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Renewables Spread to the Near East

by Sohail Barkatali and Yasser Yaqub, in Dubai

Countries in the Middle East and North Africa — the so-called MENA region — are moving to diversify the power generation base by moving away from natural gas and oil.

Various countries in the region are actively investigating potential new projects involving coal-fired power plants, nuclear energy facilities and solar, wind and waste-to-energy projects.

Renewables, Really?

The MENA countries, for the most part, have been slow to turn to renewable energy. Abundant and cheap oil has meant there has been little need. A lot of the push to renewables in the United States has been to lessen US dependence on the Middle East for oil. Not only is oil abundant, but local policies also make the price of oil and gas appear cheaper than its real cost. The region subsidizes energy prices. It also does not put a price on carbon so that emissions from burning fossil fuels are not taken into account in weighing fuel options.

Various studies undertaken in the region have demonstrated that an overwhelming case can be made for renewable energy projects. For example, a renewable energy resource study commissioned by the Authority for Electricity */ continued page 2*

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EQUIPMENT LEASES will have to be put on balance sheets under a proposal the two accounting standards boards released in mid-August.

The proposal is expected to force lessees to bring $640 billion in leased assets back on to their books. Comments are being collected until December 15. The proposal will apply to existing leases once it takes effect. No effective date has been set yet, but speculation is it could take effect as early as June next year.

US companies that use GAAP accounting classify leases currently as "capital leases" or "operating leases" for book purposes. Capital leases are a form of financing and the obligation to pay rent is */ continued page 3*

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Regulation in Oman found that the level of solar energy density in the Sultanate is among the highest in the world, particularly in northern parts of Oman and in the interior desert areas. The same is true of other jurisdictions such as the United Arab Emirates and Saudi Arabia. Similarly, it is now widely acknowledged that the potential for large-scale wind farms exists in Morocco, Egypt and Saudi Arabia, among other countries.

Electricity demand in most states in the region is increasing at an average annual rate of 6%. Not all countries are blessed with abundant hydrocarbons that can readily be deployed as fuels for power generation. This is particularly true in states such as Morocco, Egypt, Tunisia, Syria, Jordan and

Renewable Energy Projects in the MENA Region

Jurisdiction	Country facts and policy	Key projects to watch
Algeria	Energy objectives for Algeria include reaching a 5% share for renewable energy in the electricity sector by 2017 (or 750 mws of capacity) and a 20% renewable share by 2030. The renewable energy capacity in 2030 would be made up of concentrating solar power or CSP (70%), PV (20%), and wind (10%). Algeria intends to tap its sunshine on an industrial scale for: – itself (with an aim of increasing the solar percentage of its energy mix to 5% by 2010) and – Europe (to help the EU reach a target of obtaining 20% of its energy requirements from renewable energy by 2020). According to a study by the German Aerospace Agency, Algeria has the largest long term land potential for concentrating solar thermal power plants. The government is in the process of establishing laws, funds and institutions to support project development. Bidders in any tenders must be 51% Algerian-owned (public or private sector) and must include a local engineering or manufacturing concern.	Two CSP projects are currently at different stages of development: Hassi R'Mel ISCC plant: – Projected capital cost: €315 million. – It will have: – two 40 mw gas turbines, – one 80 mw steam turbine, and – two parabolic trough solar fields with a generating capacity of 25 mws. Meghair ISCC plant: –Projected capital: US$1 billion. –Estimated capacity: 400 mws, of which 70 mws will be provided by CSP (parabolic trough). – Option to expand the scope of the plant to make it a 480 mw facility, of which 80 mws would come from solar, and include water desalination. – Scheduled for commercial operation in 2015.
Bahrain	The government is exploring various renewable energy initiatives.	Bahrain is planning to develop a 5 mw solar power project and could issue tenders for the scheme during 2010.
Egypt	Egypt aims to generate 20% of its energy from renewable sources by 2020. The government expects to install more wind farms than solar projects in the early years of its renewable energy plan as solar power is more expensive. The government launched a plan in 2007 for wind power to supply 12% of electricity demand by 2020 (approximately 7,200 mws), scaled back from an initial 20%, which could indicate a desire to have greater contributions from solar energy and biomass. From a general perspective, the plan aims to engage the private sector -- and foreign investors -- in the wind sector.	The country launched its first commercial solar development, a 150 mw ISCC power plant, south of Cairo, at Kuraymat: – Parabolic-trough technology (20 mw solar field). – Projected capital cost: around €340 million. 430 mw wind farm at Zafarana. Potential to expand capacity to 2,200 mws by 2020. 200 mw wind farm at Gabal el Zeit. Expected to be commissioned during 2013. 200 mw wind farm in the Gulf of Suez to be developed jointly by the New and Renewable Energy Authority (NERA) and Masdar.
Jordan	Currently, only 2% of the energy consumed is derived from renewable energy sources. Jordan wants to increase the use of renewable energy to 10% by the end of 2010, mostly from wind and CSP. After an initial focus on solar water heaters and PV, there is now increasing interest in commercially-viable grid-connected solar projects, with international cooperation. The MDA, which runs the affairs of the Governorate of Maan in the southern part of Jordan, is working to attract more investments in the renewable energy sector and is particularly hopeful that this will be facilitated through renewables-focused legislation. New draft legislation provides for direct selling into the grid, unsolicited projects, demarcation of land for renewables projects and the establishment of a fund to facilitate renewables projects.	– Plant will also include a back-up fossil-fuel boiler to guarantee 24-hour dispatchable electric power. – Project is expected to enter operation during 2013. – Project could be the largest CSP project in the world using direct solar steam generation. Kamshah wind farm project: –Estimated capacity: 30-40 mws. Fujeij wind farm: – Estimated capacity: 80-90 mws (which could be increased to 250 mws at a later date). – Eight groups have now been prequalified to bid. – additional tender for three more wind energy plants in southern Jordan is expected: – The tender would package together three wind turbine stations at Al Harir, Maan and Wadi Araba for the winning bidder to develop and construct concurrently. – Combined, the three plants would produce 300-400 mws of wind energy.
Kuwait	Kuwait aims to produce 5% of its electricity from renewable sources by 2020. A tender for advisors for a solar project is expected to be issued during 2010.	A solar IPP is being considered.

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Yemen. There is a growing realization that some of the demand in the region, particularly in rural or electrically-isolated areas, can be met by harnessing renewable energy.

Air pollution levels in MENA are among the highest in the world. Some governments are acutely aware of this and keen to implement measures to combat these levels by taking steps to try to improve air quality and, at the same time, reduce their carbon footprints.

Renewable energy could prove a major export for some countries. The Desertec initiative is a huge multi-lateral solar project planned for the Middle Eastern and North African desert regions that aims to ensure that by 2050, more than 50% of Europe and the MENA region's electricity requirements are generated from renewable sources.

Another attraction to some MENA countries of using wind and sunlight to generate electricity is that it will free up more oil and gas for export.

Finally, the potential for stimulating the local economies should not be ignored. New development means jobs. There is also the potential in the longer run of establishing industries around the renewable energy sector — for example in research and development, manufacturing and operation and maintenance.

Solar and Wind

Solar and wind remain the two most promising forms of renewable energy for the region.

The Masdar City initiative in Abu Dhabi is focusing on solar power in its drive to establish a model sustainable city that minimizes carbon emissions. A pilot 10-megawatt solar photovoltaic project was brought on line in the summer of 2009 and, while the financial downturn delayed the roll out of further renewable power development, a consortium of Spanish company Abengoa and French company Total was awarded the Shams 1 project in June 2010 that involves development of a 100-megawatt parabolic trough technology solar thermal plant.

The project company for Shams 1 will be owned 60% by the Abu Dhabi Water and Electricity Authority and 40% by the private developers.

While Shams 1 will contribute greatly toward future development of renewable energy projects in the region, a $1 billion solar thermal project in Oman (see table for more details) is likely to be 100% private sponsor owned and developed and is more likely to be the true litmus test of the */ continued page 5*

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treated like debt. Operating leases are off balance sheet. An example of an operating lease is renting a car from Hertz or Avis.

FASB and the IASB — the Financial Accounting Standards Board in the United States and the International Accounting Standards Board in London — made the proposal in a joint exposure draft. One goal is to bring reporting of leases in the United States in line with how they are treated in other countries. The boards also said that they felt they have an obligation to investors who have told the board the investors must add back lease obligations when evaluating public companies in order to get a true picture of how deeply the companies are indebted.

The new rules will make lessees who have been using operating leases look like they are carrying more debt. PricewaterhouseCoopers said it expects the proposal to add about 58% more debt to the average company's balance sheet. This is a concern in the current economy with many companies already close to the edge in the amount of debt that lender covenants allow them to carry. At the same time, lessees may experience an increase in earnings if the rents are treated as equivalent to a debt rather than a running expense.

How lessors book the assets will depend on whether they are running a real rental business in substance where they keep getting the assets back. If yes, then a lessor would use a "derecognition" approach where it removes from its books the cost of the rights it has transferred to the lessee, but records the residual value as an asset. If not, the lessor will have to use a "performance" approach where it removes the asset entirely from its balance sheet, but has a liability to allow the lessee to use the asset. Lessors in both cases would record rental income over the lease term.

The lessee would have to record an obligation equal to the present value of the expected rental payments over the lease term. Both lessors and lessees would be required to use the longest lease term that is more likely than not to occur.

The proposal is expected */ continued page 9*

Renewable Energy Projects in the MENA Region (cont'd)

Jurisdiction	Country facts and policy	Key projects to watch
Libya	Libya's goal is to maximize crude oil (and natural gas) exports, which could be a driver for scaling up renewables. A new law on liberalization of energy markets, including renewable energies and CSP, is under discussion. Wind, PV and CSP are expected to contribute up to 10% of the electricity supply by 2020.	A feasibility study for the construction of a 100 mw CSP plant is currently being undertaken focusing on five potential sites: –The study was expected to be finished by the end of 2009. – A tender is due to be issued in 2Q 2010.
Morocco	Morocco is currently the only country in the MENA region linked to the European power grid. It is keen to become an energy exporter in the long term. Rabat aims to produce 42% of its power needs from renewable sources by 2020. In November 2009, Morocco announced a US$9 billion solar project that officials said would allow solar, wind and hydroelectric power to provide 38% of the country's electricity by 2020. The proposed solar plants would account for 2,000 mws of generating capacity. The project, to be funded by state and private investors, would use large-scale CSP technology.	Major solar projects forming a part of the solar power generation program include: Ouarzazate CSP plant: – 500 mws (trough technology). – It is due to be commissioned in 2015. Ain Beni Mathar CSP plant: –125 mws (parabolic trough technology). – Site will be contiguous to an existing ISCC system. – Wind projects include the Tarfaya IPP.
Oman	Oman commissioned a comprehensive study of renewables that concluded there are significant opportunities for renewable energy in the country: – principally for solar power (solar energy density in Oman among highest in the world), – but also in some areas for wind power (significant wind energy potential in coastal areas in the southern part of Oman and mountains north of Salalah). In particular, the study singled out CSP as a technology with promising commercial-scale potential.	Oman is planning to develop its first solar project at a cost of up to US$1 billion: – Potential capacity: between 50 mws and 250 mws. – Principal brief: to study the feasibility of establishing a CSP project from the technical, financial and legal standpoints: – First draft of the strategy report was submitted to the government in the first quarter of 2010. – If the report is accepted, then it is likely that a RFP will be out in the final quarter of 2010.
Qatar	Qatar has a substantial interest in renewable energy projects. However, available land remains a challenge. Qatar is expected to commence research into energy efficiency and renewable technologies suited to the local environment.	A feasibility study for the country's first ever solar power project is being undertaken. The projected capital cost is US$1 billion. A polysilicon manufacturing plant is also being considered.
Saudi Arabia	Interest in renewables is gathering, with modest projects being rolled out. Early 2009, the Saudi oil minister said, "Saudi Arabia aspires to export as much solar energy in the future as it exports oil now". In April 2010, King Abdullah issued a Royal Decree establishing the King Abdullah City for Atomic and Renewable Energy. This is intended to serve as a center for renewables research and for co-ordinating national and international energy policy.	2 mw PV array at King Abdullah University of Science and Technology (KAUST): – Estimated cost: €11.3 million. – The developer is Conergy Asia-Pacific (a regional subsidiary of Hamburg-based Conergy AG). – Project will be executed in collaboration with Saudi-based National Solar Systems (NSS). – Project is managed by Saudi Aramco on behalf of the Saudi government. – Saudi Oger is managing the PV portion.
Syria		Syria's Public Establishment of Electricity for Generation & Transmission (PEEGT) appointed advisers in July 2010 for a 50-100 mw wind farm to be located at either Al-Sukhna, 70 kilometers east of Palmyra, or Al-Hijana, 50 kilometers south of Damascus, or at both sites. An RFP is expected to be issued in the second half of 2010.
Tunisia	Tunisia is currently highly dependant on oil and gas. It is now keen to diversify its energy mix. During the 2009-2014 period, Tunisia aims to increase by five fold its production of renewable energies to reach 550 mws, which would amount to 13% of the country's electricity generation capacity. In 2008, the government launched a four-year plan aimed at setting up 740,000 square meters of solar captors.	Three CSP projects are in the pipeline: – Project 1 will either be a pure 25 mw CSP project (estimated cost: US$85 million) or a 150 mw ISCC plant with 125 mws generated from natural gas and 25 mws generated from CSP. – Operations expected by 2012/2013. – Project 2 will be a private CSP plant with a capacity of 100 mws using parabolic trough technology. – Production from this plant will largely be directed toward exports. – Pre-feasibility studies have identified five sites. – Estimated cost: around €320 milion. – A call for tenders is scheduled in the beginning of 2011, with work beginning in 2012-2013. Operations would begin in 2015-2016, coinciding with the commissioning of the transmission line to Italy. – Project 3 will be closely linked with the ELMED interconnection between Italy and Tunisia. The total capacity will be 1,000 mws, of which 200 mws will be reserved for renewable energy. Generation to serve this transmission line will come from a plant (or plants) developed by a selected private company. It is expected that at least 100 mws of this production will come from a CSP plant. The 100 mw plant is expected to have a cost of €320 million.

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viability and financing of such projects in the region.

Wind is also expected to gain a significant foothold. Some countries in the region have areas with high average wind speeds. The main disadvantage of wind projects lies in their intermittency: the wind does not always blow when it is needed to generate electricity and can put strain on the electricity grid. Intermittency risk can be mitigated by establishing wind farms over a large enough geographical area or by linking wind projects to hydroelectric power plants (for example, in a country like Egypt that offers both wind and hydroelectric potential) to deal with intermittency and to absorb any excess wind power by using the energy to pump water that can be run later through a hydroelectric dam.

The table lists some of the projects that are being undertaken in the region.

Government Support Mechanisms

Experience outside the MENA region shows that projects cannot be financed without the certainty of a long-term revenue stream that allows an acceptable rate of return. Governments in Europe and Canada have used feed-in tariffs to assure renewables developers high enough prices for their electricity to make the projects economic. Renewable portfolio standards at the state level and tax subsidies at the national level have performed the same function in the United States.

Thermal power projects in the region have benefited from direct offtake arrangements that require local utilities to contract on a long-term basis for power. These power purchase agreement models are now well established in Abu Dhabi, Bahrain, Oman and Saudi Arabia.

The model has also been used in certain other countries for the purposes of procuring renewable energy and has certain unique features. First, the scope is limited to an individual project and the tariff and conditions match the requirements of that particular asset. Second, the counterparty is normally a strong creditworthy entity. Third, it is based around a "take or pay" arrangement to provide certainty of revenues. Equally, it provides the offtaker with the certainty of a fixed unit price for the energy. Fourth, the contract is of a long enough duration to allow long-term debt financing. There are a number of disadvantages to this approach. Long-term fixed quota PPAs commit the offtaker to purchase power at a fixed price and amount irrespective of whether the price remains competitive or whether that power is actually required. In addition, the procurement of such projects can be costly and time consuming as each PPA is negotiated individually, although over time a precedent can be established that will be acceptable to the market.

There is a strong lobby for governments in the MENA region to implement feed-in tariffs.

Abu Dhabi announced earlier this year that it is in the process of introducing such a tariff. The details have not been announced yet.

Jordan is considering a limited feed-in tariff that would only apply to excess power sold to the grid from "inside-the-fence" facilities that use renewable energy. A factory or other industrial plant would generate its own electricity but then be allowed to sell any spare output into the grid at the tariff price. There are a number of advantages with this approach. First, it provides a socially-responsible framework in that it begins to make consumers more responsible for taking direct action for using renewable energy for their electricity. Second, it allows the government to test how a feed-in tariff works on perhaps a more manageable scale than extending it to all renewable energy purchases.

Utility Economics

The price of electricity in the MENA region is already heavily subsidized. Clearly, conventional energy remains cheaper than energy procured from renewable energy sources.

The cost base of a government utility in the region is made up of a number of elements: capital cost, operation and maintenance costs, fuel costs (at market value) and costs associated with the "wires" businesses (namely the costs associated with transmission and distribution). The price paid by end users for energy is fixed, in many cases by regional governments at cabinet level. This is artificially kept low. In order to ensure that utilities do not go out of business, they benefit from two subsidies — a direct subsidy that is provided to the utility by the government and an indirect subsidy that is inherent in the cost of fuel to the sector.

Chart 1 shows how the government subsidy operates in Oman. The Oman Power and Water Procurement Company or SAOC purchases power from generators at the true economic cost by entering into direct offtakes with independent generators. The electricity is sold to distribution companies at the "bulk supply tariff" that is the tariff that */ continued page 7*

Renewable Energy Projects in the MENA Region (cont'd)

Jurisdiction	Country facts and policy	Key projects to watch
United Arab Emirates: *Abu Dhabi*	UAE wide: Realizing that even its huge natural gas resources will not be able to sustain its growing electricity demand, the UAE is firmly set on diversifying its energy sources. Nuclear and renewables (particularly solar, as the potential for wind power is limited) are in the spotlight. The UAE has set a target of supplying 7% of its electricity from renewable sources by 2020. This is expected to create a market for renewables in the capital worth approximately US$8 billion in the next decade. There has been a strong political push to showcase the UAE as a leader in the renewable energy field, which explains the Masdar City project (see right column) as well as its application and ultimate success in winning the right to host the headquarters of the International Renewable Energy Agency (IRENA). Renewable energy, such as solar, will have competition from the existing highly-subsidized grid electricity for energy-intensive industries (e.g., desalination). As a result, solar-powered water desalination is only really being considered a good solution for remote off-grid applications (where no such subsidy incentive applies). Abu Dhabi: Abu Dhabi is planning to introduce a program of subsidies for solar power projects. The Department of Economic Development has been working on a framework for a subsidy system since at least 2008. Industry executives had expected the government to announce the program at the World Future Energy Summit, held in Abu Dhabi in January 2010. However, the details of the plans were not finalized in time. A source close to Masdar says it has held intense negotiations with the government over the program of subsidies. Such subsidies would "fundamentally change" the prospects for the alternative energy industry in the emirate, the source said, adding: "It would be the first step in making it feasible in the Gulf to build solar plants."	Masdar zero-emissions city - US$22 billion: Shams CSP plant: – UAE's first utility-scale solar power plant. – Parabolic trough technology will used. Modular design, so the plant could be expanded from an initial 100 mws (Shams 1) to as much as 2,000 mws over several years. Shams 1: – Estimated cost: up to US$500 million. – Site: at Madinat Zayed, as was originally planned. – Masdar has awarded (June 2010) the construction contract to a consortium comprising Spain's Abengoa and France's Total. Shams 2: Masdar was expected to launch a bidding round in December 2009 or January 2010. Its advancement is presumably dependant on the progress of Shams 1.
United Arab Emirates: *Dubai*		TECOM Investments (a member of Dubai Holding) has set up EnPark (The Energy and Environment Park). The business park, launched in May 2007, is a long-term project to address power shortages in Dubai and the industrial areas of Sharjah, Ajman and Ras al Khaimah. The project is a "free zone" spanning over 8 million square feet of office, research center, residential, educational and leisure facilities. The mission is "to be a profitable energy and environment business park that contributes AED 1 billion annually to the energy and environment industry by 2014." – Delayed by the financial crisis. In June 2009, the executive director of electricity affairs in the Energy Ministry said that Dubai was planning on setting up the region's largest solar power plant. – Seemingly on hold since the financial crisis. Feasibility studies are being undertaken for a US$1 billion wind farm project (may supply up to 10% of Dubai city's power in the future). – No readily available news to this effect yet.
United Arab Emirates: *Fujairah*		Wind farm (66 mws): A feasibility study to exploit wind energy in the emirate has been completed. – No readily available news to this effect yet.
All countries bordering the Sahara	**The Desertec Industrial Initiative:** The project is the idea of the Berlin-based Desertec Foundation, which was set up by the Trans-Mediterranean Renewable Energy Co-operation (Trec) network, a group of scientists, politicians and other experts in renewable energy from Europe and the MENA region. Trec has been pursuing the idea of using the desert sun to power Europe's homes and factories since 2003. (It aims to provide 15% of Europe's power demand by 2050 from renewable energy projects in the MENA region.) However, the size of the enterprise means it has often been met with skepticism. The plan does now seem to be moving closer to reality. In October 2009, the Desertec Foundation met with 12 private companies in Munich to establish the Desertec Industrial Initiative. With private companies backing the scheme, the emphasis has turned to ensuring that the technical, financial and political support is also forthcoming.	The new Desertec Industrial Initiative consortium is led by German reinsurance firm Munich Re and includes several German energy firms, consultants and banks, including Siemens, Deutsche Bank, HSH Nordbank, Schott Solar, M&W Zander, E.ON, RWE and Man Solar Millennium – the latter a consortium of Man Ferrostaal and Solar Millennium. Switzerland-based ABB, Algeria's Cevital and Spain's Abengoa Solar complete the line up. Over the next four years, these companies plan to create a political and regulatory framework in conjunction with the relevant governments and set up pilot projects. If the initiative goes ahead, the Desertec concept is likely to be rolled out as a series of new solar and wind power projects, with solar predominating. While electricity generation is the main aim, any waste heat from the power generation could also be used to desalinate water.

