and process providers for the number of opportunities that exist. This makes it difficult to get on a contractor's schedule to commence construction any time in the near future. It is also leading to higher construction costs; contractors who are in such demand can afford to charge more. This, in turn, requires developers to raise more equity in the market or to increase the leverage of the project, which may make it more difficult to close financing.

Another consequence of demand-supply economics that favor the contractor side is that it is getting more difficult to get contractors to accept risks that are typically borne by contractors in a project financing in the New York market. This can be an obstacle to financing.

Commodity price risk is probably the biggest issue on which lenders focus. By and large, / continued page 46

Ethanol

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ethanol projects have not had long term, fixed-price offtake contracts or long-term commodity hedges. That is starting to change slowly. We are starting to see medium- or long-term offtake contracts with some of the big oil and gas companies in the most recent deals. Absent such arrangements, ethanol deals are evaluated on a merchant basis. Also, the lack of correlation between the price of corn and the price of ethanol makes it difficult to lock in a "crush spread" that might give a lender comfort that its loan will be repaid.

Another concern for lenders is finite regulatory support. Ethanol production in this country depends on government support. As already mentioned, the two main forms of support are the renewable fuel standard and the volumetric ethanol excise tax credit. The amount of government support is finite. Many ethanol financings are structured around the expected excise tax credit expiration in December 2010. They contemplate low scheduled amortization coupled with high cash sweeps. These cash sweeps are stepped up to higher levels if the excise tax credit is not extended by a certain date prior to its scheduled expiration. As this date approaches without an extension, new financings will become harder to arrange. That said, high oil prices make the excise tax credit less consequential.

Figure 4
Renewable Fuels Standard

Year	Minimum Ethanol Demand (bgpy)
2006	4.0
2007	4.7
2008	5.4
2009	6.1
2010	6.8
2011	7.4
2012	7.5

Source: Muse Stancil

It is important to keep in mind that the ethanol industry is still in an infant stage. The ethanol industry has been around for a while, but it has only recently been transformed with the spike in activity, the increasing size of projects and the changing structure of financings. One things that is common to infant sectors is rapid change. If the price of feedstock spikes, or the price of oil drops, the picture could change rapidly. It remains to be seen how things will play out in the future.

Finally, let me talk about recent policy developments affecting the ethanol market. The renewable fuel standard requires that at least four billion gallons of renewable fuels be used in 2006, ramping up to 7.5 billion gallons in 2012. Figure 4 shows the ramp up from 2006 to 2012. From 2013 on, the Environmental Protection Agency is required to establish a new standard. A minimum of 250 million gallons per year of cellulosic ethanol must be included in this new renewable fuel standard starting in 2013.

The renewable fuel standard requires that there be a mechanism for trading ethanol credits. The idea is not dissimilar to what exists currently for trading sulfur dioxide credits. Once trading is implemented, it ought to provide refiners the flexibility to use ethanol where it makes most geographic and economic sense.

Another important policy measure is the excise tax credit. The credit is 51¢ for each gallon of ethanol blended with gasoline. The credit is claimed by blenders. Blenders currently pay 18.4¢ for each gallon of gasoline-ethanol mixture, but can claim a tax credit or refund for each gallon of ethanol used in the mixture. So, if a blender produces gasoline with a 10% ethanol blend, it would be entitled to a 5.1¢ credit for each gallon of gasoline. This measure is currently scheduled to expire in December 2010.

Another existing incentive is a small producer tax credit. A small producer is someone who produces up to 60 million gallons per year of ethanol. Small producers are entitled to a $1.5 million income tax credit — 10¢ per gallon for up to 15 million gallons of renewable fuel a year. This measure is currently scheduled to expire in December 2008.

With respect to MTBE, there are two things of note. One is what Congress did not do and the second is what the states actually did. What Congress did not do is it did not provide liability protection for MTBE producers. This helps boost the demand for alternatives to MTBE, such as ethanol-based ETBE. Also, many states — I believe 25 now — have actually banned MTBE. This boosts the demand for ethanol in these states.

