<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Foreword</td>
<td>iii</td>
</tr>
<tr>
<td>Section 1 — Industry Developments</td>
<td>1</td>
</tr>
<tr>
<td>Section 2 — SEC Update</td>
<td>8</td>
</tr>
<tr>
<td>Section 3 — International Financial Reporting Standards</td>
<td>17</td>
</tr>
<tr>
<td>Section 4 — Industry Accounting Hot Topics</td>
<td>22</td>
</tr>
<tr>
<td>Section 5 — Energy Contracts, Derivative Instruments, and Hedging Activities</td>
<td>41</td>
</tr>
<tr>
<td>Section 6 — Fair Value Measurements</td>
<td>47</td>
</tr>
<tr>
<td>Section 7 — Accounting Standards Codification Update</td>
<td>50</td>
</tr>
<tr>
<td>Section 8 — FERC Enforcement Activities</td>
<td>73</td>
</tr>
<tr>
<td>Section 9 — Income Tax Update</td>
<td>80</td>
</tr>
<tr>
<td>Section 10 — Renewable Energy</td>
<td>86</td>
</tr>
<tr>
<td>Appendixes</td>
<td></td>
</tr>
<tr>
<td>Appendix A — Abbreviations</td>
<td>94</td>
</tr>
<tr>
<td>Appendix B — Titles of Standards and Other Literature</td>
<td>98</td>
</tr>
<tr>
<td>Appendix C — Deloitte Specialists and Acknowledgments</td>
<td>100</td>
</tr>
<tr>
<td>Appendix D — Other Resources and Upcoming Events</td>
<td>102</td>
</tr>
</tbody>
</table>
January 2014

We are pleased to present our 12th annual Accounting, Financial Reporting, and Tax Update for the P&U industry. As our industry faces changing markets, new legislation, and emerging businesses and technologies, finance practitioners will need to consider the related tax, accounting, and reporting implications. This publication discusses relevant accounting, tax, and regulatory matters, including updates to SEC, FASB, IFRS, and tax guidance, and focuses on specialized industry accounting topics frequently seen by rate-regulated entities. It also outlines emerging accounting and reporting concerns specific to renewable energy.

In addition, to help you understand and address potential challenges in the accounting for and reporting of revenue, leases, financial instruments, and other topics related to proposed standards issued by the FASB, this publication includes a section that discusses the Board’s proposals and highlights nuances that could affect our industry.

We hope you find this update a useful resource, and we welcome your feedback. As always, we encourage you to contact your Deloitte team for additional information and assistance.

William P. Graf
Power & Utilities Leader
Deloitte & Touche LLP
Section 1
Industry Developments
This section covers some of the developments in the P&U industry that are not addressed in the rest of this publication.

**Merger and Acquisition Activity**

Mergers and acquisitions have continued to play an active role in the P&U industry in 2013. Acquiring companies have sought to increase their financial security, reduce their risk profiles and costs, strengthen their balance sheets, diversify their state regulatory risk, and enhance their abilities to employ large capital investment programs. Some companies with regulated operations have sought to grow their rate bases and provide more stable, predictable earnings.

A number of significant mergers and acquisitions have been completed in the P&U industry over the past year, including the following:

- **Fortis Inc. and CH Energy Group Inc.** — On June 27, 2013, Fortis Inc. completed its acquisition of CH Energy Group Inc. and its utility Central Hudson Gas & Electric Corp. after formal approval by the New York State Public Service Commission.
- **MidAmerican Energy Holdings Co. and NV Energy Inc.** — On December 19, 2013, MidAmerican Energy Holdings Co., a subsidiary of Berkshire Hathaway, completed its acquisition of NV Energy Inc. after receiving final regulatory clearance. FERC found the transaction to be consistent with the public interest because it will have no adverse effect on competition, rates, or regulation and it raises no cross-subsidization concerns.
- **Dynegy Inc. and Ameren Corp.** — On December 2, 2013, Dynegy Inc.’s subsidiary Illinois Power Holdings LLC completed its acquisition of Ameren Corp.’s merchant generation business, which included five coal-fired plants.
- **Laclede Gas Co. and Missouri Gas Energy** — On September 3, 2013, Laclede Gas Co. completed its purchase of Missouri Gas Energy’s assets from a subsidiary of Energy Transfer Partners LP.
- **Brookfield Renewable Energy Partners LP and Western Wind Energy Corp.** — On May 21, 2013, Brookfield Renewable Energy Partners LP completed its compulsory acquisition of Western Wind Energy Corp.’s outstanding common shares. The shares were acquired to complete the acquisition of Western Wind Energy Corp. In connection with the compulsory acquisition, Western Wind Energy Corp. withdrew its common stock from listing on the TSX Venture Exchange.

Other significant activity in mergers and acquisitions includes the following:

- **NRG Energy Inc.** announced on October 18, 2013, that it has agreed to acquire Edison Mission Energy’s assets for $2.635 billion. The assets consist of coal- and gas-fired power plants and wind farms with an aggregate capacity of 8,000 MW.
- **Fortis Inc.** announced on December 11, 2013, that it plans to acquire UNS Energy Corp. for $60.25 per share, representing an aggregate purchase price of about $4.3 billion, including the assumption of approximately $1.8 billion of debt on closing.
- **On December 13, 2013**, Entergy Corporation and ITC Holdings Corp. announced that the companies have mutually agreed to end their pursuit of a spin/merger of Entergy’s transmission business with ITC.

Mergers and acquisitions are likely to continue as the industry reacts to environmental compliance requirements; the impacts of varied natural gas prices; and, in some cases, the need to moderate customer rate increases. In some situations, regulatory approval can be a significant challenge and could influence whether companies will proceed with merger and acquisition activity.

See Deloitte’s *A Roadmap to Accounting for Business Combinations and Related Topics* for more information about accounting for mergers and acquisitions.
The Future of Nuclear

A number of companies have postponed or formally canceled the construction of new nuclear facilities because of increased costs and regulatory delays. In addition, companies have incurred increased design assessment and compliance costs for existing facilities.

There is 41,843 MW of new nuclear capacity in various stages of development, plus 583 MW of uprates at existing nuclear facilities. The majority of the new nuclear capacity in development was proposed before 2010, when projected demand for electricity was significantly higher than current projections. New nuclear capacity already under construction (seven projects) or in advanced development is coming from projects dominated by investor-owned utilities, either wholly owned or in partnership with other companies, including municipal utilities.

In developing nuclear facilities, companies may encounter many challenges, including long lead times, large capital requirements, extensive permitting processes, and uncertain future demand to support more capacity. In 2013, two operators announced plans to shut down their facilities because of economic conditions: Dominion Resources Inc. closed its Kewaunee plant in Wisconsin in May, and Entergy Corp. will close its Vermont Yankee plant in 2014. In addition, two operators announced plans to close their facilities because of ongoing mechanical problems: Southern California Edison will shut down San Onofre Nuclear Generation Station in California, and Duke Energy will close Crystal River 3 in Florida. The following companies canceled planned projects to increase capacity of existing nuclear facilities in 2013 as a result of economic conditions:

- Xcel Energy at the Prairie Island nuclear facility.
- Nebraska Public Power District at the Cooper nuclear facility.
- Exelon Corp. at the Limerick and LaSalle nuclear facilities.

A current obstacle to developing nuclear facilities is a federal appeals court decision that the Nuclear Regulatory Commission (NRC) cannot issue any new nuclear reactor licenses until the agency revises its waste confidence rule. The NRC expects to begin issuing licenses again by August 2014.

Some companies are developing and constructing new nuclear facilities, including:

- **Vogtle Electric Generating Plant Units 3 and 4** — In February 2012, the NRC issued construction and operating licenses for two new reactors at the plant located in eastern Georgia. The plant is 45.7 percent owned by the operator, Georgia Power, a subsidiary of the Southern Company; 30 percent owned by Oglethorpe Power Corp.; 22.7 percent owned by the Municipal Electric Authority of Georgia; and 1.6 percent owned by the city of Dalton, Georgia. As of September 2013, the construction project was approximately 50 percent complete. Units 3 and 4 are expected to begin commercial operation in 2017 and 2018, respectively.
• **Virgil C. Summer Nuclear Generating Station Units 2 and 3** — In March 2012, the NRC issued construction and operating licenses for the two proposed reactors at the plant located in South Carolina. Two-thirds of the plant is owned by the operator, a subsidiary of SCANA Corp., and one-third is owned by the South Carolina Public Service Authority (also known as Santee Cooper). Units 2 and 3 are expected to begin commercial operation in 2018 and 2019, respectively.

• **Tennessee Valley Authority Watts Bar Unit 2** — In April 2012, the Tennessee Valley Authority (TVA) board of directors approved continuing the construction of the unit, with revised estimates for the budget and timeline. Unit 2 is expected to be completed in 2015.

• **Tennessee Valley Authority Bellefonte Unit 1** — After the TVA completes Watts Bar Unit 2, it plans to resume construction of the Bellefonte Nuclear Plant Unit 1 in Alabama, which first began in 1974. Unit 1 is expected to be completed in 2018.

• **William States Lee III Units 1 and 2** — The NRC has delayed, until at least April 2016, its review of Duke Energy Corp.’s application for a license to build and operate two proposed units at the plant located in Cherokee County, South Carolina. The proposed capacity of the two units is approximately 2,230 MW.

Nuclear generation has environmental advantages because no carbon or pollutants are emitted, but decisions on new nuclear facilities will be affected by regulatory and siting uncertainties as well as by the significant investments required.

### Rate-Case Activity

The level of rate-case activity continued to be significant in 2013. The elevated level of rate-case activity during 2013 is attributable to increased costs driven by generation and other infrastructure upgrades and expansion projects, gas pipeline integrity assessment and monitoring, environmental compliance expenditures, renewable generation mandates, and the impact of low growth in sales because of the economy and customer conservation.

In 2013, the average return-on-equity (ROE) percentages for both electric and gas utilities, as set by regulators, were lower than the average ROE percentages in 2012 when adjusted for five rate cases for electric utilities in Virginia that incorporated ROE premiums as allowed by Virginia statutes for certain generation projects. The average ROE percentage for electric utilities in 2013 was approximately 9.8 percent, and the average ROE percentage in 2012 was approximately 10 percent. Further, the average ROE percentage set by regulators for gas utilities in 2013 was approximately 9.5 percent, and the average ROE in 2012 was approximately 9.9 percent. Despite the justified need for rate increases, regulators are cognizant of the impact of such increases on customers given the current economic conditions, which could affect rate-case outcomes.

### Shale Gas and Liquefied Natural Gas

Over the past decade, the North American natural gas industry has transformed vast, previously uneconomic shale gas deposits into valuable energy resources. While the so-called shale gas revolution has dramatically revitalized natural gas exploration and production, North American gas prices have plummeted since 2008 as a result of increased supplies and lower demand.

Production from shale gas is projected to transform historical basis relationships because much of that gas is not located in traditional gas-producing areas. To a lesser degree, the advent of new natural gas infrastructure, and evolving gas flows may also contribute to changes in historical basis relationships.

The shale gas revolution has helped stabilize natural gas prices in recent years, but there could be more volatility on the
horizon for the natural gas market as a sustainable balance between supply and demand is sought. While natural gas prices are still low, they have increased to an average of $3.69 per MMBtu (Henry Hub Natural Gas Index SNL) for the first nine months of 2013 compared with an average of $2.54 per MMBtu (Henry Hub Natural Gas Index SNL) for the first nine months of 2012. These average natural gas prices are still substantially lower than the average of $9.70 (Henry Hub Natural Gas Index SNL) for the first nine months of 2008.

The shale gas revolution has significantly affected the supply side but not the demand side. Factors that could bolster the demand for natural gas include increased exports to Mexico, higher industrial demand, liquefied natural gas (LNG) exports, and regulation-induced coal-to-gas switching. The amount of exports to Mexico has been steadily increasing and should continue for some time as the nation considers an overhaul of its energy industry.

The sustained low natural gas prices in the United States are now making it economical to export LNG to Europe and Asia despite the high costs of constructing a liquefaction plant and transporting an LNG tanker. Because there is a large price spread between U.S. natural gas prices and those in Asia and Europe, U.S. entities have expressed greater interest in constructing LNG export facilities.

FERC must approve the construction and operation of LNG export facilities, while the DOE must authorize exports to nations that do not adhere to free trade agreements, such as Japan, India, and the United Kingdom. As of November 20, 2013, the DOE has received 35 applications for export authorization to nations that operate under free trade agreements and has approved 28 of them. In addition, the DOE has received 26 applications for export authorization to nations that do not and has conditionally approved five: Sabine Pass Liquefaction LLC (a subsidiary of Cheniere Energy Inc.); two for Freeport LNG Expansion LP and FLNG Liquefaction LLC (subsidiaries of Freeport LNG Development LP); Lake Charles Exports LLC; and Dominion Cove Point LNG LP (a subsidiary of Dominion Resources Inc.).

The approval of significant LNG projects would connect the U.S. natural gas industry to the global market and may reduce the supply of natural gas in the United States, which could in turn lead to higher domestic prices. The exportation (as well as other uses) of the North American shale gas supply will continue to be heavily influenced by federal policies.

Future of Coal-Fired Generating Units

Because of regulatory requirements and market dynamics, including low natural gas prices, the rising cost of coal, and reduced demand for electricity, plans to retire coal-fired generating units continue to be announced in the P&U industry. Recent reports have indicated that companies have formalized plans to permanently shut off approximately 28,000 MW of capacity from mid-August 2013 through the end of 2022. In addition, some companies are planning to convert existing coal-fired generating units to burn other fuels such as natural gas or biomass. Recent reports have pointed out that nearly 11,000 MW has potentially been identified for conversion between 2014 and 2016. As the cost of replacement power and projected energy margins decrease, decreases in spot and forward natural gas prices may have a greater impact on the decision of whether to retrofit coal-fired generating units rather than retire them.

Regulatory requirements for coal-fired generating units were established by the EPA’s Mercury and Air Toxics Standards (MATS), which were finalized in December 2011 and were enacted to limit toxic air emissions. Companies are expected to comply with MATS by 2015–2016. In August 2012, a federal appeals court vacated the EPA’s Cross-State Air Pollution Rule (CSAPR), which would have set limits on emissions from power plants in 28 eastern states via a new cap-and-trade program. In June 2013, the U.S. Supreme Court agreed to review a federal appeals court’s decision striking down the EPA’s CSAPR. In September 2013, the EPA, the states, and public health and environmental advocates filed opening briefs with the U.S. Supreme Court; the high court is scheduled to hear the case in the upcoming term beginning in the fall, but no formal date has been set.

1 For more information, see Deloitte’s report Exporting the American Renaissance: Global Impacts of LNG Exports From the United States.
Regulations may have an even more significant effect on the construction of new coal-fired generating units and on existing fossil-fuel generating units. On September 20, 2013, the EPA released its proposed carbon pollution standard for new power plants, which would limit emissions from new fossil-fuel-fired plants to 1,110 lbs. of carbon dioxide (CO₂) per MWh, considerably less than the average coal-fired plant now emits. The only fossil-fuel-fired power plants placed in service over the past few years that are capable of meeting the proposed rule’s requirements are combined-cycle gas turbine generators. To meet proposed emissions-rate requirements, coal-fired generating units would need to use technology such as carbon capture and storage to reduce emissions. If this proposed regulation becomes effective, it is likely that no new coal-fired generating units will be constructed in the United States.

The EPA is currently developing proposed regulations concerning CO₂ emissions of existing fossil-fuel generating units. The proposal is expected to be issued by June 1, 2014, and finalized by June 1, 2015. These standards may result in higher compliance costs, along with other regulatory challenges, and may force certain companies to permanently retire coal-fired generating units or make costly retrofits.

