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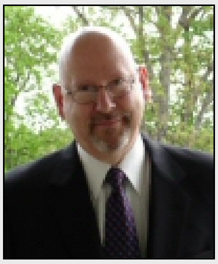

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Oil, Gas & Energy Law Intelligence

Production Sharing Contracts and CDM Projects
by L. Bossley

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Production Sharing Contracts and CDM Projects

The Kyoto Protocol Clean Development Mechanism ('CDM') concept is a project funding mechanism that requires integration into the oil and gas legislation in those hydrocarbon producing countries who are signatories of the UN Framework Convention on Climate Change and who have already ratified the Kyoto Protocol, or who may do so in the future. The issue that has to be addressed is how Certified Emissions Reductions ('CERs') arising from Kyoto CDM projects should be handled under pre-existing PSC arrangements.

CERS are tradable emissions allowances that are awarded by the UN CDM Executive Board to projects that reduce greenhouse gas ('GHG') emissions. These CERs can be sold in the market for cash or used by Kyoto countries or European installations to meet GHG reduction targets.

This issue will increase in importance when carbon capture and storage ('CCS') projects are allowed to qualify under Kyoto CDM flexibility mechanism. At the moment CCS projects do not qualify for CDM 'funding', but are very likely to do so in future. In the meantime the economics of oil and gas projects that reduce

GHG emissions in some other way, for example, by installing more energy efficient compressors, are potentially at risk if they take place under the CDM banner.

The Kyoto Protocol contains legally binding targets for developed, Annex B, countries to reduce their emissions of GHGs by 5.2%, compared with 1990 levels, during the 2008-2012 period.

The Kyoto Clean Development Mechanism ('CDM') is one of the three key planks of the Kyoto Protocol designed to promote sustainable development, reduce GHG emissions and to help developed countries meet their Kyoto commitments to reduce GHG emissions cost-effectively.

CDMs are project-based schemes, allowing carbon credits to be claimed by developed countries for emissions reductions achieved through investment in developing countries. This aims to promote sustainable economic growth and has a collateral benefit of clean technology transfer.

The CDM is a comparatively new idea that is spreading rapidly throughout the developing world as the Kyoto Protocol gains ground. But the rules for CDM projects are emerging in isolation from existing legislation governing the development of hydrocarbons in many developing countries. Unless the potential conflicts in ideologies are addressed early, disputes between joint venture partners in oil and gas projects and the ministries of hydrocarbons and the environment in Kyoto signatory countries will inevitably emerge over time.

PSC Principles

The oil and gas sector worldwide is familiar with the concept of production sharing contracts ('PSC') with host governments. The PSC is a common tool of hydrocarbon producing countries to gain overseas investment in the oil and gas sector.

Typically overseas investors provide the cash to explore and develop licensed areas and, once projects are onstream, the host government takes a share of the proceeds either in cash or in kind; usually some combination of both. The host government's interests are usually represented by a national oil company ('NOC'), who, in some cases, have an equity interest in licensed acreage. Companies operating under PSC terms are required to account to the host government in detail for costs incurred and for revenues received from sales connected to each licence and each project.

When countries open their doors to foreign investment in the hydrocarbon sector, exploration, development and production costs incurred by companies under PSCs are usually recoverable from the production arising from successful exploration when it comes onstream.

PSCs may refer to more than one licence in the country in question and each licence may involve one or more block, depending on how the host government chooses to manage its affairs. A system of ring fencing of costs and revenues ensures that the project recovers only the costs associated with that project. Also payback, which would trigger the host government's profit share, is not delayed indefinitely by the allocation of exploration costs for a different block or licence to a project in production. What qualifies as a legitimate recoverable cost is usually spelt out in considerable detail in the PSC and companies are put to proof of expenditure

Once costs are recovered, profits from the project are split between the contractor and the host government in accordance with percentages contained in the PSC. Usually each party has the right to take and separately dispose of its profit oil share. Usually the PSC will contain an agreement to agree a lifting procedure that allocates cargoes of oil to the contractor and the state oil company.

Royalty is effectively a tax on production which can be taken in cash or in kind, before or after cost recovery. Additionally some form of petroleum revenue tax can be levied either on profits or on sales revenue. This is, in most cases, taken in cash, not in kind.

Typically a principle spelt out and defended under the PSC is that contractors have the right to 'take and separately dispose' in the export market of oil and gas arising from its cost recovery and profit oil share of production. The right of joint venture partners to sell their own oil and gas is usually linked to an obligation to sell at 'market' prices. The cost recovery/ profit split and the amount of royalty and petroleum tax levied is a function of the market price achieved in the sale of hydrocarbons.