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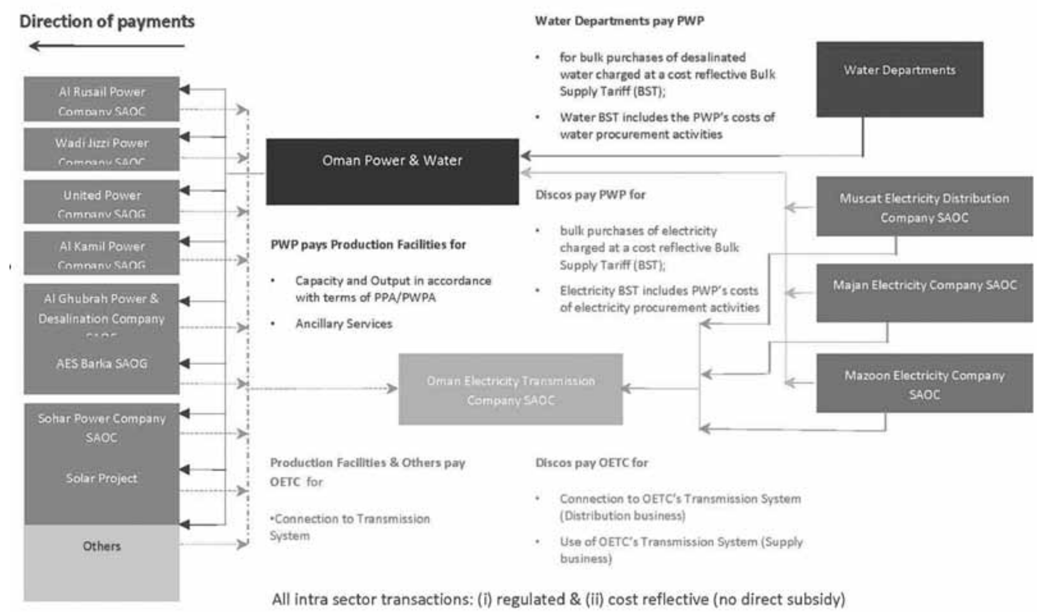
represents the purchase price plus a small up-lift or profit element. This cost includes the connection fee payable by the generator. The power is then simultaneously bought and sold at the delivery point and wheeled by the distribution companies to their respective franchise areas. A connection fee is payable to the Oman Electricity Transmission System Company. The price at which power is sold to end customers is fixed by the Council of Ministers. It is significantly lower than the true economic cost of buying and supplying the power to the end user. The difference between the sums recovered and the sums paid is the subject of a subsidy calculated by the Authority for Electricity Regulation in Oman and allocated by the Ministry of Finance in Oman for distribution between the various supply licensees in Oman.

A renewable energy project can fit within this mechanism without the need for legislative changes or the need to introduce specific regulations to ensure the viability of such a project.

Against the backdrop of such an arrangement, it is arguable that there is no need for a feed-in tariff mechanism to drive the development of a renewable energy sector. The growth of the sector can be controlled by virtue of the number of power contracts entered into with each project being bid separately and any economic purchase obligations continuing to be satisfied.

Chart 1: Financial Transaparency & Accountability Post Reform Funding



Source: Authority for Electricity Regulation, Oman

Challenges

Renewable energy projects still have a way to go before they can be successfully deployed on a large scale in the MENA region.

Such projects, even at small-scale pilot levels, are still scarce. Governments and other power sector offtakers still have to be educated about renewable technologies. Some headway is already being made with the appointment of technical, financial and legal advisers by various governments in the region.

Few parts of the MENA region have weather data (outside of metropolitan centers) of a level sufficient to provide sponsors and lenders with the comfort they need to finance projects. This is especially relevant in jurisdictions that apply the direct offtake model to renewable power procurement, as the power plant is then required under the power contract to be capable of producing at certain levels of output throughout the term of the contract. Rather than establish meteorological stations and wait for a sufficient level of insolation or wind data to build up, the offtakers can, for a defined initial period until the historical weather data has built up to an acceptable level, offer to share the risk in this respect. The sharing of risk for a limited period of time can be effectuated in a number of ways, including through the introduction of an appropriate mechanism in the tariff structure for the project.

Given the formative stage of renewable energy in the MENA region, most governments, even if they have a stated policy setting targets for renewable energy, have yet to implement a regulatory and legal framework */ continued page 8*

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that would support the stated renewable objective. There are a few exceptions to this, such as Jordan which is finalizing a renewable energy law that, among other things, facilitates the acquisition of land for renewable energy projects. The approach of some jurisdictions appears to be to run pilot renewable power projects (whether on a small or utility scale) to whatever extent the existing power sector law allows. The experience garnered from such pilot projects might then be used to make substantive changes to the sector law geared toward supporting the growth of future renewable energy projects. Such an approach is not without merit, as these initial projects will allow countries to correct course not just from a legal and regulatory perspective but also in terms of implementing of the subsidies that the renewable energy industry still needs to compete with fossil fuels.

At least 15 countries in the Near East and North Africa are actively considering large solar and wind projects.

Given that several of the larger renewable energy projects in the region are only just taking off, the appetite for lenders to provide financing to such projects has not been established. Smaller projects may not need recourse to the debt market, but utility-scale projects will and will require credit support. An encouraging fact is that the project finance market and practices in relation to large thermal power projects in the MENA region are fairly developed, with certain jurisdictions such as Abu Dhabi, Saudi Arabia and Oman having well-established precedents for financing and project documentation.

A renewable power project within the MENA region supported by an enabling government policy and regulatory framework, a well-defined and economically-viable tariff structure and project agreements based on previously-banked fossil fuel power project documents should be able to tap into the project finance lender market.

China Renewables Update

by Christopher Flood, in Beijing

China has introduced a series of new regulatory and policy initiatives focused on the wind, solar photovoltaic and biomass industries that will be of interest to both Chinese and non-Chinese industry participants.

The new initiatives are expected to provide an additional push to China's already thriving wind and solar PV equipment manufacturing industries and greatly increase the renewable energy project development opportunities within the domestic market.

Recent developments in the wind sector include elimination of a minimum 70% local content requirement on wind turbines for use in government-subsidized projects and of import duties on wind turbine components used by larger domestic manufacturers. The government also implemented a national feed-in tariff system for wind power recently as it continues aggressively to expand wind generating capacity.

In addition, China is poised to begin exploiting its vast offshore wind capacity under new rules introduced this year governing the development of offshore projects. However, foreign industry participants wishing to enter the sector will be required, at least for the time being, to form a joint venture with a Chinese majority partner. Bidding on China's first offshore wind concessions was underway as of press time.

In the solar PV industry, recent national- and provincial-level regulatory initiatives have begun providing the incentives necessary to develop a sizeable domestic market for the first time. These incentives include national government subsidies for the development of utility-scale solar installations and several examples of favorable provincial-level tariffs for solar PV-generated power.

A new national feed-in tariff for biomass announced this year is expected to increase the economic viability of biomass-fired power plants.

Another key development is a series of amendments that took effect last April to the 2006 Renewable Energy Law, the landmark legislation that enshrined renewable energy as a key feature of China's overall energy strategy and is the legislative foundation for the industry in China. The amendments are aimed at addressing some of the main issues arising from the rapid development of the domestic renewables industry triggered by that law, including transmission bottlenecks and cost-sharing uncertainties. Industry players will need to await a series of implementing regulations and the passage of time to better evaluate the amendments, but initial reaction has generally been positive.

Finally, the Chinese government has either announced or is reportedly contemplating several new policy goals relevant to the development of the renewable energy industry. These new goals include medium- to long-term targets for renewable energy capacity and for the carbon and energy intensity of the Chinese economy. Although the measures are unlikely to affect the day-to-day operations of industry participants, their importance cannot be underestimated as a guide to Chinese policy and a yardstick against which the necessity for future regulation will be measured.

National Targets

The Chinese government expects renewables to play a key role in efforts to increase China's energy security and to provide a partial response to the immense environmental pressure brought on by its unprecedented industrialization. Renewables are also expected to have the same obvious benefit of any other energy source — they will contribute needed additional fuel for rapid economic growth.

China is targeting that non-fossil fuels (including hydro and nuclear) will account for 10% of final energy consumption by this year and 15% by 2020, up from approximately 9% in 2008. Achieving these targets will require a massive amount of new investment in technology and infrastructure. China was the global leader in renewable energy and energy efficiency investment in 2009, with $34.6 billion invested, almost double that of second-place United */ continued page 10*

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to have a significant effect on the continued attractiveness of lease financing. However, interest among renewable energy developers in leasing in the United States is being driven currently by other factors than keeping obligations off balance sheets.

A LAWSUIT will test whether power projects that are awarded federal tax credits become subject to the National Environmental Policy Act.

Such projects could have to get time-consuming environmental impact statements. The case could also affect renewable energy projects that receive Treasury cash grants.

However, the environmental group that filed the suit lost another round in late July.

The suit was filed after the IRS awarded $1 billion in investment tax credits in November 2006 to developers of nine projects that planned to use gasification and other advanced technologies to generate electricity or produce other forms of energy for industrial use from coal. Section 48A of the US tax code authorizes a 20% investment tax credit for building new integrated-gasification combined-cycle power plants and a 15% investment credit for using other advanced technologies to burn coal. However, the credits were limited at the time to $1.6 billion. Developers had to apply to the US Department of Energy and the Internal Revenue Service for an allocation.

Appalachian Voices is arguing in the suit that the decision to award tax credits is a "federal action" requiring recipients to comply with the National Environmental Policy Act.

The Department of Energy and IRS disagree.

The environmental group originally asked a federal district court in Washington for a preliminary injunction to deny the recipients use of the tax credits until the case could be heard. The court declined in 2008, saying that the group had not shown any "particularized connection to the sites" that were distant from the Appalachian region. The group re-filed its argument focusing on the */ continued page 11*

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States.

Significant additional investment will be required in the future. A senior member of China's National Energy Administration estimated in July that measures required to implement its draft 2011-2020 development plan for emerging energy industries will require new investment of RMB5 trillion (about US$736 billion). In addition to wind, solar and biomass, the plan is also expected to encourage new clean coal, smart grid and alternative fuel vehicle technologies. It has been reported that the plan will also include specific renewable energy capacity targets amounting to a total of 500,000 megawatts by 2020, translating into 300,000 megawatts of hydropower capacity, 150,000 megawatts of wind, 20,000 megawatts of solar PV and 30,000 megawatts of biomass.

In addition to the specific renewable energy targets, in December 2009, China committed to reducing the amount of carbon dioxide it emits to generate each unit of GDP by 40% to 45% of 2005 levels by 2020. Doing so would be no small feat in a country that currently relies on relatively cheap coal for about 75% of its power generating capacity. However, the government has said that this target will become binding on a domestic level when it is included in China's next five-year plan covering economic development targets and priorities for the period from 2011 to 2015. China has also targeted a 20% reduction in energy intensity per unit of GDP from 2005 levels by 2020.

China led the world with $34.6 billion in renewable energy and energy efficiency investment in 2009.

Onshore Wind

China passed Germany this year for second place behind the United States in total installed wind power capacity, and it led the world in newly-installed capacity in 2009 with 13,800 megawatts. Nationwide wind power capacity has doubled every year of the past five, rising from 800 megawatts in 2004 to 26,000 megawatts at the end of 2009.

China has become home to the world's largest wind turbine manufacturing industry, with Sinovel Wind, Goldwind and Dongfang Electric each ranking among the world's top 10 manufacturers. It is also home to a large number of smaller manufacturers of generators, towers, blades and other components. Observers predict that the domestic manufacturing industry is probably entering a consolidation phase, in part because of shrinking margins, and also because of draft regulations issued earlier this year that would require that all domestic producers be capable of manufacturing 2.5-megawatt turbines. Both developments are expected to put significant pressure on smaller, less technologically-advanced firms.

One of the domestic industry's biggest benefactors in its early years was the 2005 requirement that at least 70% of turbine equipment be domestically manufactured for wind generation projects to qualify for approval by the National Development and Reform Commission, or NDRC, China's principal economic planning organ. That requirement was scrapped in late 2009, although observers have noted that it has largely served its purpose of temporarily incubating a thriving domestic industry.

Another development of interest to turbine and component manufacturers is the elimination by the Ministry of Finance in the spring of 2010 of import duties on wind turbine (and hydro turbine) components. The duties were previously set at 3% to 30%. These components can now be imported duty free by turbine manufacturers capable of meeting size and technological requirements, which may incidentally add to industry consolidation pressure.

The government also changed its pricing policy for wind power. Its previous hybrid pricing mechanism in which feed-in tariffs were set after competitive bidding for projects has been replaced. Going forward, prices will be set at one of four national feed-in tariffs that vary from RMB0.51/kWh to RMB0.61/kWh, depending on the location of the project. (The renminbi was trading at press time at RMB6.79 to the US dollar.)

Offshore Wind

A senior spokesperson from China's National Energy Administration said in June that the government has been accelerating plans for offshore wind development and expects capacity to reach as much as 5,000 megawatts by 2015 and 30,000 megawatts by 2020. China completed construction only this year on its first offshore wind pilot project.

The regulatory basis for this expansion was jointly issued by the State Energy Administration, or the SEA, and the State Oceanic Administration earlier this year. The Interim Measures for the Administration of Offshore Wind Power Development, referred to below as the "offshore measures," governs the full life-cycle of offshore projects, from the planning phase, to the project approval and construction process, to post-construction environmental and other reporting obligations.

A key consideration for foreign developers is that foreign-owned entities are prohibited from developing offshore projects, unless they do so from the minority position in a joint venture with a Chinese partner. That is, the Chinese entity must own at least 51% of any Chinese-foreign joint venture in the industry. This is in contrast to the onshore wind regulations, which do not expressly prohibit foreign-controlled developers (although in order to qualify for approval under China's clean development mechanism rules, such a structure may in fact be required in any event).

Under the offshore measures, concession development approvals are to be awarded primarily on the basis of the bid feed-in tariff, but also after consideration of the construction design and the developer's technical capability and performance record. This range of considerations reflects the added technological sophistication required for offshore projects and perhaps also lessons learned from onshore projects, which have typically been approved mostly on the basis of price.

Public tenders for the first four offshore concessions located off Jiangsu province began in May and the process is expected to conclude sometime in September. In order to avoid some of the below-cost pricing seen by / continued page 12

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one project that is nearby, an upgrade that Duke Energy plans to its Cliffside power plant in North Carolina. The utility was awarded $125 million in tax credits.

The court declined again in late July to issue a preliminary injunction. It said the Duke project will not be completed until 2012. Courts do not issue preliminary injunctions unless there is a risk of irreparable harm to one of the litigants before the merits of the case can be heard. The court said there is plenty of time to decide the case before the project is completed.

The case is *Appalachian Voices v. Chu*.

IN-BOUND ACQUISITIONS of US businesses with potential national security implications by foreign investors have run into trouble on average 14% of the time since 2006.

Two investments by Chinese companies were effectively blocked in the last 10 months — including one in the solar sector — after CFIUS, a federal panel that reviews such acquisitions, raised questions. The parties cancelled the transactions.

In one case, Emcore, a US manufacturer of components for fiber optics and solar panels, proposed to sell 60% of certain of its businesses to a Chinese company, Tangshan Caofeidian Investment Corporation, for $27.8 million. The Chinese company planned to invest another $27 million in the business after the initial purchase. Emcore planned, as part of the deal, to establish a photovoltaic manufacturing facility in China. The company announced in late June that it was withdrawing the transaction after CFIUS expressed "certain regulatory concerns."

Last December, CFIUS forced another Chinese investor, the Northwest Nonferrous International Investment Company, to drop plans to acquire a 51% interest in FirstGold, a mining company based in Nevada. FirstGold holds leases to use more than 8,000 acres of federal land. The government felt the deal would bring the Chinese too close to a sensitive Naval air base and other / continued page 13

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some as plaguing the onshore concession tender process, the SEA has indicated it will eliminate the highest and lowest bids and set a target price tied to (but less than) the average of the remainder. This, combined with the multi-factor approach in evaluating bids, is expected to result in more moderate pricing for approved projects.

Solar PV

Mainland China-based, United States-listed solar PV manufacturers Suntech Power Holdings, Yingli, JA Solar and Trina Solar each rank among the world's top 10 solar PV manufacturers based on 2009 production, and the Chinese industry as a whole supplied 43% of the world total last year.

Perhaps foreshadowing even greater visibility in world markets among Chinese manufacturers, Yingli announced in July that an affiliate was negotiating RMB36 billion (US$5.3 billion) in loans from China Development Bank to fund domestic and international expansion. Similar deals with CDB have been inked by Suntech, which in April announced a "non-binding" agreement for RMB50 billion (US$7.33 billion) in new loans over five years, and Trina Solar, which has announced a deal with CDB worth RMB30 billion (US$4.4 billion).

However, despite the growth of the solar PV manufacturing industry within China, only about 10% its manufacturing capacity was previously geared toward serving the domestic market. This situation has been changing over roughly the past year, in part as a result of several new policy and regulatory initiatives.

Most significant for the development of domestic solar projects has been the introduction at the national level in 2009 of the "Golden Sun" program of subsidies for domestic solar PV installations and related transmission and distribution systems. The subsidies range from 50% of the total investment for grid-connected projects, to 70% of the cost of standalone off-grid projects. In each case, projects must have a minimum generating capacity of 300 kilowatts at peak. The availability of the subsidies is capped provincially, and they are available through 2011 based on approvals to be granted on a project-by-project basis.

The Golden Sun program complements a set of similar incentives aimed at promoting rooftop and other building-integrated solar installations.

In addition to national-level programs, several provinces and regions have implemented their own solar PV incentives that are expected to stimulate further development of the domestic industry. For example, Zhejiang and Jiangsu, home to many of China's leading solar PV manufacturers, have implemented province-wide preferential tariffs for solar-powered electricity generation. In Zhejiang, they amount to RMB0.07/kWh.

Meanwhile, Jiangsu has introduced a three-year solar PV development plan with the target of achieving approximately 440 megawatts of installed solar PV generating capacity by the end of 2011 when the program expires. Preferential tariffs in 2009 ranged from RMB2.15/kWh for ground-based solar systems, RMB3.7/kWh for roof-based systems and RMB4.3/kWh for building integrated systems. The tariffs are scheduled to be reduced in 2010 and 2011 and eliminated thereafter.

Other provinces and regions are also offering various incentives to developers. In July, Shandong announced it would buy power from solar PV generators for RMB1.7/kWh, joining both Ningxia Hui Autonomous Region and Inner Mongolia in offering provincial-level incentives.

In 2009, the government began a competitive tendering process for its first batch of utility-scale solar projects similar to the process used earlier in the wind sector. Also similar to the wind sector experience, the government set target tariffs on the basis of bidding by potential developers during the tendering process, with feed-in tariffs reaching as low as RMB0.07/kWh. Observers have suggested that the aggressive pricing is likely in part the result of the "mandated market share" provisions under the 2006 Renewable Energy Law, which will require larger power firms to allocate at least 3% of generating capacity to non-hydro renewables by this year and 8% by 2020.

Bidding began in June and was underway as of press time to build and operate a second round of 13 utility-scale solar PV generating projects located in six provinces. The combined generating capacity of the 13 projects of 280 megawatts almost equals China's total installed generating capacity as of the end of 2009.

In much the same way that pricing for wind projects graduated to feed-in tariffs from "government guided" pricing arising from the tendering process, the solar industry is also expecting a national solar feed-in tariff program to be introduced. It was previously reported that the NDRC would bring the national solar feed-in tariff system into effect last year. However, as of press time, there has been no announcement and no new developments are available. It is expected that, when announced, the measures will include separate regional tariffs based on solar generating capacity.

Biomass

In July, the NDRC announced a new national feed-in tariff program for power generated from biomass. The new program sets a nationwide tariff of RMB0.75/kWh for biomass-fueled power, replacing the 2007 tariff that provided generators RMB0.25/kWh over the prevailing local rate for coal-fired power. The announcement signaled the NDRC's intention to make biomass power generation a profitable alternative, especially in rural regions where agricultural biomass is abundant, but generation from coal is less costly.

China's biomass industry is small compared with wind. However, it remains a focus of development, with several small biomass-fired facilities being constructed, leading to modest growth in China's installed capacity, which in 2009 reached 3,200 megawatts.

Renewable Energy Law Amendments

Amendments to the 2006 Renewable Energy Law took effect in April, with industry players now awaiting publication of a series of implementing regulations that will be required to flesh out the details. However, initial reaction to the amendments has generally been positive.

By way of brief background, the broad strokes of the regulatory regime for the renewable energy sector were introduced in 2006 with the enactment of the Renewable Energy Law, which set out a framework for the regulation of the industry that was intended to be supported by subsequent measures enacted by various national- and provincial-level bodies. The Renewable Energy Law has several main pillars:

Renewable energy targets. Generation targets must be set by the energy authority of the State Council (China's cabinet) both on an economy-wide basis and for specific renewable energy technologies. In addition, "mandated market share" provisions require major power generators to meet targets for purchasing power from renewable sources.

Grid connections. The law requires that grid companies provide grid connections for renewable energy projects developed within the geographic scope of their grid systems.

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military facilities whose locations are classified.

The withdrawals are a reminder to submit proposed in-bound acquisitions of interests in US businesses that might raise security concerns for approval. CFIUS was formed by President Gerald Ford in 1975. It is an inter-agency committee, headed by the Treasury Department, on which 16 agencies sit. Submission of proposed deals is voluntary. However, the committee has authority to set aside transactions after the fact that were not submitted for review.

The committee makes recommendations. The US president has ultimate authority to block a transaction. Only one transaction has been formally rejected by the president. The first President Bush rejected a proposed acquisition of MEMCO Manufacturing Inc., a supplier to Boeing, by the China National Aero-Technology Import and Export Corporation in 1990.

Transactions that run into trouble are usually withdrawn before they reach the need for a presidential decision.

Before 2006, at most one or two transactions a year were withdrawn. During the period 2006 through 2009, 64 transactions were withdrawn, or roughly 14% of the 469 transactions submitted to CFIUS for review during that period.

CFIUS still approves most requests, including a purchase by EdF, which is owned partly by the French government, of a minority stake in nuclear plants owned by Constellation Energy.

In July, 50 members of the House steel caucus sent Treasury Secretary Timothy Geithner a letter urging him to "thoroughly investigate" a proposed investment by the Anshan Iron & Steel Group of China in the Steel Development Company in Mississippi. Terms of the investment have not been announced but are believed to involve investments in as many of five steel mills owned by the US company. The congressmen charge that the investment could distort the US market because of the Chinese company's access to "massive Chinese government subsidies" and cost / continued page 15

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Cost sharing and incentives. The law sets out the general framework for subsidizing renewable power plant development, power generation and grid connection and allocates the cost between the generators and end users. The law envisages that incentives will be managed through future legislation on pricing arrangements, direct subsidies and tax incentives. Some incentives will be allocated directly through a government-managed fund.

The amendments are intended to deal with some of the most pressing problems arising from the industry expansion brought on by the Renewable Energy Law. A vivid illustration of these issues is the fact that an estimated 30% of China's total installed wind capacity is not connected to the grid, and where grid connections do exist, developers have been plagued by transmission bottlenecks. Without action on the policy and regulatory front, these problems were expected to intensify as China implements its plans to continue to develop renewable projects at a rapid pace. The new projects will include, for example, seven wind mega-projects, each with 10,000 megawatts of generating capacity, several of which will be located in sparsely populated regions with lower transmission capacity such as Xinjiang, Inner Mongolia and Gansu.

The amendments have three principal purposes.

First, they improve coordination among central, provincial and local government agencies on renewable energy development. Local governments must develop renewable energy plans that are consistent with the frameworks set out by the national government by requiring that the local plans be filed with the SEA. Coordination is also to be improved among the bodies responsible for renewable energy planning and development and those responsible for energy planning and development more generally.

Second, the amendments renew and strengthen the obligation of transmission companies to provide grid connections to renewable energy installations. The absence of reliable connections has resulted in, at least temporarily, a significant amount of unutilized generating capacity and inefficient capital investment. This is in part the result of the natural reluctance on the part of the transmission companies to make the required investment to expand capacity to more remote locations where many renewables projects are located. The amendments aim to address this issue primarily by reiterating and strengthening the guarantee imposed upon transmission companies to purchase, pursuant to interconnection agreements, all power generated by renewables projects within their grid systems. This guarantee is backed up by a quota system requiring that a minimum amount of power be generated from renewable sources.

China's development plan for the next 10 years calls for another $736 billion in new investments in emerging energy industries.

