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Energy Newsletter

January 2015

TRANSACTIONAL

Transactions/Mexico

Mexico: E&P Regulator Issues First Call for Bids under Round One

Adrian L. Talamantes, Ken Culotta, Vera de Brito de Gyarfas

The Comisión Nacional de Hidrocarburos has issued the first call for bids under Round One and the terms and conditions governing the tender. CNH seeks to award 14 production-sharing contracts for the exploration and production of hydrocarbons in 14 areas located in shallow waters offshore the States of Veracruz, Tabasco and Campeche in the Gulf of Mexico. **More »**

Transactions/France

Have the Challenges of the Energy Transition been Overcome?

Mehdi Haroun, Ruxandra Lazar

The ongoing debate over environmental issues and their impact on the French energy model raises many issues. Successive governments have taken different approaches to the problem and energy transition has been presented as a key initiative of President Hollande's five-year mandate. **More »**

Corporate/EU

Challenges for energy security in Europe: Do European shale gas or US LNG offer a solution?

Nina Howell

The prosperity and economic stability of the European Union, and wider Europe, is dependent on a stable, abundant, diverse and competitively priced supply of energy. In light of recent geopolitical events, we consider the roles that European shale gas, or US LNG exports could play in supplying Europe's energy markets. **More »**

Transactions/France

France: Hard Times for Electricity-Intensive Consumers

Mehdi Haroun, Ruxandra Lazar

Following the liberalisation of energy markets in the 2000s, electricity-intensive consumers in Europe have faced high and unpredictable prices. **More »**

Construction

Transactional Construction Law: Focus on Energy Projects

Scott A. Greer

Scott A. Greer, a partner in King & Spalding's Global Transactions Practice Group, describes the firm's construction practice. **More »**

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In The News

Friends and Family: Keeping Loved Ones Safe from Insider Trading Temptations **More »**

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King & Spalding Recruits Circular Energy President Brad Thompson **More »**

Environmental MVP: King & Spalding's Robert Meadows [PDF **More »**

Alex Blomfeld Is Contributing Writer of New Book on International Construction Contract Law **More »**

REGULATORY

FERC

Commentors Disagree on FERC's Proposal to Change the Gas Day Start Time

James F. Bowe, William E. Rice

Comments recently filed with the Federal Energy Regulatory Commission show that the natural gas and electric power industries continue to disagree fundamentally on government efforts to redefine the "Gas Day," a 24-hour period during which shippers nominate and schedule natural gas transportation services furnished by natural gas pipelines. **More »**

Intellectual Property

Patent Office Statistics Indicate Growth In Oil & Gas Patents

Russell E. Blythe

An analysis of data recently provided by the United States Patent and Trademark Office shows that the number of patents granted in the oil and gas sector has grown at a double-digit rate in the six years since the 2008 recession, including a 47% increase in granted patents related to wells and a 62% increase in granted patents related to earth boring, well treating, and oil field chemistry. **More »**

DISPUTE RESOLUTION

International Arbitration

ExxonMobil Decision by ICSID: A win for ExxonMobil or Venezuela?

Nina Howell, Sarah Vasani, Greg Lazarev

An ICSID tribunal has ruled on the compensation payable by Venezuela to ExxonMobil for the nationalization of ExxonMobil's Cerro Negro and La Ceiba projects. ExxonMobil had claimed US$14.5 billion and Venezuela had offered US$353 million. The ruling that Venezuela pay ExxonMobil US$1.6 billion has been declared a victory by both sides. **More »**

Oil & Gas Litigation

Media Reports on 2014 "Fracking" Verdicts Miss the Real Story: Scientific Study Continues to Demonstrate the Safety of Professional Hydraulic Fracturing

Craig Warner

Even as headlines in 2014 misleadingly suggested that lawsuits against hydraulic fracturing operations were gaining steam, continued scientific study provided new legal ammunition for energy companies defending state-of-the-art energy exploration. **More »**

Nuclear Litigation

Federal District Court Ruling in Fukushima Daiichi Case Has Implications for Global Nuclear Liability Management

Lynn Kerr McKay, Scott A. Greer

A recent ruling in Cooper v. Tokyo Electric Power Company, one of three lawsuits filed in the United States related to the 2011 incident at the Fukushima-Daiichi nuclear power plant, highlights gaps in the application of methods for managing nuclear liability and the need for global expansion and strengthening of those methods. **More »**

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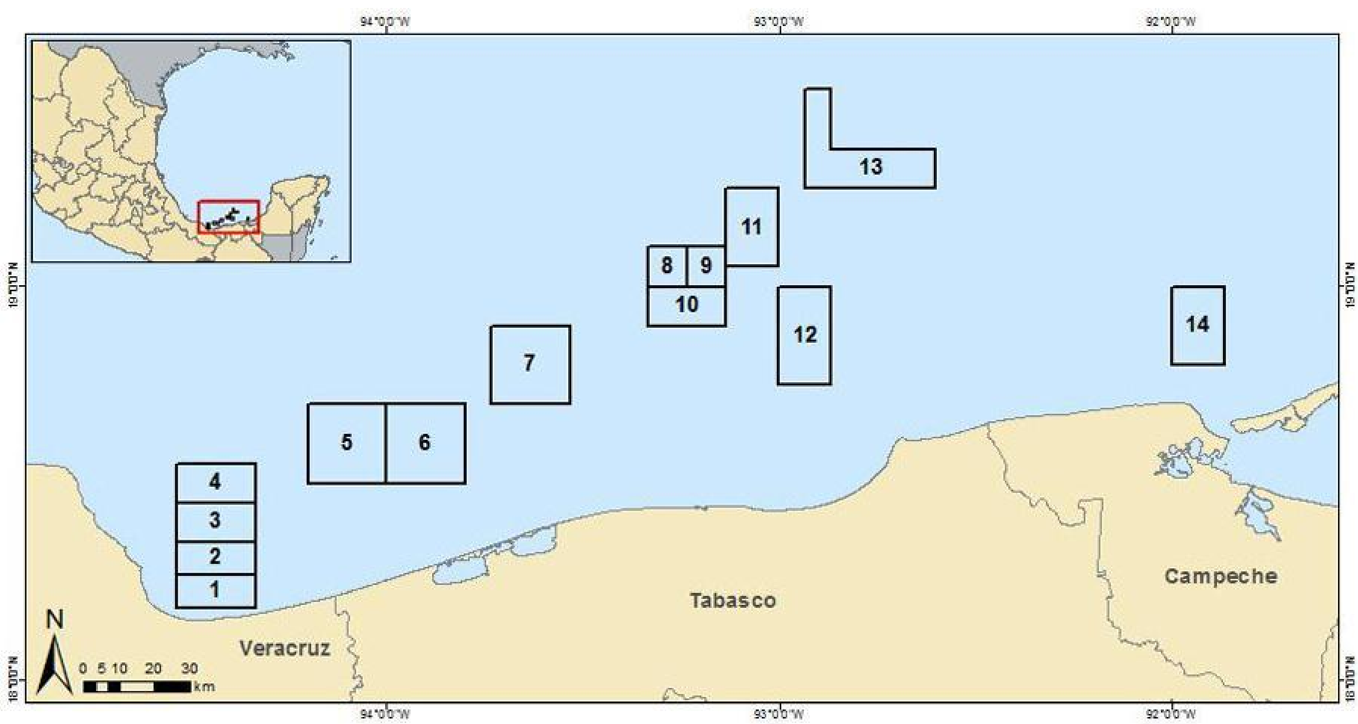
Mexico: E&P Regulator Issues First Call for Bids under Round One

Adrian L. Talamantes, Ken Culotta, Vera de Brito de Gyarfas

The Comisión Nacional de Hidrocarburos (CNH) has issued the first call for bids under Round One and the terms and conditions (T&Cs) governing the tender. CNH seeks to award 14 production-sharing contracts for the exploration and production (E&P) of hydrocarbons in 14 areas located in shallow waters offshore the States of Veracruz, Tabasco and Campeche (Gulf of Mexico). Additional tenders for the E&P of extra-heavy hydrocarbons and hydrocarbons located in the deep-waters of the Gulf of Mexico, shale plays and mature fields will be made during the first semester of 2015, also as part of Round One.

The 14 areas being auctioned by CNH under this call contain light crude and range from 116 km2 to 500 km2. All are exploration-first areas, meaning that each contractor will have to explore for hydrocarbons, and if such hydrocarbons are found in commercial quantities, proceed to produce hydrocarbons in accordance with a development plan.



Source: CNH

Bidders

Round One is open to all foreign and domestic companies, including Pemex, and each such company may bid individually or as part of a consortium. Each bidder will need to prequalify on the basis of its technical and financial capabilities.

As part of the prequalification process, the bidding operator must prove to CNH that it:

- has between 2010 and 2014 participated in at least three E&P projects, or alternatively, in at least one E&P project in which the total capital investment was at least one billion Dollars;
- has operated at least one shallow-water E&P project or been a partner in at least two shallow-water E&P projects in the last five years;
- will employ key management/operational personnel for the project with at least 10 years of experience in shallow-water projects (all of whom must be approved by CNH); and
- has experience in the management of industrial security and environmental protection in accordance with international practice and standards (including OHSAS 18001, ISO 14001, API RP 75 and ISM Code).

The bidder must also prove to CNH that it has a net worth of at least one billion Dollars; *provided* that if the bidder is a consortium (a) the net worth requirement must be met by no more than three members, (b) the operator must have a net worth of at least 600 million Dollars and hold at least one third of the participating interest in the project and (c) no other consortium member has a participating interest in the project that is greater than the operator's participating interest. Alternatively, the operator may show that it has an investment grade rating (Fitch, Moody's and S&P) and assets valued at 10 billion Dollars at a minimum.

The T&Cs also state that no company may participate in more than one consortium during the bidding process. Furthermore, companies that produce over 1.6 million barrels of crude oil equivalent per day may not join a consortium as members, and no company or consortium may bid for more than five blocks. This last limitation will not apply in future, high cost projects such as deep-water projects.

Bidding Process

CNH will open its office to all interested bidders during the week of December 15, 2014. On such date bidders will be able to purchase the T&Cs, commence the prequalification process by setting up an appointment with CNH, and file an application to access the data room, which will make available to bidders all the information held by the government for all contract areas, including 2D and 3D seismic, geologic studies and a description of existing infrastructure and investments.

The prequalification process ends on April 23, 2015.

Access to the data room will commence on January 15, 2015 and end on July 15, 2015, the date on which all bidders must submit their bids in a sealed envelope to CNH.

Bidders will have the ability to make observations to and request that CNH clarify any matter relating to the T&Cs, the prequalification process and the manner of accessing the data room, and while the prequalification requirements may not be modified or waived by CNH, the T&Cs, including the form of contract attached thereto, will be subject to revision. In an effort to ensure a transparent bidding process, all observations and clarifications must be made in writing and electronically by all interested parties, and CNH will publish any such observation or clarification as it is made. This means that no bidder will be able to meet in person or have direct contact with any specific representative of CNH to address matters relating to the tender.

CNH will publish the final T&Cs on June 15, 2015.

All bids will be received and opened, and all awards made, in a public act to be aired live through the Internet at www.ronda1.gob.mx on July 15, 2015. All contracts will be executed the following day.

Each contract will be awarded to the bidder who proposes the highest production share to the State (weighted at 90%) and the highest level of committed investment that is over and above the minimum work obligation (weighted at 10%). Ties will be broken by the bidder who proposes the highest additional cash payment to the State, and failing such tie breaker, by the bidder whose name is drawn from a sack.

Form of Contract

The forms of contract for individual and consortium bidders are fundamentally the same. The following is a general description of a few selected features of the forms of contract:

Term

- Each contract has a 25-year term, with two optional 5-year extensions.
- Each 5-year extension is subject to approval by CNH.

Exploration Phase

- Each contract will have an initial exploration phase of three years that may be extended for two more years upon approval of CNH.
- Within 45 days following the execution of the contract, the contractor must propose:
    - an exploration plan that contains a minimum work program (ranging between $57 million and $150 million, depending on the block) and programs for the transfer of technology and risk management; and
    - an annual work program.

Evaluation Phase

- If a discovery is made, the contractor may propose up to two, 12-month evaluation plans.

Production Phase

- If a discovery is made in commercial quantities, the contractor must propose:
    - a development plan that contains a description of the activities to be performed by the contractor during such phase, as well as programs for the transfer of technology, enhanced recovery and risk management; and
    - an annual work program.

Relinquishment

- The contractor must relinquish:
    - 50% of the areas it has not developed by the third year of the term;

- 50% of the remaining areas by the fourth year of the term; and
- 100% of the remaining areas by the fifth year of the term.

Rescission

- The contract may be rescinded by CNH:
  - for any reason stated in Article 20 of the Hydrocarbons Law; and
  - for any reason described in the contract, including for any act of corruption.

Applicable Law and Dispute Resolution

- All contracts are governed by the laws of Mexico.
- All cases relating to the administrative rescission of contracts must be submitted to the federal courts of Mexico.
- All other disputes will be subject to international arbitration at the Hague in accordance with UNCITRAL Arbitration Rules.