Finally, the US protects domestic producers with import tariffs. There is a 54¢ tariff for each gallon of ethanol imported into the United States. This helps protect the US ethanol industry. There are certain exceptions to the tariff, such as the Caribbean basin initiative, which allows ethanol up to a certain amount to be imported into the US from countries that are in and around the Caribbean basin without the import tariff being imposed.

ASA Deal

MR. BLACK: My company, Americas Strategic Alliances, is a merchant banking and investing firm that has been putting a lot of effort into biofuels.

When we started looking at ethanol 18 months ago, 80% of plants were owned by small companies that owned a single ethanol plant. It was a very fragmented industry consisting of 40- to 50-million gallon facilities. There was only one 100-million gallon plant, and that was under construction. We could see the opportunity for an institutional player in such a market. However, we needed to get comfortable with the demand dynamics. In doing so, we spent a lot of time researching and talking to participants in the industry, and we concluded that escalating oil prices and instability in the Middle East would lead to increasing demand over time for ethanol. We were also struck by how most existing plants are in communities of 5,000 or 15,000 people, and putting a 100- or 120-million gallon facility in a community of that size, with $150 to $200 million in annual revenue and with the trickle-down effect on the community — is a win-win situation. Ethanol also helps the environment.

Our first project was three 100-million-gallon-a-year fuel-grade ethanol plants. The plants will also produce 320,000 tons of distillers grains. We spent about three months looking at the plants. We looked at more than 20 potential sites for them in excruciating detail. The three sites we selected were on the outer edges of the corn belt. Two are in Linden, Indiana and Bloomingburg, Ohio and will serve the east coast destination markets. The third project, in Albion, Nebraska, is well positioned with rail access to the west coast. Construction began in November on our Albion and Linden facilities, and we expect to be producing ethanol by May 2007. Construction in Bloomingburg, Ohio will begin in April.

Corn represents 55% of the cost to produce ethanol. Natural gas represents another 10% to 15% of the cost. So, 65% to 70% of the costs are focused around commodities. Our approach to financing was to team with Cargill, a world leader in agriculture. Cargill will be providing 100% of our corn supply and hedging our corn risk. It will also be supplying 100% of natural gas and hedging our natural gas exposure.

The other risk side of the equation is technology. We selected a construction firm, Fagen, that has built two thirds of the ethanol plants in the United States, and it was the contractor for the only 100-million gallon plant in operation. Fagen used ICM technology that at that time was, and still is, one of the most efficient technologies for producing ethanol.

With the lower technology risk and the lower commodity risk exposure, we were able to attract institutional equity and subordinated debt. American Capital Strategies, Laminar Direct Investments, which is an affiliate of DE Shaw, and US Renewables Group stood beside us through equity and subordinated debt financing, and they continue to stand beside us for future project developments.

What makes our project attractive are its low cost, competitive advantage, and use of state-of-the-art technology. All this was important in the lenders' review of our project. Our three plants are ranked as the first, second, and fourth lowest cost producers in the markets that they will serve, and that is without consideration of the risk management around the projects but rather solely on an infrastructure and location basis.

Another key advantage is main line rail access and closer proximity to our markets, with Cargill managing the logistics and providing us with favorable freight and lease rates. This resulted in lower distribution costs. Once our project is constructed, we will be the second largest ethanol producer in the country behind ADM. This provides us with not only critical mass, but also geographic diversification.

ASA intends to grow its presence within the ethanol business to a billion gallons a year over the next two or three years.

MR. MURRAY: The financing for the ASA project was a $275 million dollar senior debt financing. It was two times oversubscribed. WestLB raised about $550 million in commitments, which is a sign of the growing interest in this market from the large banks and institutional investors.

