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Mayer Brown's Global Energy practice includes attorneys from the key disciplines of finance, corporate, securities, tax, environment, trade and energy regulation and dispute resolution. We have advised oil, natural gas, pipeline, coal and electric power companies, power and LNG project developers and alternative energy providers, as they acquire, structure and finance the deals that fuel their growth. Our clients include companies representing the full spectrum of the energy industry, as well as those that finance or invest in them.

Our group is exceptionally situated to serve our global clients because of the breadth of jurisdictions we serve, and the depth and quality of services and know-how that we provide. Our clients can take advantage of all of the resources, services and industry leading skills that we bring to every sector of the energy industry. We draw together talent from our offices around the world, including the principal energy and energy finance centers of London, New York, Brazil, Hong Kong and Houston. These market centers have a tradition of hosting, servicing or financing energy firms and we have a substantial presence in each of them.

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In this edition of Mayer Brown's *Global Energy Review*, we review recent updates at the firm as well as provide commentary on developments and trends in the energy industry that are impacting our clients' business and investment interests across the globe.

In December 2009, we announced our association with Tauil & Chequer, a leading law firm in Brazil with an excellent reputation in the energy, oil and gas sectors. Through T&C, we are now able to offer legal counsel on matters governed by Brazilian law and expand our resources in Africa. T&C has a very strong and long-standing presence in the oil and gas business advising international and national oil companies on a wide variety of legal matters in Brazil and elsewhere (including Angola).

In this issue, our lawyers discuss the rise of the nuclear sector in Asia, key developments in government funding likely to spur biomass projects in the US, international arbitration for energy projects in the Middle East and interpretative issues that remain after the release of the SEC Oil & Gas Disclosure Rules.

We are also happy to announce two transactions, where Mayer Brown served as lead counsel, have been recognized as Deals of the Year by leading trade publications:

Odebrecht Oil & Gas Drill Ships, 'Americas Deal of the Year 2009' by *Project Finance International Magazine* and 'Best Project Finance Deal 2009 by *Latin Finance*.

Chesapeake Natural Gas & Oil Hedging Facility, 'Deal of the Year 2009' by *Energy Risk*.

Don't miss our *Green Energy Projects* in the United States webinar, March 9th. For details and to register go to *http://www .mayerbrown.com/events/event.asp?id=5716*.

If you have any questions or comments on any of the articles, please contact us. ◆

Biomass is Having a (Political) Moment

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2010 is shaping up to be an interesting year for developing and financing power projects that use biomass as feedstock. On the one hand, private capital raising for biomass projects continues to be challenging, creating further pressure on biomass developers to structure "clean" projects — investors and lenders fund projects with the strongest combination of long-term, fixed-price fuel supply arrangements (historically, perhaps the most challenging issue for biomass projects), take-or-pay power purchase arrangements and other project contracts that favorably allocate risk to experienced and creditworthy project counterparties. On the other hand, the Obama administration has announced its support for bioenergy and has introduced or advanced a number of government funding programs and incentives that hold great promise for the financing of all kinds of bioenergy projects, including biomass power projects.

One of the most obvious factors compelling new biomass power project development this year is that, to be eligible for the cash grant program under the American Recovery and Reinvestment Act of 2009 (Stimulus Bill), biomass projects must meet a deadline currently requiring that, at a minimum, plant construction start by the end of 2010. Another very recent development of impact to both new and existing biomass power plants is the issuance in early February of proposed regulations implementing the Biomass Crop Assistance Program (BCAP). BCAP offers certain payments to eligible biomass suppliers and producers in order to stimulate the availability of biomass crops as fuel supply for bioenergy production. There are certainly a number of other government funding opportunities that may be available to certain biomass power projects, including, for example, Department of Energy (DOE) and US Department of Agriculture (USDA) loan guarantee programs, Rural Energy for America Program (REAP)[1] grants and various state incentives. However, current developments or deadlines relating to the cash grant and BCAP make these two in particular worth a further look as sponsors, investors and lenders search for ways to move new projects forward or improve returns on existing projects.

Cash Grant Expiration

Much has been written regarding the US Treasury's cash grant program for eligible generating facilities, but as 2010 progresses, the focus for many developers will turn to making sure that a plant commences construction by the end-2010 deadline in compliance with the relevant guidance, and determining what federal tax incentives remain available for projects that miss the deadline.

First, a bit of background. The Stimulus Bill provides qualifying biomass power projects (and other renewable energy generation projects) with the option to forgo production tax credits and instead receive an investment tax credit for 30 percent of eligible project cost or a cash grant from the US Treasury in an equivalent amount. For biomass projects in particular (compared to other renewable technologies like wind), this is a substantial additional subsidy. "Open-loop" biomass projects,[2] which currently comprise most of the operating biomass projects in the US, qualify for only half of the value of the production tax credit for wind, but the Stimulus Bill made open-loop biomass eligible for the full investment tax credit and the equivalent cash grant that is available to other technologies (equal to 30 percent of eligible project cost).

In recent years, renewable project developers unable to efficiently use the benefits of the production tax credit have successfully monetized the tax credits by transferring them to "tax-equity investors" — banks and other institutional investors with a large amount of taxable income to offset — in exchange for upfront project capital. However, the credit crisis left only a handful of tax-equity investors able to use the tax credits. The cash grant program offered a solution to this problem by funneling cash directly to the project developer and eliminating the need to find tax-equity investors to gain some benefit from the tax credits. However, the cash grant was intended to be a temporary stimulus measure that would be phased out by certain deadlines as the financial markets re-gain strength. For biomass projects, the current cash grant program deadline requires that a project must either be placed in service by the end of 2010 or must commence construction by the end of 2010 and be completed by the end of 2013.