Assignments

- All assignments require the prior written consent of CNH.
- In the event the contractor assigns 100% of its interest, the assignee will be jointly and severally liable with the assignor for all of the obligations under the contract.

Fiscal Terms

- Contractor will be required to make the following payments to the government:
  - for the first 60 months of the term, delay rentals in an amount equal to $1,150 Pesos per km2, and for the remainder of the term, delay rentals in an amount equal to $2,750 Pesos per km2;
  - the State's share of production as proposed by the bidder (which may not be less than the minimum share set forth in the T&Cs);
  - overriding or additional royalties at the rate specified in the Hydrocarbons Law (subject to adjustment for windfall operating profits);
  - income taxes at a rate of 30%; and
  - during the exploration phase, an E&P tax equal to $1,500 Pesos per km^2 being explored, and during the production phase, an E&P tax equal to $6,000 Pesos per km^2 being exploited.
- Cost recovery commences upon production and is capped at 60% per operating period, provided that costs that are unrecoverable for such period as a result of the cap may be carried forward to subsequent periods.
- Ring fence rules apply at the industry and contract levels for purposes of calculating income tax.

Contract Administration

- CNH, on behalf of the Mexican government, will directly administer all contracts.
- The Secretaría de Hacienda y Crédito Público will audit all cost recovery.
- The Secretaría de Economía will audit the performance of all contractual obligations with respect to national content.
- The Agencia Nacional de Seguridad Industrial y Protección al Medio Ambiente will ensure that all projects are operated in accordance will all laws applicable to industrial security and the protection of the environment, and audit the contractor´s performance of the risk management program set forth in an exploration or development plan.

In due course, we will provide an analysis of the T&Cs and the provisions contained in the form of production-sharing contract attached to the T&Cs, as they compare to international practice.

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Have the Challenges of the Energy Transition been Overcome?

Mehdi Haroun, Ruxandra Lazar

Introduction

The ongoing debate over environmental issues and their impact on the French energy model raises many issues. Successive governments have taken different approaches to the problem and energy transition has been presented as a key initiative of President Hollande's five-year mandate. Following an eight-month national debate and two conferences which brought together ministers, elected officials and non-governmental organisations, on July 30 2014 a draft energy transition bill was put before Parliament.

The draft bill sets out numerous measures for improving energy efficiency (*e.g.*, a 30% tax break and other incentives for the energy-efficient renovation of buildings), with a view to achieving a 50% reduction in energy consumption by 2050. Moreover, it sets ambitious targets for boosting the use of electric cars in line with the objective of a 30% reduction in fossil fuel consumption by 2030. However, the main developments demonstrating the major shift in the French energy model relate to nuclear and renewable energy.

Nuclear power cap

The existing French energy model involves a significant proportion of nuclear energy, due to an ambitious nuclear programme first established by President de Gaulle and substantially reinforced after the first oil crisis in order to ensure energy security and reduce reliance on fossil fuels.

France currently has 58 commercial nuclear reactors spread over 19 sites, with a total installed capacity of 63.1 gigawatts (GW). In 2013 these reactors produced 73.7% of all French electricity. France is the largest exporter of nuclear electricity in the European Union and second in the world (behind the United States) in terms of total nuclear power generation. The nuclear fleet is operated by EDF, a listed company in which the French state has a 84.5% stake.

In the wake of the Fukushima accident, Germany decided to shut down all its nuclear plants by 2022. Such a radical solution was not viable in France, given the importance of nuclear energy. Nevertheless, the intention is to reduce French nuclear dependency, and one of Hollande's campaign commitments was to rebalance the energy mix and reduce the share of nuclear energy from 75% to 50% by 2025.

Initially, this commitment was to be reflected in the closure at the end of 2016 of the 1,600 megawatt (MW) Fessenheim nuclear power plant, the oldest operational plant in France. However, this raised several legal and practical issues:

The authorisations for operating nuclear plants are not limited in time. However, it is a regulatory requirement that the operators of nuclear plants carry out safety re-evaluations and 10-year inspections of their facilities. On the basis of the review issued by the operators, the Nuclear Safety Authority (ASN) issues an opinion as to whether the operator can continue operating the plant. In 2011 and 2013 the ASN issued positive opinions regarding the suitability of both nuclear reactors of the Fessenheim plant to continue operating for an additional 10 years, subject to carrying out reinforcement works and implementing technical safety provisions. Therefore, from an operational perspective, the two Fessenheim nuclear reactors may be operated until 2020 and 2022.

The closure of a nuclear plant can be ordered for safety reasons by the ASN or for safety and/or industrial reasons by the operator itself. Hence, a decision to close a nuclear plant for other than industrial or safety considerations can be implemented only through legislation and entitles the operator to compensation. In the case of the Fessenheim plant, such compensation would have to take into account the investments made by EDF since the last 10-year inspections (approximately €400 million) and the expected return on the operation. More specifically, the compensation would also take into account the fact that EDF has entered into generation allocation contracts with German company EnBW and Swiss electricity group CNP in respect of the Fessenheim plant. These companies participated in the financing of the construction costs and pay a share of the plant's annual operating costs, local taxes and taxes specific to nuclear energy. In exchange for sharing the industrial risks with EDF, EnBW and CNP are entitled to 17.5% and 15%, respectively, of the energy generated by the Fessenheim plant.

The conditions of the closure and dismantling of a nuclear plant are to be authorised by the ASN. In light of the various deadlines set out by the regulations, obtaining such approval can take up to five years.

The solution proposed by the government in the draft bill in order to rebalance the energy mix is both surprising and questionable.

On one hand, the draft bill clearly provides that one objective of the energy policy is to reduce the share of nuclear energy from 75% to 50% by 2025. On the other, it caps nuclear generation capacity in France at the current level of nuclear generation (*i.e.*, 63.2GW). The draft bill provides that new generation authorisations cannot be granted if they would lead to this cap being exceeded.

In other words, the draft bill leaves it to the operator to manage the nuclear generation capacity in operation at any time. From a practical point of view, in the current situation, if EDF decides to create new nuclear capacity it cannot be granted a generation authorisation in this respect unless it closes one or more plants with a nuclear generation capacity equal to that which will be created. In this context, the commissioning of the 1,650MW European pressurised water reactor in Flamanville by EDF which is scheduled for 2016, can only be completed if a plant with the equivalent nuclear generation capacity is closed.

The proposed mechanism raises several issues that require clarification during the parliamentary debate.

It is unclear how the 50% nuclear share objective shall be achieved, given that EDF intends to extend the operating life of its nuclear power plants significantly beyond 40 years and is likely to be granted the required authorisations in this respect.

Moreover, the mechanism set out in the draft bill aims to make EDF responsible for the management of the overall nuclear generation capacity. This is intended to ensure that the state will not have to compensate EDF for the early closure of existing plants. However, from a legal point of view, it will be difficult for the state to argue that the early closure decision is actually EDF's. If EDF receives no compensation, it could argue that the cap on nuclear generation capacity amounts to expropriation. Indeed, EDF was unaware, when it decided to undertake construction of the European pressurised water reactor or to invest in extending the operating life of the Fessenheim power plant, that it would be required to make trade-offs between its various investments and would not be in a position to recover its investments. However, bringing a claim against the state on the grounds of expropriation would be difficult for EDF, as the state is its largest shareholder. Should the claim succeed, this would result in the state in its capacity as regulator/legislator indemnifying the state in its capacity as shareholder. Therefore, the risk remains that the state, in its capacity as shareholder, eventually renounces such claim, sacrificing the interests of EDF's 15% floating shareholders.

The cap on nuclear generation capacity also raises issues regarding the EU directives implemented into French law, which provide for the liberalisation of the energy sector, notably in respect of the construction of new generation capacity. The cap proposed by the draft bill may be construed as a partitioning of the French nuclear market, as the entire nuclear fleet is currently operated by EDF and new available generation capacity can be created only if EDF closes generation capacity. In practice, this amounts to granting EDF a de facto monopoly over nuclear electricity generation in France. Such situation is questionable from an EU law perspective and the European Commission could criticise the scheme.

Renewable energy

The draft bill establishes a target of boosting renewable energy to 32% of all energy consumption by 2030.

France is far from reaching the target of 23% renewable energy in overall energy consumption by 2020 in accordance with the objectives set at EU level, despite the windfall effect of the high-incentive support schemes for the development of renewable energy.

Since 2000, the main support scheme used for the promotion of renewable energy has been the obligation imposed on EDF and local distribution operators to purchase electricity produced from renewable sources by independent power generators at a preferential tariff, which is higher than the market price. This obligation applies for 15 to 20 years, depending on the type of energy.

The feed-in tariffs – the costs of which are ultimately borne by end users – have been frequently criticised by the energy regulator (the *Commission de regulation de l'énergie*) and the National Accounts Court. These institutions believe that the feed-in tariffs generated exorbitant profits for power generators. Moreover, it has been established that installations benefiting from the power purchase obligation are not exposed to the supply-demand balance. Therefore, such installations generate electricity without taking into account the actual need for electricity, resulting in a negative price effect.

In 2009 and 2010 the government made two reductions in the feed-in tariffs for solar facilities and imposed a four-month moratorium on new solar projects in an effort to burst the speculative bubble that had developed in the solar market due to the combination of excessively high tariff rates and a reduction in the cost of solar plant equipment.

Consequently, since 2010 preference has been given to the mechanism of the tender process for the construction of new renewable generation capacity. Under this mechanism, the state can choose the type of energy that it wants to promote and can determine the main conditions of projects to be awarded through tenders (*e.g.*, the technical, economic and financial conditions and the localisation of projects) on a project-by-project basis. The winner of a call for tender is awarded the right to enter into long-term power purchase agreements with EDF or local distribution operators at a guaranteed price, in accordance with the bid it submitted.

The disadvantage of these favourable support schemes is that renewable energy projects face legal uncertainty given the considerable public opposition to such projects. As an example, this opposition led to the filing of a claim which, at the end of a five-year proceeding, resulted in the annulment of the feed-in tariffs for wind farms on the grounds that they constituted unlawful state aid. Although the government has managed to secure the feed-in tariffs for such projects by obtaining European Commission approval for the support scheme, the uncertainty and lengthy proceedings have discouraged many investors from developing new projects.

The draft bill partially takes into account this criticism and the various issues faced by the renewable energy market. The main renewable energy provisions are as follows.

Compensation mechanism for renewable energy producers

In addition to the power purchase obligation, the draft bill provides for a compensation mechanism whereby producers selling electricity from renewable sources on the market at market prices would receive compensation (likely to be a cash payment). The government will choose the types of renewable energy installations that will benefit from the purchase obligation or compensation mechanism. Moreover, winners of calls for tenders will be able to choose between a power purchase agreement at a guaranteed price and the compensation mechanism. The level of compensation granted to renewable energy producers shall be revised periodically in order to take into account the reduction of costs borne by new installations that are eligible for the compensation mechanism.

The introduction of a new support scheme indicates the political desire to restrict the application of the power purchase obligation in favour of a more flexible, less costly mechanism. However, at this stage it is difficult to assess the impact of these provisions, as it is not yet known how it will be decided which renewable energy installations will continue to benefit from the power purchase obligation and which will have access to the compensation mechanism. Moreover, the level of compensation under the compensation mechanism will be set out by the government once the law is in force.

Participation of local stakeholders in renewable energy projects

Local acceptance is one of the main challenges that developers of renewable energy projects must face. In order to enhance local acceptance – and hence the legal certainty of projects – the draft bill includes provisions on the involvement of local stakeholders in renewable energy projects.

Under the draft bill, local authorities will be authorised to acquire a share in the capital of companies that are developing renewable energy projects in or near their territory. The participation of local authorities in private companies is regulated and a legislative provision is thus necessary in order to allow for their involvement in such projects.

The draft bill also provides that when setting up a special purpose vehicle for the development of a renewable energy project, the project sponsors shall allow the residents of the area or the local authority to acquire a stake in the share capital of the special purpose vehicle. Although an earlier version of the draft bill provided that the minimum stake to be proposed to such local stakeholders would be determined by the state, the latest version does not address this issue.

Comment

More surprises – whether good or bad – are expected from the implementing regulations and the related legislation.

This article was originally published in the *Energy & Natural Resources – France* newsletter of the International Law Office.

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Challenges for energy security in Europe: Do European shale gas or US LNG offer a solution?

Nina Howell

The prosperity and economic stability of the European Union (EU), and wider Europe, is dependent on a stable, abundant, diverse and competitively priced supply of energy. Most of the EU's 28 Member States are used to uninterrupted energy supply at all times and in all circumstances. However, in January 2006 and January 2009 eastern EU countries experienced temporary disruption of gas supplies when Russia's Gazprom cut off gas supply to the Ukraine. Recent tensions between Russia and the Ukraine have again highlighted concern over security of energy supply to the EU.

In this article we look at the challenges facing the EU in terms of energy supply, and consider what is being done at an EU level to address those challenges. In particular we consider whether either European shale gas, or US LNG exports could offer a solution to the EU's concerns over energy security.

EU's Energy Demand and Import Dependency

Total demand for energy in the EU increased slowly between 1995 and 2006 but since then has been falling gradually. Over the same period the EU's dependency on imported energy increased by almost a quarter: so while the EU was consuming less energy more of what it consumed came from outside the EU. Since 2006, the EU's import dependency has stabilized, but it remains a fact of life for the EU.

