BAKER BOTTS

*January 31, 2014*

## 2013 – Consolidation Among Electric and Gas Companies Continues at a Measured Pace

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This paper surveys some of the major developments in energy merger and acquisition transactions during 2013 as well as some of the key regulatory developments that either affected or are likely to affect activity going forward.

Overall, deal volumes were higher in 2013 than 2012, although still considerably below 2011 and 2010 levels. Data from SNL Financial shows total announced transaction value of about $58 billion compared to $41 billion in 2012, $135 billion in 2011 and $105 billion in 2010.[1] Anecdotally, the general economic, political and regulatory uncertainties facing energy companies in the United States seemed to dampen activity, although to a lesser extent than in 2012.

Looking at subsectors within the industry, activity among pipeline and midstream companies was roughly flat with about $25.9 billion of activity in 2013 compared to $25.6 billion in 2012. These levels also were down considerably from the $62.9 billion of 2011 and $45.2 billion in 2010. Activity among the integrated electric companies picked up considerably with transaction volume of $15.3 billion in 2013 compared to a meager $1.6 billion in 2012. 2012 was a particularly lean year when the only transaction announced was the acquisition of CH Energy by Fortis. Two major transactions were announced in 2013, MidAmerican Energy's acquisition of NV Energy, announced in May, and the acquisition of UNS Energy by Fortis in December. Only one LDC transaction was announced during the year, TECO's acquisition of New Mexico Gas for $950 million. The volume of generation transactions was up slightly at $9.8 billion compared to $7.9 billion in 2012 and $8.1 billion in 2011. Merger and acquisition activity involving renewables showed a significant decline, particularly as regards wind assets, with $2.5 billion of activity in 2013 compared to $4.6 billion in 2012.[2] The MLP space saw an increase in M&A activity, with 118 transactions for a total disclosed value of $68.0 billion in 2013 as compared to 103 transactions for $52.5 billion in 2012. We offer additional commentary about key transactions and the general trends that we see in each of these subsectors below.

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1 Source: SNL Financial, transactions with announced transaction values of $100 million or more.
2 Source: SNL Financial, transactions involving wind, solar or hydro with announced transaction values of $50 million or more; excludes entity level deals for mixed generation fleets.

On a macro level, there are still many factors that favor consolidation in the electric and gas industries. Scale and diversity are more important than ever. The energy industry in the United States is going through a period of significant change, with many companies facing capital expenditures on a dramatic scale. In general, the larger companies are better positioned to weather the inevitable volatility associated with the panoply of risks they will face as they expand and harden their systems over the coming decade. On the regulatory front, with a few notable exceptions, the attitude seems to be neutral to positive, at least with respect to mergers and acquisitions involving integrated electric companies and gas utilities. The strengthening U.S. economy also should favor further consolidation.

Of course, there also are impediments to consolidation. Many companies have a general aversion to being acquired, preferring to remain independent and focus on their stand-alone business plans. Even for those seeking a merger or to be acquired, it takes time for the various stars for a successful transaction to come into alignment. Other potential impediments to deal making in the electric sector include low growth rates in the electric industry and uncertainties with respect to future commodity prices, the regulatory framework applicable to construction of new generation, tax incentives available for renewable generation and the potential for significant increases in interest rates from the artificially low rates of the past several years.

The discussion below covers the following areas:

- Regulated Utilities
- Power Companies and Generation Assets
- Renewables
- Master Limited Partnerships
- LNG Developments
- Project Finance and YieldCos
- Environmental Regulation
- FERC
- ERCOT
- CFTC
- Mexico

## Regulated Utilities

In the regulated utilities sector, the year began with four major transactions pending from 2012 – the acquisition of CH Energy by Fortis, Laclede's acquisition of Missouri Gas and New England Gas from ETE, Steel River's acquisition of Equitable's gas distribution operations and the proposed Entergy/ITC Reverse Morris Trust transaction. While the first three transactions all eventually closed, albeit with some turbulence for the Fortis/CH Energy deal, the Entergy/ITC transaction eventually died under the weight of significant regulatory pushback from state regulators.

During the year, there were three more significant transactions announced involving regulated utilities – TECO's acquisition of New Mexico Gas, MidAmerican's acquisition of NV Energy, and another acquisition by Fortis, this time of UNS Energy. Although so far only one of these transactions has been completed, each of the others appears to be moving toward closing relatively smoothly.

***Fortis/CH Energy*** – On February 21, 2012, Fortis Inc. and CH Energy Group, Inc. announced a merger pursuant to which Fortis, Canada's largest investor-owned distribution utility, would acquire CH Energy for approximately $970 million in cash, or $65 per share to CH Energy shareholders, plus the assumption of about $500 million in debt. The consideration reflected a 10.5% premium above CH Energy's stock price prior to announcement, a premium of 13.1% above a recent 20-day trading average and 11.4 times its 2011 EBITDA. According to the press release, the deal was attractive to Fortis because it would enable the company to enter into the U.S. regulated electric and gas distribution business with a reasonably sized utility - one that operates as a single state utility.

The transaction was conditioned on approval of CH Energy shareholders, the New York State Public Service Commission and the Federal Energy Regulatory Commission (FERC), as well as HSR clearance. Shareholders approved the deal in June, followed by FERC in June, Committee on Foreign Investment in the United States (CFIUS) in July and HSR clearance in October. All was not as smooth on the state side, however, as a concerted effort by local opponents complicated the approval process.

On January 25, 2013 a proposed settlement agreement was filed with the NYPSC. Among other things, the settlement included a rate freeze until July 2014, a 50 basis point reduction in ROE, as well as approximately $50 million in total customer and community benefits. These included (i) the write-off of approximately $35 million in costs that would normally be recoverable in rates (e.g., cleanup costs from Superstorm Sandy and Hurricane Irene), (ii) $9.25 million in guaranteed savings resulting from going private and (iii) $5 million in a customer benefit fund. In addition, Fortis agreed to maintain Central Hudson as a stand-alone utility and to keep all current employees.

Despite the negotiated settlement, on May 3, 2013 two administrative law judges issued a recommended decision taking the position that the transaction did not meet the "in the public interest" standard of New York and should be rejected. The decision was the culmination of growing local opposition to the transaction, with a bipartisan majority of local legislators in Duchess County submitting a letter to the NYPSC opposing the merger, and the Ulster County legislature passing a unanimous resolution in opposition.

In response to the recommended decision, Fortis and CH Energy offered several enhancements to the proposed settlement, including extending the proposed rate freeze for an additional year to July 2015, and making clear that a proposed four year "no layoff" commitment would apply to all employees (unionized or otherwise).

On June 13, 2013, the NYPSC voted unanimously in favor of the transaction, conditioning its approval on CH Energy's continued support of two state initiatives to modernize New York's transmission grid, including equity support from Fortis for approved projects, to the extent required by CH Energy. A formal order issued on June 26, and the transaction closed the following day.

***Laclede/Missouri Gas* –** In mid-December, Laclede Group, Inc., Energy Transfer Equity, L.P. (ETE) and Energy Transfer Partners, L.P. (ETP) filed a joint press release announcing two separate transactions. Pursuant to the purchase and sale agreements between Laclede and Southern Union Company (an affiliate of ETE and ETP), newly formed subsidiaries of Laclede would acquire the assets of Southern Union's Missouri Gas Energy and New England Gas

Company for $1.015 billion in cash and nearly $20 million in assumed debt of New England Gas. Laclede's purchase of Missouri Gas is the larger of the two deals, valued at $975 million. The announcement followed what was rumored to be a very competitive auction of the two companies.

On January 14, 2013, the parties filed for approval of the acquisition of Missouri Gas with the Missouri Public Service Commission (MPSC) pursuant to which Laclede committed, among other things, not to seek recovery of any acquisition premium or transaction costs in Missouri Gas's rates and to use its best efforts to prevent any activities by its affiliates from having an adverse effect on Missouri Gas.

On July 2, 2013, a negotiated settlement was filed with the MPSC. In addition to the foregoing, the proposed settlement included commitments by Laclede for a $125 million "rate base offset" to be recorded by Missouri Gas that would be amortized over a ten-year period as well as a negative covenant that Laclede would not pledge its equity as collateral on behalf of any affiliates without first obtaining MPSC approval. Further, Laclede agreed that if its non-regulated operations resulted in a downgrade of its credit ratings to below investment-grade, then Laclede would take action to ensure that Missouri Gas has access to capital at a reasonable cost, and any increase in capital costs for Missouri Gas would not be permitted to be passed on to customers. Finally, Laclede also committed that, absent the occurrence of an "unusual event", it would not file for a general rate case with respect to its pre-transaction service territory prior to October 1, 2015, and with respect to the Missouri Gas operations, it would be permitted to file a general rate case if filed by September 18, 2013, but failing that, a general rate case would also not be permitted for Missouri Gas until October 1, 2015 unless an "unusual event" were to occur.

On July 17, 2013 the MPSC approved the transaction, with closing permitted on or after September 1, 2013, and on September 3rd, the parties announced that closing had occurred.

Separately from the Missouri Gas acquisition, on January 24, 2013 the parties filed for the approval of the acquisition by Laclede of New England Gas Company with the Massachusetts DPU. Subsequently, on February 11, Algonquin Power & Utilities Corp. announced that it had entered into an agreement with Laclede to assume Laclede's rights to purchase New England Gas Company for a total consideration of approximately $74 million, including the assumption of $19.5 million of existing debt. The existing filing with the Massachusetts DPU was amended to include approval of Algonquin's proposed acquisition, and on December 17, 2013 the DPU approved the transaction. The transaction subsequently closed on December 20, 2013.