In July 2009, the US Treasury released detailed guidance on what "commence construction" means for this purpose. A cash grant applicant qualifies if it can show that "physical work of a significant nature" has begun. Physical work of a significant nature is not preliminary work such as planning, designing or clearing, but rather foundation work or other physical construction activity. However, there is some vagueness around how this standard might be applied, so developers should try to fit within a better-defined safe harbor. The guidance also includes a safe-harbor if a developer incurs at least 5 percent of the total project cost (excluding preliminary activities that precede construction, such as planning and design) and work for such payment is completed.

However, there are questions even around the safe harbor, in particular concerning the situation where a developer hires a third-party contractor to commence assembly of the plant off-site. Developers targeting the 5 percent safe-harbor should plan on leaving a margin for error (e.g., meet the test by incurring not less than 7 to 8 percent of eligible project cost in case, for example, Treasury rejects developer's classification of certain costs as eligible costs). Treasury intends to issue, perhaps as early as this March, additional guidance that will address a number of the most common questions that have been raised. In any event, developers that hope to qualify for the cash grant, but currently anticipate the start of plant construction in the latter part of 2010 or early 2011, should carefully review their specific construction plans with their advisers to ensure the project will commence construction in compliance with the guidance and thereby meet the deadline.

Biomass power developers also need to confirm that their project meets other eligibility requirements for the cash grant program, in addition to considering whether a project can meet the construction commencement deadline. For example, among other requirements, a power plant must generally use or comprise new equipment in order to be considered qualified property. This is particularly relevant to a number of utilities and developers considering the conversion of existing coal-fired plants to biomass-fired plants as a way to comply with anticipated carbon legislation and state renewable portfolio standards. Such projects qualify for the cash grant only if the developer spends so much on upgrades that it is considered to have built a new plant under detailed standards set out by the Internal Revenue Service (IRS). Coal plants that undergo minor retrofits in order to co-fire with biomass generally won't meet the standard.[3] As a general matter, the amount spent on upgrades must be at least 80 percent of the sum of the value of the used equipment retained from the old facility plus the amount spent on upgrades.

Developers with projects that simply can't meet the current cash grant deadline obviously are not eligible for the cash grant. These projects at least have certainty that federal tax credits will be available to qualifying projects that are placed in service during the next few years. In addition to establishing the options for eligible generating facilities to take the investment tax credit or cash grant rather than production tax credits, the Stimulus Bill extended the deadline to qualify for the tax credits.

Under the relevant provisions of the Stimulus Bill, biomass projects must now be placed in service by the end of 2013 in order to qualify for production tax credits or the investment tax credit.[4] This is some comfort for developers of projects that can't meet the cash grant deadline. However, assuming (as is likely the case) that such developers cannot efficiently use tax credits themselves, they would have the risk that, when their project is ready, tax equity will not be available to them on reasonable terms and pricing. This is not a small risk.

In addition to concerns about the volume of available tax equity in general, most biomass projects seeking tax equity face the additional problem that tax equity financing (with its attendant transaction costs and potential complexity) typically makes more sense for larger utility-scale projects that are better able to bear such cost. Most biomass projects face a natural limit on size due to the prohibitive cost to source biomass fuel if it is transported from beyond a limited radius around the plant. In addition, since the cash grant is payable within 60 days of the later of the date the grant application is received or when the project is placed in service, and the investment tax credit is not realized until the project tax return is filed for the year the project was placed in service (which may be up to a year later for a project placed in service early in the year), the investment tax credit is likely worth slightly less than the cash grant due to the time value of money.

Developers that can't meet the current deadline still may be in luck. A bill is advancing in Congress that in lieu of the cash grant would give developers of otherwise qualifying renewable energy generation projects that commence construction in 2011 or 2012 a tax refund equivalent to the cash grant amount. However, it is not certain at the date of this writing if the cash grant program will be so replaced and extended (or even permitted to expire), or what the new rules are that would attach to this "refundable grant." Given this uncertainty and the other clear benefits of electing the cash grant over tax credits described above, biomass developers that have a realistic chance to meet the current cash grant deadline (and are otherwise eligible for the grant) should consider making an aggressive push to meet the safe harbor for commencing construction and to make the necessary filings for the grant as soon as possible.

BCAP

Another recent development that may provide a boost to biomass power project financing is the advancement of BCAP. Section 9001 of the Food, Conservation and Energy Act of 2008 (2008 Farm Bill) authorized BCAP. BCAP provides funding for two main activities. First, agricultural and forest land owners and operators can receive matching payments for eligible biomass material (this includes most non-food biomass) sold to qualified biomass conversion facilities. These facilities include not just power generating plants, but also any qualifying project that converts renewable biomass into heat, power, bio-based products, advanced biodiesel or certain advanced biofuels. This is known as the Matching Payment Program. Second, producers of eligible renewable biomass crops within specified project areas can receive funding of not more than 75 percent of the cost of establishing eligible woody and non-woody perennial crops and annual payments for up to 15 years for production of such crops. This is known as the Establishment and Annual Payment Program. All of the BCAP payments are intended to induce the establishment and production of certain eligible biomass crops and the collection, harvest, storage and transportation of such materials for use in qualified biomass conversion facilities.

As noted, BCAP was originally established by the 2008 Farm Bill, but it required further implementing rules. The Obama administration has aggressively accelerated this program.

In May 2009, a presidential directive was issued to lay the groundwork for investment in and production of biofuels and specifically targeted the expeditious

issuance of guidance on BCAP. Soon after the presidential directive was issued, funding and interim rules were established for the Matching Payment Program, but not the Establishment and Annual Payment Program, pursuant to a notice of funding availability (NOFA).