ENVIRONMENTAL UPDATE

Environmental Update

Fuel Additives

The US Environmental Protection Agency eliminated a requirement in May that gasoline must include an oxygenate fuel additive like ethanol and ETBE made from ethanol.

The Clean Air Act — as interpreted by the Environmental Protection Agency —required until earlier this year that all fully reformulated gasoline sold in the United States must include a 2% oxygenate additive. The main additive has historically been methyl tertiary butyl ether — called "MTBE" — but refineries had been switching to ethanol and ETBE because of concerns about possible groundwater pollution caused by MTBE.

The US government has dropped a rule that required refineries to add oxygenates like ETBE and ethanol to gasoline.

In late February, the government withdrew the oxygenate requirement altogether in California, but provided an additional 270 days of lead time before dropping it for the rest of the country.

On May 8, EPA cut short the transition period for the rest of the country.

The abrupt end of the oxygenate requirement comes amid concerns about the adequacy of ethanol supplies. Although reformulated gasoline used in air quality non-attainment areas will no longer have to comply with oxygen content requirements, it will still have to meet the other performance requirements in section 211 of the Clean Air Act. MTBE could have been used by refiners to comply with the remaining standards, but would have been gradually withdrawn from the market in response to environmental contamination problems caused by MTBE.

Where spills and leaks have occurred, it has been found that MTBE readily mixes with groundwater, resulting in potentially extensive contamination. This has led to increasing amounts of product liability litigation in which the MTBE is alleged to be a defective product for which the refiner should be held liable. The defective product claims represent a sharp departure from US environmental laws, which typically exempt manufacturers of commercial products from liability for contamination caused by their customers. Refiners have argued that the Clean Air Act's oxygen mandate provides a legal defense to the product liability claims.

Several commentators have noted that if EPA stops requiring MTBE to be mixed with gasoline, all MTBE use will immediately cease because refiners will find MTBE too risky to use if the product is no longer mandated, and this could lead to a sudden increase in demand for ethanol beyond the available supply. They also argue that emissions of other air pollutants will also increase, because ethanol evaporates more readily than MTBE.

Ethanol use is already expected to increase in the United States due to a requirement in the Energy Policy Act last August that US motor vehicle fuel must include at least 7.5 billion gallons a year of ethanol by 2012. Some people argue that ethanol supplies will be stretched too thin to make up for the loss of MTBE in the reformulated gasoline program.

Ethanol Air Permits

The Environmental Protection Agency proposed in early March to let larger ethanol facilities be built without the need to go through a permitting process first for projects considered potential "major sources" of air pollutants.

If adopted, the proposed regulation would more than double the threshold under the Clean Air Act before a major source permit is required.

Most ethanol plants are built currently with "minor source" permits that do not typically require the application of the most advanced air emissions control technologies (known as "best available control technology") and usually do not impose other potentially-burdensome requirements that might cut into profits. In order to stay within minor source levels, ethanol facilities must not emit more than 100 tons per year of any of several pollutants, including sulfur dioxide, nitrogen oxide, carbon monoxide and particulate matter. The 100-ton threshold applies, because such facilities are considered "chemical processing plants" under the applicable EPA regulations.

By specifying that ethanol facilities are not chemical processing plants, the EPA proposal would move them into a category with a much higher threshold for obtaining a major source permit. Ethanol plants would not be required to apply for a major source permit and incorporate best available control technology unless their emissions reach 250 tons per year of a covered pollutant. Environmental safety groups are objecting to the regulation, asserting that it would lead to higher emissions with the potential to harm communities near ethanol plants.

The proposed regulation addresses longstanding objections by ethanol producers and grain processors that emissions from ethanol facilities are very similar to, and should not be regulated differently than, grain processing and food production facilities. Grain processing and food production facilities not involving ethanol are not subject to the 100-ton limitation. For example, most of the particulate matter emissions from ethanol plants come from the handling and processing of grain, much like other types of grain handling and food processing operations. Similarly, SO_2, NO_X and carbon monoxide emissions are not the result of late stage ethanol production and the denaturing process, but instead come from fuel combustion associated with a power source at the facility. Such power sources are also used in many food processing operations.