**Renewable Energy and Master Limited Partnerships**

As defined by J.P. Morgan, a master limited partnership (MLP) is “a publicly traded entity that is listed on the major U.S. stock exchanges and is subject to the same accounting, reporting and regulations as a publicly traded corporation.” Investors in an MLP have an advantage in that they are taxed as partners but can trade their ownership stakes in a similar manner to corporate stock on a market. An MLP comprises two types of partners: (1) the limited partners, which provide the MLP with capital and periodically receive income distributions from it, and (2) the general partner, which manages the MLP and is compensated for its performance. For an MLP’s structure to apply to limited partnerships, at least 90 percent of its cash flows must be derived from real estate, natural resources, and commodities.

On April 24, 2013, Congress introduced the Master Limited Partnerships Parity Act (the “Act”), which would amend the Internal Revenue Code to include clean energy technologies within the MLP structure. Specific energy technologies that would qualify include wind, closed- and open-loop biomass, geothermal, solar, municipal solid waste, hydropower, marine and hydrokinetic, fuel cells, and combined heat and power. Other types of technologies that could qualify include various types of transportation fuels, such as cellulosic, ethanol, biodiesel, and algae-based fuels; energy-efficient buildings; electricity storage; carbon capture and storage; renewable chemicals; and waste-heat-to-power technologies. However, current MLPs and MLP structuring projects would not be affected by the Act.

If passed, the Act could lower the tax burden and increase the liquidity of clean energy investments, thereby lowering financing costs and removing constraints on the development and deployment of renewable energy. However, it is uncertain whether the Act will ultimately be passed since it will not be introduced as stand-alone legislation. In addition, there is uncertainty regarding the value of a tax structure that is untested in the renewable energy industry.

The production tax credit expired on December 31, 2013.

**Distributed Generation**

As defined by Appropedia, distributed generation (DG) is “generation of electricity by small-scale power plants located near the electric loads they serve.” Use of DG is on the rise because of its lower costs and the government subsidies that often support it. DG technologies often consist of modular generators such as solar photovoltaic (PV) systems, combined heat and power systems, and microgrids. Solar PV is a particularly popular form of DG because it is becoming cheaper to install.

However, there are also concerns about DG. For instance, questions have been raised about who should bear the fixed costs of solar installations, which can be disproportionately paid by nonsolar customers. Another concern is the impact of DG technologies on the long-term regulatory framework, since these technologies create financial risks for utilities (e.g., declining utility revenues, lower profitability potential).
Nevertheless, the solar industry is entering a new growth phase that will be defined by DG rather than by utility-scale projects. The growth occurring in the residential sector has resulted from net metering and third-party ownership policies, making it easier and more economical for residents and businesses to install rooftop solar panels. In net metering, customers can exchange surplus kilowatt-hours of electricity they produce on DG technologies during the day for grid-produced kilowatt-hours at night. This mechanism can allow some customers to zero-out their monthly bills.

Many industry observers expect that DG will substantially change the public utility business in coming years.

The Edison Electric Institute released a set of 21 consensus principles on distributed energy resources to serve as a framework for policymakers and stakeholders evaluating the technology’s benefits and challenges. The principles cover four main topics: financial and regulatory concerns; market development and deployment; consumer issues; and safety, reliability, and system planning. The principles also touch on such issues as subsidization and reliability.

FERC Revisits Centralized Capacity Market Rules and Structures

On September 25, 2013, FERC held a technical conference to consider how centralized-capacity market rules and structures in the regions served by ISO New England Inc., New York Independent System Operator Inc., and PJM Interconnection LLC support the procurement and retention of resources to meet future reliability and operational needs.

During the technical conference, FERC focused on the following five design elements that can influence each region’s choices about the procurement of future capacity resources:

- Demand curves.
- Forward and commitment periods.
- Definition of the capacity product.
- Performance requirements.
- Market power mitigation.
Section 2
SEC Update
SEC Announces New Chairman

On April 8, 2013, the U.S. Senate confirmed Mary Jo White as the chairman of the SEC. Ms. White’s background as a former federal prosecutor signals the Commission’s emphasis on enforcement actions. Not surprisingly, in comments made after her confirmation, Ms. White indicated that financial statement fraud is a topic she is interested in.

SEC Announces Three New Enforcement Initiatives

In July 2013, the SEC issued a press release that “announced three new initiatives that will build on its Division of Enforcement’s [the ‘Division’s’] ongoing efforts to concentrate resources on high-risk areas of the market and bring cutting-edge technology and analytical capacity to bear in its investigations.” Under these initiatives:

- The Financial Reporting and Audit Task Force will comprise Division accountants and attorneys and will focus on identifying violations related to financial statements, reporting and disclosures, and audit failures. In addition, the task force will monitor restatement activities; analyze industry performance trends; and use tools, such as its Accounting Quality Model, to analyze data.

- The Center for Risk and Quantitative Analytics will use quantitative data (e.g., XBRL-encoded interactive data) to identify and analyze “high-risk” behaviors and misconduct. The overall goal of this initiative is to increase the Division’s identification and prevention of conduct that would adversely affect investors.

- The Microcap Fraud Task Force will focus on abusive trading and fraudulent conduct related to securities issued by microcap1 companies, especially those that do not regularly report their financial results publicly.

Activities Related to Requirements Under the Dodd-Frank Act

Background of the Dodd-Frank Act

The passage of the Dodd-Frank Act in July 2010 brought a number of key reforms to the U.S. financial system. Over the past three years, the SEC has acted on a number of provisions in the Dodd-Frank Act by (1) proposing and approving various rules, (2) completing certain mandated studies, (3) submitting certain required reports, and (4) creating various offices and committees. This section summarizes Dodd-Frank Act activity that has occurred since the last edition of this publication.

Final Rule to Disqualify Felons and Other “Bad Actors” From Offering or Selling Securities in Certain Exempt Offerings

On July 10, 2013, the SEC issued a final rule implementing Section 926 of the Dodd-Frank Act. Under the final rule, covered persons, including the issuer, its predecessors and affiliated issuers, and other persons,2 are precluded from using the Regulation D, Rule 506, exemption3 to offer securities if they are party to certain disqualifying events, including:

- Felony or misdemeanor criminal convictions, court injunctions, or restraining orders in connection with the (1) sale or purchase of a security or (2) submission of a false filing to the SEC.

---

1 According to the SEC’s Web site, “[t]he term ‘microcap stock’ applies to companies with low or ‘micro’ capitalizations, meaning the total value of the company’s stock. . . . Microcap companies typically have limited assets and operations. Microcap stocks tend to be low priced and trade in low volumes.”

2 In addition to the issuer (and the issuer’s predecessors and affiliated issuers), the final rule’s definition of covered persons includes the following: (1) “any director, officer, [footnote omitted] general partner or managing member of the issuer”; (2) “any beneficial owner of 10% or more of any class of the issuer’s equity securities”; (3) “any promoter connected with the issuer in any capacity at the time of the sale”; (4) “any person that has been or will be [compensated — directly or indirectly] for solicitation of purchasers in connection with sales of securities in the offering”; and (5) “any director, officer, general partner, or managing member of any such compensated solicitor.”

3 When securities are offered to the general public, issuers are generally required to register the securities with the SEC. When certain conditions are met, however, an issuer may be exempt from registering its securities. Issuers that issue exempt securities typically rely on the exemption in Regulation D, Rule 506.
• Final orders from federal and state banking, credit union, savings association, insurance, or other regulatory agencies that prohibit the issuer from associating with one of their regulated entities or from otherwise engaging in activities that they regulate.

• Certain SEC disciplinary orders related to brokers, dealers, municipal securities dealers, investment companies, and investment advisers and their associated persons.

• SEC cease-and-desist orders related to violations of certain antifraud provisions and registration requirements of the federal securities laws.

**SEC Issues Final Rule on Lost Securityholders and Unresponsive Payees**

On January 16, 2013, the SEC issued a [final rule](#) that amends Rule 17Ad-17 of the Exchange Act in response to Section 929W of the Dodd-Frank Act. Previously, Rule 17Ad-17’s requirement to search for lost securityholders applied only to recordkeeping transfer agents; under the final rule, it applies to broker-dealers and other security market participants as well. For a “not yet negotiated” check (i.e., not cashed) of $25 or more, payment agents will be required to notify a “missing securityholder” — within seven months of a check’s issuance — that the check was issued but not cashed. The final rule also clarifies that its added notification requirements “shall have no effect on state escheatment laws.” This final rule became effective on March 23, 2013, and must be complied with by January 23, 2014.

**SEC’s Conflict Minerals Rule Upheld by Federal Court**

On July 24, 2013, the U.S. District Court for the District of Columbia upheld the SEC’s [final rule](#) on conflict minerals by rejecting a lawsuit filed by the U.S. Chamber of Commerce, the Business Roundtable, and the National Association of Manufacturers. The plaintiffs, which challenged the final rule on the basis that (1) it is too costly to implement and (2) its required disclosures violate a registrant’s First Amendment rights, have appealed the court’s ruling. Oral arguments were heard by the U.S. Court of Appeals for the District of Columbia on January 7, 2014.

As a result of the court’s decision, the final rule continues to be effective on a calendar-year basis beginning this year. A registrant that meets the final rule’s reporting requirements must file a Form SD with the SEC by June 2, 2014.⁶

**U.S. District Judge Vacates SEC Rule on Disclosures of Payments Made by Resource Extraction Issuers**

On July 2, 2013, the U.S. District Court for the District of Columbia vacated an SEC [final rule](#) that would have required resource extraction issuers to disclose certain payments. The court held that the SEC misinterpreted the part of the Dodd-Frank Act that called for the rule — specifically, that the SEC “misread the statute to mandate public disclosure of the reports, and [that] its decision to deny any exemption was, given the limited explanation provided, arbitrary and capricious.”

The court’s ruling eliminates the requirement to comply with this final rule, thereby eliminating the need for resource extraction issuers to disclose certain payments made to the U.S. federal government and foreign national and subnational

---

4 The final rule defines a payment agent as “any issuer, transfer agent, broker, dealer, investment adviser, indenture trustee, custodian, or any other person that accepts payments from the issuer of a security and distributes the payments to the holders of the security.”

5 As defined in the final rule.

6 Form SD must be submitted by May 31 of the year after the calendar year subject to the filing. Because May 31, 2014, is a Saturday, Form SD is due on the following business day, June 2, 2014.

7 The final rule defines resource extraction issuers (or “extractive issuers”) as issuers that are (1) “engaged in the commercial development of oil, natural gas, or minerals” and (2) “required to file an annual report with the [SEC].” Domestic issuers (including smaller reporting companies), foreign issuers, their subsidiaries, and other entities controlled by such extractive issuers would have been subject to the final rule’s disclosure requirements.
governments, which would have been effective for issuers with fiscal years ending after September 30, 2013. While the SEC has indicated that it will not appeal the court’s decision, it may rewrite and repropose a rule on this issue in the future.

**SEC Issues FAQs on Conflict Minerals and Resource Extraction Issuer Payment Disclosures**

On May 30, 2013, the staff in the SEC’s Division of Corporation Finance issued FAQs on applying the SEC’s final rules on (1) conflict minerals and (2) disclosure of certain payments made by resource extraction issuers.

The SEC staff also confirmed that under these final rules, both of which require registrants to file Form SD if the rule applies to them, a registrant’s eligibility to issue securities on Form S-3 is not affected by the Form SD filing requirements (e.g., timeliness of filing).

The conflict minerals FAQs clarify:

- Which registrants are affected by the rule and confirm that an issuer’s subsidiary is within the rule’s scope.
- Which activities are considered part of the mining process (i.e., not considered “manufacturing” and thus excluded from the rule).
- Certain aspects of the rule’s concepts of “necessary to the functionality or production” and “contract for manufacture.”
- The application of product packaging and the use of tools and equipment in an issuer’s manufacturing process.
- Certain Form SD preparation and filing requirements, including filing deadlines for new registrants.

The extraction issuer FAQs are broadly grouped into the following categories:

- Entities subject to the rule.
- Clarification of the definition of a resource extraction issuer.
- Definition of the term “mineral” as used in the rule.
- Payments subject to the rule.

**SEC Proposes Rule on “Pay Ratio” Disclosures**

On September 18, 2013, the SEC issued a proposed rule to implement Section 953(b) of the Dodd-Frank Act. Under the proposal, a registrant subject to the filing requirements of Regulation S-K, Item 402, would need to disclose (1) the median of the annual total compensation of its employees and (2) the ratio of this median to its CEO’s annual pay. Emerging growth companies (EGCs), smaller reporting companies, and foreign private issuers would be exempt from this requirement.

According to the proposed rule, the SEC received nearly 23,000 comment letters on Section 953(b). Commenters expressed varying degrees of support for the proposed disclosure requirements. Some were concerned about their complexity and potential implementation costs. The proposal indicates that to mitigate such concerns, registrants would be permitted a certain level of flexibility when determining the median annual compensation of their employees.

---

1 Although issuers are not required to apply the final rule on resource extraction issuer payment disclosures, which was vacated by the U.S. District Court for the District of Columbia on July 2, 2013, the FAQs issued by the SEC staff remain in effect.
2 As defined in Section 3(a) of the Exchange Act.
3 As defined in Regulation S-K, Item 10(f)(1).
4 Foreign private issuers include those that file annual reports and registration statements on Forms 20-F and 40-F.
Under the proposed rule:

- Companies would be permitted to use a valid statistical sample in determining the median employee compensation.
- Companies would be permitted to select the compensation measure to use in determining the median employee compensation in the sample.
- Once the median employee compensation is identified, companies would be required to calculate the median employee’s total compensation for the year in accordance with Regulation S-K, Item 402(c)(2)(x).
- Companies would then be required to calculate and disclose the ratio of the CEO’s annual compensation for the fiscal year to the median employee’s annual total compensation for the year in Compensation Discussion and Analysis, along with the method used to determine the median employee compensation and other assumptions and estimates used to identify the median employee compensation or total compensation (or any elements of total compensation).

In calculating the median employee’s income, registrants could annualize the income of full-time employees who have not worked the entire year (i.e., newly hired employees) but would not be permitted to annualize part-time or seasonal employees’ compensation. Registrants also would not be permitted to adjust a non-U.S. employee’s income for cost-of-living differences.

Comments on the proposed rule were due by December 2, 2013. See Deloitte’s October 2013 Center for Corporate Governance Hot Topics newsletter for more information.

**SEC and Other Federal Agencies Issue Proposed Rule on Credit Risk Retention**

On August 28, 2013, the SEC and five other federal agencies (the “agencies”) jointly issued a proposed rule to implement the credit risk retention requirements established by Section 15G of the Exchange Act in accordance with Section 951 of the Dodd-Frank Act. Under the proposed rule, a securitizer of asset-backed securities would be required to “retain not less than 5 percent of the credit risk of the assets collateralizing the asset-backed securities.” However, there would be a number of exceptions to this requirement, “including an exemption for asset-backed securities that are collateralized exclusively by residential mortgages that qualify as ‘qualified residential mortgages,’ as such term is defined by the agencies by rule.”

Comments on the proposed rule were due by October 30, 2013.

**Other Dodd-Frank Activities**

In addition to the proposed and final rulemaking activity mandated by the Dodd-Frank Act, the SEC completed the following studies and reports for Congress since the previous version of this publication:

- An annual report on use of data collected from advisers to hedge funds and other private funds to aid in monitoring system financial risk (July 25, 2013).
- A study on the rating process for structured finance products and the feasibility of an assignment system (December 18, 2012).

**Other Dodd-Frank Rulemaking Yet to Come**

While a number of the Dodd-Frank Act’s objectives have been accomplished, the SEC still needs to address certain significant areas, some of which are not specifically related to financial reporting (i.e., related to corporate governance).
For example, the Dodd-Frank Act directs the SEC to establish rules on executive compensation, including:

- Rules to implement the Dodd-Frank Act’s “clawback” provisions (i.e., recovery of executive compensation after the registrant’s financial statements are restated).
- Rules requiring proxy disclosure about whether employees and directors are allowed to hedge the value of any securities granted to or otherwise owned by them.

In addition, the SEC plans to propose rules to define “other significant matters” related to broker voting on uninstructed shares.