***SteelRiver/EQT*** **–** On December 20, 2012, Peoples Natural Gas and EQT Corporation announced they had entered into an agreement pursuant to which Equitable Gas Company, EQT's natural gas distribution business, would be merged into Peoples, with Peoples surviving. Peoples is controlled by an affiliate of SteelRiver Infrastructure Partners and operates in southwestern Pennsylvania. Equitable Gas Company is a regulated natural gas public utility that provides natural gas distribution services to customers in Pennsylvania, West Virginia, and Kentucky. Under the agreement, Peoples will pay EQT $720 million in cash, subject to purchase price adjustments. Additionally, Peoples will transfer certain midstream and storage assets and gas marketing contracts to EQT; these additional assets are expected to generate at least $40 million in EBITDA per year.

The transaction required regulatory approval by the Pennsylvania Public Utility Commission (PPUC) and the West Virginia Public Service Commission (WVPSC), as well as HSR and other federal regulatory approvals. The Kentucky Public Service Commission determined it did not have jurisdiction.

On March 19, 2013, the parties filed for approval of the PPUC, and on October 2, 2013 a negotiated settlement was filed pursuant to which Steel River committed, among other things, to cap base rates until January 2018, with $15 million in savings due to the transaction to be passed through to customers, and not to seek to recover any acquisition premium or transaction costs in rates.

On March 27, 2013, the parties filed for approval of the WVPSC, and on October 17, 2013 a proposed settlement agreement was filed. In the settlement, Steel River committed to not try to recover any acquisition premium or transaction costs in rates, agreed to freeze rates until January 1, 2017 and further agreed that if a rate case is filed within seven years thereafter, a $2.25 million credit would be provided to customers, amortized over seven years.

The WVPSC approved the transaction on November 8, 2013, and the PPUC approved the transaction on November 14, 2013, and the transaction closed on December 17, 2013.

***Entergy/ITC –*** On December 5, 2011, Entergy and ITC announced they had entered into an agreement pursuant to which Entergy would spin-off its transmission business into a new entity and then merge that entity with ITC in a Reverse Morris Trust transaction. Post transaction, ITC would be owned 50.1% by Entergy shareholders and 49.9% by former ITC shareholders, and would have more than 30,000 miles of transmission lines from the Great Lakes to the Gulf Coast.

In addition to FERC and HSR approval, the proposed transaction required the approval of regulators in Arkansas, Louisiana, Mississippi, Missouri, New Orleans and Texas. The parties filed for approval with the Louisiana Public Service Commission (LPSC) on September 5, 2012. On September 12, 2012, they filed for approval with the New Orleans City Council, and followed that up with filings in Arkansas on September 28, 2012, Mississippi on October 5, 2012, Missouri on February 14, 2013, and finally in Texas on February 19, 2013.

Difficulties with the regulators emerged, beginning with Louisiana in March of 2013 when the Chairman of the LPSC directed his staff to explore alternative deal structures for the transaction that would allow the LPSC to maintain its regulatory oversight. Then in April, staff of the Arkansas PSC recommended rejection of the deal, and they were joined in May by staff of the Texas PUC, and in June by staff of the Mississippi PSC and the New Orleans City Council, who also recommended rejection. Despite the opposition, the deal seemed to generate some momentum when ITC shareholders approved it in April and Entergy and ITC responded to the regulatory pushback in June by proposing nearly $200 million in bill credits and other benefits for customers in Arkansas, Louisiana and Texas. FERC approved the deal in June of 2013, but with many approvals still outstanding the parties extended the drop dead date for the transaction from June 30, 2013 to December 31, 2013.

On July 8, 2013, a panel of administrative law judges in Texas recommended rejection of the transaction. In advance of a scheduled TX PUC meeting on August 9, the parties increased the rate mitigation bill credits on offer to more than $450 million. On the day of the scheduled meeting, one of the Texas PUC commissioners released a list of 26 requirements that the parties would need to satisfy in order for the deal to be approved. Unable to resolve things prior to a statutory deadline of August 18th, the parties elected to withdraw their application for approval, with leave to re-file. The withdrawal triggered the suspension of proceedings before the Louisiana PSC, Arkansas PSC and New Orleans City Council. Nonetheless, the parties eventually refiled for approval in Texas on September 23, 2013, including in their application a small increase to the proposed rate mitigation credits for Texas customers. It quickly became clear that despite the parties request for a decision from Texas prior to the December 31, 2013 drop dead date, the Texas PUC would not be ruling on the request until 2014. Then, on December 10, 2013, the Mississippi PSC denied approval of the deal. On December 13, 2013, the parties announced that they had abandoned the transaction and terminated the related transaction documents.

After the deal terminated, ITC attributed the regulatory difficulties they faced to tension between states and the federal government, with state regulators wary of ceding oversight of the transmission grid to the FERC.

***TECO/New Mexico Gas* –** On May 28, 2013, TECO Energy and Continental Energy Systems announced that they had entered into a stock purchase agreement pursuant to which TECO would acquire all of the stock of New Mexico Gas from Continental for a purchase price of $750 million plus the assumption of $200 million in debt. The announcement followed what was purported to be yet another very competitive auction process for a gas local distribution company. The transaction requires the approval of the New Mexico Public Regulation Commission and is expected to close in the first quarter of 2014.

According to the press release, this will be a transformative transaction for TECO, which will add 50% to its customer base in a single transaction, resulting in more than 1.5 million regulated electric and gas utility customers in Florida and New Mexico. The transaction is expected to be accretive in 2015, the first full year post-closing.

On July 9, 2013, TECO filed with the New Mexico Public Regulation Commission for approval of the transaction. On December 2, 2013, the hearing examiner in the proceeding issued an order vacating the existing procedural schedule, as had been requested by TECO and New Mexico Gas, in order to allow for additional time to file supplemental testimony.

***MidAmerican/NV Energy* –** On May 29, 2013, Berkshire Hathaway subsidiary MidAmerican Energy announced that it had entered into an agreement to acquire all of the outstanding shares of NV Energy for $23.75 per share in cash, for a total purchase price of approximately $5.6 billion. The consideration reflected a 20.3% premium above NV Energy’s stock price prior to announcement, and a premium of 14.4% above a recent 30-day volume weighted trading average. NV Energy’s two regulated utilities, Nevada Power Co. and Sierra Pacific Power Co., service some 1.1 million retail electric customers and approximately 152,000 retail gas customers. In addition to HSR approval, the transaction required the approval of the FERC and the Nevada Public Utility Commission.

MidAmerican filed for FERC approval on July 12, 2013, and on July 17 the parties filed a joint petition with the Nevada Public Utility Commission. Interestingly, on May 31, 2013, shortly after the announcement of the transaction, NV Energy filed separate applications with the Nevada PUC and the FERC for approval to combine Nevada Power and Sierra Pacific Power into a single utility. The FERC approved the combination on November 26, 2013, while the Nevada PUC is still considering it.

HSR approval was obtained on July 26, 2013, followed by NV Energy shareholder approval on September 25, 2013. On October 24, 2013, the Nevada PUC staff filed testimony urging that recovery of any transaction premium in rates be prohibited, and on November 8, 2013 a stipulated settlement was filed in the proceeding. In the settlement, MidAmerican agreed not to seek to recover any acquisition premium, transaction costs, or transition costs in Nevada retail rates. In addition, a one-time bill credit of $20 million would apply if the Nevada PUC were to approve the transaction on or before December 20, 2013. The Nevada PUC approval followed on December 16, 2013, and was closely followed by FERC approval on December 19, 2013, with the transaction proceeding to closing the following day on December 20, 2013.

***Fortis/UNS* –** On December 11, 2013, Fortis, Inc. and UNS Energy announced a merger pursuant to which Fortis would acquire UNS for approximately $2.5 billion in cash, or $60.25 per share to UNS Energy shareholders, plus the assumption of about $1.8 billion in debt. The consideration reflected a 31.4% premium above UNS Energy's last closing stock price prior to announcement and a 26.0% premium over the volume-weighted trading average for the 20 trading days prior to the announcement of the proposed merger.

UNS Energy is a holding company providing electric service to more than 400,000 customers through its regulated electric utility subsidiary, Tucson Electric Power, and electric and gas service to more than 237,000 customers through UniSource Energy Services. Fortis is expected to invest approximately $200 million of equity into UNS following the closing, among other things in order to help fund the planned purchase of Unit 3 of the Gila River Power Plant from Entegra.

The transaction is conditioned on approval of UNS Energy shareholders, the Arizona Corporation Commission (ACC) and the FERC, as well as clearance under the HSR Act and by CFIUS. The parties filed a joint petition for ACC approval on January 10, 2014. The transaction is expected to close in the fourth quarter of 2014.

## Power Companies and Generation Assets

On the unregulated side of the electric industry, the volume of generation transactions was up slightly at $9.8 billion in 2013 compared to $7.9 billion in 2012 and $8.1 billion in 2011. The two largest transactions in this subsector during 2013 were NRG's acquisition of Edison Mission Energy's assets out of bankruptcy and Ameren's sale of its merchant fleet to Dynegy. One of the trends that was in evidence was the strong interest in operating generation in ERCOT, perhaps in reaction to the extended uncertainty over ERCOT market design, which at least anecdotally is depressing new build activity. Examples of this trend included NRG's acquisition of the

Gregory plant, Calpine's acquisition of the Guadalupe plant, Blackstone's acquisition of the Bastrop Energy Center, the Frontera Generation Facility and the Paris Energy Center, and Energy Investors Funds' acquisition of the Channelview Cogeneration Facility.

***Dynegy/Ameren*** **–** On March 14, 2013, Dynegy Inc. announced that its subsidiary, Illinois Power Holdings LLC, had entered into an agreement with Ameren Corp. to acquire Ameren Energy Generating Co., Ameren's merchant generating business, including a retail and marketing business and 4,119 MW of generation consisting of five coal-fired power plants. The five power plants are the 425 MW Duck Creek plant in Fulton County, the 919 MW Coffeen plant in Montgomery County, the 720 MW E.D. Edwards plant in Peoria County, the 1,214 MW Newton plant in Jasper County and the 1,002 MW Joppa plant in Massac County (PPL Corp. subsidiary Kentucky Utilities Co. owns 20% of the Joppa plant). All five plants are expected to be compliant with the EPA's Mercury and Air Toxic Standards that are slated to go into effect during 2015.