Grid companies are also required to improve the ability of the grids to handle increased loads through expansion and technological improvements. Generating firms are similarly required to ensure that the electricity produced complies with the technical standards required by the grid company and to cooperate with the grid companies in maintaining the stability of the grid.

Finally, the amendments fine tune and strengthen the program of financial incentives and their administration. They strengthen a fund established under the 2006 law to provide grants for the development of renewable energy projects, fund the incremental cost of energy from renewable sources and support technological research.

The fund, which is administered by the Ministry of Finance, was previously financed through a surcharge levied on power prices, but those amounts alone fell short of costs. The amendments address this issue by allowing the fund access to additional funds from the general government budget to cover the spending shortfall. The amendments also permit the fund to be used for other purposes. For example, assistance may be provided to grid companies to alleviate the financing pressure arising from the fact that costs incurred in grid expansion may not be recouped until power is sold to the end-user.

Many Options For Solar Developers In California

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

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

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

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

Solar Power Expansion

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

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

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American steelworkers their jobs.

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

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

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

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

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

The taxpayer in this / continued page 17

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

Prior to the establishment of the RPS in 2002, large-scale solar power in California consisted of nine solar thermal power projects with a total capacity of 360 megawatts and one large-scale solar PV array with a capacity of just over three megawatts. Solar power was not a focus of early RPS procurement efforts, given its price premium over other forms of renewable energy. As such, only a small number of utility-scale solar projects have become operational since 2002. However, the installed solar capacity in California has more than tripled during this period, primarily driven by homeowners and businesses that have installed 700 megawatts of small-to-medium size grid-connected rooftop PV systems.

Over the next 10 years, the utility-driven market for medium- and large-scale solar systems likely will predominate, even as the consumer market continues to expand. The size of the utility-driven market can be appreciated by looking at the project pipeline: in August 2010, the California Energy Commission was conducting environmental reviews on 4,800 megawatts of solar thermal projects. In all, more than 8,000 megawatts of solar thermal capacity and 9,000 megawatts of medium-to-large scale PV capacity are reportedly in various stages of permitting, planning and development. While it is unlikely that all of this capacity will ultimately be built, the addition of just one third of this capacity would represent more than a ten-fold increase in California solar generation.

Solar developers have a number of options for selling output in California, ranging from annual solicitations for long-term utility contracts to residential rooftop programs. The details of each utility program differ, as does the ease of participation. The programs can be roughly divided by generator size, though generators of certain sizes are eligible for multiple programs.

Project Viability Calculator

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

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

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

Annual RFOs

The three largest investor-owned utilities in California typically contract for long-term supplies of renewable energy through annual competitive requests for offers called "RFOs." The CPUC established this program for utility procurement of renewable energy to ensure that the utilities meet their RPS obligations through a transparent process.

The main features of the program are annual RFOs, standardized terms and conditions for the power purchase agreement, an independent evaluator that oversees the RFO, a procurement review group that advises the utilities on procurement-related issues, explicit codes of conduct for any dealing between a utility and any of its affiliates, and a method for determining the reasonableness of contracts that result from competitive procurement.

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

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

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

Prices in RFOs

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 2: Utility PV Program Information

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

Tradable RECs

Renewable power in some parts of the country is less expensive than the prices observed in California and Nevada. However, much of the low-cost power cannot be delivered to California given current transmission constraints.

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

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

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

The tradable REC decision imposed a cost cap of $50 per tradable REC (where one REC equals one mWh of renewable power) if the utility intends to use the tradable REC for RPS compliance. The cost cap should also sunset at the end of 2011 but may be pushed back. The $50 cap is equivalent to the existing penalty for noncompliance with RPS procurement obligations.

SCE Standard Contract

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

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

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

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

Small- and Mid-Size Solar PV

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

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

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

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

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

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

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

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

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

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

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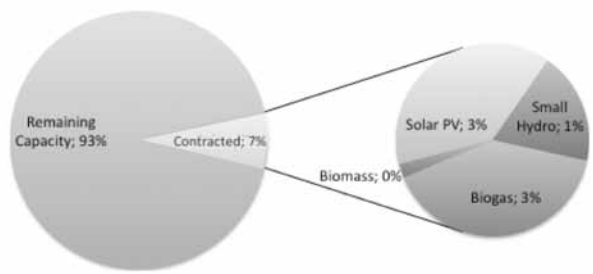
agreement prices and set caps on the capital costs of the utility-owned generation. These prices range from $235-$260 per mWh (AC) for power purchase agreements and $3.96-$4.32 per watt (DC) for the capital costs of the utility-owned facilities.

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

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



Additional information about the programs is provided in Table 2.

Feed-in Tariffs

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

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

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

In turn, the customer is not eligible for net-metering or other ratepayer-funded incentives and must relinquish the RECs for energy sold to the utility. The utility must agree to the sale as long as the renewable facility meets eligibility requirements, the utility has not yet met its share of a 498.5-megawatt statewide cap and the interconnection does not pose safety or reliability concerns.

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

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

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

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

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

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

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

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

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

Residential and Small Commercial Solar

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

The program has three components.

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

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

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

Through July 2010, 670 megawatts of PV have been installed under these programs at an average price of $9.21 per watt for systems smaller than 10 kilowatts and $7.66 per watt for larger systems. The California Energy Commission has certified more than 1,900 solar PV installers and retailers for this program, though fewer than 20 firms have more than half the market share of installations to-date. The largest players in terms of overall megawatts of installations / continued page 22

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

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

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

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

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

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

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

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

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

Multiple Options

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

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

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

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

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

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

Potential Effects of US Financial Sector Reform

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

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

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

The bill was borne out of frustration that the US and other governments had to bail out a number of large financial institutions in the fall of 2008 and into 2009 and a determination by Congress to bar banks and other systemically-important financial institutions from engaging in risky activities that might require the US government to have to spend public funds again.

The bill will take effect in stages. Even at 861 pages, an enormous amount of detail has been left to the federal bank regulatory agencies to fill in. The bill requires 243 separate rulemakings and 67 studies; 10 different federal agencies will have to write regulations. The US Securities and Exchange Commission will have to write 95 regulations and 17 one time reports. The Commodity Futures Trading Commission will be the next busiest, with 61 regulations and six one-time reports.

There are four main parts to the bill that are of particular interest to the project finance community.

The first is a Volcker rule that is supposed to bar banks from engaging in proprietary trading and taking equity positions in private equity funds. The second is a ban on banks dealing in swaps and other derivatives by taking away their access to federal deposit insurance and their ability to borrow from the Federal Reserve if they keep those businesses. The third is a requirement for swaps and hedges to be cleared through central exchanges, and the fourth is increased capital adequacy requirements for banks, including foreign banks operating in the US market, and for large non-bank financial institutions that are considered important players.

The views you will hear today from the panelists represent their own individual views; they are not speaking for their institutions.

Tax Equity Market

MR. MARTIN: John Eber, there has been a lot of talk in the press about the Volcker rule that was adopted as part of the financial sector reform bill. What is it?

MR. EBER: It is a rule that prohibits insured depository institutions and their affiliates from engaging in proprietary trading, from acquiring or retaining equity or partnership interests in hedge funds or private equity funds and from sponsoring hedge funds or private equity funds.

MR. MARTIN: What is proprietary trading?

MR. EBER: We were very concerned about how it was being defined because a broad definition had the potential to affect the ability of banks to participate as tax equity investors in renewable energy projects. The final bill / continued page 24

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India.

The tribunal said that an earlier decision in a similar case involving Clifford Chance, another UK firm, that held the firm did not have to pay tax on fees for services rendered outside the country is longer good law. The latest case is Linklaters LLP v. Income Tax Officer.

MASSACHUSETTS ruled that the state sales tax does not apply to wind turbines, towers and foundations.

The state sales tax is 6.25%. It does not apply to "machinery" that is used "directly and exclusively" in furnishing "power to an industrial manufacturing plant" or "electricity when delivered to consumers through mains, lines or pipes." An independent generator plans to install a single 1.65-megawatt wind turbine inside the fence at an industrial site. It plans to supply all of the electricity to a realty trust that is leasing it the site. The trust will provide 5% of the electricity to the other, industrial tenant on the site and resell the remaining 95% to the local utility.

The Massachusetts Department of Revenue said in a letter ruling in July that the turbine, tower and foundation are all exempted from sales tax as "machinery." The ruling did not discuss whether the independent generator is furnishing electricity to "consumers through mains, lines or pipes."

The ruling is Letter Ruling 10-3.

FLORIDA told a gas utility that offers rebates to customers as an incentive to buy energy efficient appliances that it only needs to collect sales taxes on the net price it charges for the appliances, after the rebate.

The state collects a 6% sales tax. The tax is collected on the "sales price."

The gas utility runs several programs to encourage homeowners to switch to gas or save energy. In one of the programs, it gives customers from $100 to $625 back / continued page 25

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narrowed the definition considerably. It is now defined as "engaging as a principal for the trading account of a banking organization in any transaction to purchase or sell or otherwise dispose of securities or derivatives." The key concept was trading for the trading account of the bank.

MR. MARTIN: So the definition of "trading account" is pretty important. Do you recall what it is?

MR. EBER: Trading for the bank's trading account means short-term transactions.

MR. MARTIN: I have the definition here. What the Volcker rule proscribes is trading by a bank through "any account used for acquiring or taking positions in securities" — which is a very broad term — "principally for the purpose of selling in the near-term or otherwise with the intent to resell in order to profit from short-term price movement." So you take comfort from that definition that what you do in the tax equity market for renewable energy would not be considered proprietary trading? You take long-term positions?

MR. EBER: Yes. We were fairly concerned during debate on the bill that tax equity investments might be considered proprietary trading, but the final bill makes clear that they are not. However, keep in mind that the regulators can expand or narrow the scope of that definition in the rulemaking to come.

MR. MARTIN: Marshal Salant, you are also a tax equity investor at Citigroup. Are you comfortable that proprietary trading has been defined in a way that does not cover tax equity investments?

MR. SALANT: We are. As John points out, many, many details have to be filled in by the bank regulators in regulations that are still to come. This will be a dynamic process. There will be technical corrections. There will be rules and regulations. People will challenge them. There could be new laws. There could be lawsuits. It may take years for some of these things to get resolved completely, but Congress seems to have made clear that the intention is not to treat tax equity investments are proprietary trading.

MR. MARTIN: Going back to John Eber, the other part of the Volcker rule was — I will read the language — banks may not "acquire or retain any equity partnership or other ownership interest in or sponsor a hedge fund or private equity fund." The final bill limits a bank's investments in hedge funds or private equity funds to no more than 3% of the fund's capital. Those investments could also total no more than 3% of the bank's tangible equity. I gather your view is that nothing you do in the tax equity market is considered investment in a private equity fund?

There has not been any slowdown in US tax equity deals since the financial sector reform bill passed, but the market could be affected in the long run if banks are less profitable.

MR. EBER: We do not believe it is. We have looked at that closely, and the way the terms are defined suggests to us that tax equity investments are not investments in private equity or hedge funds — again, with the caveat that the bank regulators still have to write implementing regulations.

MR. MARTIN: The regulations will take some time to write. There is a coordinating committee that has six months after the bill was enacted on July 21 to organize its thoughts. Then the bank regulatory agencies have another nine months to write regulations. The bill itself does not take effect until July 2012. I imagine there will be a lot of scrambling during that period in Washington. The lobbyists will be busy.

MR. EBER: Banks will not want to make any investments that might be prohibited during that period because they would then be required to dispose of them.

MR. MARTIN: Has there been any slowdown in work or other noticeable effect so far on the tax equity market for renewables?

MR. SALANT: Not as a result of the financial sector reform bill. Again, based on things you were just saying, we went through an analysis very similar to John's. Our investments in renewable energy projects are not short-term plays where we are intending to profit from quick price movements. We are not buying into projects at par thinking that the paper will trade at 110 in a couple of weeks. We are not buying distressed paper at 30¢ on the dollar with the intention of holding the paper for a couple of weeks and then selling at 50¢. That is just not the way this business works.

Things like whether or not the Treasury cash grant will be extended are having a much bigger effect on tax equity than this bill.

MR. MARTIN: John Eber, you deal with a lot of banks in the secondary market for tax equity paper — not that there is that large a market, but you have been trying to develop one. Have you sensed any hesitancy on the part of potential secondary market investors due to this bill?

MR. EBER: Not yet. I think everybody is watching with great interest to see how the rules are interpreted, but at this stage, we are optimistic that the market will not be affected. We worked hard with the American Wind Energy Association and both the Senate and the House committees that were prominent in putting the Volcker rule in the bill to clarify the intention was not to bar bank tax equity investments in renewable energy projects.

MR. SALANT: We are more worried about what I will call the second-order or third-order effects. It would be incorrect to say the bill will have no effect whatsoever. The second and third order effects are that the bill will add transaction costs and friction to what financial institutions do that may not be immediately bad. Some provisions in the bill are expected to reduce bank profits. If the financial institutions are making less money, then they will be paying less taxes. If you have less tax capacity, then it could eventually affect your ability to do tax equity. There are second and third order effects that will become visible over time, but in terms of direct immediate impact, we are not as concerned.

Private Equity Funds

MR. MARTIN: Next topic: are there any large private equity funds or hedge funds that invest in the renewable energy sector or independent power or infrastructure projects that anyone on this panel expects to be affected by the Volcker rule because the funds are backed heavily by banks?

MR. METCALFE: Maybe the focus should be on the next round of funds because the Volcker rule will not take effect until 12 months after issuance of rules or, if earlier, two years after the bill was enacted.

For future funds, it will be harder to raise capital from banks. Banks may still arrange these funds under */ continued page 26*

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if they will switch to gas for heating, cooking or drying clothes or replace existing gas appliances with more efficient appliances. The customer buys the new appliances from the utility directly.

The utility has other programs where it makes payments to home builders for installing gas appliances or to homeowners who buy appliances from other suppliers.

The Florida Department of Revenue said in a ruling in July that sales taxes only need to be collected on the net price in cases where the customer buys appliances from the utility directly, but in the other cases, where the utility is merely helping the builder or homeowner buy the appliance from someone else, the sales tax is collected on the gross price.

The ruling is a technical assistance advisement. The record ID is 84206.

STREET LIGHTS can be depreciated over seven years, the US Tax Court said in late July.

The decision is important because US tax rules classify equipment for depreciation purposes according to the industry or activity in which it is primarily used.

The court let two utilities in this case — PP&L and Entergy — treat street lights as a separate business and depreciate equipment used in that business more rapidly than the other equipment each uses in its main utility business.

PP&L, an electric utility in eastern Pennsylvania, had been depreciating the street lights it owns over 20 years by putting them in depreciation class 48.14, just like the rest of its power lines, poles and other electric distribution and transmission equipment. PP&L filed a form with the IRS in 1997 to let the tax agency know it was changing the depreciation to seven years. It claimed an additional $20 million in depreciation both in 1997 and as an adjustment to the depreciation it claimed in prior years.

The IRS said no. It argued that the street lights were part of PP&L's business of providing electricity to customers. */ continued page 27*

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their flags or mastheads, but they may put less of their own capital into them. We may see more third party investment by limited partners and less direct bank sponsorship of funds. Rather than changing who owns what, it may change the way in which investing occurs.

Swaps and Hedges

MR. MARTIN: Let me move to another topic, which is swaps and hedges. John Shelk, let's break this down into small pieces. Start with the context. How do you expect the bill to affect hedges and swaps in the power sector? People do interest rate swaps; they hedge currency, electricity, gas, and other commodity risks.

MR. SHELK: We are fairly pleased with how the legislation turned out, considering where we started from and what the administration, and particularly Chairman Gensler of the Commodity Futures Trading Commission, originally tried to do. The one caveat is that so many of the details have been left, in this case, to the Commodity Futures Trading Commission, and until those rulemakings are undertaken, there is still some risk.

MR. MARTIN: Tom Emmons, any general thoughts before we dive into specifics?

MR. EMMONS: I think most companies in the renewable energy sector will be considered end users and, since they are not swap dealers and they are hedging for their own accounts, they will have to notify the regulators of what they are doing but they will be exempted from most of the new restrictions.

MR. MARTIN: Let me dig into specifics. As a general rule, swaps and hedges must be cleared through a central exchange, and John Shelk, why was this such a big deal?

MR. SHELK: It is a big deal because swaps and hedges are an essential tool for power companies to manage risk. If you read any of the recent analyst reports and listen to earnings calls, the substantial drop in wholesale power prices the last two years would have had a huge effect on this industry were it not for swaps and hedges.

The concern was not the potential need to clear swaps and hedges on a central exchange. The concern was that clearing would have meant posting huge amounts of collateral and margin that today is handled on a customized and bilateral basis. Sometimes the collateral in bilateral trades is in cash; a lot of times, it is liens on property.

Our pitch to Congress and the regulators was that the industry cannot afford to have so much dead capital. We would have been parking huge amounts of cash at the clearinghouse that would be better invested in new power plants and other infrastructure.

> Most power companies should be spared by a commercial end-user exemption from having to post large amounts of cash collateral in connection with swaps and hedges.

MR. MARTIN: Didn't I hear you say that companies are posting collateral in bilateral hedges and swaps? What's the big deal if they have to post it under a standardized regime on a central exchange?

MR. SHELK: The standard clearinghouse terms would have required the collateral be posted in cash while the parties to the swap or hedge decide today on their own what form the collateral should take. Estimates were that power companies would have had to tie up hundreds of millions of dollars per company in cash collateral.

MR. MARTIN: So that did not happen. Swaps and hedges by end users do not have to be cleared because of the commercial end-user exemption that Tom Emmons mentioned that spares swap parties who are not financial institutions and who use swaps to hedge or mitigate their own commercial risks from having to clear their swaps. But I notice that this was described as an optional exemption. What does that mean?

MR. SHELK: It is optional in the sense that if the end-user party to the transaction wishes to take a particular transaction to the clearing exchange or the central exchange, that can be done at the option of the end user. There is no requirement that an end user clear.

MR. MARTIN: I noticed the bill does not expressly exempt commercial end users from the need to meet margin requirements, but I understand there was a letter from the two key Senators, Dodd and Lincoln, to the two key Congressmen, Frank and Peterson, on June 30 to say that it was not their intention to subject such swap parties to margin requirements. If you are a commercial end user, are you comfortable with that letter? Does it settle the issue?

MR. SHELK: We are comfortable. I would not say it settles the issue. I think of the bill as having two potential trapdoors that could adversely affect our ability to use swaps and hedges. The first trapdoor was the one that we just discussed that would have required mandatory clearing. The legislation is clear that if you are a commercial end user, then there is no mandatory clearing, subject to the caveat that anyone who is considered a swap dealer or a major swap participant will have to watch closely for future CFTC rulings.

The second trapdoor is the one just mentioned, which is whether or not the CFTC will require margin and capital requirements on transactions that were exempted from mandatory clearing. While it got a little messy during the sausage making on Capitol Hill, we were relieved to see both Chairman Dodd and Chairman Lincoln write the letter to their counterparts in the House. The view they expressed in the letter was reinforced by statements on the House floor that the intention was not to apply set capital and margin requirements for swaps and hedges to which one of the parties is a commercial end user.

We think that gives us a lot of comfort. I wouldn't say it settles the matter. The CFTC will have the ultimate say. If I were making a list of issues to watch carefully during the rulemaking process, this is one I would put on the short list.

MR. SALANT: Aren't there some who are a little nervous because there was language in the bill at one point that explicitly said that a bank that is a party to a swap with a commercial end user does not need to post margin, but that language was deleted from the final bill? The letters were a substitute for explicit language. People are nervous as to why Congress took the language out in the first place.

MR. SHELK: That's an accurate recitation of what happened at three and four in the morning, when most people were asleep. The letter said the explicit statement was removed from the final bill because it was redundant. Chairman Gensler was in the room at 3 a.m. when the letter was written. To be */ continued page 28*

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The US Tax Court disagreed. It said this was a separate business of lighting streets and, since the IRS had not set up a separate class in its depreciation tables for that business, the utility was free to depreciate the street lights over seven years. Assets for which the IRS has not established a separate industry class are depreciated over seven years.

The case is *PPL Corp. v. Commissioner.* The Tax Court released its decision in the case on July 28. It reached the same decision in a separate case involving Entergy called *Entergy Corporation v. Commissioner.*

Both utilities are also arguing with the IRS about their ability to credit windfall profits taxes they had to pay in the United Kingdom in the late 1990's against their tax bills in the United States. Both bought electric utilities in Britain in the 1990's. Both unexpectedly had to pay a large windfall profits tax after the government imposed such a tax soon after they bought the utilities. The Tax Court said the taxes were creditable as the NewsWire *went to press.*

A TRANSACTION WAS A LEASE despite a fixed-price purchase option.

A couple leased a truck from a Ford dealer for fixed monthly payments over a 48-month lease term. They had an option at the end of the lease to buy the truck for $17,612, which was 102% of the expected value at the end of the lease. If they did not exercise the option, then they would have to pay a "termination fee" of $395.

The couple argued they owned the truck from the start because the "lease" was an installment sale.

The US Tax Court said no. The purchase option was not nominal. It was 40% of the original cost of the truck and slightly more than the truck was expected to be worth at the end of the lease. The couple was not reasonably certain to exercise it. The judge also noted that the lease required the couple to pay an extra "excess mile charge" for each mile they drove the */ continued page 29*

Financial Sector Reform

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fair and candid, we would have preferred that the explicit exemption had remained in the bill. We complained to the committee chairmen that even if they thought the language was redundant, removing it at the last minute would create an unfortunate inference. That's when they wrote the letter.

MR. MARTIN: We were just talking about margin requirements. If the end user is exempted, must the bank or other trading company that is the counterparty to the swap clear it through a central exchange? And if the answer is yes, won't this still make swaps and hedges more expensive for power companies to arrange?

MR. SHELK: I understand the answer is no. So long as one of the parties to the transaction is classified as an end user, then there is no mandatory clearing requirement.

MR. MARTIN: Exempted commercial end users are still subject to reporting requirements. John Shelk, what reporting is required? The reporting could be to the Securities and Exchange Commission or to the Commodity Futures Trading Commission, depending on the type of swap.

MR. SHELK: There are two aspects to reporting. First, every transaction will have to be reported to a central repository, whether or not the swap is subject to clearing. Second, every company entering into a swap or hedge will have to report how it intends to satisfy its financial obligations.

MR. MARTIN: Are the swap provisions in the bill retroactive in the sense that they apply to existing swaps and hedges?

MR. EMMONS: My colleagues interpret the bill to require reporting of existing transactions, so they expect that people in the power sector will be scrambling to collect data on existing transactions and then report those to the regulators.

MR. SHELK: It is clear that existing swaps will not have to be cleared. The language is pretty specific and clear on that point. There is some uncertainty about whether any rules the CFTC adopts on margin, capital and position limits will apply to existing swaps.

MR. MARTIN: The bill has a statement that, unless there was a specific provision on point in an existing swap, no requirement under the bill shall constitute a "termination event, force majeure, illegality, increased cost, regulatory change, or similar event" that would allow one of the parties to walk away from the swap. Have you heard of any problems in this area with people trying to get out of existing swaps?

MR. SHELK: Others may know about specific transactions; I have not heard of any problems.

MR. SALANT: To the extent we are talking about a project that does floating-rate bank debt and fixes it via swaps or is doing interest rate hedges before the deal is launched to protect against interest rate risk, there we see the least impact from these rules. I don't think we have seen a lot of bid-offer impact yet. As you move into commodity swaps or other things that people might be doing — you don't see a whole lot of that in the project finance market right now, but years ago you did —the potential effect is a lot more complicated.