The Jumpstart Our Business Startups Act

Background of the JOBS Act

In April 2012, President Obama signed the JOBS Act into law to increase American job creation and economic growth by improving access to the public capital markets for EGCs. The JOBS Act addresses topics such as “crowdfunding” transactions, increases shareholder limits that would require companies to register with the SEC, and provides accommodations that allow EGCs to (1) reduce financial statements presented (from three to two years), (2) reduce periods that would be presented for selected financial data, (3) adopt new or revised accounting standards (issued after April 5, 2012) on the basis of nonpublic-company transition periods, and (4) forgo obtaining an attestation report for ICFR. Further, Title I of the JOBS Act amends the Securities Act of 1933 (the “Securities Act”) to allow an EGC to provide a confidential draft IPO registration statement to the SEC staff for review before its public filing (i.e., the SEC is prohibited from disclosing the information being reviewed).

Below is a summary of the JOBS Act activity that has occurred since the last edition of this publication.

SEC Issues Rule Eliminating Prohibition Against General Solicitation and Advertising of Certain Offerings

On July 10, 2013, the SEC released a final rule implementing the requirements of Section 201(a) of the JOBS Act to amend Rule 506, Rule 144A, and Form D under the Securities Act.

The final rule updates Rule 506 of Securities Act Regulation D to allow entities to use general solicitation and advertisements to market their securities provided that they have (1) confirmed or have reason to believe that purchasers of the securities are accredited investors (as defined in Regulation D, Rule 501) and (2) taken reasonable steps to confirm that the investors are accredited investors. An SEC fact sheet gives examples of steps entities can consider taking to confirm that investors are accredited.

The final rule also amends Rule 144A to allow an issuer to offer securities to investors that are other than qualified institutional buyers (QIBs) if the issuer reasonably believes that such investors are QIBs. Further, the final rule adds to Form D a box that issuers should check to indicate that they are relying on the provisions that allow general solicitation and advertising in a Rule 506 offering.

SEC Proposes Rule on Crowdfunding

On October 23, 2013, the SEC issued a proposed rule to implement requirements in Title III of the JOBS Act that would permit eligible companies to use “crowdfunding” to offer and sell securities. Crowdfunding is a method of raising capital through the Internet, typically by soliciting small individual contributions from a large number of people.

The proposed rule would permit an individual to use crowdfunding to invest in eligible companies, subject to certain thresholds, on the basis of the annual income or net worth of the individual, and would limit the amount of money a company can raise through crowdfunding offerings to $1 million in a 12-month period. For the safety of investors,
companies offering their securities in crowdfunding transactions would (1) need to transact through SEC-registered
intermediaries, (2) file certain information (including their reviewed or audited financial statements, subject to amounts
offered and sold during a 12-month period), and (3) disclose certain other information about their offers. However, certain
companies would be prohibited from using crowdfunding transactions to offer and sell securities, including companies
organized outside the United States and its territories, companies already subject to reporting requirements under the
Exchange Act, investment companies (including hedge funds), and others specified in the proposed rule.

The proposed rule would limit crowdfunding transactions to online platforms and would require that they be conducted
through an SEC-registered intermediary (i.e., either a broker-dealer or a “funding portal,”\(^\text{12}\) which would be a new type
of SEC registrant). The proposed rule would also create a regulatory framework for these intermediaries. For example,
funding portals would be required to perform certain actions, such as providing educational materials to investors and
taking measures to reduce the risk of fraud. Intermediaries would also be precluded from certain activities, such as offering
investment advice or making investment recommendations.

Comments on the proposed rule are due by February 14, 2014.

**SEC Issues Report to Congress on Its Review of the Regulation S-K Disclosure Requirements**

On December 20, 2013, in accordance with Section 108 of the JOBS Act, the SEC issued a report to Congress summarizing
the results of its study on modernizing and simplifying the disclosure requirements under Regulation S-K. While the
study’s purpose was to identify how to reduce the costs and burdens of these requirements only for EGCs, the SEC staff
recommended using a comprehensive, long-term approach to examine potential improvements to all issuers’ disclosures.
The staff concluded that this approach would be better than a shorter-term targeted approach for achieving its “dual goals
of streamlining requirements for companies, including EGCs, and focusing on useful and material information for investors.”

**Other SEC Matters**

**SEC Issues New Compliance and Disclosure Interpretations**

The SEC’s Division of Corporation Finance issued new compliance and disclosure interpretations (C&DIs) on various
topics, including (1) Exchange Act Form 8-K, (2) Securities Act rules, (3) Securities Act forms, (4) Securities Act sections,
(5) Regulation S-K, and (6) oil and gas rules.

One of the more notable C&DIs is Question 110.01 of Exchange Act Form 8-K, which presents the SEC staff’s view on the
Item 2.06 filing requirements. Specifically, the C&DI clarifies that a registrant would not be required to file an Item 2.06
Form 8-K when its impairment conclusion is coincidental to, but not in connection with, the preparation, review, or audit of
financial statements that must be included in its next periodic filing under the Exchange Act.

**SEC Clarifies Views Regarding Registrants’ Use of Social Media to Communicate Information to Investors**

On April 2, 2013, the SEC issued a report outlining a situation in which Reed Hastings, the CEO of Netflix Inc., announced
on his personal Facebook page that Netflix Inc. had streamed 1 billion hours of content in June 2012. The report calls into
question whether Netflix Inc. had appropriately complied with Regulation FD and Section 13(a) of the Exchange Act.\(^\text{13}\)

---

\(^{12}\) The proposal defines a “funding portal” as follows:

[A] broker acting as an intermediary in a transaction involving the offer or sale of securities in reliance on Section 4(a)(6) of the Securities Act (15 U.S.C. 77d(a)(6)),
that does not:

(i) Offer investment advice or recommendations;

(ii) Solicit purchases, sales or offers to buy the securities displayed on its platform;

(iii) Compensate employees, agents, or other persons for such solicitation or based on the sale of securities displayed or referenced on its platform; or

(iv) Hold, manage, possess, or otherwise handle investor funds or securities.
Although the SEC decided not to pursue an enforcement action against Netflix Inc., the report reiterated concerns that registrants and others have expressed regarding the use of social media outlets to communicate corporate matters to investors. The SEC concluded that registrants may engage in such communication provided that they comply with Regulation FD and that they “take steps sufficient to alert investors and the market to the channels [they] will use for the dissemination of material, nonpublic information.”

SEC Approves PCAOB Auditing Standard on Communications With Audit Committees

On December 17, 2012, the SEC issued an order approving PCAOB Auditing Standard 16 on communications with audit committees. Auditing Standard 16 supersedes PCAOB AU Sections 310 and 380, which are interim auditing standards.

Auditing Standard 16 states that the auditor’s objectives are to:

a. Communicate to the audit committee the responsibilities of the auditor in relation to the audit and establish an understanding of the terms of the audit engagement with the audit committee;

b. Obtain information from the audit committee relevant to the audit;

c. Communicate to the audit committee an overview of the overall audit strategy and timing of the audit; and

d. Provide the audit committee with timely observations arising from the audit that are significant to the financial reporting process.

The SEC, in accordance with the JOBS Act, approved the application of Auditing Standard 16 to audits of EGCs.

The new standard became effective for audits and quarterly reviews of issuers for fiscal years beginning after December 15, 2012.

EDGAR Manual Updates

The SEC periodically issues final rules to facilitate updates to the EDGAR filing manual. In 2013, the SEC posted updates in January, May, July, and September. Noteworthy changes include:

- A new EDGAR link and support for PDF as a filing format.
- Implementation of online application and submission on Form 13F and Form SD.
- Implementation of minor changes/updates to Form 13H and Form D.

Revisions were also made to support the U.S. GAAP 2013 XBRL taxonomy. The EDGAR system will no longer accept interactive data files that use the U.S. GAAP 2011 XBRL taxonomy. As noted on the SEC’s Web site, the “SEC staff strongly encourages companies to use the most recent version of the [U.S. GAAP taxonomies] for their Interactive Data submissions to take advantage of the most up to date tags related to new accounting standards and other improvements.”

13 As stated in SEC Release No. 69279, Regulation FD and Section 13(a) of the Exchange Act “prohibit public companies, or persons acting on their behalf, from selectively disclosing material, nonpublic information to certain securities professionals, or shareholders where it is reasonably foreseeable that they will trade on that information, before [such information] is made available to the general public.”
Financial Reporting Manual Updates

The FRM, issued by the SEC's Division of Corporation Finance, contains the SEC staff’s interpretations of various rules and regulations. The following noteworthy updates were made to the FRM in 2013.

- **October update (contains changes made as of June 30, 2013)** — This update (1) incorporates guidance on the JOBS Act into the manual; (2) clarifies the guidance on a registrant’s requirements related to the age of interim financial statements for an acquired business; and (3) expands guidance to include the SEC staff’s interpretive views on how a registrant should consider the effects of retrospective accounting changes in the income significance test for its equity method investees.

- **July update (contains updates made as of March 31, 2013)** — The revisions mainly address the acquisition of real estate operations under Regulation S-X, Rule 3-14, including financial statement requirements and considerations related to measuring significance. In addition, clarifications were made to sections on (1) determining the significance of a registrant’s equity method investments under Regulation S-X, Rule 4-08(g), and (2) non-GAAP financial measures.

- **April update (contains changes made as of December 31, 2012)** — Updates made include age of financial statements in foreign private issuer IPOs, Regulation S-X requirements for foreign private issuers, financial statement requirements for foreign incorporated acquirees or investees that do not qualify as a foreign business, and other changes.

- **January update (contains changes made as of September 30, 2012)** — In addition to certain minor editorial revisions, changes include clarifications and modifications to the guidance on (1) auditor-related topics, including association with cumulative amounts from inception of a development-stage company and the PCAOB’s audit requirements for nonissuer financial statements; (2) the impact of changes in a registrant’s filing status on its periodic filings; and (3) significance testing thresholds for related businesses under Regulation S-X, Rule 3-05, and triple net leases under Regulation S-X, Rule 3-14.

SEC Staff Comments

The Sarbanes-Oxley Act of 2002 requires the SEC staff to review every issuer’s disclosures, including financial statements, at least once every three years. The SEC staff’s comments and registrants’ responses are posted on the SEC’s Web site and provide valuable insight into common comment themes. Registrants can incorporate a review of the comments into their financial reporting processes to help improve their financial statements and disclosures. The SEC staff routinely comments on matters related to financial statement accounting, disclosure, and presentation.

The SEC staff’s comments to registrants from the P&U industry have focused on:

- Subsidiary and equity investee dividend restrictions and the requirement for the parent company to provide condensed financial information (i.e., on “Schedule I”).

- Accounting for the impact of rate-making.

- Accounting for energy transacting agreements.

In addition, the staff continues to question whether P&U industry registrants have complied with disclosure requirements regarding their range of loss in connection with litigation and other contingencies under ASC 450, segment reporting requirements under ASC 280, and regulatory matters pursuant to ASC 980.

See Deloitte’s **SEC Comment Letters — Including Industry Insights** for a more detailed discussion of trends identified in the SEC staff’s comment letters to P&U companies.
Section 3
International Financial Reporting Standards
The potential adoption of IFRSs remains a topic of interest for many P&U companies as the FASB works on convergence efforts and the SEC considers whether to mandate the standards for U.S. companies.

**Key IFRS Agenda Items**

The sections below discuss IFRS-related topics that are particularly applicable to the SEC, the FASB, and P&U companies.

**Financial Instruments**

IFRS guidance on accounting for financial instruments is generally similar to that in U.S. GAAP but differs in certain respects. For instance, because the definition of a derivative under the IFRS framework differs from that under the U.S. GAAP framework, contracts within the scope of derivative accounting under IFRSs will differ from those under U.S. GAAP. Furthermore, the lack of interpretive guidance in IFRSs for certain areas of accounting may result in a different application from that under U.S. GAAP. For example, IFRSs do not address many of the interpretive issues related to energy transacting that are covered in U.S. GAAP.

The FASB and IASB are currently working on a joint project to improve the accounting for financial instruments. However, the boards’ paths have diverged on each of the three phases of the project — (1) classification and measurement, (2) hedging, and (3) impairment. For example, in the fourth quarter of 2013, the FASB decided to abandon the use of the “solely payments of principal and interest” (SPPI) concept with respect to classifying financial instruments while the IASB continues to pursue a model that uses it. Furthermore, while the IASB has recently developed a new general hedge accounting model, the FASB has not yet begun redeliberating the hedge accounting phase of its project. In addition, while the FASB and IASB are both pursuing an expected-loss impairment model, the boards’ proposed models significantly differ from one another.

**Classification and Measurement**

In November 2009, the IASB issued IFRS 9, which requires entities to classify and measure financial assets on the basis of the business models for managing those assets and the assets’ contractual terms. In October 2010, the IASB amended IFRS 9 to retain the existing classification and measurement guidance for financial liabilities and to incorporate requirements for derecognition of both financial assets and financial liabilities. In November 2011, the IASB tentatively decided to reopen IFRS 9 to address potential application issues and to consider the interaction between IFRS 9 and the tentative decisions made on the accounting for insurance contracts as well as the FASB’s model on the classification and measurement of financial instruments.

In November 2012, the IASB issued an ED outlining its revisions to IFRS 9. Under this proposal, financial assets would be classified and measured on the basis of their contractual cash flow characteristics and the business model under which they are managed. An entity would be required to classify a financial asset into one of three categories: (1) amortized cost, (2) FV-OCI, or (3) FV-NI. The IASB had tentatively decided that a financial asset would meet the requirements of the contractual cash flow characteristics assessment if the contractual terms of the instrument “give rise on specified dates to cash flows that are [SPPI] on the principal amount outstanding.” The IASB will continue working on finalizing its amendments to IFRS 9 based on the SPPI contractual cash flow and business model tests and has indicated that it expects to finalize this project in either the first or second quarter of 2014.

**Hedge Accounting (General)**

The IASB issued an ED of a new general hedge accounting model in December 2010, followed by a staff draft of the model in September 2012. The board finalized its deliberations on the general hedging requirements in April 2013 and, in November 2013, the staff published its new version of IFRS 9, which incorporates the final version of the proposed hedging
requirements. The general hedging model covers just the general hedging requirements because the IASB is currently working on a macro hedging DP to address more detailed hedging programs. Changes that the IASB made to IAS 39, or to its original 2010 ED, include the following:

- **Hedging instruments** — Under IAS 39, a derivative instrument was generally the only item eligible to be designated as a hedging instrument. Under the new guidance, any financial instrument currently reported at fair value through profit or loss would be eligible as a hedging instrument regardless of whether it is a derivative. In addition, the new model allows the deferral of the time value of options, while entities would typically record those items in profit and loss under IAS 39.

- **Hedged items** — The new model permits entities to designate a component of a nonfinancial item as a hedgeable item if the component is separately identifiable and reliably measurable. This is a significant departure from IAS 39, under which only components of financial items could be designated as hedged items. In addition, the IASB is now allowing items that include derivatives (i.e., “aggregate exposures”) to be designated as hedged items. This is also a significant departure from IAS 39, which prohibited entities from designating derivatives as hedged items. Finally, the IASB has decided to allow companies to hedge certain group and net positions. Thus, a company would be permitted, in certain circumstances, to combine a group of risks (as long as each individual risk would qualify as a hedgeable risk) and to designate the net outstanding risk of the group as a hedged item.

- **Qualifying criteria for applying hedge accounting** — The ED significantly amended the hedge assessment requirements under IAS 39. Currently, IAS 39 requires entities to perform a prospective and retrospective quantitative analysis that shows an expected effectiveness of between 80 percent and 125 percent. Under the new model, a retrospective analysis is no longer required. In addition, companies are not required to quantitatively show that there is an “economic relationship” between the hedged item and the hedging instrument. Instead, companies can either qualitatively (if the hedging relationship is clear) or quantitatively (for more complex hedging relationships) analyze whether a hedging relationship exists.