As part of the transaction, three gas-fired power plants were to be stripped out of Ameren Energy and sold to Ameren Corp. for a minimum purchase price of $133 million. In addition, Ameren was obligated to fund an additional $60 million into Ameren Energy prior to closing, which will go on top of $33 million in additional cash on hand such that at closing Ameren Energy would have some $226 million in cash on hand and $160 million in working capital. At closing, Dynegy will acquire Ameren Energy for zero cash consideration.

Dynegy executives described the transaction as positioning Dynegy well for a potential rise in gas prices that leads to price recovery in the electric market without significant downside risk, given the zero cash outlay and the MATS compliant portfolio.

The parties jointly filed for FERC approval in April and, after some back and forth with FERC staff regarding their market power analysis FERC approved the transaction on October 11, 2013. In connection with the transaction, the parties also sought approval from the Illinois Pollution Control Board for variances relating to sulfur dioxide emissions limits. The plants were granted variances back in 2012 as part of a request from Ameren with respect to seven coal-fired plants, but the board had refused to transfer the existing variances without a new review. That review ultimately resulted in an order on November 21, 2013 granting multi-year variances for all seven plants, including the five being acquired by Dynegy. The transaction closed on December 2, 2013.

***ECP/Dominion*** **–** On March 11, 2013, Dominion announced the sale of three merchant power plants to Energy Capital Partners, consisting of the Brayton Point Power Station, a 1,528 MW plant in Massachusetts with three coal-fired units and one unit fired by oil or natural gas, the Kincaid Power Station, a 1,158 MW coal-fired plant in Illinois, and the Elwood Power Station, a 1,424 MW gas-fired plant outside Chicago (Dominion is selling its 50% interest in Elwood). The announced transaction value was approximately $650 million. The parties filed for FERC approval on March 21, 2013, and HSR clearance was obtained on March 29, 2013. FERC approved the transaction on August 20, 2013 and the deal closed on August 30, 2013.

***NRG/Gregory*** **–** On April 8, 2013, NRG announced that it had entered into a deal to acquire the Gregory cogeneration facility in Corpus Christi, Texas from an investor group that included Atlantic Power, John Hancock and Rockland Capital. The purchase price for the 400 MW plant is $244 million. The plant provides steam and a small amount of electric power to the Sherwin alumina plant, with the bulk of the electricity from the facility available for sale into the ERCOT market. The transaction closed on August 7, 2013.

***Emera/Capital Power*** **–** On August 28, 2013, Emera Inc. announced the acquisition of three gas-fired power plants from Capital Power Corporation for $541 million. The three plants are the 520 MW Bridgeport Energy Center, the 265 MW Tiverton Energy Center, and the 265 MW Rumford Energy Center. The deal showcased two Canadian companies with differing goals, as Capital Power continued its exit from the U.S. merchant power market with a stated intention of increasing its focus on its home territory of Alberta, while Halifax based Emera continued its investment in New England generation. The transaction closed on November 19, 2013.

***NRG/EME*** **–** Less than a year after its acquisition of GenOn, on October 18, 2013, NRG Energy, Inc. (NRG) announced its purchase of substantially all of Edison Mission Energy's (EME) assets as part of a deal negotiated with EME, certain of its senior noteholders and its unsecured creditors committee. EME filed for Chapter 11 bankruptcy protection in December 2012. The NRG purchase is part of EME's proposed plan of reorganization, and not pursuant to a more typical Section 363 stalking horse auction process. NRG is purchasing the EME assets for $2.64 billion in cash and NRG stock and the assumption of approximately $1.55 billion in debt.

The assets acquired include approximately 8,000 MW of wind, gas, and coal-fired generation. NRG will also assume EME's position in the sale leaseback transactions related to the Powerton and Joliet generation facilities. NRG has discussed publicly the possibility of dropping the EME contracted wind assets after the EME closing into NRG Yield, the YieldCo that NRG formed and spun off earlier in 2013.

The transaction is subject to FERC, PUCT, and bankruptcy court approval. The parties received HSR clearance in November 2013. The parties currently expect the transaction to close in the first quarter of 2014.

***Calpine/Wayzata*** **–** On December 2, 2013, Calpine announced that it had entered into an agreement to acquire the 1,060 MW Guadalupe power plant in Texas from a subsidiary of Wayzata Investment Partners for a cash purchase price of $625 million. This was a relatively quick and profitable flip for Wayzata, as they acquired Guadalupe in 2011 for an announced price of $331 million. The sale to Calpine includes a potential peaker development project, although comments by Calpine representatives indicated that this was not a driver of the transaction given the current economics for new build in ERCOT. The transaction is expected to close in the first quarter of 2014.

***Blackstone/Direct Energy*** **–** Continuing the trend of existing ERCOT generation attracting attention while new-build projects await further certainty regarding ERCOT market design, on December 18, 2013, The Blackstone Group announced that it had entered into an agreement to acquire three combined-cycle gas fired power plants from Direct Energy. The plants involved are the 566 MW Bastrop Energy Center, the 524 MW Frontera Generation Facility and the 263 MW Paris Energy Center. The announced purchase price was $685 million cash or approximately $455/kW of nameplate capacity. In addition to selling the three plants, Direct Energy entered into a three year call option with Blackstone for an equivalent amount of capacity, the terms of which were not disclosed. The transaction closed on January 17, 2014.

## Renewables

While interest in hydroelectric generation facilities continued in 2013, with two large transactions announced, M&A activity in the wind and solar area dropped off compared to 2012, quite significantly with respect to wind assets. Looking at announced deal values for transactions of $50 million or more (and excluding the entity level deals that included large mixed generating fleets such as NRG/EME), total announced deal value for wind, solar and hydro facilities in 2013 was approximately $2.5 billion, compared to $4.6 billion in 2012. Hydroelectric M&A activity was steady at $1.5 billion for both years, but solar dropped from $1.1 billion in 2012 to $640 million in 2013, while wind fell precipitously from $2.0 billion in 2012 to a mere $391 million in 2013.[3]

The marked lack of transactional activity in the wind space was perhaps overshadowed by the even larger slowdown in development activity. With the fiscal cliff looming at the end of 2012 and an extension of the production tax credit anything but certain, developers pushed hard to complete projects in 2012 before the production tax credit expired. The result was a record year for installations in the U.S. of 13,131 MW. In early January of 2013, Congress extended the production tax credit to the end of 2013 and liberalized the qualification requirements for meeting that deadline (switching from a “placed in service” requirement to a “commencement of construction” test). With all of the projects that were accelerated into 2012 though, it was no surprise that 2013 was a down year for wind installations. That being said, the drop off in activity was extreme. In the first half of the year, only 1.6 MW of wind capacity was installed in the U.S. with an additional 69 MW coming online in the third quarter. Fourth quarter installations are expected to increase significantly compared to the third quarter, but even so the American Wind Energy Association reported that only 2,327 MW of wind power was currently under construction at the beginning of the quarter, presumably a significant portion of which is not slated to be completed until sometime in 2014.[4]

Meanwhile, strong solar development activity continued unabated. Utility scale solar installations increased from 1,781 MW in 2012 to perhaps as much as 2,300 MW in 2013 and showed no indication of slowing down anytime soon, benefitting perhaps from the fact that unlike the production tax credit for wind, which expired at the end of 2013, the investment tax credit for solar runs until the end of 2016.[5]

Some notes on selected transactions follow:

***LS Power/First Energy*** **–** On August 23, 2013, First Energy agreed to sell 11 hydroelectric facilities to a subsidiary of LS Power. Terms of the transaction were not disclosed, although

[3] Source: SNL Financial.
[4] Source: American Wind Industry Association.
[5] Source: Solar Energy Industries Association.

there was some analyst speculation that the assets were valued in the $400 million range. The facilities total 527 MW and are located in Pennsylvania, West Virginia and Virginia, with the 451 MW Seneca Pumped Storage facility in Warren, Pennsylvania making up the bulk of the capacity. Required approvals include the Virginia State Corporation Commission and the FERC.

***NorthWestern/PPL Montana* –** On September 26, 2013, NorthWestern Corp. and PPL Montana announced an agreement pursuant to which NorthWestern would acquire 11 hydroelectric facilities from PPL totaling 633 MW, along with a related reservoir, for a purchase price of $900 million. The deal came about after PPL Montana's failed attempt to divest all of its generation portfolio in Montana, comprising coal and hydro assets, in a single transaction. NorthWestern had submitted a conforming bid of $400 million into the earlier auction process run by PPL for the entire portfolio, but simultaneously submitted a non-conforming bid for just the hydro assets at $740 million. Talks for the earlier process broke down by May and ultimately led to PPL splitting the portfolio and reaching terms with NorthWestern for the sale of just the hydro assets.

Observers will note that, upon closing, the hydro assets in question will have come full circle, as they were sold by NorthWestern's predecessor company, Montana Power, to PPL Montana back in 1998 when the Montana Public Service Commission (MPSC) forced NorthWestern to divest all of its generation assets. Completion of the transaction is contingent upon approval of the MPSC, for which NorthWestern applied on December 20, 2013, and the FERC, for which a filing was submitted on January 10, 2014. In the FERC filing, NorthWestern disclosed that perhaps not all of the assets would end up with NorthWestern, as the three-unit Kerr Dam hydroelectric facility on the Flathead River, which has a total capacity of 194 MW and is operated under a joint license with PPL Montana and the Confederated Salish and Kootenai Tribes of the Flathead Indian Nation, may end up with the tribes, who have the option of purchasing and taking over operation in 2015. Negotiations are under way between the tribes and PPL Montana.

***TransAlta/NextEra* –** On October 21, 2013, TransAlta announced the acquisition of the 144 MW Wyoming Wind Energy Center from NextEra Energy Resources for $102 million. The transaction closed on December 20, 2013 following receipt of FERC approval. The output from the facility is sold under a long-term PPA to Iberdrola Renewables.