MR. MARTIN: A member of the audience asked: "Wall Street analysts following the power sector contend that many independent power producers are likely to be considered by the CFTC as swap dealers and swap participants at a minimum. Do you agree, and if not, why not?

MR. SHELK: No, we don't agree. The question said "many." That's not our understanding of the statute, nor is it Chairman Gensler's intention. Not every company has the same business model. For companies that are more active beyond traditional power plant operations and hedging only around those, there may be some risk. There are a few companies with active power marketing operations who will probably have to look at this more closely.

MR. MARTIN: Here's another audience question, but one for which this panel may have no answer: "If a private equity fund hedges at the fund level to mitigate a risk at a portfolio company, will the fund be treated as a commercial end user? For example, if the fund owns only a minority interest in an oil and gas producer, and so is long on oil and gas and the fund wants to hedge its position in the portfolio company." Does anybody have a view?

I guess not.

Stop the press. An audience member just said in an email that it is his understanding that private equity funds are defined as financial entities and cannot be commercial end users. Hence, hedges at the fund level would have to be cleared through a central exchange.

Capital Adequacy and Trading

MR. MARTIN: Let's move to another topic. There was a Collins amendment — named after Susan Collins, a Republican Senator from Maine. She introduced the amendment at the request of the Federal Deposit Insurance Corporation — that agency pretty much drafted it — and it extends risk-based and leveraged capital standards for FDIC-insured banks to US bank holding companies, including US subsidiaries of foreign banks, and to systemically important non-bank financial companies. Many of these institutions may be required to have more true equity in their capital structures. Jim Metcalfe and Tom Emmons, will this increase the cost of money and, if so, how is it expected to be felt in the project finance market?

MR. METCALFE: I think there is likely to be some increased cost, but it is hard to predict the exact amount yet.

MR. EMMONS: I agree generally with what Jim said. It is one of several factors that will eventually mean less leverage in financial institutions. Less leverage generally means higher costs. We have seen stress tests being applied to banks in Europe this month with a probable increase in equity fundraising by a number of banks. All of these factors are pushing toward more conservative balance sheets, which could lead to higher costs. Whether it is quantifiable in our particular market, I would say not because there are many other factors in the mix, and there is a long distance between a bank's leverage and the actual pricing in a deal.

MR. MARTIN: Next question: will banks be forced by the financial sector reform bill to shed some types of trading operations? The Financial Times reported a couple weeks ago that one likely outcome from this bill is there will be opportunities for established trading companies in Europe to move into sectors that US banks are having to abandon. Has anyone seen any evidence of this? What are the opportunities?

MR. SALANT: There is a lot of noise in the system over articles published about what Goldman Sachs is or is not doing. This is one of those areas where people really have to wait to see what rules come out.

MR. MARTIN: Then let's turn to a question from the audience: "Will the uncertainty still surrounding interpretation of the legislation — for example, on proprietary trading and private equity investments — translate into higher required yields on debt or tax equity that banks finance?"

MR. EBER: It is too early to tell.

MR. MARTIN: In what direction are tax equity yields moving? Are they holding, or do you expect some further tightening for the rest of the year?

MR. EBER: The yields have been fairly constant, almost going back the past year.

MR. MARTIN: What about the debt markets, Tom Emmons?

MR. EMMONS: They have also been fairly constant. There was some talk of a softening a couple months ago. The actual instances of softening were few and, I think, specialized. The question going forward will be whether the demand starting in 2011 will be robust and whether this will affect the pricing because there could be excess capacity if the wind market, for instance, continues to shrink because of the lack of a national renewable */ continued page 30*

IN OTHER NEWS

truck above 11,294 miles a year, which is more typical of a lease than a sale.

The case is *Arthur E. Boyce v. Commissioner.* The Tax Court released its decision in late August.

The case is interesting because the IRS has been challenging big-ticket leases on audit that have fixed-price purchase options.

MINOR MEMOS. The IRS analyzed in an internal legal memorandum made public in July when a foreign corporation that owns an offshore wind farm, drilling rig or supply vessel on the outer continental shelf off the US coast must withhold US taxes on wages paid to its employees who are not US residents and pay FICA (social security) and FUTA (unemployment) taxes on the wages. Income tax withholding is required, unless a tax treaty between the United States and the country of residence of the employee exempts him from withholding. FICA and FUTA taxes must also be paid unless the US has a "totalization agreement" with the employee's home country in which the United States agreed that he will receive benefits solely under the retirement system in his home country or the vessel on which the employee works is not a US flag vessel. The conclusions are in Chief Counsel Advice 201027046 . . . . The economic stimulus bill in February 2009 authorized Indian tribes to issue up to $2 billion in tax-exempt "tribal economic development bonds" to finance projects on Indian reservations. Because of a quirk in the statute, projects on former Indian reservations in Oklahoma also qualify, the IRS said in an internal memo in July. Most of Oklahoma is considered Indian land. The IRS memo is AM 2010-003.

— contributed by Keith Martin in Washington.

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energy standard.

MR. MARTIN: John Shelk, what issues should the trade associations continue to work on, even after the bill has been enacted?

MR. SHELK: We have touched on a lot of them. There are some key terms like "end user" and "major swap participant" and "swap dealer" that will have to be defined in regulations. We need to watch how those regulations are written. We expect it will be at least a year, if not longer, before all of this is settled.

MR. MARTIN: Are there other ways the bill could affect the market besides what we have covered on this call?

MR. METCALFE: It could have an effect on the rating agencies. I believe the bill imposes potential liability on rating agencies that do not do adequate diligence before issuing ratings.

MR. MARTIN: Let me sum up. If any of you disagrees with this summary, please speak up. We talked about four areas in the bill that have the potential to affect the project finance market.

One is a Volcker rule that bars banks from engaging in short-term proprietary trading and from putting more than 3% of capital into private equity funds. I think we decided that it will not affect the tax equity market in the renewable energy sector, with one caveat. Everyone wants to see how the rules are interpreted by the bank regulators over the next couple years.

Another area is a ban on banks from dealing in swaps and other derivatives. Their access to FDIC insurance for their deposits and their ability to borrow from the Federal Reserve will be taken away if they keep those business lines. I think we concluded it is too early to tell which trading operations US banks will shed, although there has been speculation that some of the trading operations US banks will have to shed will provide an opportunity for established trading companies in Europe to move into the US market.

Another issue we discussed are swaps and hedges and whether the requirement to run them through central clearing exchanges and post margins will make swaps and hedges more expensive for independent power companies to engage in. I think we concluded that the commercial end-user exemption looks pretty good and should exempt most, if not all, of the swaps that we see in the project finance market — swaps that hedge interest rate, foreign currency, natural gas prices and other types of commodity risk.

The last topic we covered was the increased capital adequacy requirements for banks. They cannot be good news for developers interested in finding cheap money, but the word from this panel was so many things affect the cost of capital in the project finance market that it is hard to see this, certainly in the short term, pushing up yields.

MR. SALANT: One clarification about your third point — I think the bill will have a minimal impact on foreign exchange and interest rate swaps and derivatives, but I would be more cautious about the effect on gas and other physical commodities. You may see more impact on them. ◎

Under Construction in Time for a Treasury Cash Grant?

by John Marciano and John Modzelewski, in Washington

New renewable energy projects in the United States qualify for a cash payment from the US Treasury for 30% of the project cost if they are under construction by the end of this year.

The projects must also be completed by a deadline.

The deadline is 2012 for wind farms, 2016 for solar and fuel cell projects, and 2013 for other projects.

There are two ways to show that a project is under construction in time. One is show that "physical work of a significant nature" started on the project by the end of this year. The other is to show that the developer "incurred" more than 5% of the project cost by the end of the year. It is not enough merely to have made payments in 2010.

Once construction starts under the physical work test, it must be continuous. A developer starting work under the 5% test does not have to show the work is continuous.

More detailed articles about strategies for starting construction can be found in earlier issues of the *NewsWire* ("Strategies for Starting Construction," April 2010, at p. 1, "Cash Grant Update," July 2010, at p. 9).

The Treasury cash grants were intended as a temporary economic stimulus measure. They are not available for projects on which construction started before 2009.

Congress is considering extending the deadline to start construction, but it is unlikely to make a decision before a "lame-duck" session after the November elections.

The following flow charts are a simple step-by-step way for a project developer to determine in the meantime whether he or she has started construction in time. ◎

Chart A: Cash Grant Initial Decisions

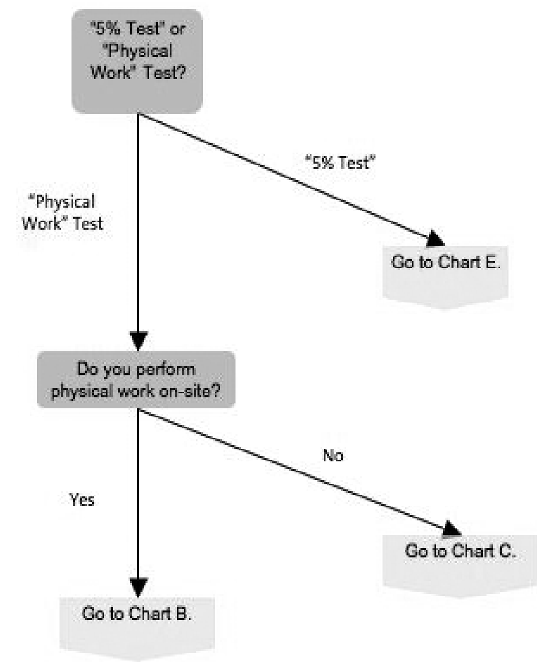
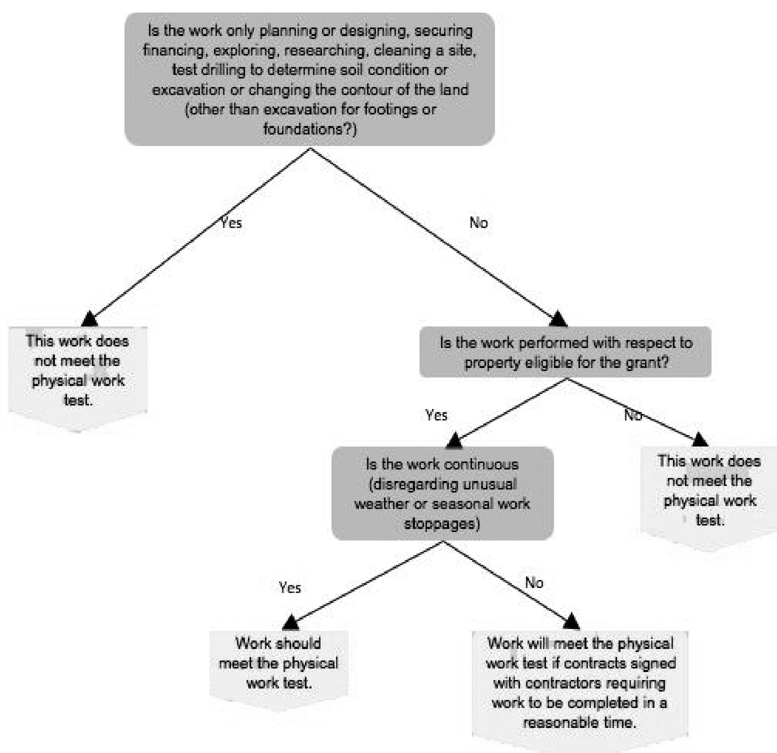


Chart B: Physical Work On Site



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Under Construction

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Chart C: Physical Work Off Site

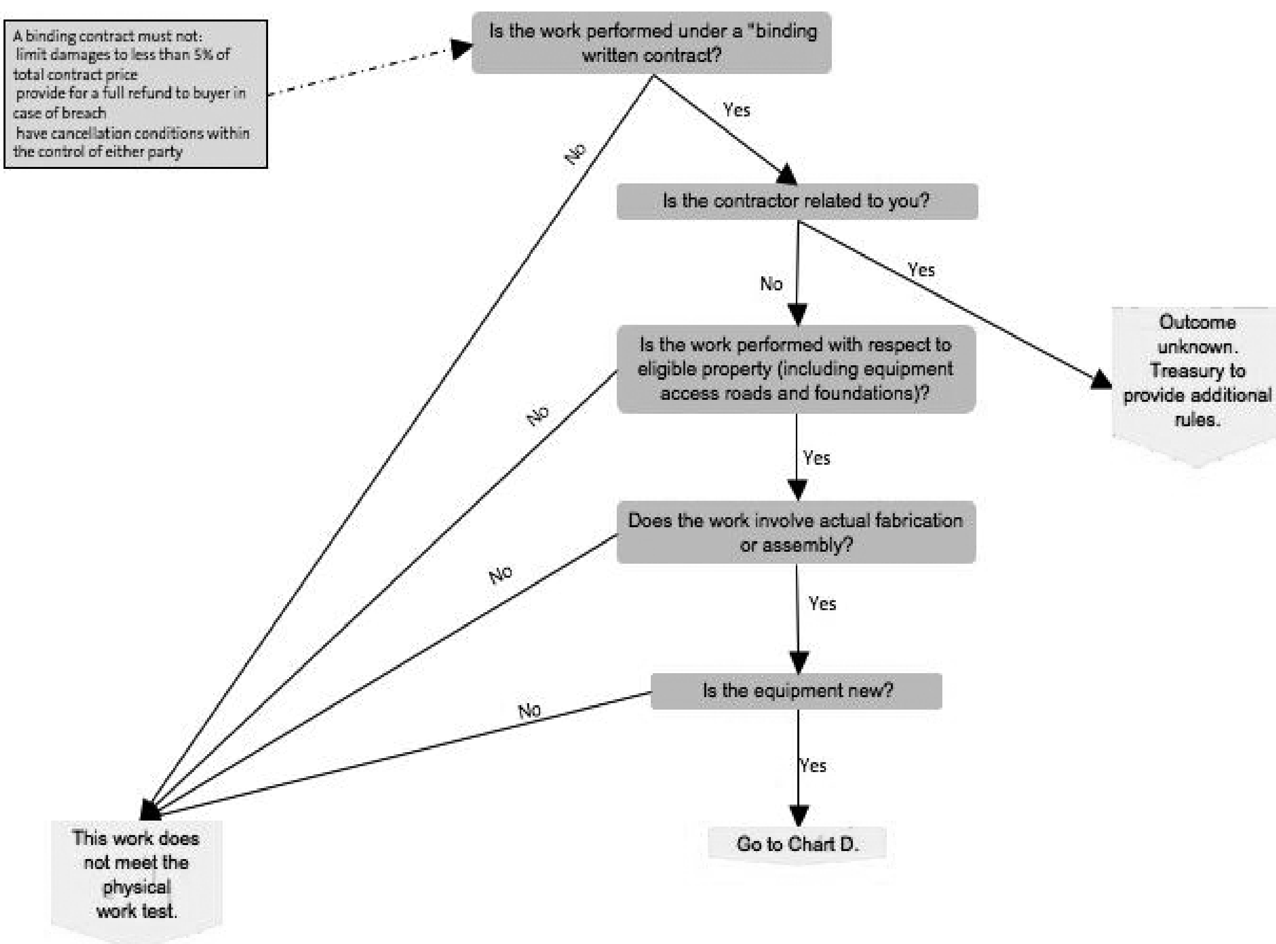
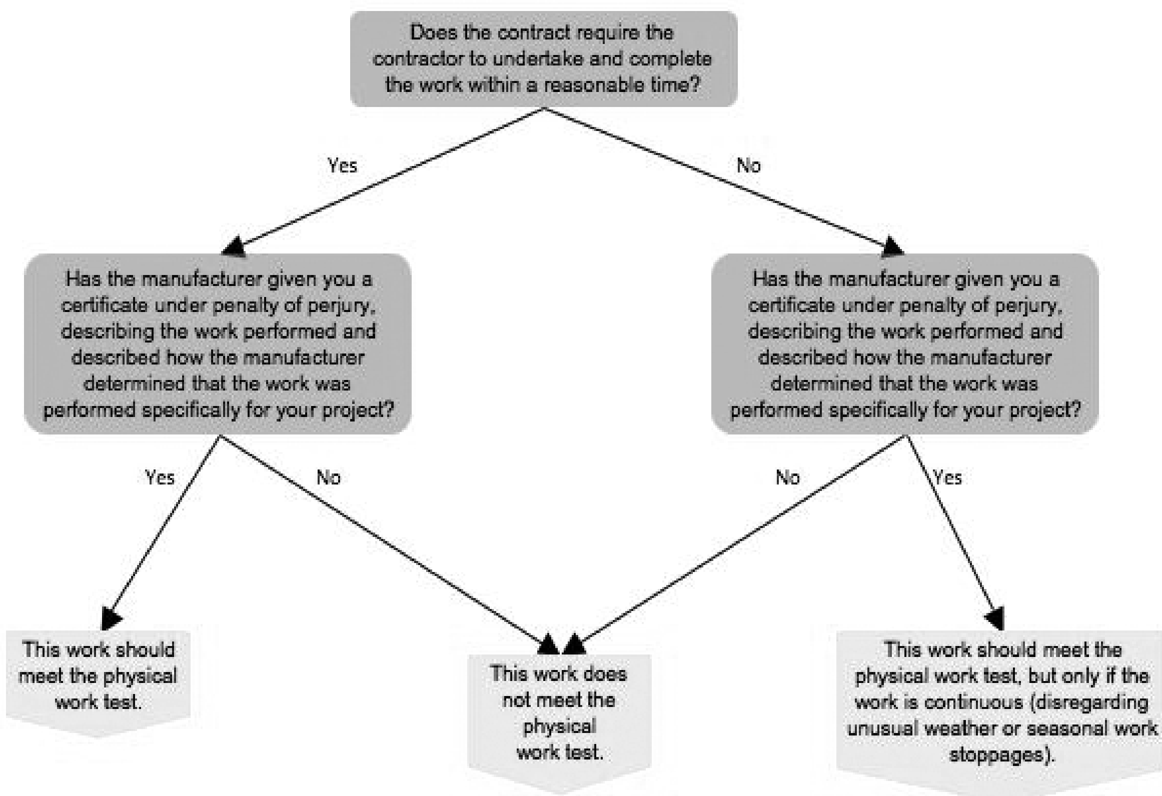


Chart D: Physical Work Off Site (cont'd)



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Under Construction

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Chart E: 5% Test

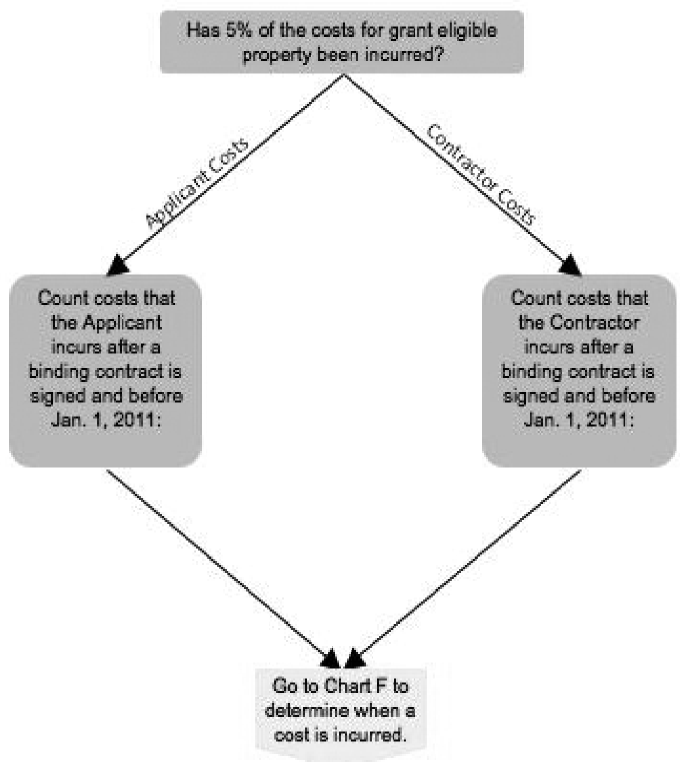
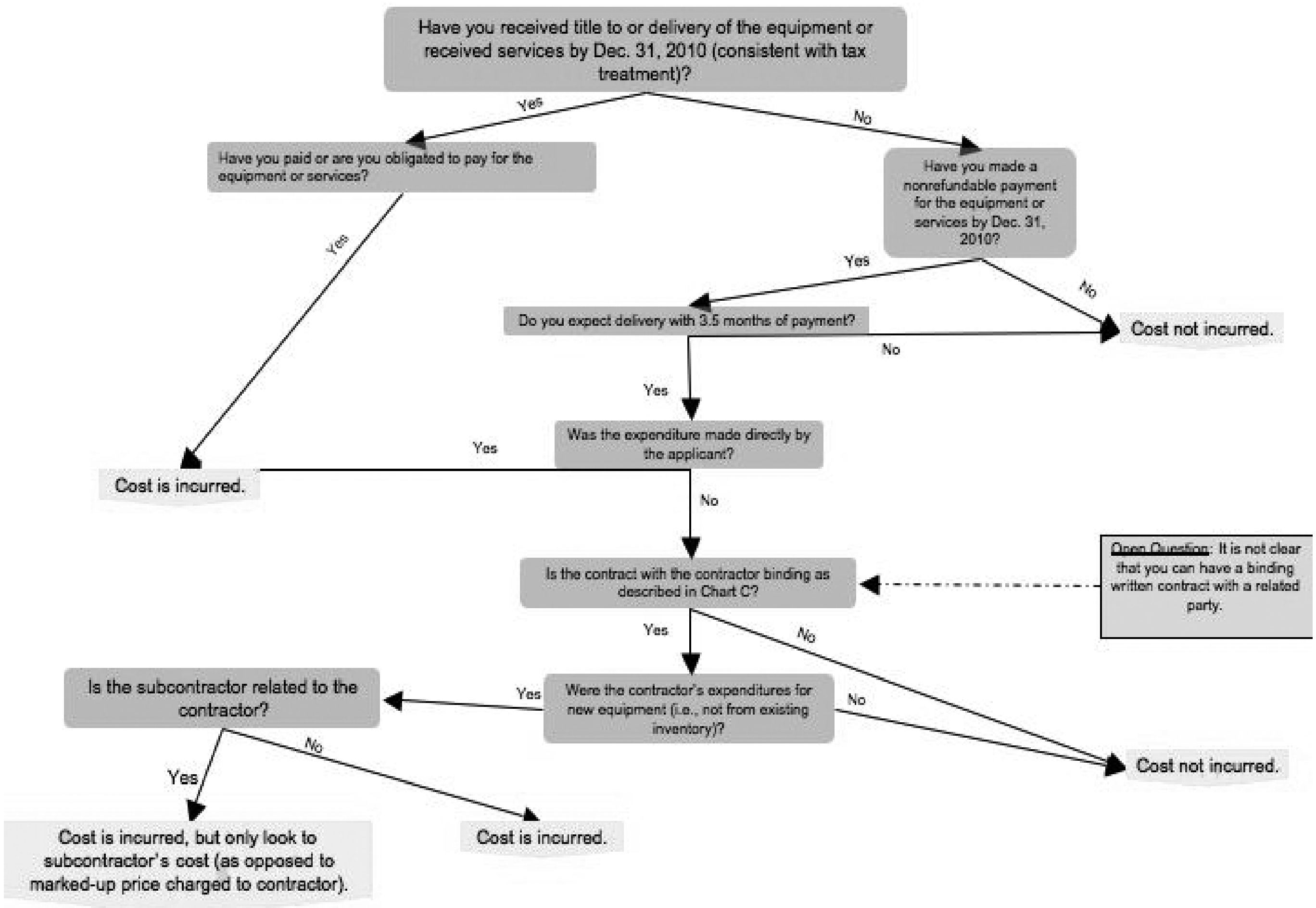


Chart F: "Incur"



Britain Moving to Establish a Green Investment Bank

by Julie Scotto, in London

The new UK coalition government confirmed soon after taking office this summer that a green investment bank will be established. Detailed proposals on the creation of the bank will be published following the comprehensive spending review, currently set for October 20, 2010.