Today the EU imports about 53% of the energy it consumes at a cost of more than Euros 1 billion (approx. US$ 1.24 billion) a day. In 2012, EU import dependency (percentage by consumption) was:

- 88% of crude oil;
- 66% of natural gas;
- 42% of solid fuels (mainly coal); and
- 4% of renewables.

Import dependency varies widely across EU Member States, both in volume and type of fuel. At one end of the spectrum Denmark is totally self-sufficient, whilst at the other end Malta's energy needs are meet 100% from imported fuels. The major EU economies of Germany, Spain and Italy all imported well over 50% of energy consumed in 2012.

EU Energy Security Strategy

Security of energy supply is now high on the EU Commission's agenda. In May 2014, the Commission published its "*European Energy Security Strategy*" which was followed in July 2014 by a 263 page "*In-depth study of European Energy Security*." At the core of the Commission's strategy is cooperation between Member States, and the development of a fully integrated and transparent energy market in the EU. The EU Commission identifies the many hurdles to achieve a well-functioning internal energy market, and recognises that they can only be overcome with a combination of new EU Directives to be adopted across all Member States, and new infrastructure – particularly in the EU's most vulnerable areas.

The key measures introduced by the EU Commission include:

The Third Energy Package: The Third Energy Package is comprised of separate Directives concerning common rules for the internal EU market in gas (Directive 2009/73/EC) and electricity (Directive 2009/72/EC), which EU Member States are required to implement into national legislation. The combined purpose of the Directives is to open up further the gas and electricity markets in the EU. Core elements of the Third Energy Package include ownership unbundling, which stipulates the separation of companies' generation and sale operations from their transmission networks, and mandatory third party access to infrastructure, including pipelines.

EU Projects of Common Interest (PCI): Current energy infrastructure in parts of the EU is outdated and often isolated. The EU Commission has identified the need to build new infrastructure, including cross border pipelines, and to update existing infrastructure and interconnectors to allow higher diversification of suppliers, promote the efficient integration of EU Member State energy markets, and generally increase EU security of supply. In October 2013, the EU Commission presented a list of 248 energy infrastructure projects of common interest to the EU. These projects were intended to be launched between 2014 and 2020 at an estimated cost of Euros 40 billion (approximately US$ 50 billion). Twenty-seven of these PCIs, mainly in the more vulnerable eastern EU Member States, have been identified as critical for the EU's energy security, and include a number of reverse flow interconnectors.

The Challenges and Solutions for Oil

Oil consumption in the EU is decreasing slowly (by 13% between 2005 and 2012), but it remains the largest single primary energy source in the EU. Oil has the highest import dependency of all fuels in the EU (almost 90%, with Russia being by far the largest supplier) leaving the EU exposed to changes in the global oil market. However, the risks associated with oil supply in the EU are global and, in the main, are not unique to the EU. The only major exception is for refineries in Germany, Poland, Czech Republic, Slovakia and Hungary that are solely dependent on oil supply from Russia that is transported through the Druzhba pipeline system.

Whilst long-term security of oil supply is not a key concern for the EU due to market liquidity, the EU is concerned by the transport sector's dependency on oil, and on reducing consumption of oil in favour of cleaner fuels. The EU Commission has introduced three legally binding policies to promote use of cleaner fuels over oil: (i) 2020 Climate and Energy Package; (ii) 2030 Framework for Climate and Energy; and (iii) 2050 EU Energy Roadmap.

The Challenges and Solutions for Gas

The share of gas in the EU's total energy demand increased from 20% to 23% between 1995 and 2012. During the same period, the EU's gas import dependency has increased as the EU's own gas reserves decline. Around 50% of gas imported to the EU is from Russia via pipeline through the Ukraine, representing about 15% of the EU's total gas consumption. The EU's increasing dependency on gas imports has increased the risks associated with security of gas supply. The challenges are greatest in Central Eastern European (CEE) countries, which are dependent on Russia as their sole supplier of gas. Today, gas supply is high on the EU's political agenda, and the EU Commission is looking at ways to guarantee a stable and diverse supply of gas to the EU whilst reducing dependency on Russian gas.

The EU Commission believes that security of gas supply requires a fully transparent, liberalized and connected EU gas market. The Gas Energy Package and PCIs are aimed at promoting security of energy supply over the long term. In 2009 the European Energy Programme for Recovery was set up to support the building of missing infrastructure links with around Euros 1.4 billion allocated to gas projects. The 2010 Security of Gas Supply regulation requires natural gas undertakings to secure supplies to protected costumers (notably households) under severe conditions, and Member States have to develop preventive and emergency plans for short term shortages.

The progress in the EU towards security of gas supply is by no means insignificant, but the EU Commission recognizes a lot remains to be done. The following are some of the key outstanding challenges for EU security of gas supply:

- Development of competitive and well integrated markets in the Baltic States and South East Europe lags behind;
- CEE gas markets remain small and poorly integrated/many landlocked;
- Gas trading infrastructure in CEE is relatively immature;
- Absence of energy hubs in SW Europe and CEE; and
- Inter-connector rates are still low.

Possible Impact of European Shale Gas

Europe has significant shale gas resources, although the estimates vary greatly. In 2013, the US Energy Information Administration estimated that Europe has 470 tcf (13.3 tcm) of technically recoverable shale gas reserves, compared to 567 tcf (16 tcm) in the US. The EU Commission has acknowledged that shale gas could partially compensate for declining conventional gas production, however development of an EU-wide policy on shale gas is still in its infancy, and there is a lack of consensus on shale gas development across EU Member States. To date, shale gas exploration in Europe has been minimal.

Poland is the most advanced EU Member State in terms of shale gas exploration. The US EIA has estimated that Poland's shale formations hold 148 tcf of technically recoverable reserves and are enough to supply domestic consumption for 250 years. However, Poland's shale gas sector has recently experienced a number of set-backs including disappointing well results causing a number of major players, such as ExxonMobil, to exit. The major EU economies of France and Germany have both imposed moratoriums on hydraulic fracking. The UK Government, on the other hand, supports shale gas development and has introduced tax incentives to promote investment in the sector.

Some of the hurdles for shale gas development in Europe (particularly when compared to the shale boom in the US) include:

- Absence of a clear legal and regulatory framework at both the EU and Member State level;
- Public opposition to drilling activities due to environmental concerns is greater in Europe than in the US. Over the last few years there have been major protests against fracking in Bulgaria, France, Germany and the UK;
- Costs of shale gas exploration are higher in Europe than the US due to harder geology and the absence of a large onshore oil services industry which has created a competitive market in the US;
- The government typically owns mineral resources in Europe. Unlike in the US, the government rather than individual land owners gets the benefit of shale gas production, which reduces the incentive to

permit shale gas activities on privately owned land;

- Western Europe particularly is densely populated with fewer available development sites away from communities; and
- Shale gas resources are often a long way from existing infrastructure to transport the gas to end markets, particularly in Eastern Europe.

Possible Impact of US LNG

The subject of who will buy US LNG exports when they start in late 2015/early 2016 is being widely discussed by the energy community. In Europe, the EU Commission and gas suppliers are considering whether US LNG can help with the EU's concerns over long term security of energy supply.

Europe has 22 LNG regasification terminals (excluding small scale LNG) with a total capacity of approximately 200 bcm/year at the end of 2013, most of which is in Western Europe. Since 2009, average capacity utilisation rates in European regasification terminals have fallen dramatically to about 25%. This drop is largely due to stagnant demand for natural gas in Europe as subsidised renewables and cheap coal squeeze gas out of power generation, and strong demand for LNG and higher prices in Asia and Latin America combined with weak demand and lower prices in Europe.

To a large degree, any view on where US LNG will be consumed is speculative as most of the existing sales commitments for US LNG are on an FOB basis (and hence the destination is unknown). The widely held view in the market is that Europe is not a prime market for US LNG, as Europe cannot compete with Asia on price. At a recent London Stock Exchange breakfast briefing on Europe's energy future, the message was clear that LNG will fail to dominate the European gas sector and cannot be an absolute guarantor of energy security. Some analysts predict that the US will supply a significant amount of LNG to Europe. However, Marina Petroleka, Business Monitor International's (BMI) head of energy and infrastructure research has said that although US LNG would "assist" the European Union in its goal of diversifying its gas imports away from Russia, "a lot of the talk is pure hyperbole."

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King & Spalding

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TRANSACTIONAL

Transactions

France: Hard Times for Electricity-Intensive Consumers

Mehdi Haroun, Ruxandra Lazar

Following the liberalisation of energy markets in the 2000s, electricity-intensive consumers have faced high and unpredictable prices. In this context, seven major industrial groups (Air Liquide, Solvay, Rhodia, Arkema, Alcan, Arcelor and UPM) established a consortium called Exeltium and launched a Europe-wide call for tender in order to negotiate better conditions for electricity supply. A contract was awarded to EDF in 2007 and the parties then signed a memorandum of understanding with the aim of securing part of the electricity supply to electricity-intensive industrial partners (Exeltium's shareholders) by providing long-term price stability.

The contract between Exeltium and EDF had to be substantially adjusted, further to European Commission concerns that such collective purchasing could foreclose the French power market to other electricity suppliers and that certain envisaged resale restrictions could have been anti-competitive. The European Commission finally cleared the contract, provided that the resale restrictions were cancelled and an opt-out clause for members of the consortium wishing to contract with other suppliers was introduced to mitigate anti-competitive effects.

Following clearance by the European Commission, in 2008 EDF and Exeltium entered into a 24-year supply contract for an electricity supply of 311 terawatt-hours (TWh). The supply was split into two phases: the first concerning 148 TWh and the second concerning 163 TWh. The first phase, which started in 2010, is structured as a take-or-pay contract. Exeltium made an upfront payment of €1.75 billion and pays additional amounts at the time of delivery.

Renegotiation of Exeltium-EDF agreement

The Exeltium consortium – which now unites 27 companies active in the steel, aluminium, chemical, industrial gas and paper sectors – called for a renegotiation of the terms of the agreement entered into with EDF. The consortium claimed that various events and parameters undermined the competitiveness of the Exeltium mechanism.

First, the financing of the Exeltium consortium was carried out in very difficult conditions, in the middle of the global financial crisis. Further, the existence of an opt-out gate at the end of the first 10-year period led the banks to refuse financing for the whole duration of the agreement. Therefore, the financing which was put in place covers only the first nine and a half years of the agreement and refinancing will be required before the end of 2014.

Second, the national and global energy context has significantly changed since 2008:

At a national level, the Exeltium arrangement has been undercut by cheaper power available under the ARENH mechanism set out by a law dated December 7 2010 to stimulate competition between electricity suppliers in France. Under this mechanism, EDF must make up to one quarter of the nuclear electricity produced (*e.g.*, 100TWh per year) available to competitors at a price reflecting the cost of its existing nuclear fleet in France. While the price of the electricity sold under the ARENH mechanism in 2014 amounts to €42 per megawatt-hour (MWh), the price of electricity sold to the Exeltium members amounts to approximately €50 per MWh. Moreover, the law requires that members of the consortium take delivery of the amounts of electricity agreed under the Exeltium arrangement before being granted access to electricity at ARENH prices.

At a global level, Exeltium members face strong competition from foreign companies in a context where electricity prices have fallen over the last few years. The competitive environment has changed, mainly as a result of decreasing demand and the significant development of other energy sources, such as shale gas in the United States or renewable energy in Europe. In addition, countries such as Norway, Canada and Germany have put proactive policies in place to support electricity-intensive companies. Such policies mean that, for instance, the price that Exeltium pays is 30% more expensive than the price which German electricity-intensive companies pay.

Third, one of the pillars of the Exeltium agreement is an industrial partnership between the consortium and EDF, whereby the consortium bears a part of the operational risks of the nuclear fleet – availability and installed capacity – as well as the risks associated with the development of new nuclear generation capacity. A major shift in France's nuclear policy, which involves reducing the nuclear fleet, will almost certainly have a negative impact on the price that Exeltium members pay for electricity, since this price increases as installed nuclear capacity decreases. Moreover, the substantial increase in building costs for the first European Pressurized Reactor in Flamanville has also negatively affected the price paid under the Exeltium agreement.

Comment

After several years of intense negotiation and successive compromises, the parties amended the agreement on July 21 2014. The core idea of the amendment was to introduce more flexibility in the contract, allowing for greater adaptability to future contingencies. The parties agreed to apply a fluctuating price, which will decrease when electricity prices are low and the economic situation has deteriorated, but will increase when the economic situation improves and prices return to normal. EDF agreed to reduce the price that members of the consortium pay by approximately 20% and it has been reported that the new price is now set at around €42 per MWh, in line with the market price. The members of the consortium agreed in turn that this price may be adjusted in the future, to reflect the evolution of the electricity market price. Finally, due to the uncertainties about the future of nuclear projects in France, the parties agreed to reduce the industrial risk borne by Exeltium.

