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USA

Stephen D. Davis & John C. LaMaster
Akin Gump Strauss Hauer & Feld LLP

Overview of the current energy mix, and the place in the market of different energy sources

The primary sources of energy consumed in the U.S. are coal, oil, natural gas, nuclear energy and renewable energy. These primary sources are all used to a greater or lesser extent to generate electricity, which is a secondary energy source. The mix of these primary energy sources used to generate electricity has changed significantly since 1990, and is expected to change even further over the next 25 years. Statistics regarding the percentage mix of various energy sources cited in part 1 of this chapter are from the U.S. Energy Information Administration.

The biggest change in the energy mix since 1990 has been the shift away from coal to natural gas and other primary sources of energy. The share of electricity generation capacity from coal has declined from 42% in 1990 to 29% in 2013. Over the same period, the share of electricity generation from natural gas has more than doubled from 19% in 1990 to 40% in 2013. The share of electricity generated from nuclear energy and from renewable energy sources, including hydroelectric, wind and solar, has also increased over the same period.

The declining share of coal used in electricity generation is due to a combination of several factors. Most of the existing coal-fired generation capacity in the U.S. is over 30 years old. The Environmental Protection Agency's Mercury and Air Toxic Standards are causing large-scale retirements of these aging facilities; it would be cost-prohibitive to retrofit most of the aging facilities to meet the newer emissions standards. The increasing supplies and declining price of natural gas have also been contributors in the shift away from coal. Finally, federal and state incentives for renewable energy contribute to the decline in the use of coal. Although coal's share of electricity generation capacity is falling rapidly, it is still expected to account for approximately 21% of electricity generation capacity in 2040, second only to natural gas.

The increase in the use of natural gas as a primary energy source has mainly been a result of the 'shale revolution', which has resulted in increased supplies of lower-priced natural gas. Another factor contributing to the rise of natural gas is the development of combined cycle technology, which is economical for providing both peak and baseload electricity supplies. As a result, it is anticipated that natural gas will account for approximately 35% of total electricity generation in 2040.

Nuclear energy's share of the generated electricity supply held steady between 1990 and 2013 at around 20%. Several nuclear reactors have been or will be retired, most of which will be replaced by new nuclear generation capacity. As a result, it is estimated that nuclear energy will account for approximately 16% of total electricity generation in 2040.

The U.S. is currently second worldwide in renewable electricity generation, after China. Approximately 13% of the electricity generated in the U.S. during 2014 was produced from renewable energy sources, including hydro, wind, biomass, geothermal and solar. The largest share, around 48%, came from hydroelectric power. We address renewables energy issues in more depth below.

Aside from electricity generation, the other major user of primary energy in the U.S. is transportation. Oil accounts for approximately 92% of the energy used for transportation. Over the past ten years, the development of hydraulic fracturing (or "fracking") has opened up significant quantities of oil and natural gas that were previously uneconomic to develop. Shale resources are found throughout the U.S., from the Marcellus centered in Pennsylvania, to the Barnett and Eagle Ford in Texas, to the Bakken in North Dakota.

The price of oil has dropped over 50% over the past year or so, from around $115 a barrel in June 2014 to less than $50 a barrel in August 2015. There are multiple reasons for this decline. Firstly, oil demand has slowed, especially in China's faltering economy. Secondly, Saudi Arabia, the leader of the OPEC cartel, has maintained high levels of production despite the reduced demand, letting the price fall, in order to maintain and grow market share and perhaps for geopolitical reasons involving Iran and Russia. Thirdly, an agreement on Iran's nuclear program is expected to result in a lifting of international sanctions on Iran and the release of more Iranian crude onto the markets. Fourthly, U.S. output has remained strong despite these other factors, which has put further pressure on the oil price.