Early clues to how the bank will operate can be found in a report that the Green Investment Bank Commission published in late June entitled "Unlocking investment to deliver Britain's low carbon future," which sets out a blueprint for the establishment of the bank. Given that the commission was established by the Conservative party (the majority party in the coalition government) while in opposition, the report is likely to be given utmost consideration.

In its report, the commission recommends that a non-executive chairman be selected by August 2010, and a board (or shadow board) by October 2010. The government has not yet given a timeframe.

Given the current economic climate and the massive cost cutting being undertaken by the coalition government, the establishment of the bank is a politically sensitive issue. Since the publication of the commission's report, there have been reports of tension between the business department and the Treasury (led by members of Parliament from different parties within the coalition) over the scale of the bank and its precise role. Last month, Andy Rose, the head of the Treasury's infrastructure finance unit, told an infrastructure conference run by City and Financial that the government is "not pursuing plans for the sale of government-owned assets" and that such financing is "not on the agenda of the current government."

The establishment of the bank is perceived by the main political parties, and by industry, as a necessity that must be addressed expediently. Given this consensus, plans for the bank are expected to evolve fairly rapidly following the comprehensive spending review in October.

Global Warming

The main driver for the bank is the Climate Change Act 2008 that requires the UK government to reduce greenhouse gas emissions in the UK by 80% by 2050. In addition, recent European Union legislation requires the United Kingdom to ensure that 15% of UK energy comes from renewable sources by 2020.

The new coalition government has acknowledged that climate change is one of the most serious threats currently facing the world and pledged to make this the "greenest government ever."

The Green Investment Bank Commission estimated that up to £550 billion of investment may be required for the UK to meet its climate change and renewable energy targets between now and 2020. The figure is staggering, not least when contrasted with the £200 billion that the coalition government had said it estimated only days before in the June 22 budget. Given this backdrop, the head of the commission, Bob Wigley, former chairman of Merrill Lynch Europe, argues that "the scale and speed required for financing low-carbon infrastructure, is impossible without government intervention."

The commission recommended that the bank should use a public-private investment model and address specific market failures and investment barriers. Its report highlighted a series of key barriers to investment that require an immediate response: market investment capacity limits and limited utility balance sheet capacity, political and regulatory risks stemming from a history of changes in government policy affecting expected returns, gaps in confidence among investors resulting from technology risks, a lack of transparency in government policy and the high level of capital required — which the commission called the "confidence gap" — and the challenge of making large numbers of small, low-carbon investments attractive to institutional investors — which the commission called the "aggregation challenge."

Role and Focus

The bank would have three main functions: to identify and to address market failures that limit private investment in carbon reduction activities, to rationalise existing government-established bodies and funds in order to provide coherence to public efforts to support climate change-related innovation, and to advise on financing issues in central and local government policy making.

As far as the public-private model is concerned, the commission stressed that the bank should not "crowd out" the private sector. The private sector should lead and execute deals wherever viable, and the bank should only operate where the result would otherwise not have been possible.

In its initial phase, the commission recommended that the bank should focus on supporting areas where maximum impact and speed to implementation can be achieved. Examples are scale up of investment in proven energy efficiency projects that can lower the overall development need of renewable energy sources, investment in enabling technology, and support of both proven / continued page 38

Product category	The Green Investment Bank Commission's recommendations
Early stage grant funding	The green investment bank (GIB) should aggregate the grant payments that are currently made to a range of quangos to ensure consistency, efficiency of distribution and returns. The level of grant funding will need to be the product of Treasury spending decisions.
Pari-passu equity co-investment	The relevant, co-investing arm of the GIB co-invests equity pari-passu alongside private capital (e.g., the utilities), buying shares in qualifying low carbon generation projects (or other essential energy projects) at the start of their development. The shares that the GIB purchases in each project should be transferable (as far as possible given typical shareholder and lender limitations).
Loan facilitation and structured finance based on "off-take" agreements	Providing a secondary market in commercial banks' project finance renewable energy/energy efficiency loans would provide liquidity to commercial banks and enable them to free up capital to lend to more projects.
Debt provision through partnerships with private sector	The GIB can partner with private sector banks to provide liquidity and financing where specific blockages exist (e.g., for residential households), the GIB can play a role providing upfront capital to householders, to be repaid as loans. The GIB's role will need to be part of a consistent government policy drive.
Intermediate/mezzanine funding	Working through partnerships with private sector banks, the GIB may be able to tackle cases of technologies which are proven but lack the extensive track record of onshore and offshore wind. They may be able to secure workable levels of project finance debt but not at gearing levels sufficient to provide equity investors with the necessary rate of return. In many such cases, the gap may be filled with intermediate or mezzanine debt or quasi-equity capital, subordinated to the principal senior bank or bond debt but ranking higher than equity. This additional leverage can make the difference between acceptable and unacceptable returns to private sector capital.
Risk management – long-term carbon underwrite/ floor price for carbon	Although the Kyoto protocol's first commitment period ends in 2012, EU policy provides a more secure framework for a carbon price until 2020 via the third phase of the EU emissions trading scheme (and, arguably, beyond). However, long-term investors in low-carbon energy assets (where asset lifetimes are sometimes 40 years) face several challenges. First, the forward curve for carbon has limited price visibility beyond 2014. For the proposed products of the GIB that relate to long-term carbon pricing, it will be critical that over-the-counter carbon derivative trading be preserved despite the ongoing EU financial services reform effort that is expected to restrict such activities. Second, that the EU allowances price may insufficiently incentivise investments in long-term clean energy assets in the UK thereby locking in high-carbon assets. Given the UK's limited ability to influence allowance pricing, there is a case for the GIB to provide a risk-reduction mechanism to projects and companies by underwriting a higher and longer-term carbon price beyond 2020. The coalition manifesto has already stated a commitment to a UK-specific price floor for carbon (external to the EU emissions trading scheme). The GIB could help manage these risks on a project by project basis.
Risk management – insurance provision and green "regulated asset base"	The provision of risk reduction products on commercial terms could unlock even greater volume of private sector investment than GIB co-investment, by unlocking project finance debt, which would also enable further equity to invest on a more attractive, leveraged basis (e.g., extreme events insurance, contingent loan facilities, etc.).
Advice	The GIB should not formulate government policy but should have a consultation role on the financing of low carbon policy. While the UK must remain the predominant focus of the GIB, the commission sees a possible advisory role for the bank in the dispersal of the UK's share of the "fast start" funding agreed at the Copenhagen summit, in support of the relevant government departments. The role of Infrastructure UK, an advisory body within the Treasury, may need to be reviewed in light of the GIB's creation.

UK Green Bank

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and high impact third-round offshore wind.

The commission recommended that the initial capitalisation come from three sources: by forcing the private sector and state-owned banks to subscribe for equity, by using part of the revenues generated by the EU emissions trading scheme auctions, and by selling government-owned assets.

There are two options for making banks subscribe for equity. One is to force banks to subscribe to equity through part of the bonus tax, with equity initially being non dividend paying (although, the 50% bonus tax introduced by the previous government lapsed in April 2010, and its replacement seems unlikely). The other is to force only state-owned banks to become shareholders.

Early clues to how a new UK "green bank" will work can be found in a blueprint released this summer.

The auction of pollution permits under the next phase of the EU emissions trading scheme is expected to raise approximately £40 billion for the UK between 2012 and 2020. The estimates of the total revenues from the electricity power sector alone in Western Europe are in the region of €13 billion a year.

The commission identified a series of government-owned assets that could be sold: the student loan book, the Tote, Dartford Crossing, High Speed 1, airport landing slots and parts of the radio spectrum.

Financing and Governance

The commission identified four sources of funds for financing the ongoing operations of the bank. They are the government funding for disbursement of grants from existing quasi-autonomous non-governmental organizations (quangos) and funds, the issuance of green bonds and green individual savings accounts (ISAs), a debt fund and a levy on energy bills.

The targeted quangos and funds have a similar remit to the bank, and have funds allocated to invest in low carbon technologies. The commission identified three quangos and six funds that could be brought into the green investment bank (such as the Carbon Trust, the International Environmental Transformation Fund and the Ofgem Low Carbon Network Fund). This rationalization process is supposed to create a unified point to advise and inform businesses and investors about how to access grants or participate in government-supported schemes.

The commission envisages using green bonds in two ways: to finance the bank (where it is the issuer) and to lower the cost of debt for projects where the bank or the government provides risk mitigation for the project debt (where the project is the issuer). Green bonds targeted at institutional investors could take the form of single project bonds, providing exposure to specific projects supporting the low carbon transition, bonds directly funding asset portfolios and secondary project finance loans, bought from commercial banks and also bundled by asset class.

Although it is envisaged that institutional investors will provide the majority of funds, the use of green individual savings accounts is the most notable proposal that has been put forward to harness an alternative source of funding — retail savings. Green ISAs are expected to be only a small part of the solution, but they could be a visible and symbolic way for retail investors to make a contribution to the bank.

Institutional investor appetite could be tapped through the development of a fund to invest in UK renewable energy and energy efficiency projects on market-based pricing and terms. Institutional money would co-invest with that of the bank. Such investment may be focused specifically on particular sized projects (or asset types), such as wind or biomass projects of less than £10 million, where the market is not focused for reasons of scale and others, but will necessarily provide a long-term investment opportunity for institutions.

In relation to the proposed levy on energy bills, the commission argued that by providing a guaranteed revenue stream, perhaps 10 years plus a 10-year run off period, the levy could, by securitizing the future receipts, provide a substantial upfront pulse of additional funding for investment.

The bank is expected to be commercially independent and, therefore, not accountable to ministers or to Parliament for individual investment and lending decisions. Key stakeholders (including ministers) are expected to be represented on an advisory council. A board of directors would have responsibility for long-term management. Below the board, a management team would run the bank on a day-to-day basis.

The commission recommended that the bank should limit direct public liabilities by placing its liabilities off the government balance sheet. Further, it warns that the bank should clearly manage the tension between investing in the public interest and the need to be commercial.

From an operational standpoint, the commission envisaged the bank having two core divisions: a UK Fund for Green Growth and a banking division. The UK Fund would administer grants and extend low-interest loans, make equity investments, provide venture capital for technological development and also advise public and private sector bodies. The banking division would offer a secondary market for conventional banks to syndicate or trade green infrastructure loans in order to provide additional liquidity and tackle other market failures.

Product Offering

The bank is expected to offer a range of products, including early-stage grants, equity co-investment, wholesale capital, mezzanine debt, offering to buy completed renewables assets, purchase and securitization of project finance loans, insurance products and long-term carbon price underwriting.

The table on page 37 shows the product range envisaged by the commission. ◎

The Chinese Have Arrived

Part of the discussion at an annual global energy conference that Chadbourne hosted this year was around Chinese efforts to break into the US wind and solar sectors. There is a new wave of investment underway by Chinese companies. Who are the new players and how big an impact are they likely to have on the US market? The conference was in San Diego in June. The following is an edited transcript. The speakers are Patrick Jenevein, president of Tang Energy, Kristina Peterson, vice president for finance of Suntech America, Songyu He, vice president of Sky Solar, and Jeff Hammond, North American director of Envision Energy. The discussion was moderated by Eli Katz with Chadbourne in New York and Ken Hansen with Chadbourne in Washington.

MR. KATZ: Don't tell us everything that you would like to or we should learn about your companies, but do tell us something that is relevant and important that we should know. Jeff Hammond, let's start with you.

MR. HAMMOND: Envision Energy is a Chinese manufacturer of wind turbines. We are looking to come into the US and Canadian markets. We are based in Shanghai.

MR. HE: Sky Solar is an established global solar PV power plant developer, investor and operator. We have been in Europe for the last five years and just entered the US market. We will focus on utility-scale PV project development, financing and construction contract work in the US.

MR. JENEVEIN: Tang Energy makes blades for wind turbines. We are the second biggest blade maker globally, and we are using those profits now to build wind farms in the United States.

MS. PETERSON: Suntech is the largest PV crystalline silicon solar panel manufacturer in the world. We have been in the US market for four years. We operate in 13 countries, and we now have almost 70 people in the US. We expect to open a factory in Arizona by the third quarter this year and to have about 90 employees there.

Attraction

MR. KATZ: Songyu He, what makes the US renewables market attractive to Chinese investors?

MR. HE: Economics. The pure size of the potential market attracts us. We think state renewable / continued page 40

Chinese Have Arrived

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portfolio standards will continue to push the market to develop further, helped by the federal and state financial incentives.

MR. KATZ: Patrick Jenevein, does the US wind market look as attractive for Chinese investors?

MR. JENEVEIN: We are attracted because of the size of the market and buying power are huge. Economics are a big part of it as is a hoped for constancy.

MR. KATZ: Kristina Peterson, how does the world's largest solar panel manufacturer see the opportunities and challenges in the US market?

The US renewables sector offers an alternative to Treasury bonds as a place for China to invest its huge dollar foreign currency reserves.

MS. PETERSON: I think, like Songyu said, the economics are indisputable as a percentage of total power generation done by solar. Germany is the largest market in the world with 5.7% of its total production. After that is Spain. After that is California with 4.7%. To give you a sense of scale, in past Aprils, the California solar initiative has usually done about 20 megawatts of deals. This last April, it was 133 megawatts. That is huge.

MR. KATZ: Jeff Hammond, how about drawbacks? If you compare the US to Europe, what are some of the drawbacks to investing in the US?

MR. HAMMOND: The main challenge for us is familiarity. The US capital markets need to know us and our turbines. It takes time in a new market to get everyone comfortable with our technology and our ability to execute.

MR. KATZ: Those of you who are also in Europe, does it feel different when you are investing there than here and, if so, how?

MR. HE: The biggest difference is the financial incentives here. Because government support for solar is in the form of tax credits, just like the US developers, we will need to partner with a tax equity investor. We don't have that impediment in Europe where the market relies on feed-in tariffs.

MR. KATZ: So it is more complicated here to transact deals, but it is still attractive enough to bring in Chinese capital.

MR. JENEVEIN: The US is still a growing market when Europe appears to be melting down. There is also a push, which is $2.4 trillion dollars of foreign currency reserves in China that have to be invested somewhere. This presents a huge challenge to Chinese leaders because there is only one real place at the moment to put all the dollar reserves and that is into US Treasury bonds. To the extent that China can shove dollars into wind or solar projects in the US, it can earn a higher return, although the idea of the Chinese making money seems to upset a few politicians in New York, not to name Chuck Schumer specifically. Unfortunately, the message our partners in China hear from Chuck Schumer is American senators do not want Chinese to make money.

Anti-Chinese Sentiment

MR. HANSEN: Well we were not going to stay away from the geopolitical for long. Jeff Hammond, maybe you can talk specifically about the Schumer incident. The Senator complained that projects that use equipment made outside the United States should not qualify for stimulus dollars. How does a Chinese company deal with that sort of sentiment?

MR. HAMMOND: The truth is there is a mix of components in any wind farm from both the US and abroad. That's just the nature of our global economy. For example, at a minimum, the towers and blades tend to be made in the US and the construction jobs to build the project, and the longer-term jobs to operate it are here. We have a master service agreement with LM Glasfiber, one of the leading blade manufacturers. We look to source many of our components from the US. I think the criticism was unfair and somewhat biased and, shockingly enough, it was probably driven partly by politics. For us, I think we are coming in with a very clear message: we are here to bring quality investment into the US. We intend to highlight the benefits and to work through the challenges. For me personally, as an American, I come with the perspective that every turbine I can get in the ground is one more step toward national energy security.

MR. HANSEN: Kristina Peterson, I see you nodding.

MS. PETERSON: The United States is the third largest market for us after Germany and Spain. The key aspect of solar is it brings a lot of jobs for the construction trades, installers, electricians, civil works. It's unfortunate when the politicians label it "Chinese investment."

MR. HANSEN: Is there really such a thing as a Chinese company? Some of you are widely held companies with shares issued on the public stock exchanges. Your operations are global. However, I suppose you remain Chinese multinationals in the same way that General Motors or General Electric are American multinationals. How do you approach being perceived as a Chinese company in a market where that probably is not the leading selling point?

MR. HE: I am not sure it is a disadvantage at the level where deals are done. We are talking to many local developers who see the Chinese background as a positive. To them, it means a good supply chain and the ability to pull off large deals. Having a track record of five-plus years in Europe also lends credibility.

MR. JENEVEIN: We actually use an approach that Rigdon Boykin, a former Chadbourne partner, and Kerin Cantwell, a current Chadbourne lawyer, both of whom worked in your Hong Kong office, recommended years ago. We have a Chinese name for our Chinese company, and we have English names for our companies that are doing work in the United States. The English names are Gallop Power and Soaring Wind Energy, and they both have connections in the Chinese language to Tang, which can mean soaring or it has the same character for gallop.

MR. HANSEN: So you Anglicize the names just like the Japanese car companies do.

MR. JENEVEIN: Only with Chadbourne advice.

MS. PETERSON: It is a global marketplace with a global supply chain and global capital flows. We went public on the New York Stock Exchange in 2005, and a large part of the 66% of our shareholders that are in the US are institutional investors. Does that make us Chinese? Our chairman is an Australian citizen. We have a global management team of which I'm the best representative of the Chinese management.

MR. HAMMOND: We have our design and engineering and research centers in Denmark. We have manufacturing facilities in Zhengzhou Province in China. We have development activities here in the US and western Europe and Australia. Although we don't try to downplay our Chinese heritage, we are a global company. All foreign manufacturers entering the North American market tend to follow the same pattern. Do they some projects using their own equipment to prove the technology works. They then make some sales that are sourced from their existing supply chains overseas after which they migrate into a North American supply chain. We are going to create American jobs and energy security. We don't downplay it at all. We're quite proud of it.

MR. KATZ: How about partners? Patrick Jenevein, have you considered partnering with US or European companies as you pursue opportunities?

MR. JENEVEIN: Absolutely. We are based in Dallas, Texas. We don't go across the Trinity River into Fort Worth without a partner. Local partners bring more expertise than your balance sheet can ever afford.

MR. KATZ: Doesn't it also bring conflicts of views, management challenges?

MR. JENEVEIN: Sure. That's true of any relationship. My dear wife would tell you I'm still working on some of those skills after so many years. [Laughter]

MR. HANSEN: Is there a level playing field at this point for Chinese companies investing in the United States?

MR. HE: I think so, at least from what a new entrant like us can perceive. That may be a more useful question to ask more established companies like Suntech.

MS. PETERSON: When you asked us this question in a prep session, each of us said, "No." There is a love-hate relationship between the US and China. The United States needs China to finance our budget deficits, but at the same time, Americans worry about the speed with which the Chinese economy is developing and that China is becoming a regional and global political power. It is something that we have to accept. We are very active in the Solar Energy Industries Association, which is the largest solar lobbying group. My boss is the chairman of SEIA. We deal with it. It has been a factor in our decision to set up a manufacturing facility in the US. In a sense, we are leveling the playing field for ourselves.

MR. HAMMOND: It is improving. The recent lifting of import tariffs on some components coming into China was a favorable development. Quite frankly, many of the people in this room are very influential on these issues, as the US capital markets have a stake in globalization.

MR. HANSEN: Kristina Peterson, what about the way China treats US and European companies investing in China? How important do you think that is to the opportunities Suntech will have outside China?

MS. PETERSON: China is fertile ground for lots of US companies. For example, Buick is the best car */ continued page 42*

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brand in China. The renewables sector is relatively new in both countries. Both are still trying to figure out the best way to support it.

Chinese Money

MR. KATZ: Songyu He, how much Chinese money do you think there is in the United States in renewable energy and where is it coming from?

MR. HE: That's a big question, and I am not sure I have any more insight than anyone else. At least so far as I have seen for Chinese companies, we are the only pure developers here. There are some manufacturing companies like Suntech that are trying to do a mix of development and manufacturing.

MR. KATZ: So there are many Chinese companies that are trying to sell their goods in the United States, but is there a lot of pure investment capital?

MR. JENEVEIN: Absolutely.

MR. KATZ: Where is it coming from?

MR. JENEVEIN: Some from the national banks. Some from our partners. We have partnered with aviation companies in China for years, and they have ambitions of competing against Boeing, Airbus and GE all at the same time.

There is an awful lot of cash, but there is a dearth of process. The Chinese companies partner with others. A large Chinese bank just formed a strategic relationship with Rabobank. We have made blades in China, sold them in China, built up a strong balance sheet, but we need to expand because we are still second biggest and that is just kind of galling to be second biggest for so long. To become number one, you have to offer financing assistance.

MR. KATZ: Who is the biggest?

MR. JENEVEIN: LM Glasfiber. Jeff Hammond was just bragging . . . .

MR. KATZ: Is there a good example of another industry that has come out of China and expanded successfully in the US? Can you think of any?

MR. HAMMOND: Consumer electronics.

MR. HE: But I don't think even that one could be compared to the solar industry. If you go to the big trade fairs — Intersolar, Solar Power International — about 20% to 25% of the exhibitors are from China.

MR. HAMMOND: China has done the same thing in electronic components, but it is all hidden behind a Dell name or somebody else's brand.

MR. HANSEN: Patrick Jenevein made the point that there is not only pull to the US market, but also push given the volume of dollars looking for a place to invest. When the time comes to look for sources of external capital, is the presumption that you should tap Chinese debt and Chinese equity? Is there a presumption that you stay at home?

MR. HAMMOND: The Asian capital markets make more sense for us in the short term until we become better known in the US market. It has to be a two-stage process. It's China first, maybe broaden to other areas of Asia, and then move toward capital markets in the US and Europe.

MR. JENEVEIN: Also keep in mind that the Chinese are as unfamiliar with the risks in this market as US investors are about new Chinese entrants and, for that reason, Chinese tend to prefer initially to put in capital in the form of debt.

Challenges

MR. HANSEN: Thinking about how you folks do business in the United States, I'm assuming a lot of this has to be approved back at Chinese headquarters. What are the hardest things to explain to them about the US market?

MS. PETERSON: I think they get it. Our CFO used to be head of Deloitte in China; we don't have any illusions about what are the pros and cons of operating in the United States. However, the US is more complex in terms of financing. When you have a feed-in tariff that is effectively a sovereign credit of a double A rated country, it is very easy. Complexity is the price of admission to the US market.

MR. JENEVEIN: We had our top management team in the States in November when the Cielo-A Power-Shenyang wind project was announced, and Senator Schumer attacked it — this is going back to an earlier question — and the experience is still a little raw for us. Our Chinese management team heard what Senator Schumer said. The anti-Chinese sentiment stung. The hardest thing for foreign investors to figure out is whether the US provides a stable enough environment in which to invest. As a proud American, it embarrasses me to have the welcome mat tarnished by such behavior.