In early February 2010, another major step was taken as the Commodity Credit Corporation (CCC) issued a Proposed Rule to implement BCAP in its entirety. However, in connection with the issuance of the Proposed Rule, the USDA terminated funding for the Matching Payment Program under the NOFA and indicated that new applications will not be accepted until the final rule is issued. The Proposed Rule is subject to a 60-day period for public comments that ends in early April and to potential revision based on the comments. It is not yet clear based upon the Proposed Rule who the Matching Payment Program "winners" and "losers" will be under the final rule. The Proposed Rule seeks comment on three different options for payments under the Matching Payment Program, each of which creates different incentives for different types of biomass-based projects.

The first option is to provide matching payments as currently provided under the NOFA at the rate of $1 for each $1 per dry ton paid by a qualified Biomass Conversion Facility (BCF) to agricultural and forest land owners and operators for eligible material sold and delivered to such BCF. Such matching payments would be limited to a maximum of $45 per dry ton of eligible material delivered, and a time period of two (2) years from the date the first payment is made. The matching payments also would be subject to a further limit, in the case of a BCF that converts wood wastes or wood residues into heat or power for its own use. In this instance, matching payments would be payable only for such wood wastes or wood residues that are converted by the BCF to heat or power above a historical baseline of the amount of heat or power the BCF produces for self-use. This option generally treats different biomass uses the same, but with perhaps some incremental advantage to uses other than heat or power that are not subject to the self-use carveout.

The second option is a tiered approach providing that the maximum rate of $45 per ton is available only to agricultural and forest land owners and operators that deliver materials to BCFs that convert eligible material to advanced biofuels. In the case of BCFs that convert eligible material to renewable energy or biobased products rather than advanced biofuels, the biomass providers would remain eligible for the $1 for each $1 per dry ton paid by the BCF, but subject to proposed cap of $16 per dry ton. This option specifically encourages the use of biomass for advanced biofuels production over other uses.

The third approach is to vary matching payments to encourage additional biomass consumption above a historical baseline. The matching payment at the rate of $1 for each $1 per dry ton paid by the BCF would be reduced in the case of facilities that do not increase renewable biomass consumption over the historical baseline. It is not certain if this option favors one biomass usage over others, but compared to the first two options described above, it seems to favor new facilities (whether greenfield or conversion projects that change fossil fuel input to biomass feedstock) over existing biomass projects. In the case of many existing biomass facilities that had qualified for 2009 matching payments under the NOFA rules, under this last option the payments to suppliers to such facilities would likely be subject to reduction. Another important limitation in the Proposed Rule that was not in the 2008 Farm Bill is that vegetative waste materials like wood waste and wood residue are not eligible materials for matching payments to the extent they would be used as inputs for higher value-added products except for the matching payment. This change is to address complaints from certain wood product producers (such as fiberboard makers) that without this limit the payments would artificially divert waste wood to bioenergy projects and create a supply shortage for the wood product industry.

In the case of both the Matching Payment Program and the Establishment and Annual Payment Program, there are numerous additional eligibility and qualification requirements not addressed in detail here. For example, before any payment can be made, the project (or in the case of the Establishment and Annual Payment Program, a project area) must be qualified by the submission of detailed information to the local Farm Service Agency and both the project and the various biomass material producers and suppliers may need to enter into certain agreements with the CCC.

BCAP is anticipated to be most helpful to projects already in operation or that are already in development and economically viable before taking into account BCAP payments. In fact, the eligibility requirements for the Establishment and Annual Payment Program gives the CCC discretion to choose projects that can best demonstrate long-term economic viability and financing commitments without BCAP. BCAP may not make a non-economic project viable, but this program certainly has potential to create additional opportunities and options in terms of fuel-supply structuring, thus addressing a critical risk for biomass project developers trying to solidify financing arrangements. ◆

Endnotes

1 Rural Energy for America Program, formerly known as the "§9006" program, was enacted in the 2008 Farm Bill and administered by the US Department of Agriculture. For more information, visit: *http://www.rurdev.usda.gov/rbs/farmbill/*.

2 "Open-loop" biomass is defined in the Internal Revenue Code generally as organic agricultural or cellulosic waste material, but excluding "closed-loop biomass" (which is biomass planted exclusively for use at a qualified facility to produce electricity) and excluding biomass used in conjunction with fossil fuel (co-firing).

3 There is an exception for certain facilities that use "closed-loop" biomass to co-fire if the modification is approved under the Biomass Power for Rural Development Programs or as a pilot project of the Commodity Credit Corporation.

4 It is not likely that any "open-loop" biomass projects would elect the production tax credit as opposed to the investment tax credit. As mentioned above, open-loop biomass qualifies for only half of the value of the production tax credit for wind, but the Stimulus Bill made open-loop biomass eligible for the full investment tax credit and equivalent cash grant that is available to other technologies, equal to 30 percent of eligible project cost.

Nuclear Power Emerges as an Option in Asia

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Rising demands for power, depleting reserves of oil, gas and coal, international pressure for reduction of carbon emissions, advances in nuclear reactor technology, and more favorable cost projections are driving the increase in nuclear power in Asia. This article will focus especially on nuclear power development in India, China and Vietnam.

In relation to these three countries, we will briefly review the factors that propel decision-makers to select more nuclear power. We will also consider the legal frameworks regulating investment in nuclear power plants (NPPs), the opportunities for foreign investment, associated investment risks and the "who's who" among private investors in NPPs. For China, in particular, nuclear power has a long history and continues to serve as a viable option to polluting coal-fired power stations and the expensive option of gas-fired power.