Many analysts predicted that this fall in the price of oil would result in the demise of the U.S. shale industry. The industry, however, has been surprisingly resilient. The fall in the price of oil has certainly had an adverse effect on high-cost projects such as the UK North Sea, the offshore Arctic and Canadian oil sands. But in comparison, the U.S. shale industry is mid-cost, not high-cost. The industry is also notable for having a large number of smaller participants, as opposed to the large integrated oil companies that are prevalent in the international oil industry. These smaller companies are more nimble and have reacted more quickly to changing marketing conditions. U.S. producers have achieved new efficiencies and lower costs by focusing on the most productive prospects and by using more efficient technology and engineering. As a result, U.S. production has actually increased in the face of the falling oil price, although for how long is an open question.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

If the energy situation over the last 12 months continues, there could be a significant shake-out in the U.S. shale industry. In particular, continuing low commodity prices for oil will have a detrimental effect. U.S. independent oil producers typically hedge up to 70-80% of their annual oil production, but many oil hedging programs that have protected producers over the past year or so are starting to expire, with the result that producers are increasingly exposed to the low commodity price. Furthermore, this October is the month in which banks that lend to oil and gas companies will do their bi-annual 'redetermination', which calculates how much the companies can borrow, based on: their oil and gas reserves; where the banks predict oil and gas prices will go; and what the oil and gas companies have hedged. During periods of reduced oil and gas commodity prices, this process has historically resulted in reductions to oil and gas companies' borrowing bases. The redetermination is expected to especially hit small- and mid-cap companies because they tend to rely more heavily on bank debt than larger-cap companies. On top of this, many shale producers have low levels of liquidity, and their share prices are already being hit by the low oil price. As a result, there will likely be short- and medium-term pain in the U.S. shale industry, and financial restructurings and bankruptcies are already under way.

The longer-term outlook, however, is more positive. The shale industry has shown the capability to rapidly reduce costs, and further cost-reductions are likely. The breakeven cost point for the best shale plays are generally thought to be in the range of $30 to $50 per barrel. Producers may be able to sustain production levels by focusing on these core areas, but the industry overall will not grow significantly in such a low commodity price environment. The U.S. Energy Information Administration estimates that U.S. oil production will be slightly lower at the end of 2015 and 2016 than it was in 2014. However, producers can react quickly to improving market conditions, because new shale wells can be brought on stream in weeks, not years. As a result, in the longer term, the U.S. shale industry will likely challenge Saudi Arabia as the oil market's swing producer.

Commodity prices for natural gas have also been low over the past 12 months, and it is expected that this situation will continue in the near term. This will accelerate the rise of natural gas as a primary source of energy for electricity generation, and the continued decline of coal as a primary source. The greater supplies of natural gas and liquids often produced in association therewith (e.g., ethane, propane and butane) have led to the development of massive new petrochemical projects, particularly on the U.S. Gulf Coast.

The recent energy situation in the U.S. has also led to a boom in natural gas pipeline investments. Many areas where shale gas has been discovered were historically consumers of natural gas, not producers. These include the Marcellus and Utica shale plays in the northeast. As a result, the pipeline infrastructure in these regions generally flows inwards rather than outwards. The industry has reacted with plans to develop billions of dollars' worth of projects to build new pipelines and to expand existing pipelines. Several of these projects are intended to transport natural gas to Mexico, where there is a rising demand for natural gas.

Developments in government policy/strategy/approach

On August 14, 2015, the U.S. Department of Commerce, Bureau of Industry and Security (BIS) indicated that it would approve a number of export licence applications permitting parties in the U.S. to swap crude oil with counterparties in Mexico. These decisions could open a new market for U.S. oil producers who are faced with an oversupply of light crude oil and have been previously foreclosed from this export market by the U.S. ban on crude oil exports. To take advantage of this opportunity, U.S. companies will need to structure swap transactions with Mexican companies that satisfy BIS's criteria for approval.

U.S. law, namely the Energy Policy and Conservation Act, has essentially banned the export of crude oil from the U.S. since the 1970s. The legal framework, which is primarily codified in BIS's Export Administration Regulations (EAR), has multiple exceptions that allow for licensed exports of crude oil in certain narrow prescribed circumstances, such as exports to Canada.

BIS also has the authority to approve export licences for swap transactions, particularly with adjacent countries, that are "consistent with the national interest and the purpose of the Energy Policy and Conservation Act". Specifically, the EAR directs that these applications must: (i) result in a true swap in terms of quantity and quality; (ii) have contractual terms to allow them to be terminated in case of national emergency; and (iii) demonstrate compelling economic or technological reasons, beyond the control of the applicant, why the crude oil cannot reasonably be marketed within the U.S.