***Algonquin/Gamesa* –** On November 28, 2013, Algonquin announced that it had agreed to acquire for $117 million the remaining 40% interest in a 400 MW portfolio of wind farms held by Gamesa. This was a follow-on transaction to the deal between the two parties in 2012, when Algonquin originally acquired its controlling interest in the three wind farms – the 200 MW Minonk Wind Project, the 150 MW Senate Wind Project, and the 50 MW Sandy Ridge Wind Project. FERC approval of the transaction was obtained on January 17, 2014. The transaction is consistent with Algonquin's aggressive growth strategy. In fact, on the same day Algonquin also announced that it had agreed to acquire the development rights to a 20 MW solar project in California, the capital costs of which are expected to be approximately $58 million.

## Master Limited Partnerships (MLPs)

Against the backdrop of strong capital markets and continually growing U.S. energy development and consumption, the flow of capital into MLPs continued to be strong in 2013, supporting a significant amount of M&A activity in the sector.[6]

*Capital Markets in 2013*. Strength in commodity prices, solid distribution growth, M&A activity, and a robust broader stock market bolstered the MLP market performance in 2013. Although MLPs lagged the broad equity market slightly,[7] the Alerian MLP Index increased 18% during 2013 with a total return of 28%. MLP equity continued to outperform other yield stocks, such as utilities and REITs, which increased 7% and 1%, respectively. Midstream MLPs and publicly traded general partners of MLPs provided the greatest total return among MLP equities. MLP equity issuances in 2013 generated record gross proceeds of $29.5 billion and the volume of MLP IPOs was greater than ever, with 19 IPOs generating $8.8 billion of gross proceeds. Sponsors continued to optimize value by taking the general partners of existing MLPs public. Highlights included: Plains GP Holdings (owner of general partner of Plains All American Pipeline, L.P.) for gross proceeds of $3.68 billion, one of the largest IPOs in any sector; Cheniere Energy Partners LP Holdings (owner of 55.9% limited partner interests in Cheniere Energy Partners, which owns LNG regasification facilities); CVR Refining Partners (formed by CVR Energy) for gross proceeds of $600.0 million; Valero Energy Partners (formed by Valero Energy Corporation) for gross proceeds of $345.0 million; Midcoast Energy Partners (formed by Enbridge Energy Partners) for gross proceeds of $333.0 million; and Phillips 66 Partners (formed by Phillips 66) for gross proceeds of $377.8 million. Institutional investor participation in MLP IPOs continued to grow, with institutions often purchasing more than half of the public equity in IPOs. This increasing access to institutional buyers supports larger securities offerings and contributes to less volatility in MLP equity, although overall institutional ownership of MLPs remains at a level well below that of other yield stocks.

The universe of qualifying income continued to expand as more industry participants analyzed potential advantages of the MLP structure. The IRS issued 25 private letter rulings (PLRs) on qualifying income in 2013, breaking the prior record of 18 PLRs issued in 2012 (which was more than double that of any previous year). In a related trend, more non-traditional businesses, such as well services, offshore drillers, water disposal services, chemical refiners and fuel transport services, either completed IPOs or began the process. Examples of new MLPs in non-traditional businesses included: OCI Resource Partners (trona ore mining); Emerge Energy Services (frac sand mining and fuel processing); OCI Partners (methanol and ammonia production); and Cypress Energy Partners (well water disposal and pipeline integrity inspection services; early 2014). Three MLP IPOs with non-traditional businesses took advantage of the relatively new variable pay structure (i.e., the MLP does not have a minimum quarterly distribution).

During 2013 there were 71 equity offerings by existing MLPs generating $20.6 billion of gross proceeds, which was consistent with historically high 2012 levels. At-the-market offering

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[6] Special appreciation to Barclays, Bank of America Merrill Lynch, Citigroup, Credit Suisse, Morgan Stanley and UBS for providing data used in preparing this section of this memorandum.

[7] In 2013, the S&P 500 increased 29% and provided a 32% return. This return represents the best performing year since 1997.

programs (ATMs), which allow MLPs to issue smaller amounts of equity over time with less cost and effort than fully marketed or overnight follow-on offerings, continued to increase in number and size. For example, MarkWest Energy Partners issued more than $1.0 billion under its ATM program in 2013. In addition, the total size of debt financings by MLPs continued to increase with 55 debt offerings generating $30.1 billion in 2013.

*M&A in 2013*. On the M&A front, consolidation continued, particularly deals involving assets in the most active basins (e.g., Marcellus and Bakken Shales). The volume of M&A transactions and asset growth in the MLP sector reached a recent high with 118 transactions for total disclosed value of approximately $68.0 billion. This compares to 103 transactions for total disclosed value of approximately $52.5 billion in 2012. Some of the largest completed transactions included: the $5.0 billion acquisition of Copano Energy LLC by Kinder Morgan Energy Partners; the $7.0 billion acquisition of Inergy, L.P. / Inergy Midstream, L.P. by Crestwood Midstream Partners LP / Crestwood Holdings LLC; Devon Energy Corp. and Crosstex Energy LP's agreement to combine nearly all of Devon's midstream assets with those of Crosstex to form a midstream business held by an MLP and a publicly traded general partner in a transaction with a value of $4.8 billion; and Regency Energy Partners LP's agreement to acquire PVR Partners LP in a transaction with a value of $5.6 billion.

MLPs continued to grow their distributions through traditional drop-downs (i.e., an MLP's accretive acquisition of assets from its sponsor), some of which involved large dollar amounts. For example, in a $12.3 billion transaction, Spectra Energy Partners, LP acquired Spectra Energy Corp's U.S. transmission, storage and liquids assets, transforming the MLP into one of the largest fee-based MLPs; Western Gas Partners acquired a 33.75% interest in Marcellus Shale gathering systems from Anadarko for $623.5 million; and EQT Midstream acquired Appalachian pipeline assets from EQT Corporation for $540 million. In addition, MLPs expanded their asset base through traditional targeted transactions of assets or businesses, such as Buckeye Partners' acquisition of LNG terminals from Hess Corporation for $850 million and Crestwood Midstream Partners' acquisition of the Bakken gathering systems of Arrow Midstream for $750 million. Generally, mid cap midstream MLPs have become more willing to make larger, transformative acquisitions.

*Expectations for 2014*. Looking ahead to 2014, we expect activity to remain strong as current trends continue. Recent economic data has been predominantly positive, suggesting the U.S. is continuing to gain momentum in 2014. An increasing need for billions in energy infrastructure in the U.S. means midstream companies will need meaningful access to capital to fund capital expenditures in excess of 2013 amounts. This need will drive a high volume of equity and debt financings, as well as acquisitions. As such, we expect consolidation through mergers and acquisitions to continue at or above 2013 levels. Larger MLPs that are more diversified among basins will be better equipped to carry larger development projects and acquire smaller growing companies. But larger MLPs are also expected to continue to be more selective while smaller cap MLPs will aggressively pursue growth acquisitions. Overall, the continued development of individual MLPs should result in solid growth in distributions and total returns (8% and 10-15%, respectively, according to one investment bank).

There are, of course, risks that could dampen activity in the MLP space. A recent survey of MLP investors indicates that an increase in interest rates presents the likeliest risk to the MLP markets, followed by declining project returns, tighter capital markets and commodity prices. How much of an impact an increase in interest rates will have on MLP equity is unclear. So far, increases have not resulted in investors' exiting the MLPs markets, although additional increases could have a negative effect on the space.[8] Historical risks relating to the energy industry continue to be present but not of particularly increased concern, such as regulation of hydraulic fracturing (essential for shale development), worldwide economic instability and development of renewable energy sources. Fear of tax reform or other legislative action detrimental to the MLP structure also does not seem to be weighing heavily on the minds of investors and participants in the sector. We view the risk of tax reform involving MLPs taking place in 2014 as small.

We expect capital markets activity to remain strong, perhaps with slightly fewer IPOs this year than in 2013 as some would-be smaller MLPs acknowledge that certain M&A alternatives are more attractive. There is a backlog of a couple IPOs that have been filed with the SEC (including Enable Midstream Partners, the midstream joint venture between CenterPoint Energy, ArcLight and OGE Energy), but there is a much larger number of non-public MLPs that are in various stages of the structuring and SEC process. These new issuers will continue to be in both the traditional pipeline business and a range of nontraditional businesses. The number of PLRs regarding qualifying income should be high again, although perhaps less than the record number set in 2013 given the extensive breadth of activities that have already been addressed and the lower IPO volume. It is possible we will see one or more variable pay MLPs but likely with less enthusiasm than a year or two ago. New MLPs will continue to take advantage of Emerging Growth Company status under the JOBS Act of 2012 that, among other things, allows issuers to file the IPO registration statement confidentially and present only two years of audited financial statements. We also expect follow-on equity and debt financings, including at-the-market offering programs and block trades, to continue to be an important source of funding for organic and acquisitive growth of MLPs as U.S. energy development and consumption continue to grow.

## LNG Developments

In our 2012 Report, we noted that 2013 promised to be a momentous year for exports of liquefied natural gas (LNG) from the U.S. Following the issuance of reports by the United States Energy Department Information Administration (EIA) and NERA Economic Consulting which concluded that the effect of LNG exports on domestic natural gas prices would be modest, our expectation was that the Department of Energy's Office of Fossil Energy (DOE/FE) would begin to process the backlog of applications for approval to export LNG to countries that do not have a free trade agreement with the United States requiring the national treatment for trade in natural gas (Non-FTA Countries).[9] That prediction turned out to be accurate, as in 2013 the DOE/FE

[8] Although the interest rate on the 10-year treasury note increased 110 basis points since May and climbed above 3.0% in December for the first time since July 2011, it was not followed by a large MLP sell-off

[9] Although the DOE/FE must approve all exports of natural gas from the U.S. based on a public interest standard, the Natural Gas Act deems it to be in the public interest to export natural gas to countries with which the U.S. has a free trade agreement requiring the national treatment for trade in natural gas (FTA countries). The U.S. currently has free trade agreements with 18 countries, although of these 18 countries, only South Korea, Singapore, Chile and the Dominican Republic import significant quantities of LNG.

approved four applications allowing the export to Non-FTA Countries of up to 4.57 billion cubic feet of natural gas per day (bcf/d).[10]

By the end of the year, however, the backlog of pending applications for authority to export LNG to FTA and Non-FTA Countries had grown from 20 at the end of 2012 to 25. If all 25 applications were granted, and all of the projects covered by the applications were built, the result would be annual exports in excess of 28.8 bcf/d, or 43% of average daily U.S. dry gas production of 66.5 bcf/d in 2013.