Nuclear Power

Over the last few decades, there have been considerable advances in nuclear technology. NPPs have progressed in their stage of development, with Generation IV reactors being the most modern prototype reactors.[1]

Most early NPPs were either boiling water reactors or pressurized water reactors that use light or heavy water as both a neutron moderator (to slow fissionable neutrons so they are better able to react with the fuel) and as a cooling agent.[2] Most NPP fuel used in early and current reactors is uranium-235 (U-235). In a typical nuclear reaction, the U-235 absorbs an additional neutron to become U-236. It then splits into fast-moving lighter elements and neutrons, thereby releasing kinetic energy and gamma radiation. Currently, technological advances have changed with respect to:

- The types of moderators used (no longer just water, but other chemicals as well).
- The types of coolants employed (liquid metals and salts are now also used instead of water).
- The sources of fuel utilized (in addition to U-235, less-enriched uranium is also used, as are plutonium-239 [PL-239] and PL-241).

In some Generation IV reactors, known as fast-breeding reactors (FBRs), the by-products of Generation I and II reactors can be used as sources of fuel, creating a cycle of fuel reserves. FBRs use higher-speed neutrons to bond with elements like plutonium-238 to make PL-239. This process is especially important in a country such as India, which has a reasonable source of uranium, as well as one of the world's largest supplies of thorium. An FBR can transform thorium-232 into a

lower-grade U-233 for use in typical Generation I and II reactors. The newer reactors are better in terms of safety, efficiency and environment, but they are much more expensive to build.[4]

Why Nuclear? Why Now?

The general issues mentioned above apply equally to India, China and Vietnam. But each country has its own history and its own reasons to push forward with nuclear power.

In India, nuclear energy currently produces about 4.1 gigawatts (GWs) of energy, which accounts for only 3 percent of its entire energy portfolio of about 138 GW. Considering that demand for power in India is expected to reach 800 GW by 2032,[5] the government is under intense pressure to bring more power solutions online. As mentioned above, while India's uranium reserves are reasonable (estimated between 80,000 and 112,000 tons), its supply of thorium is extensive. Nonetheless, thorium-fueled FBRs are expensive to build. As such, the nation's NPP portfolio comprises a number of NPP variations, including many Generation II reactors, which are less costly to build.

Another driving force for increased nuclear power in India is a result of recent legal measures. India is not a party to the Nuclear Non-proliferation Treaty and had to apply for a waiver from the Nuclear Suppliers Group, which was granted on 6 September 2008, in order to commence trading activities involving NPPs with other countries. With this waiver, a safeguards agreement with the International Atomic Energy Agency (IAEA) completed on 2 February 2009 and a signed treaty with the United States for nuclear cooperation (10 October 2008), India was on its way to ensuring the long-term viability of its nuclear power program.

In both China and Vietnam, the driving forces for developing nuclear power programs are very similar to those in India. Both China and Vietnam will require substantial increases in power over the next few decades, and the fossil fuel reserves in both countries are similarly diminishing. While increasing attention is also being given to renewable sources of energy such as wind and hydroelectric, nuclear power will need to play an increasing role in each country's total power portfolio (TPP).

To meet its expected power demands, China needs to increase its nuclear power generation from 9 GW presently to 72 GW by 2020 (representing 5 percent of TPP), and to 250 GW by 2030 (16 percent of TPP). In order to do this, China will need to build 60 more NPPs in the next 11 years, in addition to the 20 NPPs currently under construction.[6]

In order for Vietnam to meet its expected power demand, nuclear power will need to comprise 4.4 percent of its TPP by 2025 and 20 percent of TPP by 2050. The Vietnamese government recently authorized the construction of Vietnam's first two commercial NPPs, which will begin in 2014, with commercial operation expected in 2020. The two NPPs (Ninh Thuan 1 & 2) will be of the Generation-III type pressurized water reactors and will be capable of producing 2,000 megawatts (MW) of energy each. Both NPPs will be fully owned by Electricity Vietnam, the state-owned power authority.[7]

Legal Framework for Investing in Nuclear Power

In India, the primary legislation regulating domestic nuclear power is the Atomic Energy Act of India 1962 (India's AEA). Under India's AEA, only state-owned bodies are permitted to own and operate NPPs in India. While this does allow some room for minority holdings by private investors, there has been an increasing push by both energy experts and private-sector power producers to permit increased private investment.[8] However, in order to foster additional private investment, India's AEA would need to be amended. Additional amendments to India's AEA, such as liability limitations, a streamlined regulatory process, tariff clarity, and a transparent process for NPP site allocation, would also need to be included in order to provide the necessary incentives for private investment.[9]

Other international agreements and treaties have also opened the door to India for commercial nuclear trade, allowing it to purchase fuel, equipment, reactors and spare parts on the world market. Recently, a Civil Nuclear Liability Bill (CNLB) has been proposed, but it is still the subject of much debate within the legislature. The CNLB would cap NPP operator liability at an amount equivalent to US$450 million in the event of an accident.[10]

There are two international conventions on the limitation of liability for nuclear damage. The Vienna Convention on Civil Liability for Nuclear Damage sets NPP operator liability at a maximum of EUR 700 million. The Paris Convention on Third Party Liability in the Field of Nuclear Energy sets the maximum operator liability at XDR 15 million, with contracting parties permitted to set lower amounts provided they are not less than XDR 5 million.[11] India, China and Vietnam are not signatories to either of these conventions.

Vietnam's recently issued legislation governing the nuclear energy sector, Vietnam's Law on Atomic Energy (Vietnam's AEL), took effect on 1 January 2009. Vietnam's AEL is fairly broad in its scope and covers all aspects of nuclear use, including mining of radioactive ore, export and import of radioactive materials and NPP operations. Vietnam's AEL applies to domestic and foreign organizations and to individuals having operations in the atomic energy field in Vietnam, thereby opening the door — at least on paper — for foreign investment in this sector.