Up until recently, BIS did not receive a high volume of export licence applications, particularly for swap transactions. However, this reality has changed due to the substantial increase of domestic oil production in recent years. This increase has made it very difficult for the U.S. to fully utilise existing production because more light crude oil is in the local market than can be absorbed. Nevertheless, imports continue because U.S. refineries were originally designed to handle, and have been processing, heavy crude oil imported from a variety of sources, including Canada, Mexico and Venezuela.

Since U.S. refiners cannot easily process this light crude oil without modification to their existing infrastructure, swapping U.S. light crude oil for imported heavy crude would allow the product to be more efficiently processed in current market conditions. This reality has caused a number of companies to seek approval from BIS for swap transactions between the U.S. and Mexico.

As previously mentioned, BIS signalled its approval of a number of swap transactions involving Mexico on August 14, 2015. These applications had been pending with BIS for a number of months, so it appears that the Obama Administration made a policy decision to generally permit such applications with Mexico when they meet the requisite criteria. At least one of these applications reportedly involves Mexico's state oil company, Petroleos Mexicanos, SA, and could involve an exchange of as much as 100,000 barrels per day or approximately 1% of current U.S. output.

In its statement to Congress, BIS noted that it has also denied a number of applications for similar swap transactions with other countries, presumably that are not adjacent to the U.S. This announcement is consistent with the existing legal framework that favours crude oil exports with adjacent countries. Moreover, it highlights that crude oil exports will continue to be heavily restricted unless Congress takes action to repeal the export ban.

These recent developments demonstrate that further opportunities exist for companies to export crude oil from the U.S. Today companies are open to pursue crude oil swaps with companies in Mexico in light of these recent approvals. However, obtaining a licence for these transactions will require carefully structuring the transaction to meet the requisite regulatory framework while remaining commercially viable.

Beyond the licensing opportunities, the U.S. Congress is considering the repeal of the crude oil export ban. If such legislation were to come into force, companies would no longer be restricted from exporting crude oil, which could open a variety of new markets for U.S. producers.

Developments in legislation or regulation

Federal and state policymakers continue to grapple with significant changes affecting the U.S. electric power industry. Low natural gas prices, the impact of new environmental regulations on coal-fired plants, and the rapid development of distributed generation (including rooftop solar) are straining the tools historically used by regulators to ensure reliable and affordable service.

At the federal level, these developments present challenges for the wholesale, regional power markets regulated by the Federal Energy Regulatory Commission (FERC) and administered by Regional Transmission Organizations and Independent System Operators (RTOs/ISOs). In these markets, where energy prices are based on the bid of the lowest-cost marginal resource, historically low natural gas prices have made gas-fired generation frequently the marginal unit and driven prices down considerably. These lower prices – combined with the impact of new emissions restrictions – place revenue pressure on nuclear and coal-fired plants, resulting in the closure or threatened retirement of numerous units. The U.S. Energy Information Administration predicts that more than 90 gigawatts of coal-fired generation could retire by 2040. With respect to nuclear power, the Vermont Yankee plant in New England retired in 2014, and additional plants in the Midwest and Mid-Atlantic risk retirement due to insufficient revenues.

These retirements result in greater reliance on natural gas for power generation. Reliance on natural gas is most pronounced in New England, where 44% of electricity was generated by natural gas plants in 2014. Increased natural gas reliance has spawned reliability and price concerns, particularly in winter months when increased power demand strains pipelines and puts delivery of fuel to generators – who may not have firm pipeline capacity – at greater risk. The extreme cold weather in 2013-2014 highlighted these risks as several generators experienced operational challenges due to lack of access to natural gas, resulting in spikes in wholesale power prices.

To address these challenges while continuing to rely on competitive markets, FERC has pursued both industry-wide initiatives and specific regulatory actions. For example, FERC launched a broad-ranging "price formation" initiative to consider reforms to ensure that wholesale markets set accurate prices that support reliable operation and signal the need for new investment, and that existing market rules do not artificially suppress revenues. Meanwhile, to address reliability and price concerns stemming from increased reliance on natural gas, FERC ordered the RTOs/ISOs to consider how their markets address fuel supply risks.