- **Modifying or discontinuing a hedging relationship** — Under IAS 39, changes in a hedging relationship typically result in a redesignation of the old relationship and redesignation of a new relationship, which typically creates ineffectiveness in the hedging relationship. The new model removes the redesignation requirement in certain circumstances. In addition, the new model removes an entity’s ability to elect to redesignate a hedging relationship. In other words, as long as the original risk exists and the hedging strategy of the entity has not changed, hedge accounting cannot be voluntarily discontinued.

- **Disclosures** — The final amendments create new disclosure requirements to help financial statement users understand an entity’s use of hedging. These disclosures would include information about:
  - The entity’s risk management strategy.
  - How the hedges will affect future cash flows.
  - How the hedges affect the balance sheet, income statement, and statement of equity.

**Impairment**

In this phase, the IASB intends to address the “too little, too late” criticism that constituents have voiced about the existing impairment model for financial assets during the recent financial crisis. The IASB and FASB are working on replacing the existing incurred-loss model with an expected-loss model that is more forward-looking and would require entities, in determining impairment losses, to consider not only past and current information but also reasonable and supportable future events.

The expected-loss model and variations thereof have not been received favorably by constituents. In March 2013, the IASB issued for public comment an ED proposing a “three-bucket” approach that was developed jointly by the boards. The FASB, however, has determined that the three-bucket approach is overly complex and would be challenging for constituents to
understand and apply; accordingly, it developed a current expected credit loss (CECL) model, which it exposed for public comment in the fourth quarter of 2012. Under the FASB’s CECL model, an entity does not measure the loss allowance for any financial instruments by using the 12-month expected credit losses; instead, expected credit losses for financial instruments are recognized as lifetime expected credit losses. (For further discussion of this topic, see Section 7.)

The boards have taken different approaches to accounting for credit losses. Although both boards have proposed expected-loss models to replace the current incurred-loss model, the proposed models differ in the timing for recognizing those losses. The primary difference stems from the fact that the FASB does not distinguish between financial instruments whose creditworthiness has declined since initial recognition and those whose creditworthiness has not declined. Thus, entities would initially recognize expected credit losses from a lifetime standpoint. Under the IASB’s proposal, however, entities would initially recognize expected credit losses from a 12-month perspective and would reassess and recognize the expected losses from a lifetime standpoint only if the credit risk increases significantly and the resulting credit quality decreases below investment-grade. However, the expected credit losses are expected to be similar under both models for assets that have deteriorated significantly and fallen below the investment-grade level.

**Regulatory Assets and Liabilities**

**Comprehensive Project on Rate Regulation**

Under IFRSs, there is no guidance equivalent to ASC 980, which addresses the recognition and measurement of regulatory assets and liabilities. The IASB previously attempted to address this in 2009 by issuing an ED of a proposed standard on rate-regulated activities (RRAs), but the project stalled during the first half of 2010. In the meantime, Canadian utilities subject to similar cost-based regulation that have traditionally applied accounting principles similar to those under U.S. GAAP have struggled with the adoption of IFRSs in the absence of such a standard. The Canadian utilities have pursued multiple paths, including (1) taking advantage of the AcSB’s continued IFRS deferrals for qualifying utilities, (2) adopting U.S. GAAP for local filings when permitted, (3) listing securities and filing in the United States under U.S. GAAP, (4) amending legislation for certain government-controlled utilities to permit the application of a special accounting framework consisting of IFRSs plus ASC 980, and (5) proceeding with IFRS adoption (with some companies writing off regulatory balances and a few that, in certain situations, recognize regulatory assets and liabilities as financial assets and liabilities). U.S. energy companies have continued to advocate for the retention of existing U.S. accounting guidance that recognizes the economic effects of rate regulation, should the United States eventually adopt IFRSs without an equivalent standard in place.

In response to these concerns, IFRIC proposed a project on a narrow group of issues that ultimately delayed work on a 2009 international ED. On IFRIC’s recommendation and on the basis of feedback the IASB received on its three-year agenda consultation process, the IASB announced in the spring of 2012 that it would give priority to reactivating a comprehensive international project on RRAs. In September 2012, the IASB formally authorized its staff to draft a discussion paper (DP) on these issues and indicated its intention to align the project on RRAs with its separate project on its overall conceptual framework (including the definition of assets and liabilities and related recognition requirements). Because the previous project stalled because of debate about whether a “unit of account” existed (and with whom) between utilities, customers, and regulators and, if so, whether associated rights and obligations met the existing definition and recognition requirements for assets and liabilities, it is clear that the alignment of these projects is meant to “test” any related changes to these definitions and recognition requirements from the conceptual framework project. Further, it is clear that the IASB intends to study various regulatory regimes and the related accounting issues, not just the cost-of-service model commonly employed in North America and certain other countries.

The IASB issued a request for information (RFI) in March 2013, with comments due by May 2013. The RFI is an early step in the RRA research project, and the objective is to identify a range of rate-regulatory schemes to establish the scope of the project. The IASB is expected to issue a DP on RRA during the first half of 2014.
Interim IFRS

As a temporary measure, on December 17, 2012, the IASB tentatively decided to initiate a short-term project that would result in the development of an interim standard that would permit a certain level of grandfathering of existing local GAAP recognition and measurement accounting policies for rate-regulated entities that have not transitioned to IFRSs (a development that will benefit Canadian entities). This interim standard would include presentation and disclosure requirements designed to help users understand the effects of rate regulation.

As part of this short-term project, the IASB issued an ED on regulatory deferral accounts in April 2013. The ED contains a proposal for an interim standard and was designed to reduce barriers to first-time adoption of IFRSs. Under this proposal, first-time adopters of IFRSs would generally be allowed to carry forward RRA accounting as prescribed by their previous local GAAP. Companies electing to carry forward their local GAAP RRA accounting would be required to present regulatory deferral accounts and related activities separately on their balance sheet and income statement. Further, they would be subject to certain disclosure requirements (e.g., they would need to disclose the nature and risks of rate regulation). Comments on the proposal were due by September 4, 2013.

Upon considering the feedback received on this proposal at its October 2013 meeting, the IASB tentatively decided to proceed with an interim standard that would apply, as a policy choice, to first-time adopters of IFRSs that previously recognized regulatory assets and liabilities in their financial statements in accordance with the GAAP from their local jurisdiction. A final interim standard is expected to be issued during the first quarter of 2014. Further, it is expected that this standard would be effective for those years beginning on or after January 1, 2015 (the opening balance sheet would be the first day of the comparative year).

The FASB previously indicated in the summer of 2011 (during deliberations of the revenue project and the impact on specialized utility guidance related to alternative revenue programs) that the guidance in ASC 980 could be a topic for future convergence standard setting with the IASB. While the FASB is not participating in either of the projects discussed above and we are not aware of any immediate plans on the FASB’s part to reconsider ASC 980, we believe that the FASB is monitoring the IASB activity related to RRA accounting with interest and could revisit ASC 980 in the future.
Section 4
Hot Topics
Depreciation Adjustments

Certain regulatory mechanisms involving depreciation expense have been put in place to moderate or neutralize utility customer rate increases. The U.S. GAAP considerations associated with these types of regulatory actions are discussed below.

“Mirror Depreciation”

If a utility records accelerated or additional depreciation in the interest of accelerating asset recovery and subsequently determines that the excess depreciation reserves are no longer necessary, such action is referred to as “mirror depreciation” because of its similarity to the mirror construction work in progress referred to in ASC 980-340. In these situations, the utility can reverse the additional or accelerated depreciation taken in prior years to the extent that it exceeds depreciation that would have been recorded under nonregulated U.S. GAAP. Therefore, if the regulator orders or agrees to an adjustment to reduce this previously collected amount, there are no restrictions on the reversal of the excess reserves under U.S. GAAP. The previously collected amount should be reversed in a manner consistent with the reduction in rates.

Nonlegal Cost of Removal

Estimated cost of removal is generally recognized as an element of depreciation expense for regulatory purposes. However, on the basis of SEC guidance, costs of removal that are not legally required are considered a regulatory liability under U.S. GAAP because this expense is recognized sooner than would be required or permitted under general U.S. GAAP. As a result, if the regulator orders or agrees to an adjustment of this regulatory liability, there are no U.S. GAAP restrictions that would prohibit the reversal of a previously recorded and collected accumulated cost of removal. Accordingly, a negative cost of removal amortization would be appropriate and the reversal should match the rate treatment.

Negative “True” Depreciation

Because of life extensions and other factors, some utilities have concluded that depreciable lives of some assets should be extended and, in some cases, have determined that current accumulated depreciation reserves exceed the theoretical reserve levels that would be required. The theoretical depreciation reserve requirement is generally determined in connection with the performance of a depreciation study. The theoretical excess reserve may be (1) related to a change in the estimated depreciable lives, (2) from accruals of estimated removal costs (see discussion above), or (3) both. In some cases, utilities or their regulators have proposed negative depreciation or amortization to eliminate the theoretical excess of “true” depreciation reserves.

Under U.S. GAAP, generally only prospective changes in depreciation are permitted and not reversals of previously recorded “true” or regular U.S. GAAP depreciation. As a result, adjustments of depreciation expense to address theoretical excess depreciation reserves (excluding any cost of removal) should not cause net depreciation expense to be less than zero for any class of assets as defined by the applicable depreciation study for any particular period. This would permit the assumed depreciable life of a class of assets to be reduced to zero for a period until the theoretical excess is eliminated, but it would not result in the actual reversal of previously recorded depreciation.

Furthermore, a utility’s placement of any major, newly completed plant into service at the same time it intends to record less depreciation or amortization than it would record under general U.S. GAAP to adjust excess depreciation reserves may conflict with the guidance in ASC 980-340 (discussed below) because negative depreciation was not a rate-making method routinely used by regulators before 1982.
Phase-In Plans

ASC 980-340 defines a phase-in plan as any method of recognition of allowable costs in rates that (1) "was adopted by the regulator in connection with a major, newly completed plant of the regulated entity or of one of its suppliers or a major plant scheduled for completion in the near future"; (2) "defers the rates intended to recover allowable costs beyond the period in which those allowable costs would be charged to expense under [U.S. GAAP] applicable to entities in general"; and (3) "defers the rates intended to recover allowable costs beyond the period in which those rates would have been ordered under the rate-making methods routinely used prior to 1982 by that regulator for similar allowable costs of that regulated entity."

ASC 980-340 prohibits the capitalization of the allowable costs that the regulator defers for future recovery under a phase-in plan. A rate decision that defers the recognition of depreciation or other allowable costs associated with a newly completed major capital project (including a capital lease) may meet the definition of a phase-in plan.

ASC 980-340 also addresses the concept of regulatory lag, which is defined as the delay between a change in a regulated entity’s costs and a change in rates ordered by a regulator as a result of that change in costs. The definition of a phase-in plan in ASC 980-340 is not intended to encompass actions of a regulator that are designed to protect a utility from the effects of regulatory lag in the absence of a rate order, nor is it intended to encompass the regulator’s subsequent treatment of any allowable costs that result from those actions. A rate decision that defers the recognition of depreciation expense in this situation would not preclude recognition of a regulatory asset. In characterizing a rate decision as a phase-in plan or protection from the impact of regulatory lag, a utility must use significant judgment and evaluate the specific facts and circumstances.

Purchase Accounting

The second phase of the FASB’s business combinations project, which was completed in 2007, substantially elevates the role of fair value in purchase accounting and changes the way entities account for business combinations and noncontrolling interests. Below are some considerations for P&U entities with respect to the FASB’s current guidance on business combinations and fair value measurement.¹

Considerations for Regulated Utilities

Historically, regulated utilities generally recorded assets acquired in a business combination at their carrying value (predecessor’s basis). This accounting treatment was predicated on a view that the historical cost approximated fair value because of the regulated nature of utilities’ operations and the acquirer’s ability to recover, through rates, the predecessor’s cost basis plus a rate of return. In light of the fair value guidance in ASC 820, acquirers should evaluate the highest and best use of the assets by market participants. ASC 820-10-35 states that the highest and best use should be determined on the basis of potential uses that are physically possible, legally permissible, and financially feasible as of the measurement date. (ASU 2011-04 clarifies the application of the highest-and-best-use concept.) In addition, ASC 820 acknowledges that the use of an asset may be limited by restrictions the asset is subject to and by agreements that restrict the asset and its transfer upon sale (e.g., easements).

In evaluating the highest and best use of an asset by market participants, utilities should consider the following:

- Whether regulation is an attribute of the entity or whether it is associated with the individual asset.
- The mechanism for recovery and whether the asset or liability is subject to rate recovery.

¹ The FASB’s guidance on business combinations is codified in ASC 805 and ASC 810, while its guidance on fair value measurement is codified in ASC 820.
• The nature of the asset (e.g., transmission and distribution assets vs. generation assets that are currently or potentially used for merchant operation).

• Restrictions imposed by the regulator with respect to rate recovery, operations, and the asset, such as the following:
  o Regulatory approval is required before the sale or disposition of utility assets.
  o The gain on the sale of a rate-regulated asset must be shared with the regulated customers.
  o Use of the asset is restricted to public purposes.

Although an entity should use judgment in evaluating the above factors, it is generally acceptable to record rate-regulated property assets by using the predecessor’s carrying value to estimate the fair value of regulated assets in a business combination. This is because either regulation is associated with the assets or the entity’s regulation is so pervasive that it ostensibly extends to the individual assets. Generally, the acquiring entity will only be allowed to recover depreciation of the original cost and earn a regulated rate of return on that property.

In certain cases, an entity does not earn a return on regulatory assets or property. While ASC 980 does not generally permit the acquired entity to discount such assets, the acquirer generally records assets acquired at fair value (discounted cash flows under an income approach), which would be less than the predecessor’s carrying amount because of the inability to earn a return on such assets.

ASC 805 also requires that liabilities assumed, including long-term debt, be measured at their acquisition-date fair value. There are two acceptable approaches for measuring long-term debt as of the acquisition date. First, the debt may be recorded at the predecessor’s carrying value, similarly to how acquired assets are recorded at their acquisition-date carrying value, when regulation is associated with long-term debt. Under this approach, the rate of return approved by regulators for most entities within the scope of ASC 980 would be calculated as a weighted average of the approved rate of return on debt and equity and the return on debt would often be based on amounts that approximate book value. The second acceptable approach would be for an entity to apply certain concepts in ASC 820 when measuring long-term debt at its acquisition-date fair value. These concepts would include adjusting the fair value of long-term debt to account for the entity’s nonperformance risk, which includes the entity’s own credit risk.

At the 2013 AICPA Conference on Current SEC and PCAOB Developments, the SEC staff discussed disclosures made by certain registrants that valued assets acquired in a business combination at the predecessor’s carrying value. The staff asks registrants to explain how their recognition of these amounts complies with U.S. GAAP and to supply supplemental information on how they reached their conclusions about valuing their tangible assets. Such supplemental information could include the considerations discussed in the paragraphs above. The staff’s request for expanded disclosures does not change the accounting conclusion that the use of the predecessor’s carrying value is still generally an appropriate and acceptable valuation method for rate-regulated assets acquired in a business combination.

See Deloitte’s December 16, 2013, Heads Up for more highlights from the 2013 AICPA Conference.

Normal Purchases and Normal Sales (NPNS) Scope Exception

In accordance with ASC 815-10-15-35, for a “contract that meets the net settlement provisions of paragraphs 815-10-15-100 through 15-109 and the market mechanism provisions of paragraphs 815-10-15-110 through 15-118 to qualify for the [NPNS] scope exception, it must be probable at inception and throughout the term of the individual contract that the contract will not settle net and will result in physical delivery.” In assessing whether continued application of the NPNS scope exception is appropriate, an entity must consider whether the facts and circumstances suggest that the counterparty to the contract may net-settle the contract, negotiate an early settlement for the contract, or otherwise reach an outcome indicating that it no longer is probable that the contract will result in physical delivery.
A contract that no longer qualifies for the NPNS exception but that still meets the definition of a derivative would need to be recorded at fair value in the entity’s financial statements, with an offsetting entry to current-period earnings. As with other derivatives, subsequent changes in the fair value of the contract would be recognized in earnings. For rate-regulated entities with regulatory recovery mechanisms, the change in fair value of the contract would be recognized as a regulatory asset or liability rather than in current-period earnings.