Most PSCs contain a clause that describes what is meant by 'Market Price', the price which physical oil ought to achieve in the market, in the regime in question. This market price definition may be different from the price which producers actually achieve in the market when they sell the oil. As the PSC may have been signed many years before production commences, it can be very specific about how market price is to be measured when production is onstream.

Most modern PSCs have a reference to an oil or gas price that is related to prices obtained in the international market at arm's length between a willing buyer and seller. That market price may be a:

- Government Sales Price;
- Published marker price, adjusted for the specifics of each project; or,
- Generic ‘fair price’ at arm’s length in international trade to be agreed at the time and place of delivery.

Dispute resolution concerning this price tends to involve an independent expert determination. Usually ‘at arm’s length’ means trade between companies that are not affiliated in any way and does not involve barter or swap arrangements.

This PSC-defined market price has a pivotal role to play in calculating:

- Cost Recovery;
- Profit Share;
- Royalty in Cash or in Kind; and,
- Tax.

Contractors usually have an incentive to try and convince the host government that the market price of oil and gas is low, as this will boost the number of barrels that the contractor will be allowed to lift to recover its costs, lower the number of barrels to which the state oil company is entitled as profit share and will depress the taxation/royalty bill.

In some regimes the market price to apply for PSC purposes is the subject of a difficult regular negotiation between the host government or NOC and the contractor. In other regimes the market price is determined by the host government. Any shortfall between the market price, as defined by the NOC, and the actual sales price achieved by the contractor in selling its oil are, arguably, a hidden project cost.

It is interesting to consider this PSC ideology in the light of hydrocarbon projects that aim to reduce GHG emissions though the Kyoto CDM mechanism.

CDM Principles

To the best of our knowledge the integration of PSC terms with the CDM project mechanism has not yet been tested in law, but it is a factor that should be taken into account early in a CDM project life cycle to avoid disputes later when CERs are issued to a project.

As discussed above carbon capture and storage projects do not yet qualify as CDM projects but it is only a matter of time before they do. In the meantime oil and gas projects fit within the CDM framework because the sector is a power user. The development plan for the field may have alternative designs some of which are less carbon intensive than others. Also gas in particular is a cleaner fuel for power generation than the alternatives of coal and oil, so the decision to develop marginal gas fields, and to build the infrastructure to handle it, may rely on the additional funding provided by CDM CERs.

When a CDM project is considered a Designated National Authority, or DNA, in the host country is involved at an early stage in the approval process. The DNA will in all likelihood be a separate entity from the Ministry responsible for oil and gas developments and/ or the national oil company. The CDM project contracts will cover how the CERs are allocated amongst the project participants. What may not be covered is how the additional costs involved in the projects – to qualify as a CDM project additionality has to be proved- and revenue arising from the sale of CERs will be treated under the PSC.

For participants considering project economics it would be prudent to establish whether or not the CDM project costs will be recoverable under the PSC: the oil and gas ministry may query why project costs were not minimised and that a more expensive alternative low carbon development design was chosen.

Similarly it is also important to establish how the revenue from the sale of CERs will be treated in the cost recovery, profit share and taxation calculations. If CER revenue is taken into account by the oil and gas Ministry in calculating these PSC items, at what price will the sale of CERs be assessed? Logically one might expect that the actual sales price achieved for the sale of CERs would be accepted. But this is not necessarily the case.

For example, the oil and gas Ministry will rarely accept the petroleum sales price achieved by the project participants when the hydrocarbons are sold. They will instead try to establish what a fair objective price should be. In the case of CER sales many CDM project participants sell expected CERs forward under Emissions Reduction Purchase Agreements, or ERPAs. The price under an ERPA is typically a fixed price expressed in €/tonne. This price may be low because the CERs have not yet been issued and the buyer will build project and approval risk into the price it is willing to pay.

Several years down the line when the project is onstream and the CERs are issued, the price for issued CERs in the market may be vastly different from the price of unissued CERs today. By then there may be a transparent CER market with established indices that can be used by the oil and gas Ministry to establish what the CER sales revenue ought to have been, in their view, at arm's length in international trade.

A petroleum project participant under PSC terms would never sell forward the revenue stream from expected future oil and gas without taking the impact on cost recovery, profit share and tax into account. But that is precisely what is happening with the CER revenue stream.

If this issue is addressed when the CDM contractual arrangements are negotiated then there will be no problem once the project is onstream. Otherwise the CER price may turn out to be a serious bone of contention and a hidden project cost further down the road.