The obligation to limit particulate matter, SO_2, NO_x, and carbon monoxide emissions can be a significant constraining factor on ethanol facility size. Although volatile organic compound emissions at ethanol facilities are higher than grain and food production facilities, they tend not to be a material constraining factor or tend to be independently regulated under other emissions programs that require strict VOC control even for facilities that do not exceed EPA major source thresholds.

Even though most ethanol facilities are constructed in rural areas where air quality already complies with national ambient air quality standards, environmental groups and some state environmental officials are opposed to the proposed rule out of concern for damage to air quality, particularly in national parks and, in the case of state officials, out of concern for the potential to limit the state's ability to attract other industries if too much of the state's capacity to absorb new air pollutants is consumed by ethanol plants.

Carbon dioxide equivalents (CO_2e) are the universal standard of measurement for greenhouse gas trading. Each CO_2e equals one metric ton of carbon dioxide. Although there are more than 25 climate-changing gases, only six are regulated under the Kyoto Protocol on climate change. Of these six greenhouse gases, carbon dioxide is by far the most common and the least potent. The others are methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride (SF_6). For example, one ton of methane has the global warming potential of 23 tons of carbon dioxide. SF_6, which is used by the electric power industry in circuit breakers, gas-insulated substations and switchgear, is the most potent, with a global warming potential that is 22,200 times that of carbon dioxide. Thus, a project that could achieve a 10-ton reduction in SF_6 could generate 222,000 CO_2e for trading.

Greenhouse Gas

According to a World Bank report released in early May, the global carbon emissions trading market saw explosive growth in 2005 to an estimated level of more than $8.2 billion. This represents an increase of more than 10 times the value of global carbon trading activity in 2004. Not surprisingly, most of the increase was fueled by the emissions trading scheme that took effect in the European Union in 2005.

The report, entitled *State of the* */ continued page 50* *continued from page 49*

Carbon Market 2006, also covers the first quarter of 2006, in which an estimated $6.6 billion of carbon transactions also occurred. According to the report, almost 330 million tons of carbon dioxide equivalents were traded internationally in 2005 and another 209 million tons were traded in the first three months of this year. By comparison only slightly more than 16 million metric tons were traded in 2004. Of the 330 million tons, approximately 322 were traded under the European trading scheme. The next closest jurisdiction was Australia, where the New South Wales greenhouse gas abatement scheme logged transactions totaling 6.11 million tons of carbon dioxide equivalent during the 2005 and another 5.5 during the first quarter of 2006. Trading within the Chicago Climate Exchange, which is a voluntary US market for carbon emissions trading, actually declined from 2.4 million to 1.45 million tons in 2005, but the exchange almost matched its 2005 total with 1.25 million tons carbon dioxide equivalent in trades in 2006.

Although most of the market value is tied to trading in the European Union, a majority of the greenhouse gases traded come from developing countries. Projects from developing countries and economies in transition totaled 364 million tons of carbon dioxide equivalent of the 524 tons that were traded during the period covered in the report.

As the report's main author, Karan Capoor of the World Bank, points out, "[T]he data makes it clear that carbon is now a financial commodity, complete with a price and with factors that will affect that price."

Although a robust carbon trading market has developed in Europe, the price of carbon allowances in the European market fell after news from several European Union member countries that their 2005 emissions were below quota, a fact which could reduce demand for allowances in the future. Phase I of the European trading scheme, which took effect last year and ends after 2007, applies to carbon dioxide emissions from more than 12,000 European facilities, including power plants, refineries, ferrous metals and mineral operations and pulp and paperboard activities. Individual EU member countries allocate allowances to the covered plants based on operating expectations. Each plant must hold one allowance for each ton of carbon dioxide it emits in a year. The lower-than-expected carbon dioxide emission rates means that there will be less demand on the whole for allowances to cover allowance shortfalls.