MR. HAMMOND: From the standpoint of execution and development of wind farms in China compared to the US, there are various shoals to navigate in the US: the political environment, the power markets, 51 different state and federal regulatory regimes and the complexity of the financing structures.

There is a learning curve that new Chinese companies must move up when they come to the US. The level of due diligence here and in Canada is much more comprehensive than in China. It takes longer to do transactions. We partner with US groups that know the market and help guide us up the curve.

MR. JENEVEIN: That's a really good point, Jeff. Who owns the land in China? Everybody owns the land, so you go to the land bureau to find out who gets to use it and how. Here you have to negotiate with a bunch of different families who are spread out over a wide area. That is difficult and expensive.

MR. HANSEN: Jeff Hammond, if you were to identify just one big difference in the business culture within a Chinese company versus a US company, what is it?

MR. HAMMOND: Their focus. Chinese managers do their homework. Their focus, their energy and their aggressiveness stands out to an American working for a Chinese company. Their plans are well thought through before they are implemented. Chinese wind companies are hungry, and they are growing more rapidly than US wind companies. ◎

Electricity Storage: What's The Potential And When?

Five CEOs of electricity storage companies, each of which uses a different technology, participated in a panel discussion about the outlook for the storage market at the Chadbourne global energy conference in San Diego in June. The following is an edited transcript of the session. The panelists are Bob Kraft, CEO of Energy Storage & Power, Dan Vogler, CEO of GeoBattery Corporation, John Jung, CEO of GreenSmith Energy Management, Mark McGough, CEO of Pentadyne Power Corporation, and David Schramm, CEO of Maxwell Tech. The moderator is Doug Fried with Chadbourne in New York.

MR. FRIED: Each of your companies is pursuing a different technology. Tell us briefly about your company and its product, starting with you, Bob Kraft.

MR. KRAFT: We are focusing on compressed-air energy storage. My company started as an engineering and technology company and is transitioning to a technology deployment and manufacturing company.

MR. VOGLER: GeoBattery focuses on scalable grid storage. We do not make batteries, but we enable battery technology on the grid. We focus on the grid interface or the middleware. Hooking a DC battery to the AC grid is not a trivial task, and the power electronics control systems and software in the middle between the battery and the grid is of great importance. We have identified more than 12 applications for it within the energy storage space.

MR. JUNG: Our focus is distributed energy storage. Greensmith is a turnkey energy system provider to the utility industry. We believe that it is a horses-for-courses world in energy storage where centralized solutions like some of the ones represented here will be appropriate, but the industry also has to grapple with pockets of grid congestion and that is where Greensmith comes in.

The electricity storage business is at the front end of what is expected to be a 10-year growth spurt.

We are agnostic about storage technology. We believe that there is plenty of capital being put into batteries, factories and lines, and what we do is integrate the system so that it has all the software really to store energy — not just a battery in a box but a smart grid appliance that can exchange data with the rest of the smart grid infrastructure and be controlled by a centralized system.

MR. MCGOUGH: Pentadyne is trying to make the best flywheel in the world. We sell flywheels into UPS applications with manufacturers like Toshiba and General Electric that sell their UPS products with our flywheels as a backup energy storage component. We also sell our

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flywheels into rail applications; we are focusing now on the rail market. We have a large contract that we just won with New York City to capture the braking energy of a train. We can turn a subway train into a hybrid electric vehicle using our product. We have gone from zero sales four years ago to about $16 million a year today, and we are on a nice growth trajectory.

MR. SCHRAMM: Ultracapacitors store power; they don't make it. A battery makes energy, so all we do is we store it. There is no chemical reaction, so you can charge and discharge an ultra-capacitor millions of times while a battery can charge and discharge only thousands of times. Because of the lack of mass transfer, we can also upgrade from -40 to +65 centigrade, so it gives us a nice temperature range. Ultracapacitors are light-weight, very high-power, low-energy batteries. Batteries, by contrast, are typically higher energy, lower power.

Today we are into windmills for pitch control, buses for brake regeneration, automobiles for start-stop systems, computer memory backup and UPS. Studies have shown that when you couple an ultra-capacitor with a battery, you can extend the life of the battery by 30%. We are gaining traction in the market-place. Last year, we crossed the $100 million mark, which is about a 26% increase over 2008. Major geographic areas are Asia and Europe. We are doing very little business in the United States.

MR. MCGOUGH: If I could just add, the ultracapacitor and the flywheel are similar in the sense that they are very power-dense. Neither is an energy-dense technology; they are power-dense. We can deliver a lot of energy in a short amount of time, and we can also capture a lot of energy in a short amount of time, and that makes both products a different tool in the designer's toolbox.

MR. FRIED: Let's talk about how these technologies might be used in renewable energy projects. Dan Vogler?

MR. VOGLER: Most renewable energy projects produce electricity intermittently. Wind turbines are up and down all day, and they peak in the middle of the night, which is the opposite of the demand curve. Solar is off line in the middle of the night. Tidal energy has two cycles a day. All of these renewable energy sources beg for storage to smooth the electricity deliveries to the grid.

In Texas, we are the leader in wind production, but the wind often peaks in the middle of the night, so there would be a time arbitrage to store wind power in the middle of the night and shift it to day use when the utilities want it. That is one of the more obvious uses of storage. Base-load power plants run 24 hours a day, seven days a week. You don't shut them down. You might throttle them back at night, but they can generate two to three times more power in the middle of the night than demand at those hours for electricity. If we could just take all of the excess power available in the middle of the night and store it to day use, then we could avoid building another base-load coal or nuclear plant.

Early Stage

MR. FRIED: Why haven't these storage technologies been deployed more widely already?

MR. VOGLER: It takes time for new technologies to be accepted and to reach scale. Large battery prices are now falling, and utilities are gaining a better understanding of how they work. It has been the last two years when one could make a business out of a storage company. The few storage projects in the United States are still pilot projects. We are on the cusp of moving from the pilot stage to wider commercial acceptance.

MR. FRIED: So you are at the start of what could be a rapidly-growing business.

MR. VOGLER: We are at the beginning of a huge business cycle that I believe has at least 10 years to go before it slows down. In time, storage will be the largest sector of the renewable energy market, larger than solar and wind combined because it applies to all of those technologies and really everywhere else within the grid, from underneath generation, transmission, distribution, all the way to the grid edge in the customer premises.

MR. SCHRAMM: I read a good book called *The Bottomless Well*. The author goes through a lot of data to suggest that our need for energy per person goes up every year as it has for the last 150 years. Everyone used to have 40 acres of ground, and we were a carbohydrate-based society. Ten acres was to grow the feed for the horse. We have transitioned from that. At the turn of the last century, New York had a pollution problem, and it was horse manure. At the dawn of this century, its pollution problem is CO_2. The problem has not really changed; it is still energy related. It is just a question how we address it. We need more power plants to meet growing electricity demand, but nobody wants them built in his backyard. Energy storage will give us a little bit of a cushion, but it will not significantly reduce the need to build more power plants.

MR. FRIED: David Schramm, do you see energy storage supplementing renewables or competing with them?

MR. SCHRAMM: Supplementing. We have ultracapacitors today in about 12,000 windmills. They are used today as a safety device for pitch control. The windmills at which ultracapacitors are used today can be up to seven megawatts in capacity, and they are up to 500 feet tall. I had the distinction of taking something off my bucket list a year ago. I climbed to the top of one of those windmills and vowed never to do it again. [Laughter]

If the wind is blowing too strongly, the ultracapacitor alters the pitch of the blades so the windmill doesn't destroy itself, like adjusting the sails on a sailboat so that the boat doesn't tip over. Batteries are required in this application. The problem is maintenance: replacing the batteries 500 feet above ground. The ultracapacitors extend the life of the batteries so that they do not have to be replaced as often.

MR. FRIED: Mark McGough, how long will it be before electricity storage is widely used? Where are we now in the process? What has to happen to make widespread use of storage a reality?

MR. MCGOUGH: There are several types of energy storage. There are grid scale technologies: compressed air, pumped hydro, molten salt, large batteries. There is also the kind of energy storage about which David Schramm and I spoke: fast response, very powerful, but not a high amount of energy storage. It is used for tactical applications.

An investor used a metaphor with me the other day. It was RAM and ROM memory. They serve different purposes and cost different amounts on a per-unit basis, but they are both important. One of the key impediments to rapid growth of energy storage is the cost. David Schramm and I were joking before this panel: storage will be a better business proposition when we are able to stop wrapping dollar bills around everything we ship out the door.

We have gone at Pentadyne from negative margin just a few years ago to a 19% to 20% margin to a 30% margin on everything we ship today. Our goal is to get to a 45% to 50% margin product, because that's where it gets interesting. We can get volume and scale and bring our prices down. I think that is less than a decade away.

The demand is being driven partly by renewable portfolio standards at the state level. The demand for energy storage should increase over time as the RPS targets increase. There is still a lot of government funding for development of these technologies. We are a finalist for an ARPA-E energy research grant that would be used for development of a storage technology that is very high-volume and low-cost — less than $100 per kilowatt. If we can get the cost down to that level, then the industry will truly take off.

MR. FRIED: So we are really in the infancy now, really at the early stage, before storage is widely used?

MR. MCGOUGH: I think we are a petulant teenager. [Laughter] We are making progress.

MR. VOGLER: When I said 10 years, that is for storage to become a pervasive technology and find its way into everyone's home. Residential energy storage and community storage promise to do a demand price arbitrage in the customer's home. That will probably not be flywheels though. I think it will be ultracapacitors.

There are many competing storage technologies, but they address different problems.

Barriers

MR. FRIED: Bob Kraft, what are the main barriers to utility-scale integration of these technologies?

MR. KRAFT: One of the big ones is regulatory uncertainty — whether utilities investing in large-scale batteries will be able to put the cost into rate base. We are working on smaller-scale projects with NYSEG and PG&E that will be spread over a number of years. These will give us a chance to test the risk and establish the regulatory treatment.

The reason we haven't seen heavy use of storage in the renewables sector is the grid can handle a certain amount of intermittency. The burden of adjusting to / continued page 46

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the variability is falling heavily today on gas-fired power plants. In some parts of the country, they are really feeling the pain. Eventually, something will have to give.

MR. FRIED: John Jung, what is the next step for your company to grow?

MR. JUNG: We are along the classic adoption curve that any industry goes through. The utilities have a clearly defined one. There are good case studies about how utilities get comfortable with new technologies and how it usually requires some form of regulatory or financial assistance. You see all those hallmarks with energy storage.

We are serving five utilities today and are growing. They are watching not just the cost per kilowatt hour of output, but also per kilowatt of capacity. They are looking at educating themselves about where energy storage can be useful — not just in the 16 or 17 different applications that EPRI and Sandia have defined, but also the potential to capture more than one value stream. At the end of the day, whatever storage device is used must be capable of being programmed to perform differently depending upon needs at the time. The utilities are becoming sophisticated enough to want more than a single dedicated custom system that sits in the ground for 10-plus years to attack a two megawatt hour problem. Maybe the system is four different boxes that, through the dimension of smart grid, can be centrally controlled to be one block of energy storage on Monday and perform different functions across the grid on Thursday.

MR. MCGOUGH: John made an important point. If you are waiting for the industry to reach scale, don't focus on technologies that are a one-trick pony. It will be tough to reach scale for technologies that have only a single application. John spoke about a device that a utility can use for one thing on Monday and another thing on Thursday. I will give you an example. Pentadyne has an array of flywheels that we use for trackside applications for mass transit authorities. Interfacing that same energy storage with a smart grid as a reservoir, if you will, for fast response gives it a second value proposition, which is very important.

I'll just make a quick advertisement for those in the audience. Senate bill 1091, sponsored by Senator Ron Wyden (D.-Oregon), would provide a 20% investment tax credit for installing energy storage devices. It would provide a huge boost to the industry if we can generate enough support for it. Congressman Mike Thompson (D.-California) introduced a companion measure in the House.

MR. FRIED: A 20% investment tax credit for storage would clearly be a help, but I should point out that there is already a 30% investment credit for some storage devices when installed at wind, solar and other renewable energy projects.

> The challenge of adding storage to a wind or solar project is that it adds to the cost per installed megawatt of capacity.

MR. MCGOUGH: The bill would provide a tax credits to broader uses of storage.

MR. SCHRAMM: Those of us who live in southern California keep reading about electricity at 5¢ to 7¢ a kilowatt hour. Our lowest rate is 15¢, and that's for the first light bulb. When the air conditioner hits, it goes to 34¢. So we have a reason to get into energy storage faster and try to help the power companies get that cost down.

MR. MCGOUGH: It is a tiered pricing structure. There are four tiers. As soon as you turn on the refrigerator or air conditioner, you are in tier four and it is 34¢ to 37¢ cents a kilowatt hour.

Attracting Investors

MR. FRIED: Let's talk more about the economics. David Schramm, what is the current investment climate for energy storage?

MR. SCHRAMM: Most of our business is in Asia or Europe. The Europeans have very aggressive carbon requirements for automobiles. A car today in Europe is limited to about 160 grams of CO_2 per kilometer. By law, the limit will drop to 130 grams by 2012. We are working with Continental to install a start-stop system that will help reduce carbon. The penalty for exceeding the limit is the fourth gram of CO_2 over the limit costs you €95, which is pretty hefty.

If you work the chemistry backwards, to get to 130 grams of CO_2, the Europeans will need cars that make 40-some miles to a gallon. The limit drops to just 90 grams of CO_2 by 2020. This is an example of a regulatory incentive to storage technologies that will also help make European industry very competitive in global markets. They'll have cars on the market at 60 miles per gallon. To put this into perspective, the United States has a standard that says we are going to get to 35 miles per gallon.

We are attempting as a company to use a novel approach: sell your product for more than it cost and then use that money to invest in your business. [Laughter] It seems to be working so far. It let us raise money last year.

MR. FRIED: Mark McGough, where is the money coming from at this stage — friends and family, venture capital, strategic equity?

MARK MCGOUGH: Yes, from all those sources. I have been a professional beggar, all but standing on the street corner. [Laughter] I think there is an appetite for investment across the spectrum — especially in the energy storage sector which I think is a very hot area, and we are seeing that in the response we are getting from potential investors.

I also believe we are headed for industry consolidation. As some of the technologies mature and you see the economies of scale, potential synergies with other product sets appear and that will drive mergers and acquisitions. There will be the Darwinian weeding out of weak companies and, among the survivors, there will be consolidation.

MR. FRIED: John Jung, what is the best way to finance these technologies at a utility scale? Is it direct investment by utilities, financing energy storage in conjunction with financing independent power projects, completely independent financing, what?

MR. JUNG: Ah, yes.

MR. FRIED: Thanks for clearing that up. [Laughter]

MR. JUNG: What I meant to say is we are seeing all of the above. There are utilities that want to bake storage costs into rate base . Some storage companies are landing large contracts with utilities that may provide a financeable revenue stream. NGK, a Japanese manufacturer that uses a sodium sulfur technology, sold 320 megawatts to UAE in the last 12 months or so, and it has a contract for another 150 megawatts with EdF.

MR. SCHRAMM: I think it depends on the technology. For instance, community energy storage is hard to imagine without a distribution company or utility involved.

MR. VOGLER: It is the size or scalability of the storage need that will determine where the capital comes from. A utility might pay for a small project out of its own budget without the need for special financing. A larger project at a wind farm or a time shift of all the excess power from a nuclear plant to day use is a large project that will probably have to be developed by a third party on a turnkey basis with outside financing.

One of the biggest applications within storage goes to power quality. One of the biggest problems utilities face is this. Let's say there is an industrial park with five factories all tied into a substation. The local utility has a design plan for the service area, but it cannot control what those factories do. The factors are continually adding new equipment, more conveyors, more motors, more compressors and creating quality-of-power problems not only for themselves but also for everyone else tied into the same substation.

Until now, the utility had only one option. It had to upgrade the substation with a new transformer, upgrade the transmission line into that substation and maybe even add more generating capacity 10 miles away, when in fact the problem might be intermittent. Ten minutes or 15 minutes a day the lights get dim from something the neighbor is doing next door. Storage is the answer for utilities to solve these short, intermittent problems instead of having to do a full upgrade of basic capacity.

MR. JUNG: The Allen Bradleys and the Rockwells of the world look at ways they can prevent the spikes and the harmonics that are created when they turn the gear on and off. So the opportunities are not just with the utilities.

Competition

MR. FRIED: You guys seem to get along with each other. Are you competing against each other or are there synergies? [Laughter]

MR. VOGLER: We're all in the storage business, but these are different technologies. In terms of the underlying storage medium itself, it's five different lessons in Newtonian physics.

MR. SHRAMM: There's a good analogy here. We had a big solution in the 1970's after the Arab oil embargo, and that was everybody was going to build a small car. What it did was destroy the US automakers because we brought in the Japanese automakers, who were already well ahead of the US companies in producing small cars. In the 1980's, we / continued page 48

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said we are now going to solve the problem a different way. We put billions of dollars into making fuel cells. Well, there are not many fuel cells in parking lots today, so that didn't work. In the 1990's, we decided we know how to grow corn, so we decided to put every car on ethanol. Ethanol takes a lot of fresh water to make, so the unintended consequence killed that. Now we are going to have all electric cars. It is 34¢ a kilowatt/hour to charge such a car in southern California.

Our society always looks for this one silver bullet, and what you need instead of one silver bullet is a collection of technologies, and the proper mix depends on the problem we are trying to fix. Between our regulators and our lawmakers, they appear to be looking for the silver bullet, and that is the wrong place to look.

MR. JUNG: Greensmith's business is to solve grid congestion issues, and whether it is zinc bromine or lithium iron phosphate or ultracapacitors doesn't matter. From the standpoint of a burgeoning industry, it is healthy to have as much competition as possible. The utilities are not looking at VHS-or-Betamax kind of judgment. They are looking at a course of strategy implementation for energy storage. Given that context, I think you will see very little babbling up here in terms of whose mousetrap is slightly faster or better or more sanitary than the other. We are in mouse management.

MR. SHRAFT: From a compressed air energy storage standpoint, renewable stored bulk energy is different from the flywheel or the capacitor, but our product could very well compete with batteries. It is a two-megawatt, eight-hour storage device that comes on a skid mount — you drop it down — and because it is a turbo machinery type piece of equipment, it has a very long lifetime: 30 to 40 years. We think maybe it costs half of what a battery costs up front and maybe a tenth of the cost on a kilowatt hour basis. We are really excited about it, and our joint venture partner, PSEG, is working with us to build the first product.

Risks

MR. FRIED: A number of these things sound positive, and you guys are obviously excited about it, but looking at it from the other end of the spectrum, what type of risks, Mark McGough, do investors and early adopters of an energy storage technology face?

MR. MCGOUGH: We talked about a lot of variables just in this brief conversation that have a bearing on how successful we will be.

Favorable government regulations and strong renewable portfolio standards and other incentives will be necessary for the broader adoption of our technology.

Geoffrey Moore wrote a good book called *Crossing the Chasm* in which he describes the technology adoption life cycle. Many of these technologies that are still early and have not crossed the chasm. The reliability and designs of the technology have not been tested in enough applications where there is certainty around them. We like to think that we have worked a lot of the technology risk out of our product, but still we're early and there are a lot of other companies that are even earlier in the development of technology.

It starts with technology risk, and then there are the economics. We were joking about wrapping dollar bills around everything we ship. That's a problem, so you have to get past that and then you have to find the right channels to the market, and there has to be a need that develops in the market — we are all pretty bullish about that one because of the renewable portfolio standards and some of the dynamics in smart grid and energy efficiency requirements that are driving the need for energy storage.

There is good reason to be bullish about energy storage as a category, but it is still too early to determine who will be the winners and losers. I think there will be a lot more winners than one or two winners. A lot of companies could be very successful in the next five years because of these market dynamics.

MR. FRIED: Dan Vogler, where do you see the industry moving in the next few years?

MR. VOGLER: I would estimate there are fewer than a dozen real players in North America in the energy storage business today so there will inevitably be more competition and more variations in technology in the underlying storage medium, especially battery chemistry. It is a wide open market today.

The market opportunity in the wind business alone in the United States is $500 million today, and the wind market is going to double in the next three years, so this is a huge looming market for us.

The challenges ahead of us are educating the customers and educating the regulators. There is no clear classification for storage among the Texas PUC accounts, and the PUC refuses to address it. It is letting the marketplace work it out. The utilities are definitely on their own, somewhere between a study phase and a pilot project.

I think the next evolution is where we move from this developmental phase to having the bugs worked out to what I call, and John Jung called, turnkey storage where the utilities order some number of megawatts and are willing to pay for that on a dollar-per-megawatt hour basis, akin to solar and wind projects.

MR. FRIED: John Jung, what's the key to successful development of this industry?

MR. JUNG: The elevator pitch that we give has to become less about a nifty technology and more about business problem-solving. I think that will be when this industry really begins to take off. What we try to do at Greensmith is design a business where we ship units in as little as 90 days from order, where utilities feel like they're kind of ordering a transformer. It can be configured. It doesn't have to be a custom, speced-out project somewhere that takes six months to engineer, 12 months to implement and six months to certify from a safety standpoint

MR. FRIED: Mark McGough, what does the future hold?

MR. MCGOUGH: The thing to keep in mind about energy storage is that it is just that — it is storage. It is not generation. It costs money to generate the electricity, and no wants to add an incremental cost for storage. I worked for a utility. We are owned in part by a utility, and I have talked to enough utility executives who will tell you that when you are looking at grid scale, the cost is an issue because you have already had to pay to generate the electricity. The cost of storing energy can range from a few cents a kilowatt hour to half a million dollars a kilowatt hour for a hearing aid. Those are all forms of devices that store energy for different applications. What companies and investors need to do is look for the value proposition: where are the values that we can bring or the opportunities to make a profit in storing energy that fits the technology we have to offer? ◎

A Better Opportunity?

Many US wind companies are starting to look at developing solar projects in the United States at the same time that the more established US solar companies are more focused on opportunities outside the United States. Does this pattern make sense? Top executives from two US wind companies and two US solar companies talked about it at the Chadbourne global energy conference in San Diego in June. The following is an edited transcript. The panelists are Gabriel Alonso, CEO of Horizon Wind Energy, Carlos Domenech, president of SunEdison, Robert Hemphill, president of AES Solar Energy, and Paul Kaufman, executive vice president of enXco. The moderator is Noam Ayali with Chadbourne in Washington.

US wind companies are moving into solar at the same time some of the more established US solar companies are shifting focus to opportunities abroad.

MR. AYALI: Gabriel Alonso, why start looking at solar projects? Why not stick to what you have already been doing, which is wind?

MR. ALONSO: The US wind industry had a record year last year in terms of installing new wind capacity, but none of that was driven by actual demand for electricity. Ten thousand megawatts of new wind capacity was installed in 2009, driven by the fact that many players like our company had 70% of the investment committed through frame agreements for wind turbines, and we had to make the choice of putting all that 70% in committed capital in the garage while piling up financing costs, or spending the remaining 30% and getting the 30% back from the government as a Treasury cash grant and have the 70% generating at least some revenue instead of costs.

That same situation remains right now. The demand is not there. The fundamentals of the industry are weak. Demand for electricity is down. Prices for electricity are down.