Among the important investor-related provisions included in Vietnam's AEL are limitations on damage liability in the event of a nuclear accident involving an NPP (XDR 150 million) and on liability in relation to transport of radioactive materials (XDR 10 million). The statute of limitations is 10 years for environmental damage and 30 years for personal injury. Although Vietnam's AEL stipulates a mandatory insurance requirement, the requisite limits are not specified in this law.[12]

Unlike Vietnam, China appears to lack a comprehensive atomic energy law that includes liability provisions. Instead, China's nuclear policies and regulations regarding nuclear liability and damages appear to be set out in various legislative acts.[13]

Of these, the Reply (see footnote 13) specifies that liability of an operator of an NPP shall be limited to RMB 18 million (about US$2.2. million) in total per nuclear accident. If damages exceed that amount, the government is required to provide financial compensation up to RMB 300 million (about US$37.5 million).

The statute of limitations is three years from the date the claimant "should have known" about the damage, death or injury, or 10 years from the occurrence of the nuclear accident. In addition, no insurance or financial security is expressly required of the NPP operator, but the government does provide limited financial compensation as mentioned above.

In terms of foreign investment participation, China's government announced that three state-owned corporations were approved to own and operate nuclear power plants. Public or private investors are only permitted to have minority shares in new projects.[14]

Opportunities for Foreign Investment

It has been reported that construction accounts for 75 percent of the profits from nuclear generation.[15] The high costs of nuclear power do not make it an attractive investment opportunity for most investors unless there are substantial government incentives and guarantees, such as a long-term power purchase agreement (PPA) with guaranteed fixed returns.[16] Although restricted either by law or by practice from investing fully — or even from taking a majority share in the development of NPPs in India, China and Vietnam — opportunities for minority shareholdings are still open to private investors.

With each NPP costing several billions of US dollars, markets like India are valued at between US$100 billion and US$150 billion for NPP construction and supply of equipment and spare parts.[17] Opportunities for investors may also be found in mining operations and trading in nuclear fuel.

Additionally, a number of ancillary services support the nuclear power industry. Commercial banking institutions play a major part in the financing of new NPPs. In addition to loans and state funding, governments have increasingly been turning to bond issuances to support NPP development. For example, China Guangdong Nuclear Power Corporation (CGNPC) last year issued five-year bonds worth US$293 million on the interbank market, with proceeds to fund the construction of its six-reactor NPP facility in Guangdong Province (total construction costs estimated at US$10.3 billion). Bank of China and China Development Bank underwrote the bond issuance.[18]

Associated Risks

Investment in NPPs brings with it certain associated risks and costs. Examples of these include construction delays, land compensation issues, nuclear waste disposal, operational safety concerns, decommissioning costs and insurance.

Advances in technology, like the FBR, which utilizes spent fuel rods from earlier-generation NPPs, and alternative coolants such as gas and liquid lead, help to improve safety and nuclear waste conditions. However, most NPPs will still present these issues and concerns for some years to come. Investors, therefore, need to account for and mitigate such risks to the extent possible.

Who is Investing? And Where?

Major players in the construction of NPPs in India, China and Vietnam comprise a relatively small group. India's principal NPP contractors are GE Hitachi, Areva, Atomstroyexport, Rosatom, Korea Electric Power Corporation and Westinghouse, a subsidiary of Toshiba. In China, most contracting is limited to Areva and Westinghouse, as domestic Chinese companies have already refined the Areva reactor technology and have started mass-producing similar-type reactors.[19] Vietnam has just recently selected Russian NPP builder Rosatom over a competing bid by a consortium consisting of Toshiba Corporation, Mitsubishi Heavy Industries and GE Hitachi to build its first two pressurized water reactors.[20]

In terms of investing in the development and operation of NPPs in India, state-owned giants like National Thermal Power Corporation, National Aluminum Company and Bharat Heavy Electricals Limited continue to dominate among the state investors, while private investment awaits amendment of India's AEA. Companies like Reliance Power, Tata Power, JSW Energy, Jindal Power, and GMR Energy are anxious to enter India's NPP market, as they currently have other investments in-country.[21] In China, current minority stakeholders in NPPs include China Light & Power, Daya Bay and Electricité de France, with a 30 percent interest in a joint venture with CGNPC to develop the Taishan NPP in Guangdong Province.[22] ◆

Endnotes

1 *Generation IV Nuclear Reactors,* World Nuclear Association (retrieved 29 Jan 2010) *http://www.world-nuclear.org/info/inf77.html.*

2 *Fast Neutron Reactors,* World Nuclear Association (retrieved 11 Feb 2010) *http://www.world-nuclear.org/info/inf98.html.*

3 *India Energy Inc.—Energy Outlook,* Report of KPMG at *India Energy Conclave 2008* (26 Nov 2008, Mumbai) at 31.

4 *Fast Neutron Reactors;* Costs for FBRs range from 2 to 4 times higher than costs for thermal Generation II-type reactors. *See* Victor Orlov, *Nuclear Power of Fast Reactors: A New Start*, at 125, available online (last visited 10 Feb 2010) *http://www.nap.edu/openbook.php?record_id=12590&page=125.*

5 See *India Energy Inc.—Energy Outlook, supra* note 3.

6 *Nuclear Power in China* (updated on 30 Jan 2010) *http://www.world-nuclear.org/info/inf63.html.*

7 *Vietnam passes law on nuclear energy* (4 Jun 2008) *http://www.world-nuclear-news.org/IT-Vietnam_passes_law_on_nuclear_energy-040....*

8 *India's private sector power push* (6 Oct 2009) Asia Elec *available in* Asia Elec, Asia Power Monitor, v.27.