Even if all 25 applications were granted, it is not likely that all of the projects covered by the applications will ever be built. However, a significant question remaining unanswered as 2014 begins is whether the DOE/FE will impose a cap on exports by limiting the maximum export authority that it finds to be in the public interest, and if it does, what that cap will be and whether the DOE/FE will pick and choose among applications based on its view of the viability of the project to which the application relates.

Among other variables, the NERA study looked at the impact of a "low" export case of 6 bcf/d and a "high" export case of 12 bcf/d on domestic gas prices. In its November 15, 2013 order authorizing the export by Freeport LNG Expansion, L.P. of up to 0.4 bcf/d of natural gas to Non-FTA Countries, the DOE/FE noted that with the Freeport LNG Expansion approval, the total authorized export volume "only moderately exceeds the 6 Bcf/d volume evaluated by NERA in its 'low' export cases." The DOE/FE went on to state that:

> "DOE/FE will continue to take a measured approach in reviewing the other pending applications to export domestically produced LNG. Specifically, DOE/FE will continue to assess the cumulative impacts of each succeeding request for export authorization on the public interest with due regard to the effect on domestic natural gas supply and demand fundamentals."

In response to suggestions by Senator Wyden of Oregon that the DOE/FE was relying on obsolete market data in evaluating export authorization applications, Christopher Smith, now the Assistant Secretary for Fossil Energy, stated in his November, 2013, confirmation hearings that although the DOE/FE had no plans to conduct a full scale macroeconomic study to update the NERA report, it was constantly assessing changing market conditions, and that DOE/FE might pause the export application approval process temporarily.

Although the reading of tea leaves is not an exact science, the statements of the DOE/FE in the Freeport LNG Expansion order and Assistant Secretary Smith in his confirmation hearing suggest that although there may be a delay in issuing further orders while the DOE/FE considers the effect of current data on the conclusions of the NERA report, the DOE/FE has not concluded that no further export authorizations are in the public interest just because the "low" export case discussed in the NERA report has been reached.

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[10] The approved applications were for Freeport LNG (1.4 bcf/d), Lake Charles Exports (2.0 bcf/d), and Dominion Cove Point (0.77 bcf/d) and a second application for Freeport LNG (0.4 bcf/d). In addition to these projects, an export authorization for Cheniere's Sabine Pass project (2.2 bcf/d) was granted in 2012.

The DOE/FE has also recently reiterated its previous statements that it will process applications for export authority on a case by case basis in the order received, starting with the nine applications for projects that had commenced the FERC pre-filing process as of December 5, 2012, the date on which DOE/FE first gave guidance as to how it was going to proceed. The DOE/FE has issued orders for the first four of those nine applications, and if all nine applications are ultimately approved, the total export authorizations will exceed the 12 bcf/d "high" export case analyzed in the NERA report.

What the DOE/FE will do if the total authorized exports reach 12 bcf/d is not known. Possibilities range from stopping further approvals until it sees if all the projects for which approval has been granted are built (although that will take several years), to commissioning another study to determine the effect of export levels which are higher than the NERA "high" export case on domestic prices, to continue its methodical evaluation of applications on a case by case basis.

To date, the DOE/FE has not expressly considered the likelihood that any project which has filed an application for export authority will be built, and instead, has relied on the commencement of the FERC pre-filing process (with its attendant costs) as evidence that the project developer is committed to the project. If DOE/FE wants to consider the viability of a project before granting it export authority, it may have an opportunity to do so since at least one of the next five applications to be processed has drawn considerable public opposition.[11]

In summation, it is likely that the DOE/FE will continue in a methodical way to process applications for export authority to Non-FTA Countries, and more favorable orders can be expected in 2014. How many and how fast orders will be issued is impossible to predict, and may well depend on whether Assistant Secretary Smith's "pause" takes place and if it does, how long it lasts.

## Project Finance/YieldCos

Despite the limited number of greenfield power projects that came to market in 2013, the overall level of activity in energy project finance remained significant throughout the year. The constraints in the commercial bank market that arose after the crisis of 2008 seem to have eased in large part, though some banks remained cautious with respect to longer tenors because of the effects of Basel III capital adequacy standards and a variety of other factors. In addition to the stronger bank market, other categories of investors continued to show strong interest in the asset class and to provide compelling alternatives to project sponsors seeking to raise capital. Debt capital markets, institutional private placements, mezzanine loans and, most importantly, Term Loan B structures were all used with greater frequency in 2013 to finance energy projects, including projects with construction risk or merchant exposure. The increased liquidity and competition for deals allowed some borrowers, in particular those backed by private equity sponsors, to obtain looser covenants than traditionally found in the project finance market.

A number of notable transactions reached financial close in 2013. Again this year, the financing for the Sabine Pass LNG export terminal in Louisiana was at the top of the league tables. An

[11] The Catsop County Board in Oregon recently denied a land use permit for the Oregon LNG feeder pipeline. Oregon LNG has appealed this decision.

impressive total of $9.9 billion was raised during the year for that project, including $5.9 billion in credit facilities with commercial banks and Korean export credit agencies and $4.0 billion in the form of senior secured notes (the proceeds of which were used in part to reduce commitments under the bank facilities). MidAmerican Energy Holdings Company was also back in the market in 2013, after the successful capital market financing for the Topaz solar project in 2012, with a $1.0 billion bond issuance to fund the construction of the 579-MW Solar Star I and II photovoltaic solar projects in California. The projects, formerly known as Antelope Valley, benefit from a power purchase agreement with Southern California Edison.

Continuing a trend seen in prior years, the volume of project finance transactions completed in the Term Loan B market increased in 2013. Significant transactions, each in excess of $1.0 billion, that closed over the last 12 months include a portfolio refinancing for Calpine Construction Finance, a refinancing for LS Power's 945 MW coal-fired Sandy Creek power plant in Texas, which is only partially contracted, and a financing for the acquisition of a portfolio of power assets by EquiPower. Also noteworthy are the two financings completed by affiliates of Panda Power Funds to fund the construction of the 829 MW Moxie Liberty and the 829 MW Moxie Patriot natural-gas fired power projects located in Pennsylvania. These two greenfield projects, developed to take advantage of their proximity to the Marcellus Shale, included elements of merchant risk. PPL EnergyPlus, the energy marketing and trading subsidiary of PPL Corp., reportedly provided a commodity hedge for the Moxie Liberty project to mitigate some of that risk. The Moxie financings, as well as others that closed in 2012 and 2013, show that Term Loan B lenders are increasingly willing to accept some merchant risk for greenfield natural-gas fired power projects, at least those that are backed by strong sponsors and located in more attractive markets such as PJM or ERCOT. Anecdotal evidence and press reports indicate that the pricing for such transactions has decreased significantly since the landmark financing completed in July 2012 for the construction of the 758-MW Temple I project in Texas. Given the difficulty of obtaining PPAs on favorable terms, efforts to finance some projects on a merchant or quasi-merchant basis may be expected to continue in 2014.

While the debt markets were a source of considerable liquidity in 2013 and are expected to remain favorable going into 2014, one of the most interesting developments in recent months relates to the so-called "YieldCo" structures used by sponsors to monetize existing power generation assets without losing control. In general terms, a YieldCo is an entity that owns cash-generating infrastructure assets and, similar to REITs or MLPs, spins out ownership to the public markets. The objective of the YieldCo is to gather a sufficient number of contracted assets that will generate stable cash flows and allow the YieldCo to pay regular cash dividends to its stockholders, making the YieldCo's equity securities attractive to investors looking for yield, especially in the current low interest rate environment. The YieldCo structure allows a sponsor to separate its more stable, operating assets from its non-contracted assets, and to raise capital at a lower cost from a broader investor base seeking exposure to contracted assets. In order to maintain cash flows or achieve expected growth, it likely will be necessary to add assets to the YieldCo over time, which can be done through asset drop-downs by the sponsor, acquisitions, or a combination of both.

NRG pioneered the use of the YieldCo in the power sector with the successful IPO of NRG Yield, Inc. in July 2013. Based on thermal infrastructure assets and an initial generation portfolio comprised of three natural gas or dual-fire facilities, eight utility-scale solar and wind generation facilities and two portfolios of distributed solar facilities that collectively represent 1,324 net MW, NRG Yield was able to raise $468 million in net proceeds. NRG Yield also entered into a five-year agreement with NRG that includes a right of first offer in connection with any future sale of certain solar and natural gas assets currently held by NRG. Given the nature of its assets and the associated tax benefits, NRG Yield does not expect to pay significant federal income tax for a period of at least ten years. Later in the year, Pattern Energy Group Inc. completed its $352 million IPO in a similar transaction, with interests in eight wind power projects in the United States, Canada and Chile that have a total owned capacity of 1,041 MW. Various other companies have publicly stated their interest in the YieldCo structure; it will be interesting to see which of them actually move forward.

## Environmental Regulation

Another key driver of activity in the power and utilities sector is the shifting landscape of environmental regulation. In 2013, the dominant theme for the industry was climate change. EPA previously had proposed new source performance standards (NSPS) in 2012 for new fossil-fuel electric generating units (EGUs). That proposal treated coal-fired and gas-fired EGUs as interchangeable, setting a single 1100 lbs/MWH GHG emissions standard for all new EGUs, effectively requiring carbon capture and sequestration for any newly constructed coal-fired units. The proposal drew intense criticism from industry, as well as Congress, and languished.