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KING & SPALDING

Energy Newsletter

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TRANSACTIONAL
Construction
Transactional Construction Law: Focus on Energy Projects
Scott A. Greer

*The Editor interviews **Scott A. Greer**, Partner in King & Spalding's Global Transactions Practice Group.*

Editor: Please describe King & Spalding's construction practice and your role.

Greer: Our practice is unique in being among the first that is entirely focused on transactional construction and procurement law, rather than an offshoot of the litigation practice. The logic behind the firm's strategy was that focusing on a core specialty would make dominant industry experts of our lawyers and, therefore, ensure the highest quality in our work. I lead the firm's global construction transactional practice, which is the largest in the U.S. Our work is split fifty-fifty across domestic and international projects, and I've personally handled projects in 24 countries and 40 U.S. states. We have eight construction transactional attorneys in the U.S. and three more in the Middle East.

The majority of our work involves very large-scale energy, petrochemical or industrial projects, such as petrochemical facilities, liquefied natural gas (LNG) projects, power plants, or multi-state pipeline projects. For the balance, we handle infrastructure deals, such as mining projects, particularly outside the U.S.; cement manufacturing projects; and commercial projects, such as the Atlanta Falcon's football stadium.

A distinguishing feature of our team is that it comprises lawyers – five out of eight U.S. attorneys on my team alone – who hold technical degrees in engineering or architecture, most of whom previously practiced in these technical fields. This is significant because the projects we handle don't follow the familiar process we associate with building a house, which starts with a pre-existing architectural plan attached to a construction contract. Rather, it's our job to specify the output requirements and performance guarantees, for example, "design a car built to accelerate from 0 to 60 in X seconds" and, more fundamentally, "ensure that the design has not omitted basic features like seats and a radio." The important point for lawyers is that our work product is words, not drawings, so those of us with technical knowledge on the design side will have a real advantage in drafting precise contract language.

We take a holistic view and review every single aspect, including on the technical side, to ensure that a contract is seamless and clearly enforceable. Some law firms focus just on the terms and conditions, but we work as much with in-house lawyers and the commercial leads of our client companies as with their engineers.

Also, a number of the attorneys on our team were construction litigators prior to becoming full-time construction transactional attorneys. As a result, we have a good understanding of the issues that can arise during the project and ultimately in litigation or arbitration, and therefore draft and negotiate our clients' construction contracts to mitigate or eliminate these issues.

Editor: Expand on the team's industry expertise, and give us a sense of the magnitude of the work you're engaged in.

Greer: We are currently involved in over $115 billion in U.S. and international projects. We have a very strong reputation in certain sectors and are a global leader in LNG projects. As just one example, in response to a natural gas shortage in 2003, we started working on U.S.-based LNG import terminals, which essentially receive LNG that has been frozen to -273°F to shrink its volume 600 times and shipped across the ocean. The imported LNG is stored in stadium-sized tanks at the U.S. facility and then heated up before it is delivered it to customers via pipelines. Interestingly, recent shale gas discoveries have allowed the U.S. to overtake Russia as the world's largest natural gas producer, so for the past half dozen years, we've been converting projects originally designed as U.S. import terminals for the newer purpose of exporting gas to other countries.

Editor: Are these reconceived projects bringing new challenges?

Greer: Yes. For one thing, LNG import terminals are much smaller in size and value, usually costing less than $1 billion, whereas LNG export projects, depending on their size and whether they are new or an expansion, could run $5 to $10 billion or more. Export projects are more complex in terms of building the liquefaction "train", meaning the facility for freezing the gas, which was not necessary with import terminals.

Editor: What accounts for the surge in U.S. energy construction projects?

Greer: Due to a confluence of factors, we are seeing more U.S. projects relating to the shale revolution in both gas and oil. The U.S. is now not only the largest global gas producer but, as a result of shale oil, has also overtaken Saudi Arabia as the world's leading oil producer. Further, because natural gas prices have dropped significantly, the economics of U.S. production work in favor of locating projects in the U.S.

The next factor is Japan's Fukushima disaster, which resulted in the shutdown of all 50 of its nuclear power plants, accounting for 30 percent of its domestic power generation. With a need to replace that energy, and without any appreciable natural resources of its own, Japan has elected to import LNG to a significant extent. This demand adds impact to some of our U.S. and international LNG projects, as most buyers for U.S. energy exports are from Japan and, more broadly, from Asia.

Third, the U.S. Environmental Protection Agency (EPA) has implemented numerous measures that restrict the building of new coal-fired power plants, so we anticipate numerous closures of existing plants over the next decade. As a result, there is a resurgent interest in building natural gas power plants, which have a smaller carbon footprint, in the affected areas.

And further to the point about gas prices, global companies that used to build elsewhere are now coming to the U.S. to build large petrochemical facilities that rely on cheap natural gas. For example, we represent Sasol Chemicals (USA) LLC, a South African company that is building an $8.1 billion chemical facility in Louisiana and is planning to build a gas-to-liquid project on the order of $15 billion. The *Wall Street Journal* reports that this project likely represents the largest foreign investment in U.S. history, and this is just one example on the petrochemicals side.

Additionally, there is a surge in the construction of ammonia plants, which also rely on economical natural gas in the production of fertilizer. And more generally, the surge in pipeline construction relates to the physical location of shale gas and shale oil and the resulting need to build pipelines in different geographical regions.

Finally, the construction of nuclear power plants is trending downward in the United States, though there are two new plants being built in South Carolina and in Georgia. Notwithstanding that environmentalists tout their near-zero emissions, we don't expect to see further construction of nuclear power plants built in the U.S. any time in the foreseeable future for a few reasons. First, they take a long time and are expensive to build, though they are very economic once they are up and running, and second, low natural gas prices allow natural-gas-fired power plants to operate just as competitively. We do expect, however, that Asian countries will continue to focus on nuclear power, and we are representing one client that is designing and seeking to build small module reactors there.

Editor: Can you give examples of the firm's high-profile work?

Greer: The Oregon Clean Energy project, located in Ohio, is an example of a natural-gas-fired power plant that will replace coal-fired power and help in meeting a predicted 12,000-megawatt demand due to retiring coal-fired power plants, among other reasons. So far, this project has involved the negotiation of an engineering, procurement and construction (EPC) agreement for the power plant and switchyard, and we are handling a number of similar projects at various stages of development in locations such as Maryland, New Jersey, New York and New England.

We are also handling two LNG export projects for Cheniere Energy, one in Louisiana and the other in Texas, with a total value exceeding $28 billion. These projects involve the construction of liquefaction and purification facilities, or LNG "trains," which do the work of freezing natural gas in preparation for transport, as described above. The first of its kind in the U.S., the Louisiana project involves a total of six trains and is among the largest manufacturing investments in the state's history, and the Texas project, involving three trains, likely will be the largest lump-sum contract ever signed by Bechtel. The Freeport LNG project is an example of another LNG export project we are handling in the U.S. and, at $14 billion for their first three trains, represents the largest private investment in Texas history.

One of our non-U.S. projects relates to the construction of LNG trains in Mozambique for Houston-based Anadarko. Phase 1 is valued at approximately $20 billion, and the entire buildout is expected to exceed $50 billion in value. This project involves a myriad of EPC agreements relating to the onshore construction and the offshore development work, among other aspects.

In Saudi Arabia, Sadara Chemical Company, a joint venture of Saudi Aramco and Dow Chemical, is engaged in a $20 billion project that is the largest petrochemical facility built in a single phase, the largest export credit financing ever sought, and the first-of-its-kind rail project in Saudi Arabia. We are serving as external counsel to Sadara on all aspects of construction, procurement, employment, intellectual property, corporate matters, tax, trade and finance.

Editor: Talk about what's involved in putting together deals of the size, scope and complexity you've just described. I imagine staffing is critical.

Greer: It is. Generally, we staff large international projects with experienced team members from various jurisdictions. As a global firm with a leading LNG practice, for instance, we can help U.S. companies looking to build internationally or help a company looking to sell natural gas anywhere in the world. The critical element for my team relates to the contracts because these tend to be long-term projects with agreements that span twenty years or more, and unless the parties are major players like Shell or Chevron, most LNG deals are project-financed and involve non-recourse loans. Some equity is provided for these projects, but the financing for these deals is based solely on the economics of the project and, therefore, is particularly reliant on the negotiation and drafting of related construction, financing and LNG sales contracts.

The firm has 17 offices across the globe. Our international attorneys negotiate government concession agreements about building rights, obligations with respect to local labor, environmental and regulatory requirements, and all tax- and customs-related aspects of the deal. Certainly banks are involved on the finance side, but in some countries, project finance may be provided by export credit agencies, such as the U.S. Exim Bank or the JBIC (Japan's export-import bank), so the firm's expertise is needed there. And for international matters involving local issues like real estate where we don't have an office, we will often coordinate with local counsel to navigate regulations and requirements.

Editor: Let's delve into some of the contractual details.

Greer: There is a wide range of contractual structures on the construction side. The most common in the energy sector is an EPC contract, which is used by an owner that wants to hire one company to handle all aspects of a construction project – from engineering through construction completion – essentially a turnkey approach that also provides a single point of contact for issue resolution. Less commonly used are contractual structures that separate engineering and design from construction, and these are sometimes used in pipeline projects.

Construction projects involve significant risks. We have to assess the company's appetite for risk and whether it has the financial means to put its balance sheet on the line; we look at financing on a lump-sum or fixed-price basis and, depending on the risk profile and available resources, whether it is advisable to contract on a reimbursable basis, meaning that payments are based on expenses as they are incurred.

In some cases where the owner is willing to assume more risk, the owner essentially acts as the general contractor but still needs assistance to design and manage the project. These projects call for an engineer-procurement-construction management (EPCM) contract, which has the advantage of fewer embedded contingencies for events that may not occur, but also the disadvantage of greater overall risk to the owner.

Editor: In closing, give us the view from the outside for clients looking to hire a firm with a construction transactional practice for energy-related projects. What are they going to like about King & Spalding?

Greer: They will like our deep skill sets, as lawyers with technical qualifications, plus our breadth of experience within a very specialized area, particularly as it relates to the number and scale of projects we have already managed to successful outcomes. In fact, the firm strategically developed this energy practice on a project basis, meaning that we almost always get involved at the outset and manage every aspect through to completion. For instance, we will manage everything from constructing the project, selling the offtake, and dealing with regulators across the globe, whereas most major law firms involved with energy projects focus on project finance and come in much later in the game. At King & Spalding we follow the molecules and electrons, and we understand how projects work from start to finish.

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REGULATORY

FERC

Commentors Disagree on FERC's Proposal to Change the Gas Day Start Time

James F. Bowe, William E. Rice

Comments filed with the Federal Energy Regulatory Commission (FERC) in late November show that the natural gas and electric power industries continue to disagree fundamentally on FERC's proposal to promote greater coordination between the two industries by redefining the "Gas Day."

The Gas Day, which currently begins at 9:00 a.m. Central Clock Time (CCT) each day, is a 24-hour period during which shippers nominate and schedule natural gas transportation services furnished by natural gas pipelines. The Gas Day is enshrined in the tariffs of all interstate natural gas pipelines, pursuant to standards adopted by the North American Energy Standards Board (NAESB) and referenced by FERC regulations. It is also referenced in many commercial agreements involving the purchase and sale of natural gas in North America. From the time NAESB first addressed the subject, there has been a single Gas Day applicable to all interstate natural gas pipelines, regardless of location.

In March 2014, FERC issued in Docket No. RM14-2-000 a notice of proposed rulemaking (NOPR), in which it announced its proposal to change the start of the Gas Day from 9:00 a.m. to 4:00 a.m. CCT. The NOPR is part of FERC's ongoing effort to promote electric supply reliability through improved coordination between the natural gas and electric power industries.

The proposed change in the Gas Day is FERC's response to electric industry requests to make the Gas Day coincide with the electric day, which generally begins at 12:00 midnight local time. FERC has declined to make this change, noting the benefit of a standardized nationwide Gas Day. Instead, FERC proposed changes in the Gas Day that it reasoned would promote electric generation efficiency by allowing generators to schedule their gas transportation and supply on a day-ahead basis. If the Gas Day were to be changed so that it began at 4:00 a.m. CCT, the periods of peak electric demand for electric days in all time zones would generally fall within one Gas Day. In addition, the Gas Day would start before the morning ramp-up in electric demand. With the current 9:00 a.m. Gas Day, the morning ramp-up in electric demand occurs near the end of each Gas Day, a time at which there is little flexibility for generators to arrange changes in gas supply and transportation.

FERC also proposed changes to the timely gas nominations cycle (from 11:30 a.m. to 1:00 p.m. CCT). This change is intended to establish a later effective time for day-ahead transportation nominations, so that the timely cycle would remain open until after ISOs and RTOs accept generators' bids for the next day. This, FERC suggests, would allow generators to take advantage of the greater liquidity that exists as to timely day-ahead nominations. FERC also proposed to increase flexibility by adding two additional intraday nomination cycles (for a total of four) and to require that pipelines allow multiple parties to contract for service under a single service agreement. Multi-party agreements are attractive to organizations that own multiple generation entities and use a service company to arrange and manage enterprise-wide gas supply. Several pipelines already offer such arrangements.