A new World Bank report says the worldwide market for trading in carbon emissions increased 10-fold last year to $8.2 billion in transactions.

The Chicago Climate Exchange announced in early May that one of its members executed the first trade of greenhouse gas allowances between trading systems in Europe and North America. In the transaction, Baxter Healthcare Corp. transferred 100 metric tons of carbon allowances from its operations in Ireland to an account with the Chicago Climate Exchange. The allowances, which were issued under the European trading scheme, will be used by Baxter to comply with its voluntary commitment at the Chicago exchange to reduce greenhouse gas emissions. Chicago exchange members agree voluntarily to make a 4% reduction in their greenhouse gas emissions by 2006 and a 6% reduction by 2010. The Chicago exchange launched continuous electronic trading of all six Kyoto greenhouse gases on December 12, 2003. Member companies agree to achieve the reductions from a baseline established from their operations in the period 1998 to 2001.

Plant Modifications

A US appeals court in Washington set aside an EPA regulation in March that was supposed to clarify when a company making changes at an existing facility must get prior approval under the Clean Air Act. The regulation — known as the equipment replacement provision — allows more expensive repairs and maintenance of existing facilities without having to install state-of-the-art emissions controls.

Under the Clean Air Act, owners of existing plants must comply with "new source review" requirements, including installation of modern emissions controls, if they make changes at their facilities that go beyond "routine repair and maintenance."

What qualified as routine repair and maintenance in the past had been the subject of litigation during the Clinton administration, which took the position that many aging power plants had improperly avoided expensive new emissions controls and even shutdown while making extensive repairs or even improvements to their equipment.

Although the Bush administration has continued to prosecute cases initiated by its predecessor, it has generally not brought new ones and has tried to broaden the routine repair exemption. In October 2003, it proposed rules that would allow existing plants to replace components with identical or functionally-equivalent components as long as they do not exceed 20% of the replacement value of the unit as a whole and do not change its basic design parameters.

The US appeals court in Washington said in March that the Bush proposal violates section 111(a)(4) of the Clean Air Act. The court said Congress broadly intended that "any physical change" that results in an emissions increase should be subject to new source review permitting. Therefore, the Environmental Protection Agency did not have authority to limit this to "physical changes that are costly or major," nor did EPA have the power to allow changes that increase emissions by more than a *de minimis* amount.

There are recent signs that EPA may be ramping up enforcement against possible new source review violations. The agency sent information demand letters under section 114 of the Clean Air Act to power companies in Phoenix, Arizona, Topeka, Kansas and LaCrosse, Wisconsin on April 26 seeking information about possible modifications to power plants that were made without first getting proper permits. EPA has not indicated that it intends to reembrace the Clinton approach to new source review enforcement, but it may have little choice in light of the appeals court decision.

Mercury Emissions

Minnesota Governor Tim Pawlenty signed legislation in early May requiring the three largest coal-fired power plants in the state to cut their mercury emissions by 90% by 2014.

The new law forces Xcel Energy to install mercury controls at its Oak Park Heights and Becker, Minnesota power plants and requires Minnesota Power to install controls at its Cohasset power plant. The controls will be phased in to avoid shutting down all three plants simultaneously, with some controls to be in place by 2010. When implemented, the emissions of mercury at the three plants will be reduced by a total of 1,200 pounds per year, or one-third of the total mercury emissions in the state. The utilities will have the ability to use expedited rate recovery for the cost of the installations.

Various states are moving to require coal-fired power plants to reduce their mercury emissions by 60% to 90%.

Because the precise technology for achieving these reductions is uncertain, the law also allows for time extensions, if needed, and it gives Minnesota regulators the authority to reduce the 90% goal after reviewing and approving mercury reduction plans from the facilities.