FERC has taken some specific actions to address the resource performance problems experienced during the 2013-2014 winter, and to address increased reliance on gas-fired generation. In the New England and Mid-Atlantic regions, FERC approved rules to improve reliability by providing greater revenues for generators that agree to provide power when the system is strained or in an emergency condition, while imposing increased penalties when generators fail to meet their obligations. FERC has also adopted rules requiring the electric and natural gas industries to more closely coordinate to ensure that communication gaps or mismatches in timing between the industries do not threaten reliability.

While FERC continues to work to improve the rules and design of the wholesale electricity markets to incentivise better performance and investment, FERC has remained aggressive in prosecuting wrongdoings that distort market outcomes. In recent years, FERC has brought several enforcement actions against entities accused of manipulating wholesale prices. These cases frequently involve allegations that an entity purchased or sold power uneconomically in order to benefit a derivative financial position, or that an entity "gamed" or exploited loopholes in market rules. Because most enforcement actions historically were resolved by settlement, FERC's theories of what conduct constitutes manipulation have been largely untested in court. In the past few years, however, several investigative subjects have refused to settle, resulting in FERC filing civil enforcement actions in federal court. In May 2015, FERC earned what could be an important victory in one high-profile case when a federal district judge in California denied a motion to dismiss by Barclays Bank and certain Barclays traders alleged by FERC to have manipulated western power markets. The Barclays case remains ongoing.

At the state level, regulators are grappling with the rapid expansion of rooftop solar systems. As customers self-generate more and buy less from the utility, there are concerns that utilities will be unable to recover the fixed costs of the grid. States are taking a variety of approaches to address this challenge. Some states are considering fixed charges for customers with photovoltaics that would allocate a share of grid costs to customers regardless of how much they buy from the utility. Other states are considering broader market reforms to support expanded access to distributed generation. All of these efforts are significant as they require at least some departure from the traditional "cost of service" model of regulating retail electric service that has been utilised for a century.

Judicial decisions, court judgments, results of public enquiries

The landscape in the oil and gas industry is undergoing a fundamental transformation driven by technological advances in drilling efficiency. While such advances have helped the U.S. again become one of the world's largest energy producers, they have also been a double-edged sword leading to increased supply and price declines. As revenues decline, royalties decline and royalty owners (especially those in new plays) become anxious. This friction inevitably leads to an escalation in disputes over how royalty payments are calculated.

The issue is becoming increasingly relevant as regulatory barriers regarding exports are removed (*e.g.*, recent LNG and lease condensate export approvals) and opportunities to sell production at international prices become more readily available and, with those opportunities, the potential for royalty owners to stake claims tied to prices in international markets. Moreover, since royalties are generally structured to be paid free of certain costs, a royalty owner might argue that royalty payments should be calculated based upon higher prices available in international markets *and* without deduction for transportation or further handling costs.

This scenario is one that has not been well publicised, because the U.S. has not been a significant exporter of crude oil or natural gas and the sales that have occurred have typically been made by entities unaffiliated with producers. And while litigation over royalty payments is not a recent phenomenon, LNG exports (and possible lifting of the U.S. crude oil export ban) may change this picture and force parties to re-examine royalty calculations.

In any royalty dispute, the parties first look to the terms of the applicable lease. While royalty owners are free to negotiate bespoke royalty provisions, producers are generally only amenable to modifications where a royalty owner has significant leverage. During the "great shale land rush", where many producers' landmen acquired as much acreage as possible as quickly as possible, producers became more willing to accept modifications. Accordingly, today, it is not uncommon for producers to be party to leases with various royalty provisions. For example, royalty payments could be based on a variable or flat rate, sales proceeds, market value, various global indices, or a combination of each. Indeed, the possible variations are limitless. However, such provisions, which often appear straightforward during negotiations, are often less so after the fact. In such cases, parties look to the courts for interpretation.

Two recent cases provide guidance on an increasingly common royalty owner dispute – proper deduction of costs. In *Fawcett v. Oil Producers, Inc. of Kansas* (2015), where royalty payments were calculated based on higher prices downstream of the wellhead but deductions attributable to the costs incurred to transport such production downstream were challenged, the Kansas Supreme Court found that royalty owners must bear a proportional share of the reasonable expenses of transporting gas to market, even if production is marketable at the wellhead. While the *Fawcett* holding is producer-favourable, it conflicts with other cases where courts have held that operators are responsible for post-production costs.