In such an environment, we are looking for a less mature market and a little bit less competition where there are still opportunities for growth and potentially attractive returns. Solar is an interesting market. We can leverage the in-house expertise we already have. Developing, building and running a solar power plant is not that different from a wind farm. We know how to develop projects, we know how to get the / continued page 50

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land and how to do the permitting, and we understand the energy markets.

MR. AYALI: Paul Kaufman, is enXco being drawn into the solar market for the same reason?

MR. KAUFMAN: It is. Our parent company in Europe has been focused on solar for a long time, so it is a natural progression for us. Solar is a more flexible medium, which makes it interesting. It can be put in different places and there are lots of different applications. I agree with Gabriel that the skills that a wind development company has appear to translate well into solar.

MR. AYALI: Shifting to the two solar companies, Carlos Domenech, why is a solar company like Sun Edison now looking for projects overseas? Where are the best opportunities — here in the United States or abroad?

MR. DOMENECH: SunEdison is part of a company called MEMC, which is a semiconductor company that develops silicon for the semiconductor business and wafering technology for the solar business. SunEdison is a development company. Our market has been in the US and the company remains US centered. We have been looking lately overseas because we see opportunities, especially in countries with feed-in tariffs. The overseas markets on which we are concentrating are markets where we think solar will be competitive with other forms of electricity without feed-in tariffs within three to five years. They are markets like Italy, Spain, North Africa and some other parts of the world where there is an abundance of sunlight.

MR. AYALI: You have a project in the Emirates. I don't believe there is a feed-in tariff there. How does that project fit in the larger plan?

MR. DOMENECH: We are building the first rooftop project as part of the Masdar initiative. Electricity is heavily subsidized. The project is more of a strategic play in the region.

MR. AYALI: Bob Hemphill, what is the story at AES Solar? Is it looking for projects outside the US and, if so, why not the US market?

MR. HEMPHILL: When we started in the solar business two and a half years ago, the focus was entirely outside the United States. We were focused exclusively overseas because of the availability of generous feed-in tariffs. To date, probably 90% of our activity has been in European and other markets, including India. We now think that the US market may be becoming more attractive. Last year, the US built — these numbers may be unreliable — something like 570 megawatts of solar. Germany, where honestly there is no sun, built something like 2,500 to 3,000 megawatts that work something like four days a year as far as I can determine, but the Germans are willing to pay for it. We are already overseas, and we are only slowly and carefully coming back to the United States.

Best Markets

MR. AYALI: Which markets overseas remain most attractive?

MR. HEMPHILL: This may sound simple minded, but it is a better idea to build this stuff where there is sun — no one in Canada understands that either — so you look at the maps and go to the red places. [Laughter]

MR. AYALI: . . . and within those red places if you have to choose?

MR. HEMPHILL: It is Spain, Italy, the south of France, Greece, Bulgaria. It is Turkey; if it would ever pass a feed-in tariff, we would be there tomorrow. It is India, which has an interesting program, although you have to cope with the frustrations of trying to do business in India.

MR. AYALI: Both of you mentioned Spain as a good opportunity. Hasn't Spain just cut its feed-in tariff and done so in a way that not only affects new projects, but also reduces payments on which existing projects were counting in order to secure their financing?

MR. DOMENECH: I am Spanish just like my compadre here, Gabriel, so I may be a little biased. We are looking for good long-term markets, markets that show potential even after any feed-in tariffs to jumpstart the business expire. Our model is distributed generation at its core, even though we are building a 70-megawatt plant currently in northern Italy. Distributed generation is a compelling business model in countries where the cost of energy is increasing. We follow the red zones and align the regulatory environment to deploy meaningfully.

Value in Diversification?

MR. AYALI: Gabriel Alonso, coming back to you, is part of the attraction of solar for a wind company that a diversified renewable power company is a more attractive story for the financial markets when go to raise capital?

MR. ALONSO: The answer may be yes in theory, but the practical reality is no. By entering solar, you have technology diversification. However, the technology does not come without risks.

The reality is we have no difficulty raising capital as a wind company. If you have a 500-megawatt wind project portfolio with projects in Poland, the UK and here in the US, with long-term offtake contracts with creditworthy utilities, then you will have access to both debt and equity. The problem is that right now it is very difficult to secure long-term contracts to sell electricity to utilities. It does not matter whether your portfolio is made up of wind, solar or biomass projects; if you do not have long-term offtake contracts, then it will be very difficult for you to access the debt and equity markets.

MR. AYALI: Paul Kaufman, do you agree that having long-term offtake contracts is more important than geographic and technological risk diversification?

It may sound simple minded, but it is better to build solar projects where there is sun.

MR. KAUFMAN: It is all about stability right now. Stability is absolutely critical. The market would be uncomfortable today with any company that has a large merchant exposure. Maybe in the longer term when the market recovers, diversification will again add value.

MR. AYALI: Bob Hemphill, AES has been focused primarily outside the United States from the start. Who is your competition in those places — local solar companies, large European utilities?

MR. HEMPHILL: The principal competition is EdF EN, the parent company of enXco, Paul Kaufman's company. It is very good and quite committed to both the wind and solar markets.

There are some US players starting to move carefully into Europe. SunPower is an example. Then there are some local companies who play on a national scale within particular countries. For example, there are three or four solar companies that grew up in the solar market in Spain and that are starting to expand outside their national turf.

The thing that has always interested me, and for which I say a small prayer of thanksgiving every morning when I get up, is that the really big players are so far not present. There is no Iberdrola, no Enel, none of the Germans. Except for EdF EN, there isn't any really large, well-capitalized solar-only player yet. I am sure that will change, sadly, but it is pretty neat at the moment.

MR. AYALI: You suggest that it is inevitable that the larger utilities like Iberdrola and Enel will step into the solar market. Why?

MR. HEMPHILL: A question about which each of us on this panel thinks about is whether it better to be a single-focus company if you want to extract the maximum value for your investors from the market place or to be slightly balanced. If you look at the most recent data, EdF EN is able to raise capital at a better multiple to earnings than the pure wind guys, but it could be that they just are better overall and execute better, or could it be they are smaller and, therefore, they haven't gotten to that 7,000 to 10,000 megawatt plateau from which it is difficult to continue to grow at 20% a year because the miracle of compounding starts to work against you. I don't think anybody knows yet.

MR. ALONSO: I think it is important to be a player with a balanced portfolio, but your balance does not come from diversifying your technology exposure. We are talking about regulatory exposure. It is important to be in different markets so that you can cope with the craziness of a government like the one in Spain. You also have to keep an eye on the different credit risks as you enter into long-term contracts. If you are building wind and solar projects in California, I don't know how much your regulatory risk is being diversified, but your credit risk will be diversified if the offtakers are different.

For the bigger players like Iberdrola and EdP in our case, it is a matter of finding the best value for our shareholders and, right now, we at EDP look for long-term contracts. That is the reality of the market. Long-term certainty is what the investors are demanding currently, and if those long-term contracts are easier to get in solar, then that is where we apply our existing expertise as developers.

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Agnostic About Technology?

MR. AYALI: Paul Kaufman, is your focus in solar primarily photovoltaic or concentrating solar projects?

MR. KAUFMAN: We are looking as a company at all the resources, but PV appears to have an edge. There is less technology risk, and it easier to deploy. We are interested in central station power plants.

MR. AYALI: Gabriel Alonso, you have stronger views on the benefits of PV versus CSP, I believe?

MR. ALONSO: No, we are developing solar projects, but we are technology agnostic. The reality of the US business is that you have to monetize both the electricity you are producing and the tax benefits you receive. You have to be guided on technology by the preferences of your two partners — the utility buying the electricity and the tax equity investors who are willing to take the tax subsidy. At the moment, PV looks like it has the lead. The prices for PV equipment are coming down fairly fast.

The competition between the two solar technologies reminds me of the wind market in the 1990's. There was a debate between pitch and stall technology. Pitch was the more complex of the two. It was more expensive, but also more productive. Stall was simpler to operate and less productive, but cheaper in price and operational costs . In the end, the pitch technology applied by Vestas, Gamesa, Enercon, GE and others won the technology race. It won because you had a very attractive feed-in tariff in Europe, and the incremental megawatt hours you could generate with a more productive turbine justified the additional expense and spread the operational fixed costs over a larger number of megawatt hours.

We are seeing the opposite happening today in solar. The cheaper technology, the one that is easier to permit and deploy, is the one that is winning at this point in the race. We will see what happens ultimately. Utilities don't appear to care which technology is used as long as the developer delivers the megawatts hours he has promised in the power contract. CSP has a problem with water; it needs a lot and water is not easy to find in sunny locations. CSP has failed so far at creating volume to bring down the cost. I think people went from five-megawatt prototypes to entering into 1,000-megawatt PPAs with utilities, and they thought that the market would be right there just because they have a contract. I don't think that is happening.

MR. DOMENECH: The technology that wins is not necessarily the best technology; it is the best enabled technology. We are technology agnostic as well. We test multiple technologies, but one of the reasons we have put more emphasis on PV is we see a three- to five-year path to grid parity.

There is no justification for the support structure -- what is essentially an electric fence -- to cost up to $2 million a megawatt when a gas-fired power plant can be built for $1 million a megawatt.

MR. AYALI: Bob Hemphill, is AES Solar also technology agnostic?

MR. HEMPHILL: I know the answer is supposed to be that we are technology agnostic. I am not technology agnostic. Solar thermal is a stupid technology. The ideal place for it would be a desert where there is plenty of water. It relies on too much engineered metal. It will never be cheaper than photovoltaic. I wouldn't take a solar thermal plant if you gave it to me. [Laughter]

MR. AYALI: That is pretty clear.

MR. DOMENECH: But would you put PV in Germany? [Laughter]

MR. HEMPHILL: No. I wouldn't do that either. [Laughter]

Comparisons

MR. AYALI: Let's spend a little more time on comparing the US and overseas opportunities for solar developers. PPA economics — are they more favorable overseas than in the United States?

MR. HEMPHILL: They are far better in Europe. It is pretty simple. Europe is not a demand-and-supply market. The tariffs are set ahead of time, and the miracle of competition has driven down the cost of photovoltaic installation much faster than the tariffs in Europe have come down. The US remains interesting, but that is principally because of the generosity of the federal tax credit and the five-year MACRS depreciation.

MR. ALONSO: When we look at investing in a wind farm or a solar project in Spain, Italy or Germany, versus doing a project in the US, it is not the same. In the US, you have a contract with a utility to supply power for 20 years whose rates will be approved by the state public utilities commission, and the rates will be passed through to consumers. There is a tax subsidy that you convert into cash in the first years of the project rather than rely on a feed-in tariff that will run for the full 20 years of the project life.

What the experience today in Spain is teaching is that your risk of not realizing the full deal may be lower in the US with a long-term offtake contract than in countries with feed-in tariffs because, at the end of the day, when countries like Spain are facing a severe downgrade in their credit ratings, they prefer to default on the incentives for wind and solar developers than on their own debts as a country. End consumers are more reliable on the long term.

So I think we prefer a long-term power contract in the US, even at a slightly lower return. I lived in Germany and, as Bob Hemphill mentioned, it is sunny four days a year and the four days that it is sunny, there is not much demand for air conditioning because people are outside enjoying the day.

The fundamentals of the solar business are in question in places like Germany. How long will the country be willing to pay more for solar than other forms of electricity? The business will survive only if the cost of equipment comes down quickly as it did with wind.

MR. HEMPHILL: There are other factors that affect your decision-making about where to invest. Public policy support explains why there is so much solar investment in New Jersey, which is only slightly sunnier than Germany, and in Ontario, which has a very active solar development market, and we are participating there as well. In Europe, there has been a lot of investment in solar, and a lot of expertise is centered in the balance-of-system contractors. You try to translate that to the United States and there isn't the same concentration of experience. The reduction in balance-of-system costs in Europe is a reflection of that. Europe has spent a lot of time and energy on balance of system, and the US is not quite there yet.

MR. AYALI: I am still trying to get into some granular notions of the comparative opportunities. How would you compare construction costs in overseas markets to the United States?

MR. DOMENECH: The Germans have worked up the learning curve and know how to do things well. There are labor-related costs that plague them, but our experience has been that there are a number of very sophisticated European companies that are really great because they have lots of experience, and now they can deploy very quickly.

We have the capacity today to install 600 kilowatts of capacity a day, which is relatively meaningful for PV solar. In the US, we had to do our construction in house because we couldn't find independent contractors experienced enough to do it well, but in the last couple of years, we have been working closely with a few to push them up the learning curve, and we are pleased with what we are seeing. The same thing is true in Canada.

The knowledge and experience base is still better in Europe, but the US is catching up. I think the US will eventually pass Europe because of competitiveness and the way the US deploys resources. Construction costs in India are perhaps the cheapest we have seen. We do not have a lot of experience in China. We are building a plant there, but we are not getting the same quality that we see in other countries.

MR. HEMPHILL: It is an interesting question, and it is a conundrum for the industry. When you look at the cost, look at what you are paying for panels versus balance of system, and it is about half and half. Your balance of system is some holes in the ground, some posts, a bit of cable and some inverters, and you are paying, in utility terms, somewhere between $1,200 to $2,000 a kilowatt for what is essentially an electric fence. I can build a combined-cycle gas plant for under $1,000 a kilowatt, so there is no reason on God's green earth why what is basically a support structure should cost me more than $1,000 a kilowatt.

The cost has come down dramatically, but there is enormous room for it to come down more. I am confident that — who knows how many — a thousand panel manufacturers or 150, depending on which list you read, will bring the price of panels by beating each other up and I don't have to worry about that, but the balance of system needs specific effort on the part of developers to make it much less expensive than it is.

MR. DOMENECH: When you have multiple form factors with different panel types, it is really hard to achieve scale and to have the harmonics rightly aligned to where the utilities really need. That's where the technology becomes important. For us, we are literally going to cut in half our cost from what it was two years ago just by having a systems roadmap that is aligned with a technology roadmap. We do it by working with vendors to get panel form factors that make sense for us versus what they think makes sense and to focus on elevating the quality. I mean, 600 kilowatts a day doesn't happen just because you hire more installers. It happens because

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you align technology.

Audience

MR. AYALI: We have just a few minutes for audience questions.

AUDIENCE MEMBER: Mac Irvin from SunPower. Question for Mr. Hemphill. How does political risk factor into your market entry decisions? How do you measure your progress and how do you decide to leave?

MR. HEMPHILL: Fortunately, not everywhere we are is drowning in political risk, although several places are.

What is most useful is if we have people already on the ground who understand the country and we already have other facilities there. For example, when the Bulgarians passed a generous feed-in tariff, we already had a 650-megawatt thermal power plant about 80% complete and we had a 150-megawatt wind plant in construction. It enabled us probably to save the six months that it might take another company to establish operations. We already had an office. Our team there already knew which lawyers were good and which ones were not. It already knew which auditors to use. It already had relationships, and we could piggyback on the existing relationships with the national utility.

The opposite can also be true. Ukraine passed a generous feed-in tariff. We have businesses in Ukraine. I called up our guys in Ukraine, and they said, do not come here. This place sucks. [Laughter]

MR. AYALI: Not to put too fine a point on it.

MR. HEMPHILL: They give you some guidance. [Laughter]

MR. MARTIN: Of the wind companies, Horizon and enXco in that order, how much new capacity will you install this year in solar PV versus wind?

MR. ALONSO: Zero solar PV in 2011, and zero solar PV in 2012. We are right now building our pipeline. As long as the US Treasury is only offering cash grants under the economic stimulus measures on wind farms through 2012, we are focusing our efforts 100% on wind. If we do some solar, and we have a couple of opportunities, it will be small. We are more on a walk-before-you-run approach to solar. We will start small before we do a much larger, utility-scale project.

MR. KAUFMAN: We are very active up in Canada and expect to have 30 to 40 megawatts of solar in service by the end of this year. Our activities in the US are on a smaller scale, but we do a lot of distributed generation and have started to do some transactions where we develop for others.

MR. MARTIN: A final question for the two solar companies: How much does utility-scale PV cost per installed megawatt? With wind it's about $2 to $2.2 million on average per megawatt.

MR. DOMENECH: I'll let him go first.

MR. MARTIN: Okay, Bob Hemphill?

MR. HEMPHILL: It's more. [Laughter]

MR. MARTIN: Carlos Domenech, can you add to that?

MR. DOMENECH: I concur. [Laughter] ◎

US Tightens Sanctions Against Iran

by John Modzelewski, in Washington

New tighter US sanctions against companies doing business with Iran took effect in July and apply not only to US citizens and companies, but also to many foreign companies.

The new law — called the "Comprehensive Iran Sanctions, Accountability, and Divestment Act of 2010" — is targeted principally at non-US entities.

Americans have been prohibited since March 1995 from investing in the petroleum industry in Iran under an executive order issued by President Clinton. A second executive order issued in May 1995 banned essentially all other new investment in Iran by US entities. The bans in the two executive orders have been extended every year since then by the Bush and Obama administrations.

In addition, a separate statute –- originally called the "Iran and Libya Sanctions Act" but now called the "Iran Sanctions Act" — has been on the books since 1996 that bars any person from making investments in the Iranian petroleum sector. Libya was dropped as a target, as well as from the name of the law, in 2006.

Congress was not happy with enforcement of the existing sanctions and moved to tighten them in the new statute. The new law took effect on July 1, 2010.

Iran Sanctions Act

The Iran Sanctions Act required the President to impose two or more sanctions from a list of six sanctions upon determination that a person made an investment of at least $20 million that contributes to development of Iranian petroleum resources.

The onshore oil fields and oil industry infrastructure in Iran were past peak and in need of substantial investment. Iran openly sought foreign investment in these areas in November 1995, and Congress sensed an opening to apply pressure by banning investment in petroleum resource development.

An investment could include entering in to a contract to provide services or guaranteeing performance by someone else.

The Iran Sanctions Act was later amended also to make it illegal to provide Iran technology related to chemical, biological or nuclear weapons of mass destruction or to provide a "destabilizing number and types" of advanced conventional weapons. However, the statute did not bar the purchase of oil, petroleum or natural gas from Iran.

One problem with the existing statute was that a person had to have actual knowledge that a sanctioned activity was undertaken. It was not enough to show that the person should have known he was dealing with Iran had he made even modest inquiries.

However, sanctions could be imposed on a parent of the company violating the sanctions if it could be shown that the parent had actual knowledge or should have known.

New Statute

The new law is still focused on investments in the Iranian petroleum sector.

The sanctions can now be triggered for investments or assistance of at least $1 million in value in any one transaction or at least $5 million over a 12-month period, although the threshold remains $20 million for help to Iran with developing its oil and gas fields.

Investments must "directly and significantly" contribute to Iran's ability to develop its petroleum resources to be covered by the sanctions.

Petroleum resources have been expanded from "petroleum and natural gas resources" under the Iran Sanctions Act to include refined petroleum products, oil and liquefied natural gas. tankers for transporting such products, natural gas resources, and equipment used to construct or maintain pipelines that transport oil or liquefied natural gas.

The new law expands the list of sanctioned activities in three ways.

The US tightened economic sanctions against Iran in July.

First, sanctioned activity now includes any sale, lease or provision of goods, services, technology, information or support to maintain or expand Iran's ability to produce "refined petroleum products," including any direct and significant assistance constructing or modernizing refining facilities.

Second, sanctioned activity includes any export of refined petroleum products to Iran, or provision of goods, services, technology, information or support for Iran's ability to import refined petroleum products. Refined petroleum products include diesel, gasoline, jet fuel (naphtha- and kerosene-type) and aviation gasoline.

Third, sanctioned activity includes the sale, lease, or provision of goods, services, technology, information or support to Iran that could directly and significantly improve Iran's capability to import refined petroleum products. This includes underwriting or providing insurance for, or providing financing or brokering for, the sale, lease or provision of such items, or providing ships and shipping services to deliver refined petroleum products to Iran. An underwriter or insurer may not be sanctioned for activities described above if the President determines that it establishes proper due diligence policies and procedures to avoid providing financial support to sanctioned activity. / continued page 56

Iran Sanctions

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Sanctioned activities must still be committed knowingly by a party, but it will be easier for the US government to prove knowledge. A person will be treated as having knowledge of what he should have known had he done proper diligence. Thus, a US parent company will be treated as having knowledge of what a foreign subsidiary is doing if it should have known about the activity.

The President must now impose at least three out of a list of nine possible sanctions.

The sanctions are:

1. Bar the US Export-Import Bank from issuing any guarantees or insurance or extending credit in connection with the export of any goods or services to any sanctioned person.

2. Order US government agencies not to approve licenses for sensitive technologies, goods or services that require a US license to export (or re-export).

3. Prohibit US financial institutions from making loans of more than $10 million to the person in any 12-month period.

4. If the person is a financial institution, bar it from being designated as a primary dealer for US government securities or from acting as a repository of government funds.

5. Forbid US government agencies from buying any goods or services from the person.

6. Prohibit transactions in foreign exchange that are subject to the jurisdiction of the United States and in which the sanctioned person has any interest.

7. Prohibit banks and other financial institutions that can be reached by US law from transferring money or extending credit where such transfers involve the sanctioned person.

8. Freeze assets belonging to the person and bar others from engaging in any transactions with the sanctioned person that involve property within the reach of US law.

9. Restrict US imports from the person.

Sanctions must be imposed for a fixed period of at least a year. They will be kept in place longer if the sanctioned activity does not cease.

Persons bidding on or entering into contracts with the US government will have to certify in the future that neither the contractor nor any person owned or controlled by the contractor is engaging in sanctioned activity. A false statement will lease to cancellation of any contract issued and will cause the person be barred from other federal contracts for up to three years.

The sanctions not only apply to US companies, but will also ensnare many foreign companies that do business with Iran.

Separate Bank Sanctions

New US Treasury regulations prohibit US financial institutions from establishing, maintaining, administering or managing correspondent or payable-through accounts in the United States on behalf of any non-US financial institution that engages in prohibited transactions with Iran. These regulations have been in place since August.

The list of prohibited transactions includes any transaction that assists Iran in acquiring or developing weapons of mass destruction or in supporting terrorist organizations. The list also includes any transaction that benefits persons subject to financial sanctions under UN Security Council resolutions that target Iran. Any money laundering activity or assistance provided to any Iranian financial institution related to prohibited transactions are also prohibited. Financial assistance and services provided to the Islamic Revolutionary Guard, any of its agents or affiliates or any financial institution whose property interests have been blocked on account of aiding Iran are also prohibited.

Foreign financial institutions that do this type of business with Iran risk having their names placed on a public list. The Treasury may prohibit US persons from having accounts with institutions on the list. Instead of publishing the name of the institution and barring all account activity, the Treasury may impose any of four listed strict conditions on maintenance of an account with a sanctionable non-U.S. financial institution. These conditions include prohibiting trade finance through the account, restricting the types or dollar amounts of transactions that may be processed through the account, and requiring pre-approval for all transactions processed through the account.

Financial institutions that violate the Treasury regulations can be fined up to $250,000 or twice the transaction value and subjected to additional criminal penalties up to $1 million and 20 years in jail.

The new sanctions law requires US banks that maintain correspondent accounts or payable-through accounts in the United States for foreign financial institutions to do internal audits to check for prohibited activities by the account holders, to report any transactions or financial services provided with respect to these activities and to certify to the best of their knowledge that the foreign financial institution who opened the account is not knowingly engaging in a prohibited activity.