On June 25, 2013, President Obama announced his Climate Action Plan. While the Plan addresses climate change across the entire economy, much of the plan focuses on the electricity sector. The most important element of the Plan is a requirement that EPA expeditiously promulgate NSPS for all future fossil-fuel fired EGUs and establish regulations addressing GHG emissions from existing EGUs by June 2015. Further discussion on this aspect of the Plan is below. The other key elements affecting the power industry include:

- Making up to $8 billion in loan guarantee authority available for a wide array of advanced fossil energy and efficiency projects to support investments in innovative technologies;

- Directing DOI to permit enough renewables projects—like wind and solar – on public lands by 2020 to power more than 6 million homes; designating the first-ever hydropower project for priority permitting; and setting a new goal to install 100 megawatts of renewables on federally assisted housing by 2020; while maintaining the commitment to deploy renewables on military installations; and

- Expanding the President’s Better Building Challenge, by focusing on helping commercial, industrial, and multi-family buildings cut waste and become at least 20 percent more energy efficient by 2020.

*New Regulations to Reduce Greenhouse Gases from the Electric Industry*

A central component of President Obama’s Climate Plan is its direction to EPA to establish NSPS for all future EGUs and to develop regulations to reduce GHG emissions from existing fossil-fuel fired EGUs. In response to the Plan, EPA developed a revised NSPS for new EGUs (and withdrew the prior proposal), which was published in the Federal Register on January 4, 2014. The NSPS would impose an 1100 lbs/MWH standard for all new coal-fired EGUs; a 1000 lbs/MWH standard for large (over 850 mmBtu) natural gas combined cycle units (NGCCs); and a 1100 lbs/MWH standard for small NGCCs.

EPA also began the process of developing its GHG regulations regarding existing EGUs. This regulatory process, under Section 111(d) of the Clean Air Act, is different than most in that Congress gave the states the initial and primary authority to set standards for existing sources. EPA is directed to establish a "procedure" under which the states submit plans to EPA regarding the establishment of performance standards for existing sources. The standards must reflect the "best system of emission reduction" (BSER) achievable from existing sources. The Clean Air Act anticipates that the states will set source-specific standards based on four factors: 1) the costs of achieving the standards; 2) non-air quality health and environmental impact; 3) energy requirements; and 4) the remaining useful life of the existing source.

EPA will promulgate "guidelines" for the states to follow in developing their state plans to reduce GHG emissions from existing EGUs, with the proposed guidelines to be issued by the end of June 2014. EPA plans to finalize the guidelines the following year and require the states to submit their plans within one year.

EPA conducted numerous "listening sessions" and hearings to garner input from the states, environmental groups, industry and others. There are many issues that will be highly contentious in EPA's rule making. A critical issue will be whether EPA's guidelines will direct the states to consider measures that apply beyond the EGUs; that is, whether EPA can direct the states to consider BSER to include renewable energy supplies, investments in reducing demand for electricity (through conservation), environmental dispatch (preferentially utilizing higher-cost, low-carbon generation) and other measures that are not traditionally considered as BSER, or that do not directly relate to the affected EGUs. Another key issue is how EPA will allow the states to recognize and credit early actions by states and the electric industry, including compliance with existing renewable portfolio requirements, demand-side management programs and efficiency upgrades. Similarly, many companies have incorporated a proxy cost of carbon in their resource plans in making decisions to retire coal plants in the coming years. How EPA credits these retirements in its guidelines will be crucial to companies' decision-making processes and could result either in additional retirements or deferred retirements, depending on EPA's final regulations.

*Air Toxics and Cross State Air Pollution Rules*

The Mercury and Air Toxics (MATS) rule, which was finalized in 2011, establishes standards for coal- and oil-fired EGUs for hazardous air pollutants. The rule had been challenged in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit), with oral argument finally being held on December 10, 2013. Generally, most observers believe the MATS rule will be largely upheld such that industry will be required to comply with the standards in 2015 or 2016.

The Cross-State Air Pollution Rule (CSAPR), a 27-state NOx and SO2 emissions trading program targeting the power industry that EPA developed to reduce the interstate transport of pollutants causing or contributing to exceedances of national ambient air quality standards in downwind states, had been promulgated in August 2011. It was set to go into effect less than five months later, on January 1, 2012, but was vacated by the D.C. Circuit, creating uncertainty regarding the implementation of several other regulatory programs affecting the industry. EPA appealed that decision to the Supreme Court and oral argument was held on December 10, 2013. The Supreme Court seemed inclined to rule in favor of EPA on several of the crucial issues before it. However, even if the Court were to remand the rule to the D.C. Circuit, it is unclear how EPA would proceed with the rule given how much time has passed, and in light of the fact that many of the areas that ostensibly were affected by the transported emissions targeted by CSAPR have since come fully into attainment with the national ambient air quality standards. Further, the D.C. Circuit had ruled on only a portion of the issues raised by petitioners challenging the CSAPR. EPA also had issued a supplemental rule and a corrections rule, both of which were subject to challenges that have been held in abeyance in light of the D.C. Circuit's vacatur of CSAPR. Thus, it is likely that EPA will need to repropose major elements of the CSAPR rule before moving forward.

*Enforcement*

Finally, there have been some important court rulings in connection with law suits brought by EPA and environmental groups against coal-fired power plants under the new source review/prevention of significant deterioration (NSR/PSD) provisions of the Clean Air Act. The U.S. Courts of Appeals for the Third and Seventh Circuits each upheld lower courts' dismissal of PSD claims brought by EPA against past and present power plant owners and operators. In United States v. Midwest Generation, the Seventh Circuit rejected EPA's argument that power plant owners could be liable under the federal PSD regulations for operating without a PSD permit and held that no injunctive or penalty relief was available outside of the 5-year statute of limitations period. The Third Circuit, in United States v. EME Homer City Generation, similarly concluded that the failure to obtain a PSD permit before construction is not an ongoing violation and does not provide a basis for civil penalties or injunctive relief against either current or past owners of the facility. These rulings undermine EPA's traditional NSR/PSD enforcement theories, particularly for projects completed more than five years in the past. However, EPA and environmental groups have continued to move forward with enforcement actions against other coal-fired power plants in other Circuits, raising both traditional arguments and additional arguments based on language in particular state NSR/PSD programs.

## FERC

In late 2013, the Federal Energy Regulatory Commission (FERC) had a change in leadership as President Barack Obama named Commissioner Cheryl LaFleur Acting Chairman of FERC. LaFleur replaced Jon Wellinghoff, who had served as Chairman of FERC since 2009. There are currently four sitting Commissioners at FERC, with one vacancy yet to be filled. President Obama's initial nominee, Ron Binz, withdrew his nomination last October after it became evident that his nomination would not be reported favorably by the Senate Energy and Natural Resources Committee. In December, Acting Chairman LaFleur's congressional testimony before the House Energy and Commerce Subcommittee on Energy and Power indicated that

FERC would retain its focus on natural gas and electric coordination issues, transmission planning and cost allocation, and grid reliability. Major FERC initiatives, as well as proceedings of interest, are discussed below.

***FERC Rejects Application for Failure to Pass Horizontal Market Power Analysis* –** In March 2013, FERC took the unusual step of denying an application to authorize the sale of the Harquahala merchant generating facility in Arizona, finding that the applicants (MACH Gen, LLC, New Harquahala Generating Company, LLC, and Saddle Mountain Power, LLC) failed to demonstrate that the proposed transaction would not have an adverse effect on competition. Specifically, FERC found that the market power concerns raised by the proposed buyer's affiliation with another large electric generation facility in the Arizona Public Service (APS) balancing authority area (BAA) through a common fund manager were not mitigated by an Energy Management Agreement (EMA) with a third party, where the common fund manager retained indirect control over the facility's operating limits, dispatch curves, operating costs, and ability to enter into long-term contracts.

The proposed buyer, Saddle Mountain, is wholly-owned by a subsidiary of Wayzata Investment Partners, LLC (Wayzata), and as a result, is affiliated with various energy projects, including Sundevil Power Holdings, LLC (Sundevil), which owns two of the four generating units that comprise the Gila River facility in Gila Bend, Arizona (also in the APS BAA). Because of Saddle Mountain's affiliation with Sundevil, the applicants conceded that the proposed transaction would fail FERC's horizontal market power screen, and proposed a mitigation plan whereby New Harquahala would transfer control over the Harquahala Facility to an independent third party at closing by entering into an EMA with Twin Eagle Resource Management, LLC (Twin Eagle). Under the proposed EMA, New Harquahala established the parameters for Twin Eagle's operation of the Harquahala Facility, including the operating limits, dispatch and efficiency curves to be used by Twin Eagle. In addition, New Harquahala would retain responsibility for the Harquahala Facility's operations and maintenance, and would therefore be cognizant of the Harquahala Facility's operating costs. New Harquahala also proposed to retain the right to market the output of the Harquahala Facility for long-term contracts.

FERC found that the EMA was inadequate to address the potential adverse competitive effects of the proposed transaction. According to FERC, because New Harquahala would dictate the Harquahala Facility's dispatch model through the EMA, New Harquahala would have access to market information that would allow Sundevil (under common control with New Harquahala) the opportunity to make anticompetitive sales sourced from the Gila River Facility by either withholding output or raising prices in the APS BAA.

FERC's decision in this case sheds further light on how FERC will assess the "totality of circumstances" when considering whether an EMA provides adequate mitigation for an acquisition that otherwise fails FERC's horizontal market power screen. Under FERC's current view, it appears that any EMA that does not approximate a firm, long-term sale will face a high level of scrutiny. Reaching this bar could be especially problematic in geographic areas with limited liquidity or no organized energy markets.

***Order No. 1000: Transmission Planning and Cost Allocation –*** FERC's policies on transmission planning and cost allocation continued to evolve in 2013, with the issuance of several orders addressing regional Order No. 1000 compliance filings and with submission of interregional Order No. 1000 compliance filings for most of the U.S.