In North Carolina, the Department */ continued page 52*

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of Environment and Natural Resources issued a proposed mercury reduction regulation for new and existing power plants in May. The regulations would adopt many of the same requirements that are in the "clean air mercury rule" that the federal government proposed in March 2005, but the state will also go beyond the federal requirements to impose additional controls on particular facilities and more stringent rules in general. The proposed regulation would require a 60% reduction in mercury emissions by 2013.

Owners of new units have been given several options, including reducing emissions by 90% and requiring emissions sources to offset their emissions with reduction credits obtained from other sources. The rules could affect possibly 20 power plants in North Carolina. Public hearings on the new regulations will held in June.

The Pennsylvania Department of Environmental Protection will propose soon a 90% reduction in mercury emissions from coal-fired power plants in that state by 2015. The rule would also bar such power plants from trading any mercury emissions allowances that their control efforts might otherwise generate under the federal clean air mercury rule. Instead, each of the power plants would have to meet a strict facility-wide mercury emissions cap.

Opponents of the expected new Pennsylvania regulation assert that it would lead to premature retirement of more than 20% of the state's coal generating capacity and would force power companies to spend more than $1 billion on new pollution controls without any clear benefit to Pennsylvania residents. A bill has been introduced in the Pennsylvania general assembly that would bar the state environmental department from adopting the expected rule.

Environmental groups have criticized the federal clean air mercury rule. They argue that power plants can use allowances purchased from other locations instead of controlling their own mercury emissions, thereby creating mercury hot spots even if overall mercury emissions are reduced nationwide. A May 15, 2006 report issued by the EPA inspector general criticized the EPA approach on the same grounds, asserting that recent studies undermined EPA's position that hot spots would not be created. The inspector general said the studies show high levels of mercury deposition from coal-burning facilities and suggested the agency develop a plan for monitoring the effects of its clean air mercury rule. The federal clean air mercury rule is supposed to reduce mercury emissions from coal-fired power plants in two phases. In phase I, mercury emissions would be reduced approximately 21% by "co-benefit" reductions resulting from emissions controls that need to be put in place to control SO_2 and NO_x emissions under another EPA program. In phase II starting in 2018, additional mercury controls will be required, leading to reductions of 70% from current emissions levels. Several states and environmental organizations are challenging the federal rule in court, asserting that it will not be effective and that tighter controls are necessary. ◎

— contributed by Andrew Giaccia, in Washington.

Chadbourne & Parke LLP
30 Rockefeller Plaza
New York, NY 10112
+1 (212) 408-5100

1200 New Hampshire Ave., NW
Washington, DC 20036
+1 (202) 974-5600

1100 Louisiana, Suite 3500
Houston, TX 77002
+1 (713) 571-5900

350 South Grand Ave.
Suite 3300
Los Angeles, CA 90071
+1 (213) 892-1000

Beijing Representative Office
Room 902, Tower A, Beijing Fortune Centre
7 Dongsanhuan Zhonglu, Chaoyang District
Beijing 100020, China
+86 (10) 6530-8846

90 Shevchenko Street, 3rd Floor
Almaty 050022, Kazakhstan
+7 (3272) 585-088

Riverside Towers
52/5 Kosmodamianskaya Nab.
Moscow 115054 Russian Federation
+7 (495) 974-2424
Direct line from outside C.I.S.:
(212) 408-1190

5 Italianskaya Str., office 56/57
St. Petersburg 191186 Russian Federation
+7 (812) 326-9300

11 Mykhailivska Street, 4th Floor
Kyiv 01001, Ukraine
+380 (44) 230-2534

Chadbourne & Parke
Radzikowski, Szubielska and Partners LLP
ul. Emilii Plater 53
00-113 Warsaw, Poland
+48 (22) 520-5000

Chadbourne & Parke
a multinational partnership
Regis House
45 King William Street
London EC4R 9AN, UK
+44 (0)20 7337-8000