**Impact of Contract Modifications and Force Majeure**

Flooding or other disasters may affect the ability of entities with coal-fired generation to receive delivery of coal quantities under contract. Historically, entities have (1) experienced increased cycle times; (2) modified coal contracts by negotiating delayed deliveries or a reduction in contractual volumes, prices, or both; or (3) invoked force majeure provisions under the terms of the existing contracts. Entities should carefully evaluate modifications and force majeure provisions to evaluate the impact of such circumstances on their ability to assert that the contract in question and other similar contracts will not settle net and will result in physical delivery.

Contract restructuring activities may negatively affect an entity’s ability to apply the NPNS scope exception. If a contract designated as NPNS is restructured, that restructuring may indicate a net settlement of the original contract and execution of a new contract, potentially calling into question whether the original contract resulted in physical delivery throughout the original term of the contract and whether similar contracts (e.g., the newly executed contract) are expected to result in physical delivery throughout their term. Entities should carefully evaluate each contract restructuring to determine whether the original contract was simply amended or whether there is effectively a termination of the old contract and issuance of a new contract. Generally, any significant modification to contractual cash flows would result in the contract’s being deemed to have been terminated and replaced with a newly executed contract. Determining whether a modification to the terms of a contract is deemed significant is a matter of judgment, and companies may analogize to guidance in ASC 470-50-40-6 through 40-20 to make the determination. In addition, entities should carefully evaluate force majeure provisions to determine the impact of invoking such provisions on the entity’s rights and obligations under the contract, including whether invoking such provisions results in net settlement.

**Impact of Reduced Purchase Quantities and Volumetric Optionality**

In recent years, a reduction in demand for coal-fired base-load generation has resulted in an increase in coal inventories for companies with significant coal-fired generation. In certain instances, entities have negotiated new coal contracts to provide for volumetric optionality. Decreases in demand or the need for flexibility may affect the accounting for long-term coal contracts and could be driven by factors such as:

- The current economic conditions.
- Low natural gas prices.
- Additional wind or other green generation.
- Increased use of lower-sulfur coal or early plant retirements to comply with environmental regulations.

In addition to evaluating modifications of existing coal contracts, entities may negotiate cash settlements, enter into offsetting positions, or enter new contracts that provide for volumetric optionality. Entities should carefully evaluate modifications, early cash settlements, and offsetting contracts to assess the impact on their ability to assert that the contract in question, and other similar contracts, will not settle net and will result in physical delivery. Entities should also consider whether the ability to enter into offsetting positions indicates that the coal is “readily convertible to cash” (RCC), as that phrase is used in the determination of whether a contract meets the definition of a derivative. When contracts contain volumetric optionality, entities should carefully consider whether the contract meets the definition of a derivative.
(i.e., whether the coal is RCC). An example of a coal contract with volumetric optionality is a contract for the delivery of 2 million tons per year in which the purchaser has the option to reduce annual delivery to 1.8 million tons or to increase delivery to 2.2 million tons. If volumetric optionality exists, the contract will not qualify for the NPNS election.

Impact of Subsequent Events Related to Regulatory Matters

Regulatory developments often occur after the balance sheet date but before entities issue financial statements. The discussion below (1) outlines the accounting framework companies should use in considering the impact of subsequent events in general and (2) presents some examples illustrating application of the framework in the P&U industry.

ASC 855 prescribes the accounting for events and transactions that occur after the balance sheet date but before entities issue financial statements. Under ASC 855, there are two types of subsequent events. Type 1 subsequent events, which are recognized in the financial statements, provide additional evidence about conditions that existed as of the balance sheet date, including estimates inherent in the preparation of financial statements. Type 2 subsequent events provide evidence about conditions that did not exist as of the balance sheet date but arose after that date. Although Type 2 subsequent events are not recognized in the financial statements, material Type 2 events should generally be disclosed in the financial statements.

Loss Contingencies Versus Gain Contingencies

A loss contingency that was being evaluated as of the balance sheet date, including one in which no accrual had been recognized, should be recognized in the financial statements if the loss contingency is resolved after the balance sheet date but before issuance of the financial statements. This is a Type 1 subsequent event because the event that gave rise to the contingency occurred before the balance sheet date. The resolution, which may have been in the form of a court or regulatory order, a settlement agreement, or something similar, is a subsequent event that provides additional evidence about the probability and amount of the loss and should be reflected in the financial statements.

It would also be appropriate to reverse a contingent liability to the extent that the liability that had been recorded in a previous financial reporting period was in excess of the settlement amount and is settled after the balance sheet date but before issuance of the financial statements. A settlement generally constitutes additional evidence about conditions that existed as of the balance sheet date and would be considered a recognized subsequent event. For loss contingency events that occurred after the balance sheet date but before issuance of the financial statements, an entity would not recognize the loss but may need to disclose it. For example, if an accident occurred after the balance sheet date and the company faced liability exposure, it would not recognize amounts related to the accident in the financial statements.

In addition, note that ASC 855-10-15-5 states, in part, that “gain contingencies . . . are rarely recognized after the balance sheet date but before the financial statements are issued or are available to be issued.” The guidance in ASC 450-30-25-1 further states that a “contingency that might result in a gain usually should not be reflected in the financial statements because to do so might be to recognize revenue before its realization.” Thus, the resolution of a gain contingency after the balance sheet date but before issuance of the financial statements should generally be considered a nonrecognized subsequent event.

Entities should exercise considerable judgment when assessing contingencies and the effect, if any, of a subsequent event. While sometimes the accounting conclusion may be clear, in other cases entities may need to perform a careful analysis to address questions such as the following:

- Has the matter been resolved? If not, did developments occur?
- Was there a contingency or some uncertainty about the matter as of the balance sheet date? If not, did the loss event truly occur after the balance sheet date?
Considerations for Regulated Utilities

ASC 980 does not specifically address subsequent events unique to the P&U industry. Accordingly, entities should use the general guidance above to evaluate the accounting for subsequent events related to regulatory matters. Note that legislation does not constitute a regulatory matter. The enactment of a law after the balance sheet date but before issuance of the financial statements would be accounted for as a nonrecognized subsequent event (because the newly enacted law does not provide evidence of conditions that existed as of the balance sheet date).

Although a regulated utility’s application of the above guidance will depend on its particular facts and circumstances, the examples below illustrate how such a company might apply the guidance to typical subsequent events.

Subsequent-Event Examples

**Fuel Order Issued After the Balance Sheet Date**

On July 15, 2013, Utility A’s regulator issued an order with respect to a routine review of A’s fuel clause adjustment calculation for the period from January 1, 2012, to December 31, 2012. Utility A had not yet issued its June 30 financial statements. In this order, the regulator ruled that A should have credited certain wholesale sale margins to its retail fuel clause. The order required A to refund $5 million. Utility A was aware that intervenors were questioning this item on the basis of testimony that had been filed a few months earlier but had expected to prevail in this matter, which represented a loss contingency as of June 30. The July 15 order was a Type 1 subsequent event that provided additional information about the probability and amount of the loss as of June 30. Therefore, A accounted for the effect of this order in its financial statements as of and for the period ended June 30, 2013, and included the disclosures prescribed by ASC 980-605.

**Interim Rates Implemented — Final Rate Order Received**

Utility B was permitted to implement an interim rate increase that was subject to refund. Under ASC 980-605, when an entity initially records the revenue, it uses the criteria in ASC 450-20-25-2 to determine whether a provision for estimated refunds is accrued as a loss contingency. On the basis of past experience and an evaluation of all information in the proceeding, B concluded that a refund was probable, was able to reasonably estimate an accrual for the revenue subject to refund, and appropriately recorded a provision for the estimated refunds in its most recently issued financial statements. After the balance sheet date but before B’s financial statements were issued, its regulator approved final rates and no portion of the interim rates was required to be returned to the rate payers. In this example, the regulator’s decision is considered a Type 1 subsequent event. Therefore, B appropriately reversed the previously recorded reserve. If the approved final rates had been lower than the implemented interim rates and the previously recorded reserve was not sufficient to cover the amount required to be returned to the customers, the reserve would also be adjusted accordingly.

**Appeal of Prior Unfavorable Rate Order**

In a prior period, Utility C’s regulator ordered that a gain on a sale of an asset be used to reduce future rates. Therefore, C recorded a regulatory liability to recognize this obligation but appealed the ruling. After C’s balance sheet date but before its financial statements were issued, an appellate court decided in favor of C and ruled that it did not need to reduce future rates. Intervenors immediately announced their intent to appeal the court ruling. Because of the numerous uncertainties inherent in a litigation proceeding (e.g., additional appeals), C determined that the court order constituted a change in legal status but not the realization of a gain and concluded that this was a Type 2 subsequent event. Utility C did not reverse the regulatory liability.

**Rate Order After the Balance Sheet Date — Order Includes a Disallowance**

In conjunction with its ruling on a rate case, Utility D’s regulator concluded that there was significant management error in the planning and construction of a recently completed power plant. In the order issued after the balance sheet date but before the financial statements had been issued, the regulator required that plant costs in excess of a specified amount not be recovered in rates. The recovery of this plant was a key issue throughout the proceedings and the primary basis
for the request for an increase in rates. In accordance with ASC 980-360, when it becomes probable that part of the cost of a recently completed plant will be disallowed for rate-making purposes and the amount of the disallowance can be reasonably estimated, the estimated amount of the probable disallowance is deducted from the reported cost of the plant and recognized as a loss. The terms “probable,” “reasonably possible,” and “remote” are defined in ASC 450-20, and entities must exercise considerable judgment when applying them. Before the issuance of the rate order, D had concluded that the likelihood of a disallowance was reasonably possible but less than probable. Utility D concluded that the post-balance-sheet ruling constituted additional significant objective evidence about the likelihood of disallowance as of the balance sheet date. Accordingly, D updated its assessment of the probability of a disallowance as a result of this Type 1 subsequent event and recorded a charge to earnings in the current period. Post-balance-sheet events other than a final order from a regulator may also constitute significant objective evidence about conditions that exist as of the balance sheet date.

**Subsequent Natural Disaster Affects Likelihood of Recovery of a Regulatory Asset**

Utility E had recorded a regulatory asset as of the balance sheet date related to recovery of major maintenance costs in connection with a particular power plant. Utility E’s regulator had previously ordered that the incurred costs be recovered in rates over the period between planned major maintenance outages. After the balance sheet date, a tornado severely damaged the power plant and E decided to shut down the plant. Utility E had a rate-case proceeding in process at the time of the tornado. On the basis of discussions E had with the staff of the regulatory commission, E learned that the staff was planning to propose that the deferred costs no longer be recovered. Utility E had not yet issued its financial statements and concluded, on the basis of precedent in which the commission agreed with these types of staff recommendations, that recovery of the deferred major maintenance costs was no longer probable.

Utility E concluded that the change in judgment about likelihood of recovery of the regulatory asset resulted from a Type 2 subsequent event. Utility E, in its judgment, determined that the tornado that occurred after the end of the period did not constitute additional evidence about facts and conditions that existed as of the balance sheet date. Utility E also believed that in the absence of the tornado, the power plant would have continued to operate and that its regulator most likely would have continued to allow recovery of the deferred costs. Utility E issued its financial statements and continued to report the regulatory asset on its balance sheet but disclosed the expected impact of the tornado in the notes.

**Surprise Development in a Proceeding**

Utility F had recorded a regulatory asset in prior periods in connection with storm damage costs. The regulator had previously ordered that costs related to a specific storm may be recovered in rates over a five-year period. Utility F had been recovering these costs in rates for the prior three years. As of the balance sheet date, the regulatory asset balance reflected two years of remaining costs to recover. The company had requested continued amortization of these costs in its current rate proceeding. As of the balance sheet date, no testimony had been filed that had questioned the continued recovery of the storm damage costs and F concluded that future recovery of its regulatory asset balance was probable.

In connection with its current rate proceeding, shortly after year-end, F commenced settlement discussions. Intervenors indicated that they were willing to settle the case if F would forgo the remaining amortization of the storm damage costs. While F strongly disagreed with the intervenors’ position on storm damage costs, in the context of the overall settlement proposal, F was likely to agree to the settlement. On the basis of the settlement terms, no other existing regulatory assets were at risk (i.e., F did not concede the storm cost asset to protect another regulatory asset whose loss was otherwise probable as of the balance sheet date), and the return on equity was slightly higher than F was expecting. Shortly before the financial statements were issued, the parties agreed to the settlement. On the basis of precedent, F believed it probable that its regulator would approve the settlement. Utility F concluded that this settlement represented a Type 2 subsequent event. Utility F, in its judgment, determined that the subsequent settlement discussions did not provide additional evidence about facts and conditions that existed as of the balance sheet date. Utility F believed that in the absence of its decision to agree to the settlement, its regulator most likely would have continued to allow recovery of the deferred costs over the remaining two years.
Companies need to exercise judgment when there are surprise developments. For example, had there been any discussions with intervenors before the balance sheet date about the potential to forgo recovery of the deferred costs, or had testimony been filed advocating no further recovery, questions would have been raised as of the balance sheet date about the probability of recovery and the settlement may have indicated a Type 1 subsequent event. In most cases in which a rate order issued after year-end contains an unexpected ruling affecting a regulatory asset as of the balance sheet date, such a rate order is typically considered a Type 1 subsequent event if commission staff or intervenors have questioned the matter as part of the rate proceedings or it was clear that the item disallowed was subject to a prudency review in the current regulatory process.

**Plant Abandonments and Disallowances of the Costs of Recently Completed Plants**

ASC 980-360 provides guidance on accounting for (1) plant abandonments and (2) disallowances of the costs of recently completed plants. The guidance typically applies to operating assets or assets under construction, most commonly at electric generating plants, but can also apply to other assets such as transmission and distribution assets. Generally, “plant” could be viewed as anything capitalized in “plant in service” or in “construction work in progress.”

For information about the related topics of impairment and disposal of long-lived assets, see the Impairment Considerations section.

**Plant Abandonment**

ASC 980-360 states that when it becomes probable that an operating asset or an asset under construction will be abandoned, the associated cost should be “removed from construction work-in-process or plant-in-service.” ASC 980-360 further indicates that if the regulator is likely to provide a full return on the recoverable costs, a separate asset should be established with a value equal to the original carrying value of the abandoned asset less any disallowed costs. If the regulator is likely to provide a partial return or no return, the new asset value should equal the present value of the future revenues expected to be provided to recover the allowable costs of the abandoned asset and any return on investment. The utility’s incremental borrowing rate should be used to measure the present value of the new asset. Any disallowance of all or a part of the cost of the abandoned asset should be recognized as a loss when it is both probable and estimable. During the recovery period, the new asset should be amortized to produce zero net income on the basis of the theoretical debt and interest assumed to finance the abandoned asset.

SAB Topic 10.E states that losses recorded pursuant to ASC 980-360 should not be reported as an extraordinary item. ASC 980-360 also implies that an entity is not permitted to treat losses from abandoned assets as an extraordinary item. When a utility uses the traditional rate-regulated utility reporting format, the effects of a cost disallowance based on ASC 980-360 should be reported gross as a component of other income and deductions (below the line) and should not be shown net of tax.

**Matters Related to Abandonment Accounting**

The discussion above describes the overall accounting model for asset abandonments in a regulated environment; however, utilities should carefully assess facts and circumstances to determine what constitutes abandonment of an asset and the likelihood that abandonment will occur. While ASC 980-360 provides no explicit guidance on what constitutes an abandonment of an operating asset, an asset that will be retired in the near future and much earlier than its previously expected retirement date typically is subject to the ASC 980-360 disallowance test. Alternatively, if an asset is to be retired, but not in the “near future” and not much earlier than its previously expected retirement date, the use of abandonment accounting in accordance with ASC 980-360 may not be appropriate. Instead, the appropriate accounting may be to prospectively modify the remaining depreciable life of the asset in accordance with ASC 360-10-35. Under this accounting,
depreciation would be accelerated to fully depreciate the asset to the expected early-retirement date. Determining whether an early retirement of an asset constitutes an abandonment is a matter of judgment. Factors for entities to consider in evaluating whether a plant is being abandoned include the following:

- A change in remaining depreciable life of the operating asset outside the utility’s normal depreciation study.
- Any accelerated depreciation because of a change in depreciable life that is not currently reflected in rates or expected to be reflected in rates in the near future.
- Retirement of the asset sooner than its remaining useful life and in the near future.
- Reduction in the estimated remaining depreciable life by more than 50 percent.