FERC took the novel approach of establishing an eight-month comment period under the NOPR. The longer-than-usual comment period was intended to afford industry participants time to work with NAESB to develop and agree upon possible modifications to FERC's proposal. NAESB responded by forming the Gas and Electric Harmonization (GEH) Forum to consider changes to the Gas Day and nomination cycles. On September 29, 2014, NAESB reported that, while through its GEH Forum it was not able to achieve consensus as to the start time for the Gas Day, it was able to achieve consensus on a revised nominations schedule that would include three intraday cycles and adopt the 1:00 p.m. timely nomination cycle.

Over 75 individuals, groups and organizations filed comments on FERC's proposed Gas Day and related changes. Commentors aligned with the natural gas industry strongly oppose the change in the start of the Gas Day, citing safety and staffing concerns. They observed that advancing the start of the Gas Day to 4:00 a.m. CCT would compel industry participants to undertake significant activities in the middle of the night, and that computer system modifications required to implement the modified Gas Day would be costly. The Interstate Natural Gas Association of America, representing North America's interstate natural gas pipelines, noted that more than a year would be required to implement the proposed change in the Gas Day start time. The American Public Gas Association, representing municipal and other publicly-owned gas utilities, claimed that the Gas Day change alone would cost the natural gas industry "hundreds of millions of dollars." The natural gas industry comments also question whether the change could achieve its intended result of promoting reliability, generally noting that the change in Gas Day start time is not a substitute for electric generators contracting for firm services, which would allow development of needed pipeline infrastructure.

Electric industry comments, filed by independent electric transmission system operators (ISOs), regional transmission organizations (RTOs) and electric power generators, strongly support the proposed 4:00 a.m. Gas Day start time. Electric sector interests generally concur that the change would achieve the benefits that FERC describes in the NOPR.

Other aspects of the NOPR, including the proposal to increase the number of intraday nomination cycles and multi-party contracting for services, received positive comments from both natural gas and electric power industry commentors. A number of commentors support NAESB's proposed three intraday nominations cycles; however, a small number of commenters claim that the NOPR and NAESB proposals don't go far enough. For example, the Tennessee Valley Authority (TVA), a major electric power generator which also owns substantial transmission, stated that, rather than taking what it describes as "small steps" towards aligning gas transportation with electric generators' needs, FERC should consider "further steps to eliminate bumping rights, increase nomination opportunities, and close loopholes in using secondary out-of-path transportation." The Council of ISOs and RTOs, representing the managers of the organized electric markets, as well as other electric power sector commentors, urged the Commission to promote hourly nominations, noting that some pipelines already allow such flexibility. In addition to TVA, several other commenters questioned retention of the "no-bump" rule. FERC's "no-bump" rule prohibits firm transportation from displacing ("bumping") interruptible transportation services during a Gas Day's last intraday nomination cycle.

A small number of commenters, including the Desert Southwest Pipeline Stakeholders, suggested that FERC should allow primary firm nominations to bump secondary firm nominations. Current FERC policy requires that, once scheduled, secondary firm transportation services must have the same priority as primary firm transportation services. The Desert Southwest Pipeline Stakeholders have claimed that earlier scheduled secondary transportation services interfere with their ability to ramp-up gas-fired generation throughout the course of a Gas Day as required to integrate intermittent renewable generation (wind and solar) onto the power grid.

Comments filed by representatives of the natural gas and electric power sectors indicate that there is no compromise on the Gas Day start time that would be acceptable to both the natural gas and electric industries.

Given the divergence in the comments on the Gas Day start time issue, FERC now has a difficult decision to make. In an apparent attempt to obtain more information to help with its decision, FERC sent data requests to six ISOs and RTOs on December 12, 2014 requesting information regarding circumstances in which generators were unable to operate due to a lack of gas supply near the end of the current 9:00 a.m. Gas Day.

Once FERC reaches a decision and issues a rulemaking order, the focus may shift to the electric ISOs and RTOs. Concurrent with the NOPR, FERC issued an "Order Initiating Investigation into ISO and RTO Scheduling Practices," under Section 206 of the Federal Power Act, directing six major ISOs and RTOs to consider changes to their tariffs that may be required to implement any changes made in the Gas Day rulemaking. Proceedings under that order are currently dormant, pending FERC's decision in the Gas Day NOPR. If, however, FERC decides in favor of the electric industry on the Gas Day start time, it will become incumbent on the ISOs and RTOs to make changes to their tariffs and practices that will ensure that the benefits of the Commission's controversial action are realized.

There is no set time for FERC action on the NOPR; however, it is likely that the Commission will issue a rulemaking order sometime in 2015. A rulemaking order, however, will not mark the end of FERC proceedings on the subject. Any FERC decision is likely to be opposed by segments of the natural gas and/or electric power industries on rehearing and, possibly, judicial review. NAESB will need to finalize standards incorporating the changes adopted by any FERC rulemaking order and interstate pipelines will need to modify their tariffs to incorporate the new NAESB standards. ISOs and RTOs may also need to modify their tariffs. If FERC changes the Gas Day start time, natural gas pipelines will likely need a year or more to make changes to their computer systems. On the other hand, if FERC elects to retain the 9:00 a.m. Gas Day, the remainder of the nominations and scheduling changes proposed in the NOPR could probably be implemented in a shorter timeframe.

In any event, FERC has embarked on a course that will likely result in uncertainty as to the Gas Day and natural gas scheduling procedures for years to come. In the end, the NOPR may ultimately reveal that the benefits of improved gas-electric coordination and communications may be limited in practice. This could clear the way for the natural gas and electric power industries to focus on the need for development of new pipeline infrastructure that can support additional firm natural gas transportation services, and even ISO/RTO rules that would allow generators to recover the costs of securing reliable firm transportation services.

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KING & SPALDING

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REGULATORY

Intellectual Property

Patent Office Statistics Indicate Growth In Oil & Gas Patents

Russell E. Blythe

Patent disputes and licensing deals have frequently reached the headlines over the past few years. Many of these high profile stories have involved telecommunications, computers, and pharmaceutical patents. But statistics provided by the United States Patent and Trademark Office (USPTO) show that the number of patents granted in the oil and gas sector has grown at a double-digit rate in the six years since the 2008 recession. This increased volume is worth noting as oil and gas companies evaluate their patent portfolios and IP strategies.

Patent Office Statistics and Class System

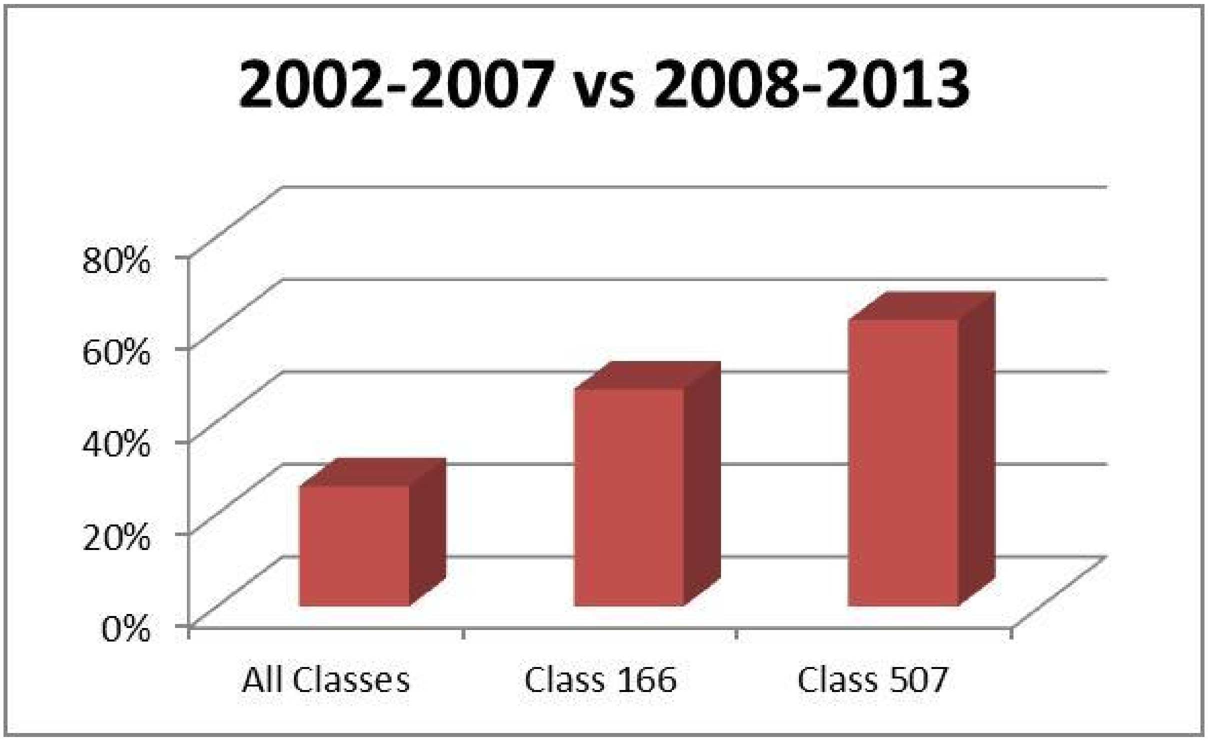
The USPTO's Patent Technology Monitoring Team periodically issues general reports profiling patenting activity. Some of these reports – including the Patent Counts by Class by Year Report that is the focus of this article – show the number of patents granted in each of the approximately 475 U.S. patent classes. [1]

Patent classes are major divisions of technology in the U.S. Patent Classification System. Two classes of particular interest to the oil and gas industry are Class 166 (Wells) and Class 507 (Earth Boring, Well Treating, and Oil Field Chemistry). While not every patent in these classes is necessarily an oil and gas related patent, oil and gas is a major component of this technology area.

The analysis below compares the number of patents that issued in the six years for which data is available since 2008 *(i.e.*, 2008-2013) with the six prior years (*i.e.*, 2002-2007).

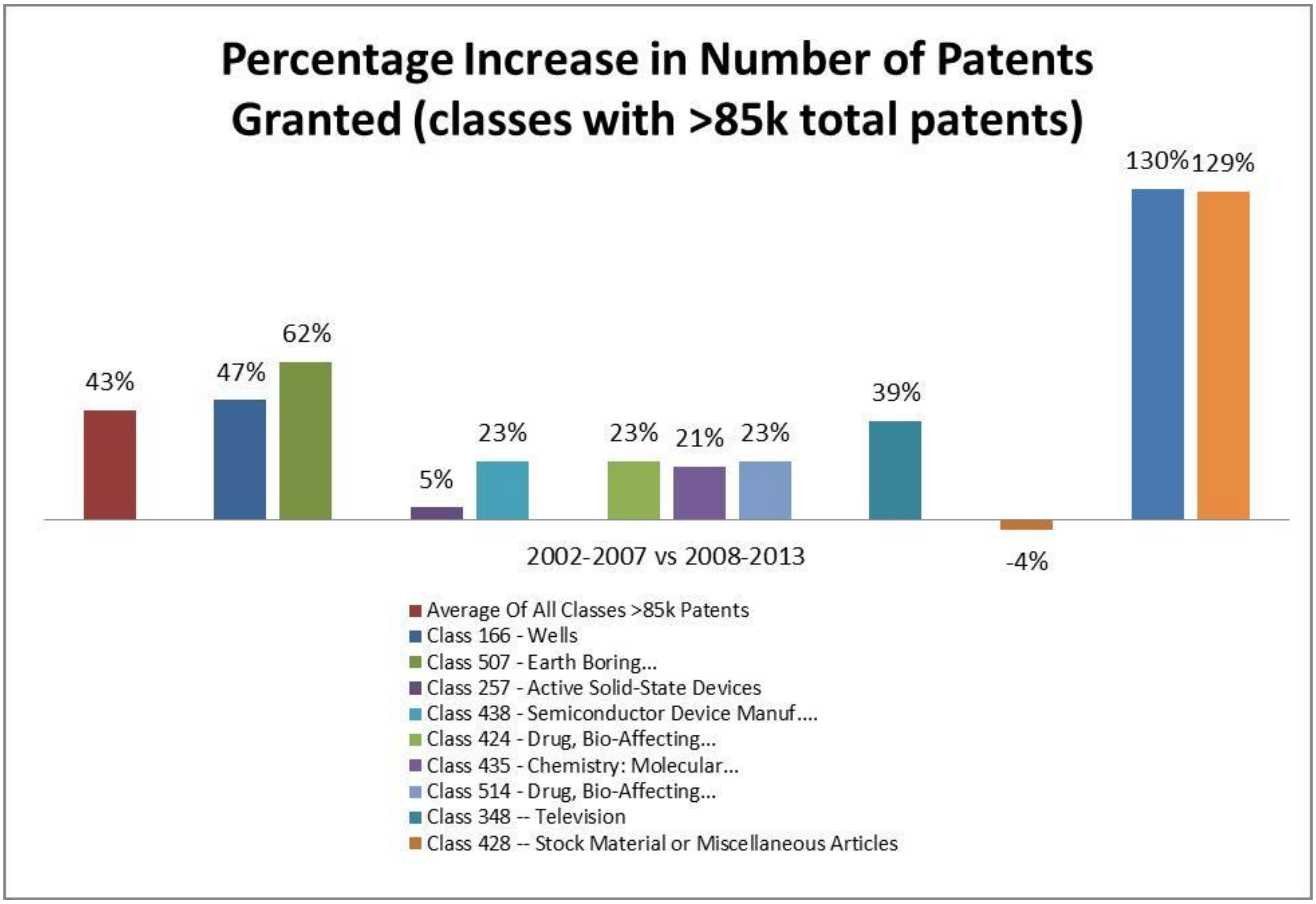
Growth In Classes 166 (Wells) and 507 (Earth Boring, Well Treating, and Oil Field Chemistry)

The USPTO granted 5,043 patents in Class 166 (Wells) between 2002 and 2007. Between 2008 and 2013 that number grew to 7,436 – an increase of 47%. The USPTO granted 747 patents in Class 507 between 2002 and 2007. Between 2008 and 2013 that number grew to 1,210 – an increase of 62%. By way of comparison, the number of patents across all classes was up only 23% in the same period.