9 See *India Energy Inc.—Energy Outlook, supra* note 3, at 32.

10 Sheila Bhatt, *Cabinet approves Civil Nuclear Liability Bill* (last modified 20 Nov. 2009) *http://news.rediff.com/report/2009/nov/20/cabinet-approves-civil-nuclear-liability-bill.*

11 XDR means Special Drawing Rights, the IMF currency, based on a basket of 4 currencies: USD, EUR, JPY and GBP.

12 Vietnam's Law on Atomic Energy No. 18/2008/QH12, effective 1 January 2009.

13 (i) Reply in Respect of Handling Nuclear Third Party Liability to the Ministry of Nuclear Industry, the State Nuclear Safety Bureau and the State Council's Nuclear Power Leading Group, issued by the State Council 29 March 1986 (the *Reply*); (ii) PRC Regulation on the Supervision and Management of Safety for Civil Nuclear Operations, issued by the State Council, 29 October 1986; (iii) Provisional Measures on Administration of Road Transportation of Spent Nuclear Fuel for Nuclear Reactors, issued by PRC National Defense Science and Technology Industry Commission, Ministry of Public Security , Ministry of Communications, and Ministry of Health, 18 June 2003; and (iv) PRC Prevention and Treatment of Radioactive Pollution Law, effective 1 January 2003.

14 China National Nuclear Corporation, China Guangdong Nuclear Power Corporation, and China Power Investment Corporation.

15 Chris Sholto Heaton, *How to Generate Profits from Nuclear Power,* Moneyweek, 30 Nov 2007.

16 Fabien Roques, William Nutall and David Newbery, *Using Probabilistic Analysis to Value Power Generation Investments under Uncertainty* (Jul 2006), Univ. of Cambridge, *http://www.electricpolicy.org.uk/documents/upload/poste13.pdf#page=31.*

17 *BHEL, NTPC look at nuclear option* (19 May 2009), *available in* Asia Elec, Asia Power Monitor, v.7.

18 *China Guangdong Nuclear Plans bond issue to fund Yangjiang* (9 Jun 2009) *available in* Asia Elec, Asia Power Monitor, v.10.

19 *Nuclear Power in China* (updated 9 Feb 2010) at 2-3, *http://www.world-nuclear.org/info/inf63.html*; *see also, China to set even higher nuclear targets* (4 June 2009) *http://www.vaec.gov.vn/news/print_baiviet.php?EV=0&idbv=2195&iddomain=18*.

20 *Japan Loses Vietnamese nuclear project to Russia, Nikkei Says,* (10 Feb 2010) Intellasia/Bloomberg *http://www.bloomberg.com/apps/news?pid=20601072&sid=aiNkaChoLAPQ*.

21 *BHEL, NALCO expand nuclear horizons* (29 Sep 2009) *available in* Asia Elec, Asia Power Monitor, v.26.

22 *Nuclear Power in China, supra* note 19 at 8.

Middle East Energy Projects: Just How Important is International Arbitration?

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International contractors and engineering companies bidding for large and complex energy projects in the Middle East generally insist on international arbitration clauses that provide for arbitration in London or Paris. Banks involved in funding such projects also require such clauses.

The current global credit crunch, however, has had a major impact on the Middle Eastern procurement market. Project finance is much more difficult to obtain, and employers are often funding projects themselves without external funding. Two to three years ago, contractors were able to pick and choose projects on which to bid. But now, with many projects being cancelled or scaled down, the pendulum has firmly swung the other way.

The balance of power has shifted in favour of the employer, and contractors are in a weaker position to insist on the usual caps and limitations of liability. Employers may want to subject contracts to the jurisdiction of their local courts or to domestic arbitration, instead of, perhaps, to an ICC or LCIA arbitration in London or Paris.

What should contractors do about this? Should they dig in their heels and insist on the usual international arbitration clause? What about local arbitration centres in the Middle East? Are these a viable alternative? And do bilateral investment treaties and ICSID arbitrations offer protection for contractors operating in the region? What are the current trends?

Are Local Courts an Option?

On the whole, the region's courts tend to be slow. In many instances, too, they lack the relevant expertise to deal with the sort of complex project dispute that may arise on a substantial energy project in the region.

It is often claimed that courts in the region favour the local party, but there is no evidence of this. Local courts regularly deliver judgements in favour of foreign parties. The main difficulties are lack of expertise and delays because the court system is overburdened. Accordingly, in the event of a dispute that has to be dealt with in the courts, contractors might have to wait a long time before being able to enforce their rights. Since employers will know this, commencement (real or threatened) of proceedings may not be much of a deterrent. The answer for contractors is to insist on arbitration because, by virtue of the New York Convention, arbitration awards can be enforced almost everywhere.

There may be a middle way, however. In return for rejecting the jurisdiction of local courts and insisting on arbitration, an attractive option for contractors is to accept the applicability of local laws in the Middle East. The

local laws are, on the whole, more favourable to contractors because they seek to balance contractual rights with principles of fairness. This provides an opportunity for contractors to claim their entitlements in circumstances that may not be available to them under English law.

Is Arbitration Accepted in the Region?

It is sometimes suggested that arbitration is not accepted in the Middle East. Not so. Arbitration, or *Tahkim*, is reported to have been used by the Arabs as early as the seventh century. In many countries, arbitration is therefore part of local custom. Historically, however, there was difficulty with international arbitration because of several arbitration awards in the 1950s and early 1960s that were unfavourable to state governments.

In one of these arbitrations, between *Sheikh of Abu Dhabi and the Petroleum Development Company* (1951), Lord Asquith said:

If there exists a national law to be applied, it is that of Abu Dhabi. But no such law can reasonably be said to exist. The Sheikh administers a purely discretionary justice with the assistance of the *Koran*, and it would be fanciful to suggest that in this very primitive region there is any settled body of legal principles applicable to the construction of modern commercial instruments.

Not surprisingly, Arab countries became suspicious that international arbitration would not provide them with a fair means of resolving their disputes and, even today in Saudi Arabia, state entities are forbidden by law from agreeing to arbitration clauses without obtaining government consent. The global trend toward international arbitration and various conventions in favour of international arbitration have, however, substantially eroded hostility to international arbitration and increased its acceptance, as evidenced by the increasing number of local arbitration centres and the growing number of arbitrations in the region, particularly in Dubai.