Order No. 1000, issued by FERC in a series of orders from 2010 to 2012, reforms FERC's electric transmission planning and cost allocation requirements for public utilities. The order requires public utilities to engage in regional and interregional processes to develop procedures for identifying transmission needs and allocating the responsibility for identified projects in the most efficient and cost-effective manner. In addition, Order No. 1000 instructs public utility transmission providers to remove from their FERC tariffs and agreements any right of first refusal for incumbent utilities, subject to certain limitations, including state or local laws or regulations regarding the construction of transmission facilities.

Throughout 2013, public utilities, including RTOs and ISOs, received their first orders generally accepting parts of their Order No. 1000 compliance proposals, but also directing further reforms which are now pending before FERC. In July 2013, RTOs, ISOs and groups of utilities combined to submit interregional Order No. 1000 compliance filings. In many cases, however, the entities were unable to come to complete agreement on the preferred rules. For example, PJM and MISO submitted filings with identical proposals for interregional transmission planning and some aspects of interregional cost allocation, but they were unable to agree on a procedure for allocation of costs associated with baseline reliability projects and instead submitted competing proposals on this aspect of compliance. Similarly, in areas without RTOs and ISOs, where utilities were instead required to form groups and submit proposals, such as the South and West, there typically remain areas of dispute between the utilities.

These disputed interregional Order No. 1000 compliance filings present a real test of FERC's commitment to creating opportunities for transmission planning and growth. The Commissioners and the Administration continue to identify transmission planning and construction as a high priority. Development of clear, uniform rules that establish interregional planning criteria and priorities, along with opportunities for cost recovery when supported by recognized cost-benefit criteria, could be an important step in attracting the investment needed for this kind of growth. It is not clear whether the Order No. 1000 compliance filings as submitted, however, have the potential to spur the intended outcomes or create opportunities for prospective transmission investors. The industry may learn a lot more from the orders on the interregional filings expected in early 2014.

***FERC Policy Facilitates New Merchant Transmission Development –*** On January 17, 2013, FERC issued a policy statement modifying its policies governing the allocation of capacity for new merchant transmission projects and new non-incumbent, cost-based, participant-funded transmission projects. Under FERC's new policy, developers of merchant transmission projects may select a subset of customers, based on not unduly discriminatory or preferential criteria, and negotiate directly with those customers (including affiliates) to reach agreement for procuring up to 100 percent of a line's transmission capacity.

In response to the Commission's policy initiative, three merchant transmission projects have sought authorization to sell transmission rights at negotiated rates. The first application under the new policy was filed by the Lake Erie CleanPower Connector (LECPC), proposing a 60-mile HVDC transmission project of up to 2,000 MW that will directly interconnect the markets operated by PJM and the Independent Electricity System Operator of Ontario, Canada (IESO). On September 16, 2013, FERC issued an order conditionally authorizing LECPC to sell transmission rights on the proposed line at negotiated rates. This will allow LECPC to allocate up to 100 percent of the project's capacity through an open solicitation process, subject to a subsequent compliance filing.

Grain Belt Express Clean Line, LLC and Champlain VT, LLC also filed applications in the last three months of 2013, seeking to construct new transmission under FERC's new policy, and those applications are currently pending before the FERC. All three projects are supported by private equity funds.

***Transmission Owners' Return on Equity Under Scrutiny –*** Several parties have filed complaints with FERC in recent months challenging the return on equity (ROE) collected in the rates of public utilities for electric transmission.

Multiple complaints have contested the practice where a public utility that is a transmission-owning member of an RTO or ISO adopts the ROE that FERC approved for use by members of that RTO or ISO. In one such case, in December 2012, a consortium of customers and other interest groups filed a complaint against several transmission owners in ISO-NE, seeking to reduce the ROE from 11.14 to 8.7 percent. Similarly, four PJM transmission owners are the subject of a February 2013 complaint filed by a group of state utility commissions, municipal utilities, and ratepayer advocates from Delaware, Maryland, New Jersey, and the District of Columbia. That complaint seeks a reduction of the utilities' base ROE for transmission rates (currently between 10.8 and 11.3 percent) to 8.7 percent. And a November 2013 complaint filed by a group of industrial transmission customers in the Midwest challenges the transmission rates of several transmission owners within the MISO. The complaint seeks a reduction in the utilities' base ROEs from 12.38 to 9.12 percent, as well as a reduction in the equity component of the assumed capital structure in their rates.

In addition to these multi-respondent complaints, parties have also filed challenges to the ROE components of individual transmission-owning utilities in recent months. In late 2012, a group of municipal utilities filed a challenge in several proceedings to the transmission rates of NYISO transmission owner, Niagara Mohawk Power Corp. These complaints seek to reduce Niagara Mohawk's ROE from 11.5 to 9.25 percent. Similarly, in May 2013, Seminole Electric Cooperative and the Florida Municipal Power Agency filed a complaint challenging Duke Energy Florida's ROE of 10.8 percent, requesting a reduced ROE of 8.84 percent. In addition, several California municipals have challenged the 13.5 percent ROE of CAISO transmission owner, Trans-Bay Cable. That complaint, filed in December 2013, seeks to reduce Trans-Bay Cable's ROE from 13.5 to 11.9 percent.

All of these ROE challenges are ongoing at FERC.

***FERC Natural Gas - Electric Coordination Initiative Moves Forward*** – After the extreme cold weather event in Texas and the Southwest in February 2011, FERC opened a major policy-making initiative to explore whether changes needed to be made in the way that it regulates natural gas pipelines and natural gas-fired electric generation. FERC's objective was to identify and address potential reliability issues, if any, that may emerge as natural gas-fired generation accounts for an increasingly large percent of the available resource base.

FERC staff held a series of nine technical conferences, identifying the following four primary areas for further study or development of new rules: (a) communication and information-sharing among electric transmission operators and natural gas pipeline operators, especially making explicit the propriety of sharing information in circumstances that might otherwise be inhibited by FERC Standards of Conduct; (b) lack of alignment of gas and electric scheduling practices and gas market capacity release rules; (c) firm and non-firm gas transportation products that do not match electric market commitments; and (d) regional differences in resource mix, climate, scheduling and other factors which make one-size-fits-all solutions impractical.

In December 2013, FERC issued its first rulemaking on gas and electric market coordination, a final rule adopting new standards to address communication and information-sharing. This rule expressly authorizes the day-to-day sharing of non-public, operational information between electric transmission operators and interstate natural gas pipelines when such information is shared for the purpose of promoting reliable service or operational planning. The rule places the burden to maintain confidentiality of information on the recipient so that the conveyor of the information will not be inhibited in sharing information when it determines that it is expedient to do so.

This first rule has caused very few ripples in the industry. Rules addressing the second and third categories FERC staff identified, however, may have significant market implications for multiple sectors, depending on the approach that FERC takes. For example, some technical conference participants suggested that the best practice to ensure reliable natural gas supply to electric generating facilities in the future would be for FERC to require generators to purchase firm gas supply to back up any capacity or energy commitment, instead of the common current practice of purchasing a combination of firm and interruptible supply. A change of this type would have obvious and immediate effects for sellers trying to understand PPA pricing, capacity market bids, and develop strategies to participate in spot energy markets, along with potential price effects for utilities that buy power using any of these tools.

It is not clear at this point what FERC's next step will be in its gas-electric coordination initiative. As long as this initiative continues to be an area of focus for the FERC, though, it will be important to monitor the proceeding for any changes that may impact long-term and short-term capacity and energy pricing.

## ERCOT

In Texas, debate continued over how best to address the need for new capacity on the Electric Reliability Council of Texas (ERCOT) grid. In February 2011, with the Texas Legislature in session, an historically severe and widespread cold snap led to numerous generation outages in Texas, which in turn precipitated the need for rolling power outages in much of the state to maintain reliability in ERCOT. Months later, drought and prolonged historic heat nearly necessitated more rolling blackouts. ERCOT's reserve assessments at the time indicated that reserve margins were in danger of falling below the PUCT's 13.75% target. Thus began what has become a protracted debate over the best way to attract investment and secure adequate resources to meet the demand for power in one of the nation's fastest growing economies.

The debate has centered on whether to retain the energy-only design of the ERCOT market or shift to some form of capacity market. Retained in March 2012 by the PUCT and ERCOT, the Brattle Group issued a report in June 2012 on the factors that influence generation investment in Texas, the outlook for maintaining adequate reserves, and options for enhancing long-term resource adequacy in ERCOT. Brattle concluded that (1) new investment in ERCOT is impeded because low natural gas prices and an efficient generation fleet have driven down prices; (2) ERCOT's energy-only market is unlikely to support sufficient investment to meet the PUCT's 13.75% resource adequacy target and may only be able to support a "long-term economic equilibrium" reserve margin as low as 6%; (3) given several years, reliability targets could be achieved with a significant increase in demand response programs; and (4) that either the ERCOT market design must be adjusted or the 13.75% target reserve margin revised.

In a market with no capacity payments, adequate scarcity pricing is key to attracting sufficient generation investment. Recognizing that a complete market overhaul could take several years, and concerned by projections of rapidly shrinking reserve margins, the PUCT took steps in 2012 to improve scarcity pricing signals in the existing energy-only market. In June 2012, the Commission temporarily raised the ERCOT price cap from $3,000/MW to $4,500/MW; and in October 2012, the Commission voted to permanently increase the cap to $5,000/MW in June 2013, $7,500/MW in June 2014, and $9,000/MW in June 2015.

By the end of 2012, ERCOT assessments of resource adequacy indicated an improved outlook for early 2013. However, projected reserve margins were still expected to be slightly below the 13.75% target and to continue falling in future years. As 2013 approached, the PUCT scheduled a January workshop to consider options for implementing an operating reserves demand curve (ORDC), an administratively set, sloped demand curve, that would begin providing increasing scarcity prices as soon as reserves fell below some threshold rather than waiting until reserves were largely exhausted and moving immediately to the price cap. In theory, the sloped curve would provide generators with scarcity prices over a longer period of time, providing a better incentive.