It may be probable that a plant will be abandoned before a final decision has been made to retire the plant. Factors for an entity to consider in assessing the likelihood of abandonment may include:

- If environmental rules require additional spending for the plant to continue operating after a certain date, whether management’s cost-benefit analysis indicates that this additional spending is cost-justified.
- If a possible early-retirement decision will not be made for several years, whether the factors that most affect the decision (such as power and gas prices) could reasonably change in the next several years.
- If the decision to retire a plant requires approval from an RTO or a regulator, whether it is unclear that approval will be granted.

Entities concluding that a plant abandonment is probable should also consider the abandonment’s impact on related items, such as materials and supplies and asset retirement obligations directly associated with the asset.

Reconsideration of Abandonment Decision

Some regulated utilities may have previously concluded that an asset abandonment was probable. It may no longer be probable that regulated asset whose abandonment was probable in a prior period will be abandoned. A regulated utility may have also recorded an abandonment loss in an earlier period in which abandonment became probable. On the basis of these general facts, we believe that it would be reasonable for the regulated utility to reclassify the carrying amount of the asset to plant-in-service. Further, ASC 980-360-35-4 describes the notion of adjusting the amount of the abandoned asset as estimates change, which supports reversal of a charge from a prior period if the likelihood of abandonment is no longer probable. The accounting for the decision to “unabandon” an asset requires judgment and a careful assessment of the regulated utility’s facts and circumstances.

Disallowances of Costs of Recently Completed Plants

As noted above, ASC 980-360 provides guidance on accounting for both plant abandonment and disallowances of costs of recently completed plants for rate-regulated entities.

There is no specific guidance in (1) ASC 980-360 or ASC 360-10-35 defining a “recently completed plant” or (2) ASC 980-340 defining a “newly completed plant.” It is reasonable to conclude that both terms should have the same definition; however, note that the ASC 980-340 definition of “phase-in plan” also incorporates the term “major.” However, in practice these terms have been effectively defined on the basis of facts and circumstances, so some diversity has resulted. The starting point for determining what constitutes a recently or newly completed plant is typically the time from the completion-in-service date until the plant owner files its initial rate request for inclusion of the plant in allowable costs.
Some questions that have arisen about the definition of a new or recently completed plant include:

- Is a newly acquired “used” plant (e.g., the purchase of a 10-year-old power plant) considered a new or recently completed plant?
- If a component of an asset is replaced (e.g., a replacement turbine at a power plant), is that replacement component considered a new or recently completed plant?
- If a new operating plant was included in rate base in the last rate case but was not the subject of any evaluation of the prudence of the costs, but cost recovery is being scrutinized in the current rate case, is the plant currently considered a new or recently completed plant?

ASC 980-360 stipulates that when a direct disallowance of the cost of a recently completed plant becomes probable and estimable, the estimated amount of the probable disallowance must be deducted from the reported cost of the plant and recognized as a loss. Future depreciation charges should be based on the written-down asset basis.

An explicit, but indirect, disallowance occurs when no return or a reduced return is permitted for all or a portion of the new plant. In the case of an indirect disallowance, if the regulator does not specify the amount of the disallowance, the amount must be calculated on the basis of estimated future cash flows. To determine the loss resulting from an indirect disallowance, entities should estimate and discount the future revenue stream/cash flows allowed by the regulator by using a rate consistent with that used to estimate the future cash flows. This amount should be compared with the recorded plant amount, and the difference should be recorded as a charge to current earnings. Under this discounting approach, the remaining asset should be depreciated in a manner consistent with the rate-making and in a manner that would produce a constant return on the undepreciated asset that is equal to the discount rate.

If an unregulated affiliate transfers a recently completed plant to the rate-regulated utility, because such plant costs are then subject to the provisions of ASC 980-10, impairment should be evaluated under ASC 980-360 at the time of the transfer.

Disallowances of costs for plants that are not recently completed are recognized in accordance with general U.S. GAAP. For example, assume that (1) a company puts a new plant into service and then goes through a rate case when the prudency of the costs are scrutinized and (2) the regulator concludes that the entire amount capitalized should be included in rate base, with depreciation expense on the entire capitalized amount included in cost of service. Further assume that the plant costs are questioned a few years later in the next rate case and that the regulator disallows a specific amount of the plant cost. A disallowance charge based on ASC 980-360 should not be recorded because that plant is no longer a recently completed plant.

**Accounting for Renewable Energy Certificates**

Several states have adopted renewable portfolio standards that require specified levels of renewable energy production. In these states, electricity generators receive RECs for generating electricity from qualified renewable facilities and other entities receive RECs for capturing or reducing carbon emissions. Electricity suppliers demonstrate compliance by redeeming RECs with the applicable regulatory or governmental body. They typically accumulate RECs through some combination of (1) internal renewable energy generation, (2) purchase contracts with third-party owners of renewable energy facilities, or (3) transactions in secondary markets. Because of the various mechanisms by which electricity suppliers obtain RECs, uncertainties about how many RECs will ultimately be required for any annual or other compliance period, and the absence of authoritative accounting guidance from either the FASB or IASB, accounting complexities have emerged with the advent of renewable portfolio standards.

RECs acquired through contracts with third-party owners of renewable energy facilities and transactions in secondary markets must first be evaluated under the guidance on leasing and derivative accounting. The asset type, accounting value, and shortfall provisions should be assessed for all RECs, whether these RECs are generated internally or acquired through transactions with third parties. The discussion below focuses on topics of particular interest in connection with REC accounting.
Lease Accounting

As noted above, electricity suppliers often purchase RECs from third-party owners of renewable energy generation facilities. Frequently, the underlying renewable energy is also sold to the electricity supplier, and it is fairly common for a purchaser to acquire 100 percent of the electricity and RECs associated with the facility. Entities should evaluate such contracts under ASC 840 to determine whether they contain a lease.\(^2\)

The determination of whether an arrangement contains a lease can have a pervasive impact on the financial statements and related disclosures. For example, the conclusion regarding lease accounting could affect the (1) timing of income statement recognition (e.g., straight-line expense for operating leases), (2) balance sheet presentation (e.g., establishment of an asset and a liability for capital leases), and (3) classification in the statement of cash flows (e.g., principal payments on capital lease obligations within financing activities).

Regarding the determination of whether a contract contains a lease, ASC 840-10-15-6 states:

> An arrangement conveys the right to use property, plant, or equipment if the arrangement conveys to the purchaser (lessee) the right to control the use of the underlying property, plant, or equipment.

ASC 840-10-15-6(c) states that the right to control the use of the underlying PP&E is conveyed under the following circumstances:

> Facts and circumstances indicate that it is remote that one or more parties other than the purchaser will take more than a minor amount of the output or other utility that will be produced or generated by the property, plant, or equipment during the term of the arrangement, and the price that the purchaser (lessee) will pay for the output is neither contractually fixed per unit of output nor equal to the current market price per unit of output as of the time of delivery of the output.

While electricity from specified renewable energy generation assets should always be an output in an evaluation of whether a contract contains a lease under ASC 840, views differ about whether associated RECs are also considered outputs in this determination. One view is that RECs are not considered outputs and that only “tangible” outputs (e.g., electricity) are evaluated in the determination of whether a purchase contract contains a lease. Proponents of this view believe that, although RECs represent an attribute and a marketable benefit of the PP&E, they should not be considered outputs because they are not produced or generated by operation of the PP&E but by governmental or regulatory action.

Another acceptable view is that RECs may be considered outputs because they (1) result directly from a facility’s production process and (2) represent discrete marketable elements.\(^3\) Proponents of this view believe that it is not necessary for outputs to be “tangible” as long as they are generated as a result of the operations of the PP&E and represent discrete elements that could be sold to other entities or other market participants. Such proponents also note that because RECs can significantly affect the underlying value of the PP&E, they are an important consideration in the evaluation of whether the right to use the renewable energy generation facility has been conveyed to the purchaser. They should therefore also be considered in the determination of whether parties other than the purchaser are taking more than a minor amount of the output or other utility that will be produced or generated by the PP&E.

It is important to evaluate whether RECs are considered outputs in the determination of whether the arrangement contains a lease because the pricing of all of the outputs must be assessed under the “fixed per unit of output” or “market price per unit of output” criterion in ASC 840-10-15-6. This assessment may be difficult when the pricing terms are bundled (i.e., the individual products do not have discrete prices).

In addition, companies should consider the particular facts and circumstances of the contract (e.g., the stand-alone marketability of the RECs) and should consistently apply whichever of the two approaches they choose.

---

\(^2\) The guidance in ASC 840 applies to both sellers and purchasers; therefore, this evaluation should be performed by each party to the contract and both parties would be expected to reach the same conclusion about the presence of a lease.

\(^3\) Economic attributes are generally not considered outputs in the determination of whether an arrangement contains a lease unless they are both (1) generated by the facility’s production process and (2) separately marketable. For example, although PTCs are linked to a renewable facility’s production levels, they are not considered outputs because they can only be conveyed through an ownership interest and therefore are not separately marketable.
Derivative Considerations

Entities should distinguish between the accounting for actual RECs and the accounting for forward contracts to buy or sell RECs. As noted above, RECs are obtained through generation or acquisition activity and represent a benefit that the owner can use in the future like inventory or an intangible asset (see further discussion regarding classification in the Asset Type and Accounting Value section below). Therefore, like owned inventory or intangible assets, an owned REC is not considered a derivative instrument. Although RECs are not derivatives themselves, contracts to purchase, sell, or exchange RECs may meet the derivative criteria as would contracts to buy, sell, or exchange other goods (e.g., forward contracts to purchase electricity). In the absence of certain scope exceptions (e.g., the NPNS exception), a derivative contract must be reported at fair value in each reporting period.

Renewable portfolio standards in several states have resulted in secondary markets for REC exchanges (e.g., the Green Exchange). Because such markets are still evolving, the assessment of the “net settlement” criterion (more specifically, whether the RECs are RCC) can be challenging and may require entities to use significant judgment. One consideration is whether an active spot market exists for the REC itself, and the determination may vary depending on state or region.

Because entities continually evaluate contracts to buy or sell RECs over their lives, contracts that did not previously qualify as derivatives may later meet the definition. Therefore, as REC markets develop, entities should consider use of the “conditional” NPNS designation to reduce the risk of potential effects on the financial statements.

In addition, in some contracts, RECs may be combined with the purchase or sale of energy; energy is generally considered RCC. See Section 5 for additional discussion of derivatives in arrangements with multiple deliverables.

Asset Type and Accounting Value

The FASB and IASB are currently working on a joint trading schemes project to address emissions accounting, which may also include accounting for other tradable rights such as RECs. Although both U.S. and international accounting standard setters have previously attempted to address the issue, the FASB and IASB have not provided any authoritative accounting literature on this topic or on emission allowances. In the meantime, many companies have developed accounting policies in the absence of explicit authoritative guidance.

As discussed above, RECs are often accumulated through a combination of (1) internal renewable energy generation, (2) purchase contracts with third-party owners of renewable energy facilities, or (3) transactions in secondary markets. Regardless of the acquisition method, the view that RECs are assets appears to be consistent in practice; in previously effective or contemplated accounting literature; and in comments made by the FASB, IASB, and SEC. However, opinions differ about the asset type, the appropriate expense recognition model, and the applicable accounting value.

Asset Type

Most companies classify RECs as either “inventory” or “intangible assets.” As further described below, both classifications have some basis and are widely used. In determining whether RECs are inventory or intangibles, entities may consider how they have historically used RECs, their prospective intent, and the accounting ramifications of each classification. Some companies that use RECs for different purposes may treat groups of RECs differently on the basis of their business intent as long as the REC pools are not intermingled or the RECs are not transferred between pools.

In addition to differing in their apparent balance sheet classification (both specific line item and short vs. long term), the two widely used classifications might affect financial statements differently with respect to:

- Timing and presentation of amortization or cost-of-sales expenses.
- Classification of both purchases and sales of RECs in investing or operating activities in the statement of cash flows.
• The frequency and mechanics of subsequent carrying value adjustments ("lower of cost or market" vs. "impairment").

• Disclosure requirements.

Both the inventory and intangible asset classification models are acceptable accounting policies and should be consistently applied to similar groups of assets.

Accounting Value

As described in more detail below, determining the accounting value of RECs often involves allocating acquisition or production costs to RECs and other related products (e.g., electricity, capacity credits). The significance of determining the accounting value of RECs can vary depending on how and when entities use acquired or internally generated RECs. If an entity consumes RECs in the same accounting period as the related products (e.g., in the period in which electricity was purchased or generated), determination of the asset value will not significantly affect the entity’s financial statements. However, if acquired or internally generated RECs are “banked” for use or sale in accounting periods after the period in which the related products are used, the accounting value determination can affect reported earnings and the REC asset balance.

RECs acquired through purchases are commonly recorded at cost. However, because RECs are often purchased in a bundled contract with electricity and other deliverables (e.g., capacity credits), entities typically allocate the purchase price to determine the appropriate cost basis. Many entities base that allocation on the relative fair values of the deliverables in the contract.

Entities may use multiple accounting models to determine the carrying value of RECs from internal renewable generation sources. Three such models are described below: 4

Incremental Cost

Under the incremental cost method, RECs are considered to be “produced” contemporaneously with electricity and are recorded as inventory or as an intangible asset at the incremental cost of the REC in excess of the cost of the electricity. This method results in the allocation of minimal costs to RECs because it generally costs no more to produce RECs (e.g., the certification costs are relatively insignificant). Thus, the cost assigned to the RECs (which is typically insignificant) would be deferred and recognized as expense when the REC is used or sold.

Joint Product Allocation

Joint products are two or more principal products that are produced together. Electricity and RECs are often both significant to the economic viability of a renewable energy generation facility. As a result, electricity and RECs may be considered joint products. Under the joint product allocation method, the cost of production is fully allocated between electricity and RECs and is generally based on their relative fair values. This method results in the allocation of more cost to the RECs and less cost to electricity than under the incremental cost method. Thus, under the joint product allocation method, expense recognition is backloaded (i.e., electricity costs in the current-period income statement are relatively lower) if RECs are sold separately and at a later date than the electricity.

By-Product Allocation

In some circumstances, RECs may be considered a by-product of electricity generation. In other cases (e.g., if renewable portfolio standards may exist in a state without an abundance of renewable generation), RECs may be the primary product developed by the renewable facility, with electricity considered a by-product. Under the by-product method, the

---

4 The accounting value models described in this section are applicable to RECs accounted for as “inventory.” ASC 350-30-25-3 notes that the “[c]osts of internally developing, maintaining, or restoring intangible assets [should be] expensed when incurred.” Therefore, capitalization of internally generated RECs is not typically supportable under current accounting guidance.
by-product would be assigned cost at its fair value, with the residual amount recorded as the cost basis for the principal product. Depending on the principal product and by-product designations, this method could result in faster or slower cost recognition than the previous two methods.

**Accounting Value Summary**

Which of the three methods an entity uses to determine the accounting value of internally generated RECs will depend on the applicable facts and circumstances, including the unique environment in each jurisdiction. Irrespective of the accounting method used to determine the original accounting basis, entities should apply the appropriate ongoing accounting and impairment models to their REC asset types. For example, REC assets should generally be expensed as they are used or sold to third parties and are subject to considerations related to lower-of-cost or market inventory or amortized intangible impairment.