Tighter Noose

One problem with the earlier sanctions under the Iran Sanctions Act was the President had to make a formal finding that someone violated the sanctions, but there was no deadline or means to force the administration to act, even if there were newspaper articles about the sanctions violations.

The sanctions act was amended in 2006, but only to urge the President to investigate — "the President should initiate an investigation" was the statutory language — upon the receipt of credible information. If the President actually did initiate an investigation, a report was required to Congress within 180 days.

The new law goes father. It says the President must investigate upon receipt of credible information. This new standard generally took effect in July 2010, but will not take effect until July 2011 for sales of refined petroleum to Iran or provision of goods or services that help maintain or upgrade refineries in Iran.

The President must impose sanctions under the new law, unless he declares not doing so is necessary to the national interest.

The new law broadly prohibits both US imports of any good or service of Iranian origin and exports to Iran of any good, service or technology of US origin. Certain exceptions apply for food, medicine, humanitarian aid, internet communication, goods to support the safe operation of aircraft and exports in the national interest. Civil penalties up to $250,000 or twice the transaction value and criminal penalties up to $1 million and 20 years in jail may be imposed.

The new law prohibits the US issuance of export licenses related to nuclear material, facilities, components or other goods or services to any country if a sanctionable person under that country's jurisdiction has engaged with Iran in transactions related to nuclear weapons or the delivery of nuclear weapons. It will be interesting to see whether this is applied to Russia. Exceptions apply if the country's government does not know or have reason to know of the sanctioned activity, or is taking all reasonable steps to penalize the sanctioned person and prevent further sanctioned activity.

New or renewed US government procurement contracts are denied to any person that exports communications equipment to Iran that is used to monitor or disrupt the free speech or the free flow of unbiased information to Iran.

Enforcement History

Sanctions enforcement has been lax. Sanctions have been in place against Iran since 1995, but the US government has not charged anyone with having violated them.

The closest the US came was in 1998 when the Clinton administration determined that a project involving major international exploration companies to develop a natural gas field in Iran was sanctioned activity. However, the administration waived sanctions to avoid a trade confrontation with the European Union.

Secretary of State Hillary Clinton testified before the House Foreign Affairs Committee in February 2010 that the State Department had conducted a preliminary review of a series of investments in Iran, and that some of the investments "deserve[] more consideration" and would be scrutinized further. In June 2010, Assistant Secretary of State William Burns testified before the Senate Foreign Relations Committee that there were "less than 10" cases that, in the State Department's view, could be considered sanctioned activity under the existing sanctions and that the State Department was conferring with other agencies about possible action.

Several countries have expressed */ continued page 58*

Iran Sanctions

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concern to the United States about the new statute. India's foreign secretary said his country was concerned that "unilateral sanctions recently imposed by individual countries [could] have a direct and adverse impact on Indian companies and, more importantly, on our energy security." US officials have reportedly been talking to Turkey about Turkish companies who deal with Iran on refined petroleum products.

What Happens If the US Ethanol Tariff Expires?

by Daniel Spencer, in São Paulo

Brazil has temporarily reduced its import tariff on foreign ethanol to zero until the end of 2011 in a move aimed at provoking the United States into letting its ethanol import tariff expire as scheduled at the end of 2010.

The US Congress is expected to debate by year end whether to extend both the tariff and a domestic tax credit that encourages blending of ethanol with vehicle fuel. Farm state legislators want to extend both through 2015. The politics of ethanol in the United States are changing. There is more opposition to the subsidies than the last time they came up for renewal.

If the US Congress is unable to pass the necessary legislation this year to keep ethanol import tariffs in place beyond 2010, what effect is this likely to have on the US and the Brazilian ethanol industries?

Outlook for a US Tariff Extension

Brazil and the United States are the two biggest ethanol fuel producing and consuming nations in the world. Brazil produces 54% of world output (10.75 billion gallons per year) and the United States produces 34% (6.57 billion gallons).

The two countries are entering an interesting new phase in ethanol diplomacy.

Both have historically had import tariffs to protect their industries from foreign competition, with the result that most of their production has gone to domestic use. The United States exported 113 million gallons of ethanol in 2009, or roughly 1% of domestic output. Brazil exported 933 million gallons, or roughly 15% of domestic output. Most US exports went to Canada, the Netherlands and the Middle East. Most Brazilian ethanol was exported to the United States.

Brazil eliminated its import tariff in April, but only through 2011. The US collects a tariff of 54¢ a gallon on imports. The tariff expires at the end of 2010.

Brazil produces ethanol from sugar cane at a cost that is one third cheaper than US ethanol, which is made principally from corn. Brazil also has a significant amount of land available to increase its current production.

Ethanol still enjoys bipartisan support in the US Congress. Democrats who control both houses have been frustrated this year by their inability to put legislation through the Senate, where Republicans have enough votes to block bills from passing by "filibustering" or objecting to votes and then voting against motions to shut off debate. It takes 60 votes out of the 100 Senators to stop debate. The Democrats have only 59 (counting two independents who tend to vote with the Democrats).

Some Democrats are hoping that support from Republican farm Senators for ethanol will allow a broader bill that includes not only an extension of the ethanol tariff and tax credit but also other ideas favored by the Democrats, like an extension of Treasury cash grants for renewable energy projects, to clear the Senate before Congress adjourns for the year.

Senators Charles Grassley (R.-Iowa) and Kent Conrad (D.-North Dakota) are leading the charge in the Senate for an extension.

However, opposition to an extension is greater this year than in past years. A coalition of cattle and hog farmers, food processors who rely on corn or corn oil, some conservatives like Senator John McCain (R.-Arizona) who are concerned about growing government budget deficits and Senators from urban states seem more outspoken this year in their opposition.

Ethanol proponents have agreed in principle with House leaders to extend the tax credit at a reduced rate of 36¢ a gallon and to maintain the current import tariff at 54¢ a gallon for another year.

The biggest risk at this point to an extension is the legislative gridlock in Washington. Little is getting through Congress. The next biggest risk is if there is a vote on the Senate floor to strip ethanol subsidies from any end-of-session bill to which the ethanol extension is likely to be appended. That will be a test of whether opponents have gained the upper hand.

Opponents in the US complain that current US ethanol production is causing food prices to rise, has a debatable environmental benefit and is incapable of making a serious dent in US reliance on foreign oil since, based on current production techniques, there are not enough US corn fields both to feed and fuel the United States. The Russian forest fires are not helping with their upward pressure on grain prices.

The picture is very different in Brazil, which has enough available agricultural land to run its entire passenger vehicle fleet easily on domestically-produced ethanol without interfering with food supplies.

The US tax credit for ethanol blending would cost US taxpayers roughly $31 billion to extend through 2015. This makes it more likely that the import tariff will be extended at the same time because advocates must find a way to pay for the extension.

The United States also supports the domestic ethanol market through a "renewable fuel standard" that requires the US vehicle fuel mix to include at least 13 billion gallons of ethanol, biodiesel and other alternative fuels this year, increasing to 36 billion gallons per year by 2022.

Effect if US Tariff Expires

The most interesting question is what effect would expiration of the US tariff have on the US and Brazilian ethanol industries?

Opinion is divided.

The Renewable Fuels Association in Washington says the effect would be significant. It says 112,000 US jobs would be lost and there would be a 38% reduction in US production capacity as foreign ethanol, mainly from Brazil, would flood the US market. A study by Iowa State University concluded that the impact would be much more limited. The study was sponsored by UNICA, the Brazilian sugar cane association.

As noted, both the US and Brazilian ethanol industries are currently structured primarily to produce ethanol for domestic, and not foreign, use. This is significant in assessing the potential consequences for two reasons.

First, if the US tariff expires, most ethanol production from both nations will continue to be directed in the short- to medium-term toward domestic use in order to meet domestic consumption targets. Second, Brazil probably lacks the infrastructure in the short term to increase output greatly for the export market.

Even if the US tariff on ethanol imports were to lapse at year end, it would not lead to a huge influx of Brazilian ethanol.

Some analysts are concerned that the US could face an ethanol shortfall. The US renewable fuels standard requires use of at least 36 billion gallons a year of renewable fuels by 2022. Ethanol is currently the only renewable fuel that has the potential to contribute meaningfully to this target, and US ethanol production is expected to rise to about 30 billion gallons by 2022.

In Brazil, UNICA predicts that ethanol production will increase by 150% through 2020. However, according to Petrobras, the state-owned oil company in Brazil, the main factor driving the increase is the projected rise in the sale of flex fuel cars that can run on both gasoline and ethanol. Ethanol is expected by 2020 to fuel 75% of Brazilian cars as gasoline-only cars are replaced with flex fuel vehicles. Almost 100% of new vehicles sold in Brazil today are flex fuel.

Accordingly, both the US and Brazilian ethanol industries will require significant investment in the coming years just to meet their increasing domestic ethanol targets. It is not clear whether significant additional investment will be available for these industries to grow beyond their current domestic needs.

For example, growth in the Brazilian ethanol industry has largely been financed by Banco Nacional de Desenvolvimento Econômico e Social (BNDES), the Brazilian state-owned development bank, which has limits on how much funding it can provide to the industry. It currently provides approximately BRL4 billion per year. Foreign investment in the industry has also been slow, although there are signs that this is starting */ continued page 60*

Ethanol Tariff

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to change. According to the consulting group Dextron Management, the proportion of Brazilian ethanol mills backed with foreign capital has jumped to 22% from 7% in 2007-8. Petroleum giant Shell has also recently entered into a US$12 billion joint venture with Cosan, the largest sugar producer in Brazil, for the production of ethanol, sugar and power and the supply, distribution and retail of transportation fuels.

In contrast, the US ethanol industry has grown backed largely by finance from Wall Street investment banks and farm co-operatives. Although it is expected that this trend will continue, according to the Nebraska ethanol board, the biggest challenge that new ethanol projects face in the United States is finding financing in the fallout from the 2008 financial crisis and low oil prices.

Brazil needs to invest heavily in its infrastructure before it can increase its ethanol exports substantially. Most ethanol for export is transported to the coast by road or, to a much lesser extent, rail. Although new pipelines are currently being built by Petrobras and a consortium led by Cosan to transport ethanol from inland production areas to coastal ports, these projects have been slow to develop and have faced financing difficulties. Brazil's ports are also overcrowded and are struggling to cope with the general growing demand for Brazilian exports, in particular from China.

Accordingly, perhaps the US should not fear free ethanol trade with Brazil.

In fact, earlier this year, the market price of US ethanol was reportedly lower than Brazilian ethanol making it hard for Brazilian producers to justify diverting output for sale in the US market. There has been a recent surge in US exports of ethanol in 2010 resulting from oversupply in the US market.

Looking to the long term, the future of ethanol as a fuel that can realistically replace gasoline on a global scale is dependent on technological advances being made in next generation cellulosic ethanol (ethanol that can be produced from virtually any type of plant fiber) and neither the US nor Brazil, being the world leaders in ethanol production, has a process that can produce mass quantities of cellulosic ethanol on a cost-effective basis. It is possible that free ethanol trade might encourage producers in both countries to adopt more of a joint venture approach to development that may produce quicker technological advances.

Brazil Will Need Massive Capital for Infrastructure

by Felipe Creazzo, in São Paulo

Brazilians go to the polls on October 3 to elect a new president.

Luiz Inácio Lula da Silva — or Lula as he is called — the country's president since 2003 leaves off with an unprecedented 77% popular approval rating.

He is viewed as having elevated Brazil from its perennial status as a major emerging market with unrealized potential to a global powerhouse. Brazil now has the eighth largest GDP in the world, most recently having surpassed Spain in the GDP rankings.

Three candidates are vying to succeed Lula as president. They are Dilma Rousseff, Lula's former chief of staff and a member of the governing Workers Party, José Serra, former governor of the state of São Paulo and a member of the Brazilian Social Democracy Party, the principal opposition party, and Marina Silva, former environmental minister in the Lula administration and currently a senator. Ms. Silva is the candidate of the smaller but active Green Party.

Recognizing that they have big shoes to step into, all of the candidates have more or less voiced support for pursuing the general economic policies established by Lula.

However, there are some important differences of view among the candidates relating to Brazilian infrastructure development.

Rousseff, who is currently favored to win and is Lula's handpicked successor, would stick closest to Lula's infrastructure agenda. In written statements filed with the election commission, she said she plans to construct new hydroelectric plants, develop geographical centers of alternative energy plants (wind and solar), continue exploration of the massive so-called pre-salt oil and gas reserves off the coast of Brazil, create a Brazilian oil and petrochemical services industry and invest in the reconstruction of railroads, highways, subways, airports and shipping.

Serra has adopted the strategy of gently exposing some of the sector's weaknesses and underachievement. He must walk a fine line because direct criticism of Lula's achievements in infrastructure could undermine voter sympathies. He has adopted a "Brazil can do more" position, pointing to the fact that it is more expensive to transport one ton of soy from Mato Grosso, a state in the center west of Brazil, to a port in the southern state of Paraná than to transport a ton of soy from the same Brazilian port to China. His example exposes the magnitude of the persistent logistical bottlenecks within Brazil. But his general position on infrastructure development sounds very similar to Rousseff's: "Should I win these elections, there will be construction sites all over this nation, as we've done in São Paulo. We need new roads, ports, airports, urban trains, subways."

Serra and Rousseff part ways in two basic areas: the regulatory regime to be applied to the massive offshore pre-salt oil exploration and the planned rapid transit rail system. called the "TAV," that would connect Rio de Janeiro and São Paulo.

Oil and Gas

Lula pushed for reforms in the Brazilian oil industry to prepare for a surge in exploration and development activity as the country pursues the pre-salt oil and gas discoveries. Proposed legislation that is currently in the final stages of approval would replace the current concession model with a production-sharing model similar to what is used in countries like Iran, Iraq, Norway and Saudi Arabia. The proposed legislation would grant Petrobras the exclusive right to operate (or subcontract the operation of) all pre-salt blocks, create a new holding company to manage the pre-salt projects and implement a new contract system that would give the federal government a share of the oil.

Rousseff supports moving to a production-sharing model and creating a new holding company on the basis that the scale of the reserves requires it.

Serra questions both the production-sharing model and the necessity of establishing a new company to manage the pre-salt projects, arguing that Petrobras and energy sector regulator, ANP, are already able to manage development of the pre-salt reserves. If elected, Serra would probably revisit some aspects of the proposed new development model.

To Serra, the proposed TAV is another mistake by the current administration that should be avoided. He believes that the TAV will benefit only a few thousand people daily by relieving congestion in the two busiest airports in the country, the Congonhas airport in São Paulo and the Santos Dumont airport in Rio de Janeiro. Serra believes that the proposed US$18.7 billion investment in the TAV could be better spent on improving subways and other mass transit in the big cities. He also questions the economic feasibility of the TAV project.

Rousseff calls his opposition to the TAV "small thinking." In line with Lula's aggressive growth policies, Rousseff believes that nothing prevents the government from spending on both the TAV and new subways.

Brazil needs 7,000 megawatts of additional generating capacity annually to keep up with growing electricity demand.

Renewable Energy

Despite disagreement on offshore oil exploration and the TAV, Rousseff and Serra agree on one thing: with a GDP growing at 5% or more a year, Brazil will need 7,000 megawatts of additional electric generating capacity a year to meet demand. Hydroelectric projects account currently for 78% of generating capacity. New large-scale hydroelectric dams are under development in the Amazon region, but these projects are sensitive to water shortages and environmental restrictions. As a consequence, the country is putting more emphasis on renewable sources of energy.

The most viable alternative energy option (and the one considered most voter-friendly) is wind power, which experts say offers 305,000 megawatts of energy potential in Brazil.

Sugar cane-derived biomass by contrast offers only 15,000 megawatts of energy potential.

Solar energy development is still not significant at all in Brazil due to economic feasibility and is limited to small projects.

Brazil has currently only 794 megawatts of installed wind capacity, most of which has been developed through a pilot renewable energy program, Proinfa, that offers 20-year power

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purchase agreements with utilities. In December 2009, the first wind auction in Brazil attracted 13,000 megawatts of bids and led to contracts being signed for 1,800 of new capacity. Proinfa is responsible for another 300 megawatts of wind projects that are in construction; the projects are being built by Impsa and Enegias de Portugal.

Local content regulations have encouraged foreign manufacturers to invest in, or enter into joint ventures with, Brazilian-based turbine manufacturers.

Ibedrola Renovables was the first major wind player to develop a significant presence in Latin America, but a number of other large international developers have entered or are reported to be entering the market, often through joint ventures with locals.

By 2025, it is expected that Brazil will install 31,600 megawatts of wind capacity, making Brazil a major current and future market for wind power. Thus, although wind power is not at the center of political discussion in the current election, it remains very much a point interest for those focused on Brazil's continued economic growth and related demand for energy.

Private Capital Needed

Who will win the election?

Polls taken just before the NewsWire went to press showed Rousseff with 41% of the vote, Serra next with 33% and Marina Silva, the Green Party candidate, trailing with 10%. Rousseff's lead is a new development. Polls until now have shown Rousseff and Serra in a virtual tie. Rousseff's recent surge is probably due to campaign help from Lula and to new economic forecasts that show the Brazilian economy growing at around a 7% annual rate.

However, the election is far from over.

The real campaign did not start until August 17 when all political parties received free television network time to explain their agendas.

The good news for project developers and lenders is that no matter who wins, Brazil can be expected to undertake unprecedented and massive infrastructure development in coming years.

Lula's Growth Acceleration Program, in its second phase, foresees investments in infrastructure in the US$540 billion range between 2011 and 2014. After 2014, the plan is to invest approximately US$360 billion more in civil works, bringing total investment to an impressive $900 billion. The oil and gas sector alone, boosted by the exploration of the Brazilian pre-salt reserves, is expected to receive US$380 billion of investment in the next 10 years, according to the Ministry of Mines and Energy. The Brazilian Development Bank (BNDES), which has been the principal source of infrastructure funding in Brazil to date, estimates that Brazil will require more than US$175 billion in private capital during the next four years to fund new infrastructure development. That number may well be understated. ◎

Environmental Update

Greenhouse Gas Emissions

The federal government moved closer in August to regulating carbon dioxide and other greenhouse gas emissions by regulation, without waiting for Congress to act.

The US Environmental Protection Agency released two proposals in August to ensure that state agencies will be in a position to start issuing air permits covering greenhouse gases on January 2, 2011 when a new EPA "tailoring rule" takes effect.

The tailoring rule will require developers building new power plants, factories or other "sources" of emissions — or modifying existing sources — to get air permits before starting work if the greenhouse gas emissions are expected to exceed certain thresholds. The rule is part of the "prevention of significant deterioration or PSD program that already applies under the Clean Air Act to some other pollutants. Greenhouse gases are being added to the list.

The federal government relies for the most part on state agencies to issue PSD permits. States use "state implementation plans" or SIPs to implement the PSD program.

EPA had to take the action it did in August because some state air permitting programs do not currently authorize regulation of greenhouse gas emissions.

The tailoring rule phases in greenhouse gas regulation. The need for a PSD permit will initially be triggered only for existing facilities that are already subject to the PSD program and that increase their carbon dioxide or other greenhouse gas emissions by more than 75,000 tons per year of CO_2-equivalent.

The EPA proposal in August would require states that lack authority under state permitting rules to regulate greenhouse gas emissions to implement the federal standards. EPA asked all states in August to examine their SIPs to make sure they cover greenhouse gas emissions. It identified a number of areas of the country that definitely require revised SIPs with respect to greenhouse gases. These areas include Alaska, Arizona, Arkansas. the Sacramento Metropolitan Air Quality Management District in

California, Connecticut, Florida, Idaho, Kansas, parts of Kentucky, Nebraska, Clark County, Nevada, Oregon and Texas.

EPA recognized that states may not have the time or resources to revise their SIPs and, accordingly, it also proposed a "federal implementation plan" or FIP (as an interim measure for states that cannot or are unable to revise their SIPs by January 2, 2011.

States have 30 days after publication of the proposal in the Federal Register to provide EPA with a letter explaining how their PSD programs regulate greenhouse gas emissions.

The August proposals are the first of three proposals that are needed to put the machinery in place to regulate carbon dioxide and other greenhouse cases. Other proposals will follow to address state authority to issue operating permits and what will be considered the "best available control technology" or BACT that owners of power plants, factories and other sources will be required to employ to control covered emissions.

Clean Air Transport Rule

EPA proposed a "clean air transport rule" or CATR in July that would require reductions in emissions of nitrogen oxides (NOx) and sulfur dioxide (SO2) in most of the east and midwest.

The new proposal replaces an earlier "clean air interstate rule" or CAIR that the agency proposed in 2005 but that was sent back to the agency by the courts for further work.

Along with the proposal, EPA asked for comments on two alternatives to reduce power plant emissions of NOx and SO2.

The earlier CAIR rule would have ordered reductions in power plant emissions of NOx and SO2 in the District of Columbia and 28 eastern and midwestern states through a cap-and-trade system. NOx and SO2 can form particulate matter, and NOx is a precursor of ozone. A federal appeals court remanded CAIR to the agency in 2008 in a case called State of *North Carolina v. EPA*.

The new proposed rule, along with other state and EPA actions, is expected to reduce SO2 emissions by 71% and NOx emissions by 52% by 2015 compared to 2005 levels.

The new rule is based on the existing ozone national ambient air quality standard of 0.075 parts per million. EPA announced in February 2010 that this standard would be reduced to between 0.060 to 0.070 parts per million. EPA is expected to issue the final ozone standard in October and then to update the new CATR rule in 2011.

The new rule would require reductions in power plant emissions of NOx and SO2 emissions in the District of Columbia and 31 eastern and midwestern states. There would be three categories of reductions: states required to reduce annual NOx and SO2 emissions, ozone season NOx emissions or annual NOx and SO2 emissions and ozone emissions.

EPA expects power plants to meet the requirements in the new CATR by operating existing emissions control equipment more frequently, using lower sulfur coal or installing additional pollution control equipment like low NOx burners, selective catalytic reduction, or scrubbers.

The EPA proposal includes federal implementation plans for each state covered by the CATR, although each state may develop its own implementation plan. EPA is accepting comments on the proposed rule and alternatives until October 1, 2010.

Hydraulic Fracturing

The US government is taking a closer look at a technique that natural gas producers are using to reach potentially huge new supplies of gas trapped in shale rock formations, like in the Marcellus formation. The technique is called hydraulic fracturing or "fracking." There are concerns about whether it pollutes the groundwater.

Such hard-to-reach gas could account for more than 20% of the US gas supply by 2020. According to some estimates, there is enough natural gas in the Marcellus formation in parts of Pennsylvania, New York and West Virginia to supply demand in the entire United States for 14 or more years.

Fracking refers to the process by which water, chemical additives and sand or similar material are injected under high pressure down a well. The fluids force existing fractures in the subsurface to open wider while the sand or another propping agent holds the fractures open, allowing natural gas to be extracted. The process uses tremendous amounts of water — up to two to four million gallons for a horizontal well — which also raises concerns about the availability of that much water.

Regulation of fracking is left currently largely to the states. The federal underground injection control program regulations only cover fracking related to oil, gas or geothermal wells where diesel fuel is used as a propping agent. In addition, oil and gas wells are exempted from a federal reporting requirement in the "Emergency Planning and Community Right-to-Know Act," which requires certain facilities to report the amounts of toxic chemicals released, stored or transferred each year.

Fracking has been used by the oil and gas

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

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

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

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

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

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

— contributed by Andrew Giaccia and Sue Cowell in Washington.

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