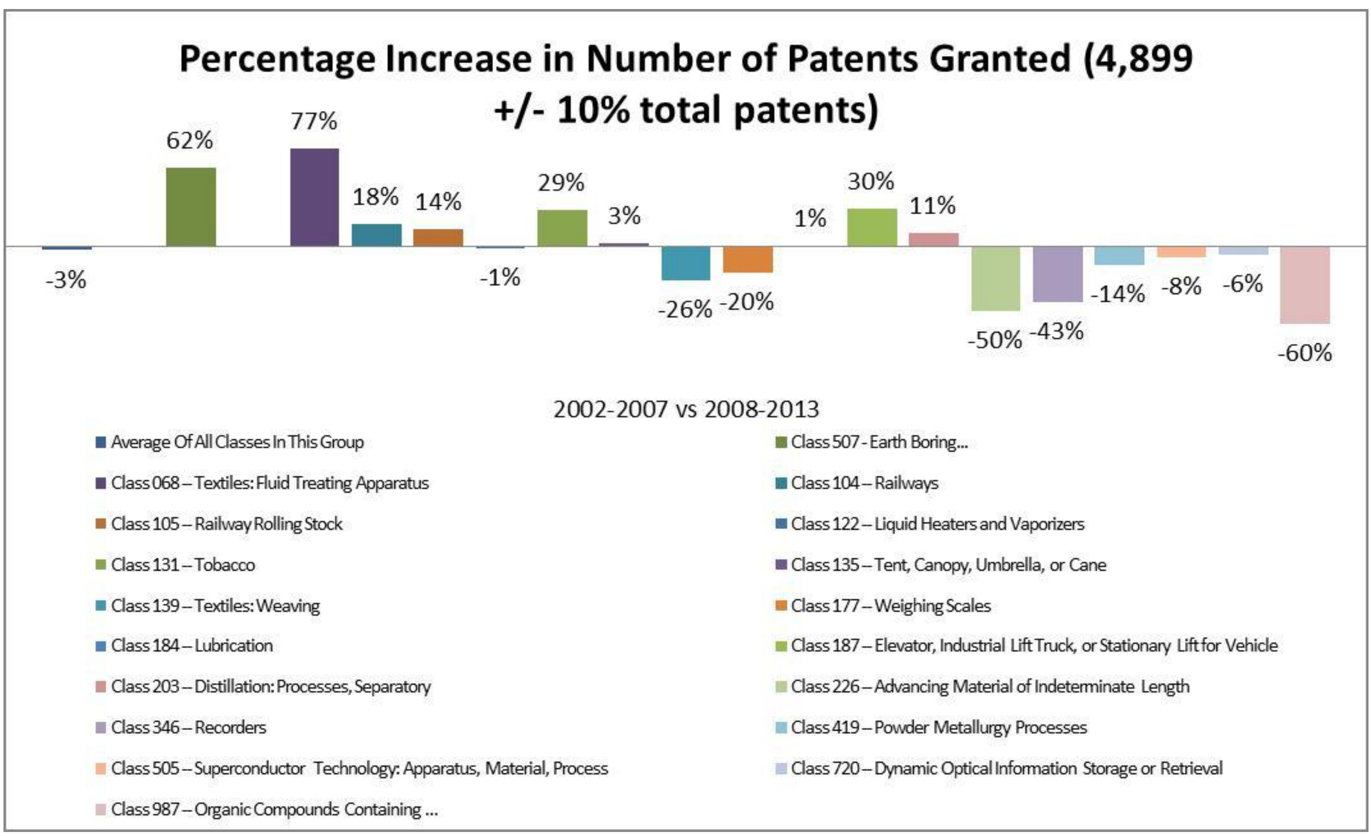


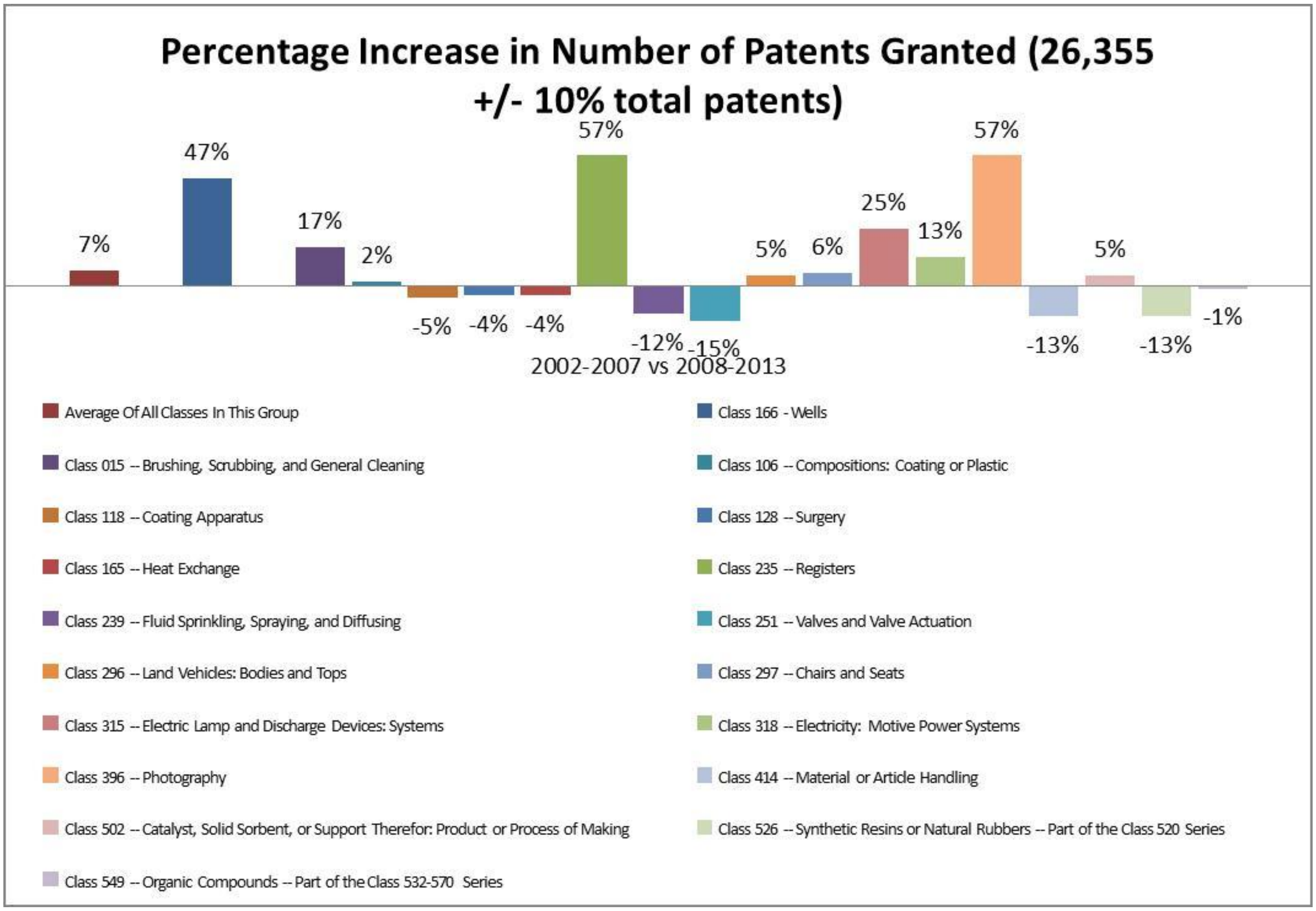
How This Growth Stacks Up To Other Technology Areas

The growth of patents in Classes 166 and 507 outpaced growth in most of the largest patent classes. For example, Classes 166 and 507 grew at a faster clip than Class 348 (Television – up 39%), Class 424 (Drug, Bio-Affecting and Body Treating Compositions – up 23%), and Class 438 (Semiconductor Device Manufacturing: Process – up 23%). Indeed, among the largest classes, only Classes 370 (Multiplex Communications – up 130%) and 455 (Telecommunications – 129%) grew at a faster rate between 2008 and 2013.



Thus, when compared to similarly sized classes, growth in the oil and gas-related classes exceeds all but a handful of other technology areas. The growth of oil and gas-related classes also far exceeds the average growth for these groups.





Possible Impacts and Strategies

The increased number of oil and gas-related patents could have a number of effects.

Enforcement litigation related to oil and gas patents may increase. After all, a large part of a patent's value is in the right to exclude others from practicing the claimed invention. With more patents in this space, there is a greater potential for litigation to enforce those patent rights.

Indeed, the number of patents may continue to grow – and at an even faster rate. As industry participants obtain more patents, their competitors may also have an incentive to increase the size of their patent portfolios. Indeed, a sizeable patent portfolio can be a useful tool. Not only can patents be used to exclude others from practicing inventions, they can also discourage lawsuits (or create favorable settlement leverage) through infringement counterclaims against competitors.

Yet another possibility is that more oil and gas companies will take advantage of new post-grant review proceedings offered in the USPTO. Post-grant review proceedings allow a party to challenge the validity of issued patents at a lower cost and faster pace than typical federal court litigation. There is generally less discovery in these proceedings as the process focuses on invalidity, and infringement is not at issue.

With the number of oil and gas patents on the rise, these issues are likely to be encountered with greater frequency. Developing a sound patent strategy will be important for energy companies in 2015 and beyond.

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[1] In particular, this article focuses on Part II of the Patent Counts by Class by Year Report. See www.uspto.gov/web/offices/ac/ido/oeip/taf/cbcby.htm.

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KING & SPALDING

Energy Newsletter

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DISPUTE RESOLUTION

International Arbitration

ExxonMobil Decision by ICSID: A win for ExxonMobil or Venezuela?

Nina Howell, Sarah Vasani, Greg Lazarev

On 9 October 2014, an International Centre for Settlement of Investment Disputes (ICSID) tribunal comprised of H. E. Judge Gilbert Guillaume (President), Professor Gabrielle Kaufmann-Kohler and Dr. Ahmed Sadek El-Kosheri ruled on the compensation payable by Venezuela to ExxonMobil for the nationalization of ExxonMobil's Cerro Negro and La Ceiba projects. [1] ExxonMobil had claimed US$14.5 billion and Venezuela had offered US$353 million. The Tribunal's ruling that Venezuela pay ExxonMobil US$1.6 billion has been declared a victory by both sides.

This article summarizes the key findings of the award.

Summary of Background Facts

Between 1976, when Venezuela officially nationalized its oil industry, and 1990, all petroleum activities in Venezuela were conducted exclusively by PDVSA, without any participation from private or international companies.

The Government of Venezuela, recognizing the benefits of foreign investment to explore new oil fields, adopted a series of measures in the 1980s (collectively known as "Oil Opening") to allow foreign investors to participate in the Venezuelan oil industry by means of an operating services agreement or association agreement with PDVSA.

Cerro Negro: In October 1997 Mobil Cerro Negro, an ExxonMobil subsidiary, became a party to the Cerro Negro Association Agreement with PDVSA. The Cerro Negro Project, contemplated by the Cerro Negro Association Agreement, included (i) exploiting and developing the extra-heavy crude oil fields in the Cerro Negro area; (ii) constructing and operating an upgrader in the Jose Industrial Complex; (iii) laying and operating pipelines between the Cerro Negro area and the Jose Industrial Complex; and (iv) selling the resulting products of Mobil Cerro Negro and PDVSA-CN to Chalmette Refining. The Association Agreement authorized the parties to expand the capacity of the Project to produce extra-heavy crude as well as its capacity to upgrade that crude into synthetic crude oil. An expansion project could be undertaken by unanimous agreement of the participants or, alternatively, under certain conditions, by fewer than all of the participants. Importantly, the Association Agreement required PDVSA to compensate Mobil Cerro Negro (and its partner Petro-Canada) for the economic consequences of governmental measures defined as "Discriminatory Measures".

La Cieba: On 10 July 1996 Mobil Venezolana, together with other international partners, entered into the La Ceiba Association Agreement with PDVSA to explore, develop and exploit oil fields in the La Ceiba area, an area with light and medium crude oil potential, on a share-risk-and-profit basis. A Development Plan for the La Ceiba project was approved by Administradora La Ceiba on 27 January 2007. The Development Plan then should have been submitted to the Control Committee for final approval. However, as asserted by ExxonMobil, the Venezuelan Government frustrated that step and soon thereafter expropriated Mobil Venezolana's interests in the La Cieba Project.