**REC Shortfall Considerations**

In certain states with renewable portfolio standards, penalties may be assessed on electricity suppliers for REC shortfalls below the required level for the compliance period. Shortfalls of RECs that result in penalties represent obligations that should be recorded as liabilities; however, the timing of liability recognition differs in practice. Some support recognition of a liability only when the entity’s RECs have been exhausted, while others believe that consideration related to expected shortfalls should be recognized throughout the compliance period in accordance with ASC 270. Renewable portfolio standard penalties in several states will become more prevalent as compliance requirements begin over the next several years. Because of the evolving nature of penalties and the diversity in accounting views, companies should consider discussing the accounting for expected shortfall penalties with their auditors.

**Rate-Case Settlements**

A utility company periodically files a rate case with its regulatory commission. This may be due to the commission’s requirements that the utility company file a new rate case or because the utility company has chosen to request new rates. When fully litigated in front of the regulatory commission, the rate-case process is often long, sometimes lasting more than a year from the date the utility company initially files its rate-case request to the date the regulatory commission approves the request. The rate-case process involves data requests from the commission staff and intervenors to the rate case as well as testimony and hearings.

However, in many regulatory jurisdictions, the utility company and the intervenors will hold settlement discussions. The goal of the settlement discussions is for the utility company and the intervenors to agree to the significant terms of the rate case. The settlement is filed with the regulatory commission in the form of a settlement agreement that the regulatory commission can then review and vote on. The advantage of a settlement agreement is that it reduces the period before new rates can be established because hearings and testimony are not required. A settlement agreement may settle all aspects of a rate case or it may refer a portion of the rate case (e.g., recovery of a specific cost) back to the regulator. Significant terms in a settlement agreement may include the revenue requirement, recovery of various regulatory assets, or the return on rate base.

The challenge with a settled rate case is the extent of the information included in the settlement agreement. A settlement agreement may include little more than the approved revenue requirement. It may not include any information about the types of currently incurred costs that are to be recovered or about the recovery of previously incurred costs that are
deferred as regulatory assets. Utility companies must therefore exercise significant judgment to determine the appropriate accounting for a settled rate case. When making this determination, utility companies should take the following considerations into account:

- A utility company should consider preparing a calculation of the hypothetical settled revenue requirement on the basis of the initially filed rate case, filed testimony and responses to intervenor requests, discussions with intervenors and the regulator, and the settlement agreement. To perform this calculation, the utility company may need input from regulatory, accounting, and legal departments, as well as management, and will need to use significant judgment depending on the level of detail in the settlement agreement. The calculation of the hypothetical settled revenue requirement should be sufficiently detailed for parties to understand the significant judgments and the allocations made.

- Specific considerations may include (1) the estimated capital structure ratio and cost of capital components, (2) a determination of how previously deferred costs will be recognized for both the amount of costs and the duration of recovery, and (3) whether any regulatory assets should be written off because they are no longer collectible.

The judgments about the capital structure ratio and cost of capital components will affect the amount of allowance for funds used during construction (debt and equity) that are capitalized to utility plant for the periods after the rate-case settlement is approved. The judgments regarding the regulatory assets may be significant for both the current period (deferral of costs incurred or a write-off of costs previously incurred) and for future periods for costs recovered in future rates.

In exercising its professional judgment, a utility company may consider weighting the evidence used to calculate the hypothetical settled rate requirement similarly to how it weights the evidence used to determine whether it is probable that a regulatory asset will be recovered. Such judgments will be based on the facts and circumstances of each settlement agreement. The SEC staff has unofficially suggested that evidence that could support future recovery includes:

- Rate orders from the regulator specifically authorizing recovery of the costs in rates.
- Previous rate orders from the regulator allowing recovery for substantially similar costs.
- Written approval from the regulator approving future recovery in rates.
- Analysis of recoverability from internal or external legal counsel.

Impairment Considerations

ASC 360-10-35 addresses financial accounting and reporting related to the impairment or disposal of long-lived assets. In accordance with ASC 360-10-35, an entity must recognize an impairment loss only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and must measure an impairment loss as the difference between the carrying amount and fair value of the asset.

Asset Grouping and Identifiable Cash Flows for Impairment Recognition and Measurement

In applying ASC 360-10-35, an entity must determine the asset grouping for long-lived assets. ASC 360-10-35-23 states that “for purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities.”
Entities should determine the level at which assets are grouped on the basis of their facts and circumstances. An important consideration may be whether the entity is regulated or nonregulated. For many rate-regulated utilities, the entire generating fleet, as well as purchased power agreements, are used to meet the utility’s obligation to serve, and the revenues from regulated customers cannot be identified to any subset of assets. Accordingly, many utilities have concluded that the lowest level of identifiable cash flows is related to the entire regulated generating fleet or a larger group of regulated assets.

One example of a grouping concept could be an electric utility that is subject to traditional, cost-based rate regulation and uses various sources of generation to fulfill its service obligation. An electric utility’s generating mix could range from high-cost nuclear power plants and peaking units to lower-cost fossil fuel units and inexpensive hydroelectric facilities. Because this collection of plant assets is used together to meet the electric utility’s service obligation and produce joint cash flows (generally based on system-wide average costs), such plant assets are interdependent and potentially could be grouped for recognition and measurement of an impairment loss under ASC 360-10-35.

By contrast, unregulated operations may be able to identify cash flows at a lower level than the entire fleet, such as by region or individual plant.

When performing the asset grouping assessment, an entity may consider the following factors:

- **The presence and extent of shared costs** — Generally, individual plants have certain discrete costs that are directly attributable to the plant. However, a portion of the cost structure may also be shared. These shared costs may include legal; accounting; trading; marketing; and, in certain circumstances, fuel. The degree of shared costs could serve as evidence of the interdependence of cash flows between plants.

- **The extent to which the entity manages its business at various levels, such as by state, ISO, or region** — An entity may manage its generation fleet as individual assets or as an asset group. For example, an entity may manage a group of assets within an ISO territory and plan to make the assets available for dispatch to the operator. Depending on the territory, each plant within the ISO may receive similar prices; in this case, management may operate the assets on a fleet basis. The determination would also depend on whether management makes operating decisions on a plant basis or maintains a diversified mix of generating assets to take advantage of various economic environments. An entity should also consider how the results of operations are reported to the executive team and those charged with governance as well as how employees are compensated. For example, employee compensation plans that are based on the profit of an individual plant may be a strong indicator that the plant’s cash flows represent the lowest level of identifiable cash flows that are largely independent of other assets.

- **The entity’s distribution characteristics, such as regional distribution centers, local distributors, or individual plants** — The entity may consider how it manages outages and maintenance for its various assets. If management adjusts output at one plant to compensate for an outage at another, interdependent cash flows may exist. By contrast, if each plant is managed individually and there is little coordination throughout the group, an asset grouping method may not be appropriate.

- **The extent to which purchases are made by an individual location or on a combined basis** — The assessment of this criterion may show that certain costs are incurred for the benefit of individual plants while certain purchases may be for the use of more than one plant. For example, fuel for plants may be purchased from a common fuel source and may be allocated by a central function. This may depend, among other things, on the similarity of the plants as well as their proximity to each other.

- **The interdependence of assets and the extent to which such assets are expected or required to be operated or disposed of together** — The entity may consider how it operates its assets. The more an entity enters into plant-specific commitments to provide power, for example, the more independent the plant may be. On the other hand, if an entity has an overall aggregate commitment, such as a portfolio of retail customer requirements contracts, and management has the ability to dispatch its fleet depending on market conditions, cash flows may
be considered interdependent. Likewise, if a group of plants is committed to serve an ISO and dispatch decisions are controlled by the ISO, there may be a greater interdependence among the assets. Another consideration would be whether an entity is able to dispose of or deactivate an individual plant and whether this would affect the operation of other plants.

An entity should consider each of the relevant characteristics and make an informed judgment about its asset grouping. In determining the lowest level of identifiable cash flows, an entity must exercise significant judgment as well as identify and assess all relevant facts and circumstances. The determination should be revisited when there are changes to the entity, its operation strategy, and the environment in which it operates.

**Master Limited Partnerships**

MLPs are publicly traded partnerships that allow investors to purchase units on a securities exchange similarly to how they purchase common stock. Because MLPs are classified as partnerships, they do not pay corporate tax and avoid double taxation on dividends, thereby lowering the cost of capital and making these partnerships more advantageous than corporate structures. Income from the MLP flows through to the partners and is taxed at the partners’ individual tax rate. The established legislation on MLP structures requires that 90 percent of the revenue from the partnership be derived from activities related to natural resources, commodities, or real estate. Typically, midstream assets (e.g., gas transmission and storage facilities) meet the requirements for qualifying income.

There are two types of partners in a typical MLP structure: the general partner and the limited partners. The general partner is responsible for managing the operations of the partnership and shares in the periodic cash distributions at varying levels. As the performance of the entity and the associated cash available for distribution increase, the general partner’s portion of the cash distribution often increases. This structure appropriately compensates and rewards the general partner for growth and performance. The limited partners provide capital to the entity in exchange for the right to collect periodic cash distributions.

**Industry Considerations**

Many P&U companies are further exploring MLPs since these partnerships have become useful for realizing value for qualifying midstream assets. P&U entities can use these vehicles to gain access to capital by creating attractive EBITDA multiples for their gas transmission and storage assets.

MLPs need stable cash flows to consistently fund the periodic cash distributions. To increase the amount of cash available for distribution, MLPs need to grow their asset base. P&U companies that opt for an MLP structure will most likely hold back certain qualifying assets to drop into the MLP after the public offering.

**Accounting Considerations**

**Predecessor Entity**

The historical financial statements of the business being contributed to a newly formed entity need to accurately reflect the results of operations of all similar assets managed and financed together as a single operation. To include the appropriate financial statements in the registration statement, entities will need to determine what the predecessor is. The SEC staff has commented that it would be inappropriate to select certain assets while excluding other similar assets, since such selectivity could result in a financial statement presentation that is not representative of management’s track record. Often, entities preclear their proposed predecessor financial statement presentation with the SEC to avoid the costly and time-consuming process of redrafting financial statements.
Carve-Out Financial Statements

A parent company often forms an MLP by contributing certain qualifying assets, in which case the predecessor historical financial statements included in the registration statement will be a carve-out of the parent company’s business. Carve-out financial statements are intended to reflect all costs of doing business. Because many costs are incurred by the parent on behalf of the carve-out entity, a reasonable allocation method must be used to appropriately include expenses incurred on the carve-out’s behalf. In addition, an entity should analyze shared assets or liabilities, including intercompany or third-party debt, to determine whether they should be included or excluded.

Materiality

Management might need to establish a new materiality level for the predecessor entity. When an entity is required to prepare carve-out financial statements, the materiality levels are often substantially lower, in which case an entity must take a fresh look at certain accounting decisions, previously established capitalization thresholds, and disclosures.

Additional Financial Statements

In situations in which the predecessor entity has recently acquired a significant business or has significant equity method investments, additional audited financial statements may need to be included in the registration statement. Under Regulation S-X, Rule 3-05, registrants must perform the asset test, investment test, and income test to measure the significance of any recently acquired businesses. Registrants must also perform the investment test and the income test (the asset test does not apply to equity method investments) to measure the significance of any equity method investments under Regulation S-X, Rule 3-09. The level of significance is used to determine the financial statement periods that a registrant must include in the registration statement.

Pro Forma Financial Statements

When the historical financial statements do not reflect the ongoing entity, pro forma financial statements are required. Many MLPs require pro forma financial statements because of newly revised cost-sharing arrangements as well as long-term commercial agreements entered into with the parent. In addition, the consummation of the IPO and the use of the proceeds will need to be reflected.
Section 5
Energy Contracts, Derivative Instruments, and Hedging Activities
This section summarizes current trends and activity in the P&U industry and how potential rulemaking changes may affect (1) the accounting and reporting for energy contracts, (2) derivatives, and (3) risk management and fair value measurement efforts.

**Market Activity**

**Coal and Natural Gas**

The recent increased supply of shale gas caused by hydraulic fracturing (“fracking”) has driven utilities across the United States to explore switching their energy-generating fuel from coal to natural gas. The abundant supply of gas led to a drop in prices from about $12 per MMBtu in 2008 to about $2 in late 2012. The trend toward gas, however, ended in February 2013, when gas prices again increased by 60 percent to $4 per MMBtu. By March 2013, coal-fired power generation in the United States had risen by 21 percent relative to March 2012, while gas-fired generation had fallen by 11 percent. Because of the increased gas prices, as well as the expectation that they may rise even further, coal has regained some of its lost market share.

However, coal’s recovery is uncertain in the long term, since higher gas prices are likely to lead to more exploration and more drilling, thereby repeating the cycle by increasing supplies and lowering prices. Moreover, according to the EIA, four other factors will continue to help gas displace coal in the long term: efficiency, flexibility, competitiveness, and regulation. Consequently, companies with coal-generation assets continue to focus on the accounting implications of coal displacement. Coal inventories may also continue to increase as forward demand weakens, triggering consideration of lower-of-cost-or-market (LCM) analysis and possible impairment.

Companies with coal transactions should be mindful of the following:

- **Implications for NPNS elections and hedge accounting** — The application of derivative accounting elections (hedge accounting or NPNS) is directly related to certain assertions entities make about their business strategy or operations. Companies will have to continue revisiting their assertions to determine whether the existing accounting elections are still appropriate.

- **Impairment of coal generation assets, coal inventories, or both** — Coal generation may be displaced as the transition to natural gas occurs, which could have implications for the economic useful life of generation assets and related inventories.

**Readily Cash Convertible Consideration on RIN and LNG**

**RIN (Renewable Identification Number)**

The renewable fuel standards (RFS) adopted as part of the Energy Policy Act of 2005 require that motor-vehicle fuel in the 48 contiguous states contain specific volumes of renewable fuel (ethanol, biodiesel, etc.) for each calendar year. Effective September 1, 2007, refiners, blenders, importers (of traditional fuels), and other applicable parties are subject to a renewable volume obligation, the purpose of which is to measure the amount of renewable fuel making its way into motor-vehicle fuel sold or introduced into U.S. commerce. Under the EPA’s RFS program, every gallon of renewable fuel produced by a “producer” or imported by an “importer” and reported to the EPA is assigned a renewable identification number (RIN). Each RIN has a vintage-year designation with an expiration date of when it can be claimed for a credit from the EPA. RINs were intended to represent proxies for the amount of renewable fuels actually blended into motor-vehicle fuel annually.

1 Section §80.1401 defines an importer of transportation or renewable fuel as follows:

A[n] importer of transportation fuel or renewable fuel is any U.S. domestic person who: (1) Brings transportation fuel or renewable fuel into the 48 contiguous states of the United States or Hawaii, from a foreign country or from an area that has not opted in to the program requirements of this subpart pursuant to §80.1443; or (2) Brings transportation fuel or renewable fuel into an area that has opted in to the program requirements of this subpart pursuant to §80.1443 from a foreign country or from an area that has not opted in to the program requirements of this subpart.
used in the United States. Each year, obligated parties — including refiners and importers — must acquire sufficient RINs to
demonstrate compliance with their volume obligation.

Before 2013, RIN prices had consistently ranged from $0.01 per gallon to $0.05 per gallon. At the start of 2013, ethanol
RIN and biodiesel RIN prices began to increase exponentially, with ethanol RINs reaching highs of about $1.00 per gallon
in early March and biodiesel RINs reaching highs
of about $0.80 per gallon in February. The spike in
prices resulted from the increase in RFS targets by
the American Taxpayer Relief Act of 2012 (which
was signed into law on January 2, 2013) and the
introduction of RIN transacting during 2013 on the
Intercontinental Exchange (ICE) and the New York
Mercantile Exchange (NYMEX) (Ticker “D63” for D6
ethanol RINs and “D43” for D4 biodiesel RINs).