In *Chesapeake Exploration, LLC v. Hyder* (2015), where a royalty owner challenged the deductibility of post-production costs, the Texas courts found that the operator improperly deducted post-production costs. The Texas Supreme Court intimated that just because a royalty owner might be subject to post-production costs if the royalty owner had taken in kind does not necessarily mean the royalty payment must be subject to those costs. The Texas Supreme Court has been asked to reconsider its decision. While these cases involve unique lease terms, they make clear the importance of careful pre-acquisition lease analysis to help mitigate the risk of royalty litigation in this low price environment, and particularly where any hint of an integrated project may exist.

Major events or developments

Next year will mark the 35th anniversary of the first commercial wind farm in the U.S. Like the renewable energy projects being built today, those early projects were supported by federal tax benefits and government-mandated purchase obligations. However, unlike the renewable projects of yesteryear, today's wind and solar projects have a level of efficiency and reliability that allows them to compete directly and effectively with conventional power projects. Combine this with the ever-increasing public concern over climate change caused, in part, by burning fossil fuels to make electricity, and we could be sitting on a "perfect storm" for a new wave of renewable energy growth in the U.S.

While each technology proponent will have its own view of where coal, nuclear, natural gas or non-hydro renewables will fit in the country's energy mix, and we noted some experts in the field predicted that by 2040, coal would still produce 21% of the country's energy, while natural gas would produce 35%, the renewable industries would undoubtedly take issue with that. For example, in March of this year, the White House and the U.S. Department of Energy released a report entitled "*Wind Vision: A New Era of Wind Power in the United States*", which was prepared after two years of research and peer review. The report updated and extended a 2008 Bush Administration report, "*20% Wind Energy by 2030*". *Wind Vision* describes a new scenario for wind to reach 10% by 2020, 20% by 2030, and 35% by 2050, and provides a road map for government and industry to get there. In light of wind's current 4.5% contribution to the country's energy mix developed over 35 years, doubling wind energy in the country by 2020 and doubling again by 2030, would appear a tall task. However, as one drills down into the *Wind Vision* report, the numbers seem rationally developed, although it will take expanded policy support to achieve them.

Regardless of whose numbers are used, it is clear that non-hydro renewable energy projects, mostly wind and solar projects, have been growing dramatically over the past several years – despite a relatively flat growth of energy demand in the U.S. Based on installed capacity reported at the end of last year, since 2010, wind energy in the U.S. has increased by over 60%. Solar energy, on the other hand, has seen a nearly 20-fold increase in installed capacity since 2010. The U.S. Solar Energy Industry Association predicts that solar capacity in the U.S. will double in the next two years, moving overall capacity from 20,000 MW to over 40,000 MW.

So what is fuelling this growth, and, more importantly, is it likely to continue? There appear to be four primary sources that are contributing to the growth of renewables in the U.S. Two of these factors have played a historic role in the growth of renewables, whereas the two other factors are relatively new to the scene. The two elements that have played a role in the growth of renewables for several years are the federal government's tax policies supporting wind and solar, and the "renewable portfolio standards" that currently exist in 29 states and that require that a portion of such state's electricity be produced from renewable resources. Federal tax policy currently provides a $23 per MWh tax credit for the first 10 years of production for wind farms and a 30% investment tax credit for solar projects (and wind projects that elect the investment tax credit rather than the production tax credit). Both of these credits are scheduled to either cease, in the case of the production tax credit, or be reduced to 10%, in the case of the investment tax credit for solar, by the end of 2016. While it is likely that the production tax credit will be renewed or extended (as it has been approximately nine times since its enactment in 1992), and it is possible that the solar investment tax credit will be revised to effectively extend it for a couple of years as well, there is no guarantee that these renewals or amendments will occur. As a result, there is likely to be a push to complete as many wind and solar projects as possible prior to the end of 2016. State renewable portfolio standards may play less of a role going forward (with some exceptions, such as California where there is legislation to expand the 33% renewable portfolio standard to 50%) as many of the states are beginning to reach their renewable targets.