Local Arbitration Centres: Good Compromise?

Traditionally, arbitration centres across the Middle East have been part of the local chamber of commerce. Their expertise varies considerably and, on the whole, they have not yet built a track record for dealing with the large and complex disputes likely to arise on energy projects where hundreds of millions of dollars may be at stake

While there is movement across the Middle East to reform arbitration laws and to adopt laws based on the United Nations Commission on International Trade Law (UNCITRAL) model, there is still another hurdle to overcome. If arbitration requires assistance from the local courts — for example, where the court's enforcement powers are required in respect to interim measures — then progress, as we have seen, is likely to be slow, affecting the conduct of the arbitration. Despite this, substantial advances have been achieved in international arbitration across the Middle East. The following centres are especially noteworthy:

- **The Cairo Regional Centre for International Commercial Arbitration**
  This is perhaps the most established arbitration centre in the Middle East, with over 30 years' experience. It attracts many arbitration cases, mainly those connected with Egypt and North Africa.
- **DIAC**
  None of the centres in the Gulf has attracted more cases than the Dubai International Arbitration Centre (DIAC), which has clearly established itself as a leading centre. Approximately 180 new cases were reported to have been registered in the DIAC by August of last year, mainly as a result of the collapse of the real estate market. The DIAC has the advantage of new rules that were published in May 2007 and that are in line with other major arbitration centres around the globe.
- **DIFC – LCIA**
  Dubai's reputation as a regional arbitration centre was further bolstered in February 2008, with the opening of a joint venture between the Dubai International Financial Centre (DIFC) and the London Court of International Arbitration (LCIA). The alliance added LCIA's expertise in administering arbitrations. Yet another boost to the centre's reputation came with the enactment in October 2008 of the new DIFC Arbitration Law 2008, which enables parties anywhere in the United Arab Emirates and beyond to choose the DIFC as the seat of their arbitration. Thanks to the new law, a DIFC award, once ratified by the DIFC Court, is theoretically enforceable without any

opportunity for challenge in the Dubai courts, unlike an arbitral award obtained outside the DIFC. The advantage of a DIFC award is clearly potentially significant.

Despite Dubai's growing reputation as an arbitration centre, it is generally acknowledged that the UAE needs to enact a satisfactory federal arbitration law as soon as possible. A draft law based on the widely accepted UNCITRAL Model Law was circulated for consultation last year, but so far it remains unclear whether the draft will become law. Until the new law is enacted, choosing the DIFC as the seat of arbitration remains the better bet which of course can be combined with, for example, choosing the DIAC to administer the arbitration.

- **Other Centres in the Gulf**
  Arbitration centres are situated throughout the Gulf states. Doha, the capital of Qatar, is home to the Qatar International Conciliation Arbitration Centre. In Bahrain, the newly established Bahrain Chamber for Dispute Resolution has teamed with the American Arbitration Association. And in Abu Dhabi, the Abu Dhabi Commercial Conciliation and Arbitration Centre has been in operation for many years. However, none of these centres in the gulf have as yet the credentials of the LCIA-DIFC or the DIAC centres.

Enforcement of Arbitral Awards

Enforcing arbitration awards in the Middle East may be problematic, particularly in Libya and Yemen, which have not yet acceded to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards. Even where the New York Convention is in place, most Arab countries will decline enforcement on the basis of its public policy exemption (Article V.2b) if the award contravenes domestic public policy instead of international public policy (Lebanon, Algeria and Tunisia excepted). Enforcement is particularly difficult in Saudi Arabia, where the enforcement of foreign awards will be declined if it is inconsistent with Sharia' law. Very few awards have actually been enforced in Saudi Arabia on the basis of the New York Convention.

If, therefore, there are assets outside the Middle East, the best course is to start enforcement there. If enforcement is to take place in the Middle East, however, in order to increase the chances of successfully enforcing an award, conducting the arbitration and the pleading of claims should be done in a way that, as far as possible, is careful to avoid falling afoul of procedural and substantive local law.

ICSID/BIT arbitrations

The use of International Centre for Settlement of Investment Disputes (ICSID) standards has expanded rapidly across the region as the number of bilateral investment treaties has increased. Contractors now regularly consider whether they have rights under "bilateral investment treaties" (BITs) before entering into major energy projects in the region. The cases registered at ICSID are indicative of the increasing number of state disputes that have arisen in the Middle East. Egypt, to date, has more cases than any other Arab country.

In assessing possible routes for recovery of entitlements, any existing BITs should be reviewed to see if they might help. The threat of BIT proceedings can often unlock disputes. Not to be forgotten, however, is the fact that a number of countries such as Qatar, where substantial energy projects are being undertaken, have yet to accede to the ICSID Convention.

Conclusion

Contractors will know from experience that, in complex energy projects, the process of enforcing entitlements should not start with the commencement of proceedings. They should begin considerably earlier, when issues arise during the course of the project. The key in many respects is careful and prudent project management.

Absent an effective deterrent to disputes in the form of proper dispute-resolution machinery, more disputes may arise and resolution may be prolonged. Arbitration is a key means of avoiding disputes and, if amicable resolution cannot be achieved, of achieving an appropriate resolution of a dispute. For arbitration on large energy projects, it is preferable to chose a seat outside the Middle East with a well-established arbitration centre such as the ICC or the LCIA. Choosing a local arbitration centre in the Middle East could be a good compromise, but careful consideration needs to be given to all project circumstances before signing a contract that provides for this. ◆

Recent Staff Interpretations of the SEC's New Oil and Gas Disclosure Rules Leave Many Questions

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In December 2008, the US Securities and Exchange Commission (SEC) adopted new oil and gas disclosure rules, which are now in force. The new rules apply to public companies with calendar fiscal-year ends and to registration statements filed after January 1, 2010.[1] For details of those rules please reference the Mayer Brown article from March 2, 2009.