For both the Cerro Negro and La Cieba projects, the Exxon Mobil subsidiaries executed Royalty Reduction Agreements which granted a reduced exploitation tax (royalty) of 1%.

Subsequent to ExxonMobil's commitment to the Cerro Negro and La Cieba projects, Venezuela implemented the following fiscal measures which affected the value of ExxonMobil's investment:

Increased Royalty**:** In 2004 and 2005 Venezuela unilaterally terminated the Cerro Negro and La Cieba Royalty Reduction Agreements and thereafter hiked the royalty rate to 16 2/3%. The average monthly production from Cerro Negro above 120,000 barrels per day would be subject to a royalty rate of 30%.

Extraction Tax**:** In May 2006, Venezuela imposed a further increase in the royalty rate through the creation of an "extraction tax" of 33 1/3%. Royalty payments were to be credited to the liability of the extraction tax.

Increase in Income Tax**:** In August 2006 Venezuela increased the Income Tax Rate applicable to participants in the Orinoco Oil Belt (including the Cerro Negro and La Cieba projects) from 34% to 50%.

Production and export curtailments**:** In 2006 and 2007 Venezuela imposed a series of production and export curtailments on the Cerro Negro Project.

Expropriation**:** On 26 February 2007 President Chávez issued Decree-Law No. 5200 which ordered the associations located in the Orinoco Oil Belt (such as the Cerro Negro Association), and the At-Risk-and-Shared-Profits Associations, (such as the La Ceiba Association), be "migrated" into new mixed companies in which PDVSA or one of its subsidiaries would hold at least a 60% participation interest. The Decree-Law gave Mobil Cerro Negro and Mobil Venezolana until 26 June 2006 (*i.e.* four months) to agree to participation in the new mixed companies, failing which "*the Republic, through Petróleos de Venezuela S.A. or any of its affiliates [...] shall directly assume the activities of the associations*". On 27 June 2007, as no agreement had been reached, the Government of Venezuela seized the investments of Mobil Cerro Negro in the Cerro Negro Project and the investments of Mobil Venezolana in the La Ceiba Project.

Summary of ICSID's Ruling

The Tribunal made a number of key findings regarding jurisdiction, expropriation, fair and equitable treatment, and compensation.

Jurisdictional issues involving alleged treaty shopping:

In its earlier Decision on Jurisdiction, the Tribunal held that its jurisdiction was limited to disputes that arose after Mobil had restructured its Venezuelan assets through the creation of a Dutch holding company in 2005-2006, in order to bring them within the protective ambit of the Netherlands-Venezuela BIT. While the Tribunal considered restructuring an investment to gain access to ICSID arbitration through a bilateral investment treaty a legitimate aim, it likewise stressed that "*[w]ith respect to pre-existing disputes, the situation is different and the Tribunal considers that to restructure investments only in order to gain jurisdiction under a BIT for such disputes would constitute, to take the words of the Phoenix Tribunal, "an abusive manipulation of the system of international investment protection under the ICSID Convention and the BITs*." [2] Accordingly, the Tribunal decided that it had jurisdiction over claims relating to disputes that arose only after the restructuring had taken place (*i.e.* after 21 February 2006 for the Cerro Negro Project and after 23 November 2006 for the La Ceiba Project).

In deciding its jurisdiction, the Tribunal considered the "*distinct measures taken and contested at different dates.*" [3] In relation to the extraction tax adopted by Venezuela in May 2006 (*i.e.* after the BIT'a protections became applicable), the Tribunal was persuaded by the fact that earlier correspondence sent by Exxon to Venezuela warning of various disputes did not mention that tax. Accordingly, the Tribunal found that the dispute relating to the extraction tax arose after the BIT became applicable, and was within the Tribunal's jurisdiction. [4] However, the Tribunal did not have jurisdiction over claims relating to the increase in income tax, as a dispute with respect to those claims had arisen in mid-2005, even though such measures were not formally enacted until August 2006.

Expropriation

Venezuela did not indirectly expropriate Claimants' investment through its implementation of pre-migration measures.

The Claimants argued that prior to directly expropriating their investment, Venezuela had permanently deprived them of the benefit of discrete rights pertaining to their investments by measures having an effect equivalent to expropriation. These pre-migration measures included imposing a higher income-tax rate, adopting an extraction tax, imposing production and export curtailments, and appointing a new operator for the Cerro Negro Project.

The Tribunal rejected with relative ease Claimants' contention that the stated measures had an effect equivalent to expropriation within the meaning of Article 6 of the BIT. According to the Tribunal, a measure which does not have all the features of a formal expropriation may be equivalent to an expropriation only if it gives rise to an effective deprivation of the investment as a whole. In the Tribunal's view, such an indirect expropriation "*requires either a total loss of the investment's value or a total loss of control by the investor of its investment, both of a permanent nature.*" [5] As Claimants had failed to demonstrate such permanent and total losses in relation to the pre-migration measures, the Tribunal held that those measures could not be properly characterized as an expropriation.

Venezuela's direct expropriation of the Cerro Negro and La Ceiba Projects in June 2007 was lawful.

While the parties agreed that the Claimants' investments were expropriated on 27 June 2007 through the implementation of Decree-Law No. 5200, they disagreed on the legality of the expropriation. The Claimants contended that Venezuela's measures amounted to an unlawful expropriation under Article 6 of the BIT because they (i) were taken without due process of law; (ii) were contrary to Venezuela's undertakings; and (iii) were taken without any compensation, let alone just compensation. Because of the alleged unlawful nature of Venezuela's actions, Claimants argued that Venezuela was required to make full reparation for the damages caused, in conformity with international law. By contrast, Venezuela contended that the expropriation was lawful, and that the indemnity to be paid to the Claimants must represent the market value of the investment in June 2007.

The Tribunal noted that the expropriation resulted from laws enacted by the National Assembly and decisions taken by President Chávez, which were aimed at creating new "mixed companies" majority-owned by the State. To accomplish this goal, negotiations with international oil companies (IOCs) were conducted for a period of four months. Nationalization was envisaged only in the event that those negotiations failed.

While Claimants described the negotiations as "*a coercive process which did not follow any established legal procedure to determine their rights before title of the assets was transferred to a PVDSA subsidiary*," the Tribunal did not accept this contention. It found that although negotiations with ExxonMobil had failed, negotiations with other IOCs such as Chevron, Total, Statoil, Sinopec and BP had been successful. The Tribunal found that the negotiation process "*enabled the participating companies to weigh their interests and make decisions during a reasonable period of time*," and was therefore compatible with the due process obligation of Article 6 of the BIT.

The Tribunal likewise held that Venezuela's expropriatory measures were not contrary to Respondent's undertakings carried with regard to Claimants' investments; indeed, Venezuela had reserved its sovereign right to expropriate.

Finally, the Tribunal noted that "*the mere fact that an investor has not received compensation does not in itself render an expropriation unlawful. An offer of compensation may have been made to the investor and, in such a case, the legality of the expropriation will depend on the terms of that offer.*" [6]

To decide whether an expropriation is lawful or not in the absence of payment of compensation, the Tribunal had to consider the facts of the case before it. Ultimately, the Tribunal found that Venezuela made proposals during the negotiations and that Claimants had failed to submit evidence demonstrating that such proposals were incompatible with the requirement of "just" compensation of Article 6(c) of the BIT. The fact that the two sides did not reach agreement on the compensation to be paid, and that Exxon thus resorted to ICSID arbitration, was not enough to transform a lawful taking into an unlawful one. As a result, ExxonMobil's claim for unlawful expropriation was rejected.

This key finding will undoubtedly be seized upon by Venezuela in pending disputes against it. The distinction between lawful and unlawful expropriation is a critical one for the purposes of compensation. A tribunal finding an unlawful expropriation may set the valuation date after the taking if the value of the assets has appreciated since the time of the taking, and award full compensation to restore the claimant to the position it would have been in had the unlawful taking not occurred. In contrast, a tribunal finding a lawful expropriation is typically restricted by most BITs to award compensation based on the value of the investment immediately before the taking, even if the investment has appreciated significantly thereafter. In light of the rising oil prices over the course of the last decade, this distinction can be momentous.

The ExxonMobil tribunal's finding of lawful expropriation can be contrasted with the majority of the ConocoPhillips tribunal, which found that Venezuela failed to negotiate with ConocoPhillips in good faith, and that Venezuela had offered only book-value, rather than fair market value, compensation for its assets. Based on those findings, the arbitrators concluded that Venezuela's expropriation was unlawful, thereby enabling ConocoPhillips to seek, in a further stage, compensation based on more advantageous numbers than those which applied in 2007.

The characterization of Venezuela's taking as lawful will undoubtedly be viewed as a major victory for the resource rich state.

Fair & Equitable Treatment

In addition to expropriation, ExxonMobil argued that Venezuela had breached the standard of Fair and Equitable Treatment (FET) provided for in BIT Article 3. The Tribunal analyzed Claimants' FET claims with respect to the (i) Extraction Tax; (ii) production and export curtailments; (iii) coercion and the expropriation measures; and (iv) severance payments.

<u>The Extraction Tax</u>

Claimants' FET claim related to the extraction tax was rejected on the merits. The Tribunal held that the FET provision of the BIT (Article 3) did not extend to tax or fiscal measures. In so doing, the Tribunal considered significant the fact that Article 4 of the BIT "*comprehensively regulates the standards of treatment with respect to fiscal measures by providing for national and most favored nation treatment, and a list of applicable exceptions*." [7] In the Tribunal's opinion, applying Article 3 to Article 4 would lead to an incoherent reading of the BIT insofar as certain exceptions in Article 4 would be rendered meaningless, as they could be circumvented by relying on the broader provisions of Article 3. Moreover, a redundancy would appear in that both articles contain an exception for treatment in customs and economic unions.

As a result, the Tribunal found that fiscal measures like the extraction tax were only subject to the national and most favoured nation treatment obligations of BIT Article 4, and were carved out of Article 3's FET obligations. As the extraction tax claim was based exclusively on Article 3(1) of the BIT and not on Article 4, it was rejected.

<u>The Production and Export Curtailments</u>

The Tribunal opined that the FET standard "*may be breached by frustrating the expectations that the investor may have legitimately taken into account when making the investment" and that such legitimate expectations "may result from specific formal assurances given by the host state in order to induce investment.*" [8] The Tribunal reasoned that because the Cerro Negro Project Association Agreement fixed the level of extra-heavy oil production at 120,000 barrels per day, Claimants reasonably and legitimately could have expected to produce at least that volume when deciding to invest in Venezuela. As a result, the production and export curtailments imposed from November 2006 "*were incompatible with the Claimants' reasonable and legitimate expectations, and thus breached the FET standard contained in Article 3(1) of the BIT.*" [9] The Tribunal awarded ExxonMobil US$9,042,482 in relation to the production and export curtailments, as compared to the of the $53.6 million sought by Claimants for that claim. The tribunal further underscored the Claimants' assurances to refund sums already obtained from PDVSA through the ICC award in relation to this claim.

The Expropriation Measures and Severance Payments

The Tribunal easily rejected Claimants' contention that the same measures that gave rise to the ultimate expropriation of Claimants' investments should be deemed to constitute a violation of the FET standard as well. The Tribunal referred to its finding that the expropriation was conducted in a lawful manner, and noted that the FET claims based on the expropriation measures had been too briefly and too unconvincingly developed to enable the Tribunal to rule in Claimants' favour. The Tribunal likewise gave little weight to Claimants' contention that the removal of the operator of the Cerro Negro project was arbitrary and that ensuing severance payments that came due should be compensable events. As a result, those claims were dismissed.

Quantum

The Tribunal considered that the "just compensation" under Article 6 of the BIT had to be determined immediately after the failure of the negotiations between the Parties and before the expropriation, *i.e.*, on 27 June 2007, and it must correspond to the amount that a willing buyer would have been ready to pay to a willing seller at the time in order to acquire the expropriated interests. As noted previously the Tribunal's adoption of the 27 June 2007 valuation date had a significant impact on the damages ExxonMobil was entitled, especially in light of the significant increases in oil prices post-2007.

The Tribunal undertook a detailed analysis of the quantum for the largest head of claim relating to the expropriation of the Cerro Negro Project. The parties agreed that quantum should be assessed on a discounted cash-flow (DCF) basis. Accordingly, they evaluated the net cash flows that would have been generated by the investment over its remaining life, *i.e.*, until June 2035, and discounted them to their present value. While the parties agreed on the general DCF approach, they disagreed on the determination of net cash flows and discount rates. So far as the net cash flow (prior to discounting) was concerned, the main disagreements concerned the volume of production and the projected oil prices, both relating to the revenue side of the equation. The Tribunal determined (by reference to relevant agreements and physical conditions of the project) that the volume of future production could not be increased from the initial production level of 120,000 barrels per day of extra-heavy oil to 344,000 barrels per day by 2014, as suggested by Claimants. On that basis, the Tribunal accepted that the net cash flow should be assessed by reference to an average monthly production of 120,000 barrels per day of extra-heavy oil. The Tribunal also determined that the projected oil prices had to take into consideration the position in the market at the time immediately prior to the expropriation (including the position of OPEC, of which Venezuela is a member), and therefore adopted Claimants' expert evidence on the point. The Tribunal also held that on the facts, a number of expenses, such as costs of operations, investments, special contributions and income tax, should be deducted from the gross revenue to arrive at a the projected net cash flow for the Cerro Negro Project from 2007 to 2035 of USD 7,399.8 million.