A more significant impact on the growth of renewables, however, appears to be coming from two other sources: a decrease in the cost of capital for renewable energy projects driven by the so-called "Yieldco" vehicle for raising capital; and the Obama Administration's and the Environmental Protection Agency's "Clean Power Plan" designed to reduce global warming emissions from power plants – particularly coal-burning plants.

Over the past 24 months eight major developers have formed public vehicles, commonly called "Yieldcos", in which the developers drop down or acquire energy-producing assets (mostly renewables) with contracted offtake agreements into a separate company. With current reliable technology and a contract with a utility or other offtaker to buy the power, these assets should produce a steady stream of income over their useful lives or the term of the offtake agreements. This allows the sponsor to sell a portion of the shares of the Yieldco company to the public, promising an immediate dividend and growth potential. The demand for Yieldco shares has been outstanding, allowing sponsors to raise funds at a cost of somewhere between 2.2% and 6%, as opposed to rates in the low teens that are often seen in private equity arrangements. This lower cost of capital has further decreased the cost of power from renewable projects and has made them even more competitive with fossil fuel-generated electricity (in some cases dramatically below the cost of fossil fuel-generated electricity).

While the lower cost of renewable power will certainly help fuel its demand, in order to see continued growth, there needs to be a demand for new power plants in the U.S. The market can then decide whether those new power plants will be natural gas, wind or solar. However, with flat or very limited demand in energy growth, the demand for new power plants would seem limited. That will change, however, if the Administration's Clean Power Plan is put into effect. Under the Clean Power Plan, climate change emissions will be limited, likely resulting in numerous aging coal burning power plants being retired. We have already seen the cost of operating coal plants become increasingly expensive and have seen electricity produced from coal in the U.S. drop from nearly 50% to under a third in the past 20 years. While the Clean Power Plan, which will be implemented by the Environmental Protection Agency without separate legislation from Congress, is likely to be challenged and be tied up in the courts for several years, many believe that it will eventually be implemented and have a dramatic impact on the use of coal as a fuel for electric generation. While time will tell as to the outcome of the Clean Power Plan, it is likely that many in the electric power industry are making contingency plans that involve additional renewables if and when the

Clean Power Plan is put into effect, and may even be contracting for wind or solar energy before the current tax credits benefiting those technologies might expire.

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Stephen D. Davis
Tel: +1 713 220 5888 / Email: sddavis@akingump.com

Steve Davis is a partner in the Houston office of Akin Gump Strauss Hauer & Feld LLP. He has over 30 years of experience representing sponsors/developers and project companies, sellers and buyers, financial institutions, private equity investors and other parties on major transactions relating to oil and gas, LNG, midstream, pipeline, processing, petrochemical, power, refining, renewables and cleantech, as well as other energy industries. He was named Houston Energy Law 2013 "Lawyer of the Year" by The Best Lawyers in America®, as well as one of the Top 30 energy and natural resources lawyers in the United States by The Best of the Best USA 2014 as published by Expert Guides, a Euromoney publication. Mr. Davis spent over six years of his practice in the Asia-Pacific region. In addition to his law degree, he holds an Honours degree in Chemical Engineering.

John C. LaMaster
Tel: +44 20 7012 9729 / Email: jlamaster@akingump.com

John C. LaMaster is a partner in the London office of Akin Gump Strauss Hauer & Feld LLP. His principal areas of practice are international mergers, acquisitions and divestitures, joint ventures, project development and related activities, with a particular emphasis on the energy industry. Mr. LaMaster has over 30 years of experience in virtually all areas of the energy industry, including upstream, midstream and downstream oil and gas, electricity generation, biofuels, chemicals and petrochemicals. Mr. LaMaster has worked on energy transactions throughout Europe, Africa, Russia and the former Soviet Union, the Middle East, India and the U.S. He is one of only seven 'Band 1' rated lawyers for "Energy & Natural Resources: Oil & Gas – UK Wide" in the 2015 edition of Chambers & Partners, which described him as a "quality energy lawyer who understands the industry and has the experience of market practice".

Akin Gump Strauss Hauer & Feld LLP
1111 Louisiana Street, 44th Floor, Houston, TX 77002-5200, USA
Tel: +1 713 220 5800 / Fax: +1 713 236 0822 / URL: http://www.akingump.com

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