Shortly after the SEC's adopting release was issued, questions began to arise about certain of the new rules' applications in practice. The Commission sought to address these questions on October 26, 2009, when its Division of Corporation Finance issued Compliance & Disclosure Interpretations (CDIs) to clarify interpretive issues under the new rules.[2] The CDIs provide helpful guidance in a number of areas. As is so often the case with major overhauls of federal regulatory schemes, however, they also raise new uncertainties for practitioners.

The New Rules

The new rules modernize SEC oil and gas disclosure standards to better coincide with current industry practices and to provide greater transparency and clarity for investors. The most significant rule changes include:

- The economic producibility of reserves will now be calculated using a 12-month average price, instead of a year-end spot price.
- The definition of "oil and gas producing activities" will now include non-traditional and unconventional sources, such as bitumen extracted from oil sands and oil and gas extracted from coal and shale.
- The previously undefined term "reasonable certainty" is now defined to mean "high degree of confidence" to better align SEC rules with the definitions of the Petroleum Resources Management System.[3]
- The definition of "reliable technology" broadens the categories of technologies that a company may use to establish its reserves estimates and categories.
- Optional disclosure of "probable" and "possible" reserves is now permitted.
- Disclosures must be provided about the company's chief technical person overseeing the company's overall reserves estimation process.
- Third-party reports (i.e., independent petroleum engineers' reports), where a third party has estimated or audited the company's reserves, must be filed as exhibits.

Similar to a number of SEC rule regimes adopted in recent years, the new rules are principles-based, leaving many areas open to broad interpretation. This has led, in turn, to numerous requests for interpretation from practitioners during 2009.

Remaining Interpretive Issues and Observations

1. *PUDs and the Five-Year Rule.* One of the biggest areas of uncertainty that remains under the new rules deals with reserves classified as "proved undeveloped reserves" (PUDs). The new rules state that undrilled locations can be classified as having PUDs only if a development plan has been adopted. The plan must indicate that those locations are scheduled to be drilled within five years, unless "specific circumstances" justify a longer interval before development will be initiated. Examples of relevant "specific circumstances" might include projects in which offshore platforms are to be constructed or environmentally sensitive areas are to be developed. The CDIs state that classifying a location as having PUDs in instances where the location's development is scheduled to extend more than five years in the future should be the exception, rather than the rule.

   Today, many choice drilling prospects are located in difficult-to-access environments, such as deep offshore properties or uninhabited jungle locations. Thus, new productive fields can often take years to bring online. In order to classify locations as having PUD reserves whose development within five years is not probable, the CDIs indicate that a re gistrant should consider a list of factors — including past history of completing development of comparable long-term projects — before it may establish that an exception to the five-year rule is warranted. Neither the rules nor the CDIs provide any examples or checklists of what should be required. Consequently, the registrant should take care to document its consideration of these factors and its resulting determinations.

2. *What is "reliable technology"?* The new rules no longer confine companies to actual production or flow tests to establish the proven status of their reserves. Instead, one or more alternative technologies, including computational methods, may be employed as confirmation. To be considered "reliable," the technology or technologies must have been field tested and demonstrated to provide "reasonably certain" results with consistency and repeatability in the formation being evaluated (or in an analogous formation). Companies are grappling with technologies that will satisfy this definition so that they can justify certain reserve determinations.

   The new rules and CDIs do not contain specific definitions of "consistency and repeatability," nor do they provide examples of what reliable technologies the staff will accept. The registrant will also be required to disclose the technology or technologies used to create reserve estimates and categorizations. As part of its review and comment process, the SEC's staff may request companies to provide supplemental data regarding their reserve estimates, including information sufficient to support the conclusion that the technology used constitutes reliable technology.

3. *Internal Controls and Technical Person's Qualifications.* The new oil and gas disclosure rules require a company to provide a general discussion of the internal controls that it uses to assure objectivity in its reserves estimation process. They also require disclosure of the qualifications of the technical person primarily responsible for overseeing the preparation of the company's reserves estimates. If the company's reserves are audited by a third party, the technical qualifications of the audit's overseer must be described. This has led some to question whether the actual identity of the third-party technical person responsible for managing the reserves audit would be the outside engineering firm or the individual at that firm who is responsible for the technical aspects of the audit.

4. *The New MD&A Requirements.* Instead of rules, the SEC chose to provide guidance relative to the topics that an exploration and production company should consider in its Management's Discussion & Analysis disclosures. These topics include: (i) changes in proven reserves; (ii) the sources to which those changes are attributable; and (iii) the technologies used by the company to establish the appropriate level of certainty for additions to, or increases in, its reserves estimates. Other topics include trends in prices and costs (and their impact on depreciation, depletion, and amortization and the full cost-ceiling test); geopolitical risks where material concentrations of reserves are located; and the need to use enhanced

recovery techniques to maintain production. The fact that this guidance is contained in the SEC's adopting release and not in its final rules may result in the inadvertent omission of important disclosures of these topics in 2010. ◆

Endnotes

1 SEC Release No. 33-8995 (December 31, 2008). These final rules and interpretations represent the first significant revisions in 30 years to Rule 4-10 of Regulation S-X and Item 102 of Regulation S-K (and the related Industry Guides) under the Securities Act of 1933 and the Securities Exchange Act of 1934.

2 The CDIs can be found at the SEC's website at *http://www.sec.gov/divisions/corpfin/guidance/oilandgas-interp.htm*.

3 The Petroleum Resources Management System (PRMS) is a widely accepted standard for the management of petroleum resources developed by several industry organizations, including the Society of Petroleum Engineers, the World Petroleum Council and the American Association of Petroleum Geologists.

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