As the policy debate continued into 2013, two political issues hampered progress. The Texas Legislature meets at the beginning of odd-numbered years, and resource adequacy was expected to be hot issue in the 2013 Legislative session that convened on January 8th. Then, in February 2013, Commissioner Rolando Pablos announced his resignation effective March 1. His departure left an evenly split (and therefore paralyzed) Commission for most of the past year. Commissioner Ken Anderson championed a continued energy-only market while Chairman Donna Nelson made clear her belief that ERCOT needs to move toward a capacity market. Chairman Nelson has remained committed to ERCOT's reliability standard of only one rolling blackout every ten years and has maintained that only some form of capacity market can ensure reserve margins high enough to meet that standard. Commissioner Anderson has argued that current modeling techniques overstate the severity of the problem and that capacity markets will increase prices without significantly reducing the risk of occasional rolling outages. In the absence of a third vote, and given uncertainty about whether and how the Legislature might choose to address resource adequacy, most of 2013 was spent searching for compromise measures that could satisfy both Chairman Nelson and Commissioner Anderson.

The compromise position that drew the most attention in 2013 was some form of ORDC. Two key inputs for an ORDC are the threshold at which the price curve is implemented and the value of lost load (VOLL) used to calculate prices. During the first half of 2013, while the Legislature was in session, resource adequacy was discussed relatively little during the Commission's open meetings. Instead, the PUCT focused on developing data to inform the ORDC decision as well as the larger resource adequacy debate. ERCOT studied the cost impact of using various thresholds for the ORDC, while London Economics International worked on a VOLL study for ERCOT. The Brattle Group was tasked with studying the likely effect of various ORDC designs on the ERCOT reserve margin. ERCOT was also asked to examine whether implementation of an ORDC would also require the co-optimization of real time energy and ancillary services and, if so, how long it would take ERCOT to implement co-optimization. Most estimates indicated at least a 2-3 year timeline for co-optimization.

As the studies progressed, the Commission held a pair of workshops in March 2013 to discuss the role of demand response in ERCOT and whether the inputs currently used to project future load growth in ERCOT are producing meaningful results. Commissioner Anderson has been a vocal critic of ERCOT's load forecasting methodology, arguing that it routinely overestimates load growth and therefore overstates the resource adequacy problem.

In June 2013, the PUCT held a workshop to consider the results of the various ORDC studies and hear presentations by representatives of various market segments. In July, Commissioner Anderson proposed a range of ORDC options for consideration and urged implementation of an ORDC before Summer 2014. Discussion of whether and how to proceed with an ORDC continued through the summer of 2013, with discussions in the deadlocked Commission often becoming heated.

The Legislature's regular session adjourned at the end of May, but a number of unresolved issues prompted three special sessions that extended the legislative season into early August. Once the Legislature had finally adjourned for the year (making confirmations unnecessary until 2015), Governor Perry appointed Brandy Marty to fill the vacant spot at the PUCT. The addition of a third Commissioner (and vote) quickly refocused the resource adequacy debate. In September, the PUCT voted unanimously to implement an ORDC and directed ERCOT to begin designing the ORDC through the stakeholder process, using a 2,000 MW threshold and $9,000/MW VOLL. The PUCT also directed Brattle to begin developing a report on the optimum, or equilibrium, reserve margin for ERCOT. With the new Commissioner on board, ERCOT scheduled a workshop in October to address a broad range of resource adequacy issues.

Following the October 8 workshop, the Commission had a heated debate at its October 25th open meeting over whether to move to a capacity market. Just two months into her appointment, and over strong objections from Commissioner Anderson, Commissioner Marty joined Chairman

Nelson in concluding that ERCOT's reserve margin should be mandatory, not merely a target -- a decision tantamount to endorsing a capacity market. Though no official vote was taken, Chairman Nelson scheduled a workshop for late January 2014 to begin considering options for implementing a mandatory reserve margin. The year ended with a controversial resource adequacy workshop set for January 29 and 30 and momentum leaning toward some form of capacity market.

The apparent move toward a capacity market sparked an outcry from capacity market opponents, including at least one influential state legislator, who even questioned the Commission's authority to redesign the market to that extent. At the December meeting of the ERCOT Board of Directors, attended by the PUCT Commissioners, the Board directed ERCOT to delay publication of its December forecast of ERCOT capacity, demand, and reserves (CDR Report) pending completion of changes to its load forecasting methodology. Commissioner Anderson has long advocated for such changes, arguing that the CDR Report routinely overstates the resource adequacy problem. At the end of January 2014, the new CDR Report was still not available, but a preliminary load forecast, using the newer methodology, suggests that reserve margins may be higher than envisioned in 2011 or 2012. Also in January 2014, Brattle notified the PUCT that its report on ERCOT's equilibrium reserve margin would not be ready by the end of January. Given the delay in these two important reports and Commissioner Marty's impending maternity leave, the much anticipated resource adequacy workshop has been postponed until May 2014. What looked like a possible victory for capacity market proponents in October 2013 is once again in doubt.

## CFTC

The Commodity Futures Trading Commission (CFTC) has implemented several requirements under the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), including transactional reporting requirements, which became effective in 2013, recordkeeping obligations, as well as central clearing requirements with respect to certain swaps. These clearing requirements are currently limited to specified interest rate and credit default swaps and do not yet extend to energy-related derivatives. Parties that enter into the affected swaps for purposes of hedging risk may elect the "end-user" exception to the clearing requirement. End-users may claim the exception by filing an annual certification with a swap data repository, including a board resolution authorizing the company to enter into non-cleared swaps.

The CFTC also has issued guidance on the extra-territorial application of its Dodd-Frank rules, explaining that it will regulate swaps involving non-U.S. subsidiaries of U.S. entities, as well as non-U.S. entities that either guarantee the swap-related obligations of their U.S. affiliates or that enter into swaps for the purpose of hedging the risks of their U.S. affiliates. This cross-border application of the Dodd-Frank rules is currently subject to judicial challenge on the grounds that the CFTC's guidance is a binding rule rather than a statement of policy, and that the CFTC failed to engage in the necessary cost-benefit analysis before promulgating a binding rule. If the court agrees with this challenge, it may severely limit the extra-territorial application of the Dodd-Frank Act. The CFTC also announced that it will more lightly regulate commodity trade options in which the parties intend that, if exercised, the option will be physically settled. Trade options between non-swap dealers need only be reported on an annual basis (on March 1) rather than a transaction-by-transaction basis.

Two of the CFTC's five commissioners, including Chairman Gensler, departed the agency in 2013, and a third, Commissioner Chilton, has remained for the present to assist in transition to a successor. President Obama has nominated Timothy Massad to serve as the new Chairman and Sharon Bowen and J. Christopher Giancarlo to fill the remaining seats. One of the continuing Commissioners, Commissioner O'Malia, has often voted against proposed Dodd-Frank regulations, which means the CFTC may move slowly in adopting further regulations until the Senate confirms the three nominees.

## Game Changing Energy Reform in Mexico

At the end of December 2013, Mexico enacted amendments to the Mexican Constitution and accompanying transitional legislation (the "Energy Reforms") that will end the state-owned monopolies of Petróleos Mexicanos (Pemex) and Comisión Federal de Electricidad (CFE). The Energy Reforms will have transformational changes for Mexico's energy sector and are expected to have a macroeconomic effect in Mexico comparable to the one provided by the North American Free Trade Agreement.

The Energy Reforms will allow:

- Mexico's Energy Ministry to grant and enter into E&P licenses and production-sharing contracts, as well as profit-sharing and service agreements and other such arrangements, with private sector entities, domestic and foreign;
- private sector investors to book the oil and gas reserves associated with such agreements under the U.S. Securities and Exchange Commission's "economic interest" methodology;
- Pemex to enter into joint venture arrangements with private sector entities;
- for the conduct of a "Round Zero" in which Pemex will choose those initial fields in which it desires to maintain its existing interests and/or develop future ones;
- direct private investment in the midstream and downstream oil and gas sectors;
- for the creation of a new regulatory agency, the National Center of Natural Gas Control, which will oversee the operation of the national pipeline network currently operated by Pemex;
- for the creation of a wholesale power generation market with the newly formed National Energy Control Center acting as the system operator independently of the CFE;
- for the creation of a new regulatory agency, the National Agency for Industrial Safety and Environmental Protection, which will be independent of the Ministry of Environment and Natural Resources and which will regulate industrial, operational safety and environmental matters; and
- for the establishment of a sovereign Mexican oil fund, similar to the Norway model.

The Energy Reforms also specify the timing requirements for additional implementing steps and detailed “Secondary Legislation”:

- March 21, 2014: deadline for Pemex’s identification of its Round Zero fields;
- April 20, 2014: deadline for the Secondary Legislation;
- September 17, 2014: deadline for the Ministry of Energy’s granting of Pemex’s Round Zero allocation requests;
- December 21, 2014: deadline for the enactment of additional environmental laws governing oil and gas activity;
- April 20, 2015: deadline for establishing the National Center of Natural Gas Control (independent pipeline operator) and the National Energy Control Center (power market ISO); and
- December 20, 2015: deadline for Pemex and CFE to become “Productive State Enterprises”.

Looking ahead for 2014, there is a “bullish” outlook that the Secondary Legislation will embrace the types of “market-facing” policies that are necessary to attract needed foreign investment in Mexico’s energy sector. Expectations are that by late 2014 or early 2015, Mexico’s new legal landscape will have been established and deal-making will begin.

## Conclusion

Looking forward to 2014, we expect the level of deal activity to vary among sub-sectors. In the MLP area, we expect the relatively high level of activity to continue. Among the regulated companies we expect activity to be measured as consolidation continues, although given the episodic nature of the activity in this subsector makes it hard to predict. In the generation sector, we anticipate activity to remain at roughly current levels, although if there is increased clarity around ERCOT market design, the manner in which that debate is resolved will likely have an impact (positive or negative) on the level of activity. On the renewables front, we would not be surprised to see a continuing drop in activity, as the unusual level of M&A relating to hydroelectric assets will probably not be repeated.