The issue of appropriate discount to be applied in that case concerned primarily the so-called confiscation risk. The Claimants said that the confiscation risk should not be included in the assessment of the country risk, whereas the respondent asserted the opposite. The Tribunal considered that the confiscation risk would be taken into consideration by a willing buyer at the relevant time (immediately before the confiscation), and therefore such confiscation risk should be included in the country risk for the purposes of calculating the applicable discount. On that basis, the Tribunal held that the deep discount of 18% should be applied in that case.

The Tribunal rejected Venezuela Respondent's defence based on a price cap under the Cerro Negro Association Agreement. In the Tribunal's view, that agreement involved different parties and, on proper construction, the relevant cap did not apply to the claims in the instant case. A final point concerned the risk of double recovery by the claimant, as it received compensation in respect of the measures in dispute under a separate ICC arbitration against the state-owned PDVSA. However, the Tribunal noted that Claimants had been contractually required to pursue claims available to it to mitigate damages and to indemnify PDVSA in respect of any "net benefits" that it might receive as a result of such legal actions. The Tribunal noted that Claimants had agreed to comply with the indemnity provisions and, on that basis, the Tribunal was satisfied that no double recovery would result from granting relief in the instant proceedings.

In relation to the La Ceiba Project claim, the Tribunal agreed with Claimants that the quantum should be assessed by reference to the actual value of Claimants' investments at the date of expropriation; a DCF calculation was not warranted given the early stage of development of that project. The Tribunal awarded Claimants USD 179.3 million, which corresponded to Claimants' invested capital.

Whilst the monetary relief granted by the Tribunal was significantly lower than Claimants' claims, it was still considerable by any standard. On that basis, each side claimed a victory. The Tribunal's own view may perhaps be best understood from its decision on costs. Each side was ordered to bear its own legal costs and pay half of the arbitration costs.

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[1] *Venezuela Holdings and others v. the Bolivarian Republic of Venezuela*, Award, 9 Oct. 2014, ICSID Case No. ARB/07/27.
[2] *Id*. at ¶185.
[3] *Id*. at ¶203.
[4] *Id*. at ¶207.
[5] *Id*. at ¶286.
[6] *Id*. at ¶301.
[7] *Id*. at ¶ 243.
[8] *Id*. at ¶ 256.
[9] *Id*. at ¶ 264.

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KING & SPALDING

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DISPUTE RESOLUTION
Oil & Gas Litigation

Media Reports on 2014 "Fracking" Verdicts Miss the Real Story: Scientific Study Continues to Demonstrate the Safety of Professional Hydraulic Fracturing

Craig Warner

In April 2014, press reports widely suggested that a Dallas, Texas case was the first large verdict awarded on the basis of environmental damages sustained due to fracking. One advocacy journalism website's description of the verdict was typical:

> A Texas family claiming they were sickened because of pollution from hydraulic fracturing operations near their home should be awarded $2.95 million for their troubles, a jury ruled on Tuesday.
>
> The Parr family had sued Aruba Petroleum Inc. in 2011, alleging the oil and gas producer exposed them to hazardous gases, chemicals and industrial waste that seeped into the air from 22 wells drilled near the family's 40-acre plot of land, which sits atop the Barnett Shale.

But *Parr v. Aruba Petroleum* did not, in fact, represent progress for plaintiffs' attorneys seeking to undermine the case for the safety of hydraulic fracturing. The plaintiffs in *Parr* had their fracking-specific complaints dismissed long before verdict. The $2.95 million award in the case was instead based on claims of physical and mental pain and loss of property value that are commonly brought against all types of oil and gas operations.

Even as some journalists used *Parr* to push an anti-fracking narrative, a bigger story has developed beneath the radar: The scientific foundation has continued to shift in favor of expanded energy exploration by professional operators. Scientific inquiry into hydraulic fracturing has increasingly demonstrated that expertly built and operated fracking operations pose few new environmental dangers. One late-2014 study, in particular, should be consulted when faced with a plaintiffs' attorney seeking to undermine the case for the safety of hydraulic fracturing: A comprehensive examination of 130 drinking water wells near natural gas operations in Pennsylvania and Texas. The study, which was published in September 2014 and conducted by scientists from Duke, Ohio State, Stanford, Dartmouth, and the University of Rochester, found eight instances of contaminated water wells near natural gas projects - seven in Pennsylvania and one in Texas. The study found *no* evidence that this water contamination was due to fractured shale; instead, flaws in the cement and steel tubing used to seal the outside of vertical wells at shallow depths were to blame for the contamination in each case.

Dr. Thomas H. Darrah, the study's lead author, told the New York Times that the contamination at the test sites was generally due to disruptions in the shallower gas-rich pockets above the shale. In a press release, Duke

University gave specifics: "In four of the affected clusters, the team's noble gas analysis shows that methane from drill sites escaped into drinking water wells from shallower depths through faulty or insufficient rings of cement surrounding a gas well's shaft. In three clusters, the tests suggest the methane leaked through faulty well casings. In one cluster, it was linked to an underground well failure."

According to Dr. Darrah, as technological developments continue to improve well integrity, gas exploration companies can "probably eliminate most of the environmental problems with gas leaks." Investments by energy companies in improved well casings and tubing are likely to pay dividends in the future by protecting citizens from water contamination, and protecting investors from future lawsuits.

In the short term, the study's findings are most valuable for efforts to advance hydraulic fracturing projects through regulatory processes and defend them against opportunistic litigation. The study provides a ready-made rebuttal for assertions that water well contamination is specifically due to hydraulic fracturing. The methodology of study was described in depth by Duke University:

> Using both noble gas and hydrocarbon tracers -- a novel combination that enabled the researchers to identify and distinguish between the signatures of naturally occurring methane and stray gas contamination from shale gas drill sites -- the team analyzed gas content in 113 drinking-water wells and one natural methane seep overlying the Marcellus shale in Pennsylvania, and in 20 wells overlying the Barnett shale in Texas. Sampling was conducted in 2012 and 2013. Sampling sites included wells where contamination had been debated previously; wells known to have naturally high level of methane and salts, which tend to co-occur in areas overlying shale gas deposits; and wells located both within and beyond a one-kilometer distance from drill sites.

The study should be kept close to hand by litigators and general counsel defending natural gas operations involved in hydraulic fracturing. Because the study's results are not yet commonly known, educating courts through prompt filings pursuant to Rule 702 of the Federal Rules of Evidence, and state equivalents, is a necessity. This education process will pay dividends for the natural gas exploration and production industry as a whole over time, as more judges and regulators become acquainted with the scientific literature establishing the safety and effectiveness of hydraulic fracturing.

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Energy Newsletter

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REGULATORY

Environmental

Federal District Court Ruling in Fukushima Daiichi Case Has Implications for Global Nuclear Liability Management

Lynn Kerr McKay, Scott A. Greer

A recent ruling in *Cooper v. Tokyo Electric Power Company*, No. 12-CV-3032, S.D. Cal., Oct. 28, 2014, one of three lawsuits [1] filed in the United States related to the 2011 incident at the Fukushima-Daiichi nuclear power plant, highlights gaps in the application of methods for managing nuclear liability and the need for global expansion and strengthening of those methods.

Nuclear Liability Laws and Conventions

Claims involving injuries from a nuclear incident in the United States are governed by the Price Anderson Act, 42 U.S.C. § 2210(n)(2), which establishes a regulatory/liability management scheme for nuclear power in the United States. Other countries with commercial nuclear power facilities, including Japan, have enacted laws adopting similar nuclear liability regimes. The main principles of these nuclear liability laws include:

1. Channeling liability to the operator of the nuclear facility where an incident occurs;

2. Strict (no-fault) liability;

3. Limits on liability and/or government participation in funding liability in extraordinary circumstances;

4. Mandatory insurance for operator's liability;

5. Consolidation of claims in the jurisdiction where the incident occurs; and

6. Allowing for relief for all those impacted by the incident, regardless of citizenship or residence.

Due to their proximity, countries in Europe recognized the need for consistent laws managing nuclear liability, and were among the first nations to enter into international conventions for this purpose. Members of these conventions agree to abide by the principles of nuclear liability regimes and to enact laws adopting these principles in their own countries. The Convention on Third Party Liability in the Field of Nuclear Energy (Paris Convention) and related supplements are open to countries that are members of the Organization for Economic Cooperation and Development (OECD), and to other countries with the approval of all other parties. The Vienna Convention on Civil Liability for Nuclear Damage is open to all countries that are members of the United Nations. The Conventions, along with a joint protocol – the 1988 Joint Protocol Relating to the Application of the Vienna Convention and the Paris Convention - linking the two Conventions, provide for consistent handling of responsibility a nuclear incident, even if an incident occurs in one country, but affects residents in other countries. Additional information regarding which countries are parties to, have signed and/or ratified the conventions, is available by clicking here.

However, the United States and Japan, and other countries with commercial nuclear power are not parties to the Conventions or the Joint Protocol. Nuclear industry suppliers and designers doing business with operators in countries that are not members of the Conventions have relied upon nuclear liability statutes in those countries, and on contracts and insurance to manage their liability. In 1997, the International Atomic Energy Agency created the Convention on Supplementary Compensation for Nuclear Damage (CSC) to further encourage more uniform global management of nuclear liability and consistent nuclear liability laws. To have official force and effect, the CSC requires ratification by five countries with collectively a minimum installed nuclear capacity of 400,000 MWs of thermal power.

The CSC's goal is to establish treaty relations between countries that belong to either the Vienna or Paris Conventions and CSC countries, and increase the amount of compensation available for nuclear incidents through defined contribution from participating countries. Japan was not part of any convention at the time of the Fukushima-Daiichi incident. Japan's legislature recently passed a law permitting it to ratify the CSC. It will join the United States, Romania, Argentina, and Morocco, and the United Arab Emirates as CSC ratifying countries. Japan's participation will trigger the CSC's entry into force.

Cooper v. Tokyo Electric Power Company

In 2012, United States sailors and their families filed an action in the Southern District of California against Tokyo Electric Power Company (TEPCO). The plaintiffs allege injuries resulting from the sailors' exposure to radiation from Fukushima-Daiichi. The sailors had been aboard the *USS Ronald Reagan* off the coast of Japan when it was sent to the region to provide assistance in the aftermath of the Great East Japan earthquake and tsunami. In October 2014, the court issued an opinion which denied TEPCO's motion to dismiss the case on *forum non conveniens* and international comity grounds. TEPCO has moved for reconsideration or, alternatively for certification of interlocutory appeal of the court's opinion. Briefing is scheduled to be completed by January 29, 2015.

Regarding *forum non conveniens*, the court determined that it would be more convenient for the parties to litigate in a United States court. Notably, as to the factor concerning familiarity with governing law, the court found, "TEPCO does not suggest at any point that Japanese law would govern the dispute if the Court retained jurisdiction. In all likelihood, the Court would be applying some version of U.S. law, be it maritime law, federal common law, or California state law." *Cooper,* No. 12-CV-3032, slip op. at 28 (S.D. Cal. Oct. 28, 2014).

As to dismissal on international comity grounds, the court considered arguments based on Japan's nuclear liability law and on the United States' participation in the CSC that all claims for relief arising from the Fukushima-Daiichi incident should be tried in the same court in Japan, that Japanese law provides an effective system for compensating all individuals harmed by the incident, and that all liability for the incident is channeled through TEPCO. The court rejected reliance on the CSC because it has not yet been ratified, and found that the United States had a slightly stronger interest in the matter. The court also granted plaintiffs' motion to add four defendants who were "responsible in part for the design, procurement, maintenance, management, or servicing" of the facility.

Conclusion

If it stands, the ruling in *Cooper* may provide an impetus to additional countries to participate in the CSC or other conventions. Although laws addressing nuclear risk in both Japan and the United States provide for liability channeling and consolidation of claims in a court where a nuclear incident occurs, the ruling in *Cooper* leaves open the possibility that a lawsuit could be tried in a court outside the country where the incident occurred, and could be decided using state common law, instead of nuclear liability laws. In light of this ruling, those in the nuclear industry should work to further unify and harmonize global nuclear liability regimes. Ratification of the CSC by additional countries is an efficient and effective way to accomplish this goal.

Two other cases, *Sasaki Body Ltd., et al. v. General Electric Corp., et al. and Okura et al. v. General Electric Company, et al.*, were filed in state court in New York. In these cases, Japanese citizens sued General Electric, alleging negligence in its design of the Mark I reactor in the Fukushima-Daiichi plant. Because Japanese nuclear liability law provides for channeling of all liability for a nuclear incident to the operator of the facility, TEPCO is the only party Japanese citizens may sue in Japanese courts for alleged injuries arising from the incident. These cases in New York have been dismissed.

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