The growing popularity and increased transacting
of RINs have revived the question regarding net
settlement of RIN contracts (e.g., a forward to deliver
a RIN), specifically whether RIN contracts should
be considered readily convertible to cash (RCC) in
accordance with ASC 815. While the RIN market has
evolved over the past year (e.g., the introduction of
RIN futures trading on the NYMEX), RIN contracts
should not automatically be considered RCC. RCC
conclusions will continue to be based on the facts
and circumstances and to depend on the views of RIN market participants.

Companies with RIN transactions should be mindful of their RCC conclusions and should reevaluate these conclusions
as appropriate.

In addition to the derivative accounting considerations discussed above, preparers and auditors should consider the
balance sheet presentation of RINs and related EPA compliance obligations. There is diversity in practice in balance sheet
presentation. Some companies employ a net presentation, while others present the RINs and the associated obligation
on a gross basis. This difference in presentation is sometimes driven by the manner in which cost is allocated to bundled
purchases of biofuel and RINs and other times is based on company interpretations of the balance sheet offsetting
guidance. We encourage consultation when costs are not allocated to acquired RINs (including discrete purchases of RINs
and RINs acquired with the related biofuel) or when the EPA obligation is otherwise presented on a net basis on the balance
sheet, since we would generally expect a gross presentation of the RINs and the compliance obligation.

LNG (Liquefied Natural Gas)

Liquefied natural gas (LNG) is natural gas that has been converted to liquid form for ease of storage or transport. The
natural gas is condensed into a liquid at close to atmospheric pressure by cooling it to approximately −260 °F. In recent
years, the growth in the demand of LNG has been directly correlated with the increasing popularity of natural gas.
LNG is principally used for transporting natural gas to markets, where it is "regasified" and distributed as pipeline natural
gas. The cost of transforming LNG back to natural gas remains substantial, and the technology is not widespread in the
United States.

Historically, the United States has imported LNG through regasification facilities located on the East and Gulf Coasts. The
development of these facilities was supported by the $12 per MMBtu natural gas prices in 2008. However, given the $2 to
$4 prices for 2012 and 2013, along with the increased supply of shale gas, regasification facilities have begun to convert
from regasification to liquefaction in anticipation of LNG export. Despite this trend in activity, the market for bilateral LNG forwards has remained very small. Broker-dealer markets have been slow to develop for LNG, and there are still no exchange-traded LNG contracts.

That said, companies with LNG transactions are encouraged to keep up to date with their RCC conclusions as the market continues to evolve.

Alternatives to Hedge Accounting

While a revisit of hedge accounting standards has been on the financial instruments convergence agenda for some time, differences in the FASB’s and IASB’s views have stalled momentum. As an alternative to the administrative burden of applying hedge accounting, some energy companies have moved toward using non-GAAP financial measures to explain or discuss operating and economic performance. Although non-GAAP financial measures may enable companies to avoid applying hedge accounting, companies using these measures may be required to provide some additional disclosures to avoid misleading financial statement users.

Regulation G — Disclosure of Non-GAAP Financial Measures

Under Regulation G, public companies that issue financial information (e.g., earnings releases, MD&A) presented on a non-GAAP basis must reconcile the disclosed non-GAAP financial measure to the most directly comparable GAAP financial measure. P&U companies typically use non-GAAP financial measures to assess operational performance (e.g., commodity margin, adjusted EBITDA excluding the mark-to-market impact of economic hedging activities, or inventory value adjusted for the price of physical forward contracts hedging the inventory). P&U companies should ensure that any reconciliation between the GAAP and non-GAAP measure is accompanied by explanations that describe how the adjustment is calculated and how the supplementary non-GAAP measure helps stakeholders assess the company’s operations.

Alternative Energy — Focus on RECs

The immediate and long-term forecasts for alternative energy are becoming clearer, especially because of updates in environmental and economic policy. Central to the alternative energy considerations is the extension of the production tax credit for renewable energy facilities. The possibility for tax credits through involvement in alternative energy projects has created unique investment opportunities for organizations interested in alternative energy sources with the ability to offset taxable earnings.

This evolution in the renewable energy sector has led to some unique challenges for accountants. First, there is limited accounting guidance applicable to some of the more complicated alternative energy structures. Second, there can be significant tax ramifications if the project is not properly structured. In addition to the information presented in Section 4 and Section 10, summarized below are some of the more pressing derivative issues in the alternative energy industry.

Contract Assessment Consideration

Although electricity procurement is typically the primary purpose of a power purchase, renewable energy contracts often include RECs along with the energy output. These types of contracts are often referred to as bundled contracts. The accounting considerations for these renewable bundled contracts are similar to those for other energy offtake agreements; however, the primary complexities associated with these contracts typically affect the following topics:

- **Lease accounting** — As noted in ASC 840-10-15-3, this portion of the contract assessment is intended to identify whether an arrangement “contains a lease.” Accordingly, a contract could contain lease and nonlease elements. ASC 840-10-15-18 notes that the nonlease elements “shall be accounted for in accordance with other applicable
generally accepted accounting principles (GAAP).” If a REC is **not** considered a unit of output and the contract is considered a lease, the contract includes nonlease elements that must be separately assessed. Whether a REC is a unit of output continues to be a company policy that must be elected and applied consistently. See **Section 4, Lease Accounting**, for additional information.

- **Derivative accounting** — To the extent that an element in a bundled arrangement is considered a nonlease element, entities would need to assess it to determine whether that portion of the contract meets the derivative requirements. Because RECs are generally not considered RCC, a forward REC sale contract is generally not considered a derivative. This statement assumes that net settlement is not contractually permitted.

- **Embedded derivatives** — In this model, the contract consists of a host and one or more potential embedded derivatives. Because ASC 815-15 does not specify how to identify a host for executory contracts with multiple elements, two views have developed in the P&U industry with respect to identifying the host contract in a bundled arrangement.

  - **Predominant characteristics** — In this view, the host is defined as the portion of the contract that embodies the most significant economics under the transaction on the basis of the relative market value of the various contract elements. For bundled electricity contracts, electricity is often (but not always) the element with the most significant value and thus is defined as the host; therefore, the entire contract (including any potential nonderivative elements) would be deemed a derivative contract and fair value would be assessed for the entire contract. While we believe that this approach is fairly common in practice, we also think that it increases accounting risk and that reporting entities should consult with their auditors about whether it continues to be acceptable.

  - **Nonderivative host** — In this view, the host is defined as the portion of the contract that does not meet the derivative criteria. For example, the host contract in a bundled contract containing both electricity and RECs would be the REC element (as long as the REC element does not qualify as a derivative), and the entity would assess whether the electricity forward needs to be bifurcated. If the electricity portion of the contract must be bifurcated, the guidance in ASC 815-15-55-21 permits reporting entities to elect the NPNS scope exception for embedded derivatives (as long as the appropriate criteria are met). It would be rare for a company to recognize an inception gain or loss as a result of bifurcating an embedded derivative.

In practice, an entity determines whether an embedded derivative is “clearly and closely related” to its host contracts in accordance with ASC 815-15-25 by performing either a quantitative assessment or a qualitative assessment. Under the quantitative assessment approach, entities regress the market values or costs to produce the host and embedded elements (e.g., power and REC) to assess the level of correlation. Generally, there is not a high level of correlation between electricity prices and other elements in a bundled contract, such as RECs. Under the qualitative assessment approach, entities identify and compare the characteristics of the host and embedded derivative by using a broader perspective than they would under the quantitative approach.

### Fair Value Measurements

#### Balance Sheet Offsetting

Both ASU 2011-11 and ASU 2013-01 became effective for interim and annual reporting periods beginning on or after January 1, 2013. The ASUs instill new requirements for reporting both gross and net asset/liability information for certain derivatives and financial instruments recognized on the balance sheet, including retrospective application for any period presented. See Deloitte’s **December 20, 2011**, and **February 5, 2013**, **Heads Up** newsletters for full discussion of the accounting implications of the respective ASUs.

---

2 ASU 2013-01 clarifies which instruments and transactions are subject to the offsetting disclosure requirements established by ASU 2011-11. See Deloitte’s February 5, 2013, **Heads Up** newsletter for more information.
ASU 2013-01 has largely addressed industry concerns related to ASU 2011-11 by clarifying the latter standard’s scope. ASU 2013-01 clarified that trade receivables and payables would not be subject to the disclosure requirements but confirmed in ASC 210-20-55-10A that derivative contracts not subject to an MNA (e.g., retail forward energy sales) would be included within the tabular disclosures required by ASU 2011-11. Therefore, P&U companies that have elected to offset their derivative positions in accordance with ASC 210-20 have been able to leverage their existing ASC 815-10-50 tabular disclosures to address the incremental balance sheet offsetting disclosure requirements in ASU 2011-11. Further, ASU 2013-01 does not specify the characteristics that would make an agreement similar to a MNA; therefore, any underlying agreement containing provisions that allow either party to net in the event of default should be examined carefully to determine whether such an agreement is within the scope of the ASUs.

Despite the scope clarifications of ASU 2013-01, the new offsetting disclosures in ASU 2011-11 will increase the impact on P&U companies that did not previously elect to offset their commodity derivative positions in accordance with ASC 210-20. Those entities should consider the adequacy of their existing systems and may need to implement tools, as well as processes and controls, to produce the data necessary to comply with the disclosure requirements. It is possible that some of the required information may reside in existing systems or processes (i.e., credit and margining or those related to ASC 820 fair value disclosures). See Balance Sheet Offsetting on page 59 for additional information.
Section 6
Fair Value Measurements
Observations

In accordance with ASC 820, a fair value measurement should incorporate “assumptions that market participants would use in pricing the asset or liability.” Because the structure of commodity markets (e.g., PJM, ERCOT, MISO, CAISO, NYMEX) can affect transaction costs (e.g., transmission and congestion) and market prices (market price caps), entities should consider the associated market framework in determining the fair value of commodity transactions. Changes in these markets could affect fair value models or inputs. Activities in the commodity markets over the past year that could affect the valuation of commodity transactions include, but are not limited to:

- The changing mix of coal and natural gas.
- ERCOT nodal pricing caps.
- As noted in PJM’s April 30, 2012, *FTR Revenue Stakeholder Report*, PJM has experienced shortfalls in financial transmission right (FTR) funding over the past several years. Because FTRs are typically considered derivative instruments under ASC 815, we encourage companies to consider the effects of this underfunding in valuing their FTRs.

A Reminder Regarding Fair Value Measurements

In May 2011, the FASB issued ASU 2011-04, which resulted in various amendments to ASC 820, including minor amendments to measurement principles (e.g., consideration of offsetting credit and market risks) and expanded disclosure requirements (e.g., those related to Level 3 fair value measurements). The guidance in the ASU became effective for interim and annual periods beginning after December 15, 2011, for public companies.

The primary provisions of the ASU to affect the P&U industry appear to be the expanded disclosure requirements for Level 3 fair value measurements, some of which include the following:

- Quantitative disclosures about significant unobservable inputs and assumptions used in the measurement (see ASC 820-10-50-2(bbb)).
- A description of the valuation processes in place (e.g., how the entity “decides its valuation policies and procedures and analyzes changes in fair value measurements from period to period”) (see ASC 820-10-50-2(f)).
- A “narrative description of the sensitivity of the fair value measurement to changes in unobservable inputs [and] interrelationships between those inputs” (see ASC 820-10-50-2(g)).

However, note that nonpublic entities are exempt from the following fair value disclosure requirements in ASU 2011-04:

- The “amounts of any transfers between Level 1 and Level 2 of the fair value hierarchy, the reasons for those transfers, and the reporting entity’s policy for determining” whether a transfer has occurred (see ASC 820-10-50-2(bb)).
- A (1) “narrative description of the sensitivity of the fair value measurement to changes in unobservable inputs if a change in those inputs to a different amount might result” in a significantly different fair value measurement and (2) description of the interrelationships between unobservable inputs, including how such relationships might magnify or mitigate the impact of changes in such inputs on fair value (see ASC 820-10-50-2(g)).

For more information about the ASU’s amendments, see Deloitte’s May 13, 2011, *Heads Up*.
Because the sample disclosures in ASU 2011-04 are not specific to the P&U industry, management has needed to exercise significant judgment in adopting the standard, resulting in diversity in practice. Entities should consider the following factors as they refine their disclosures:

- **Significant unobservable inputs** — The quantitative disclosures should “provide enough information for users to assess whether the reporting entity’s views about individual inputs differed from their own and, if so, to decide how to incorporate the reporting entity’s fair value measurement in their decisions.”\(^2\) We believe that to meet this objective, reporting entities should consider the commodity type (e.g., power, natural gas), valuation technique, and instrument type in determining the appropriate level of disaggregation of their Level 3 fair value measurements in their quantitative disclosures. In addition, the ASU requires entities to disclose the “significant unobservable inputs” used in their Level 3 fair value measurements. Accordingly, we believe that entities should disclose all unobservable inputs that are considered “significant” to their Level 3 measurements.

- **Sensitivity** — As noted above, the ASU requires reporting entities to discuss any relationships between unobservable inputs that could magnify or mitigate the sensitivity of their Level 3 measurements to changes in the unobservable inputs. This discussion (1) must incorporate all unobservable inputs included in the quantitative disclosures discussed above and (2) could incorporate unobservable inputs that are not considered significant. An example of a relationship that could be pertinent to this disclosure requirement is the relationship between forward price and implied volatility inputs. Accordingly, entities that disclose multiple inputs for a given category in their quantitative table should also include a discussion of the relationships between these inputs.

See Deloitte’s October 2012 *Power & Utilities Spotlight* for more information about the effects of ASU 2011-04’s disclosure requirements on P&U entities.

---

\(^2\) Paragraph BC86 of the Basis for Conclusions of ASU 2011-04.
Section 7
Accounting Standards Codification Update
Revenue Recognition Project

Overview

The FASB and IASB have continued to redeliberate various aspects of their November 2011 revised ED on revenue arising from contracts with customers and expect to issue a final standard in the first quarter of 2014. The proposed model is based on a core principle under which an entity “shall recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.”

Sales arrangements involving energy commodities with customers that are not accounted for as derivatives (including NPNS contracts) or leases in accordance with ASC 815 and 840, respectively, will be within the scope of the final revenue standard.

In applying the standard’s provisions to contracts within its scope, an entity would:

- “Identify the contract with a customer” (step 1).
- “Identify the separate performance obligations in the contract” (step 2).
- “Determine the transaction price” (step 3).
- “Allocate the transaction price to the separate performance obligations in the contract” (step 4).
- “Recognize revenue when (or as) the entity satisfies a performance obligation” (step 5).

The revised ED implies that a relatively vanilla, nonderivative forward energy sales contract would constitute a series of individual performance obligations, each delivered at a point in time. However, during redeliberations, the boards concluded that a series of distinct performance obligations to deliver homogeneous goods that are transferred to the customer consecutively and for which the measure of progress is the same would be treated as a single performance obligation. Thus, a simplistic forward energy sale for which delivery of the same energy commodity product is required over time would be treated as a single performance obligation satisfied continuously throughout the contract if it meets the criteria in the proposed standard. In this case, the entity would determine an appropriate method for measuring progress toward complete satisfaction of the single performance obligation (i.e., the transfer of control of the promised goods over time) and would recognize the transaction price as revenue as this progress is made.

The final revenue standard may also change P&U entities’ accounting for contract modifications. Under the proposed guidance, contract modifications would be accounted for as separate contracts when they result in (1) additional performance obligations that are “distinct” (as defined in the standard) and (2) additional consideration that reflects the entity’s stand-alone selling price for the additional performance obligations (including certain adjustments). If a contract modification is not considered a separate contract (i.e., does not meet the criteria above), an entity would consult the proposal’s criteria for evaluating the remaining goods and services in the modified contract and determining whether to account for the modification prospectively or retrospectively. Therefore, the accounting for common blend-and-extend contracts for power or other commodity deliveries could change.

The proposed ASU significantly expands the current revenue recognition disclosure requirements. Entities would be required to disclose both quantitative and qualitative information about (1) the amount, timing, and uncertainty of revenue (and related cash flows) from contracts with customers; (2) the judgment, and changes in judgment, exercised in applying the proposal’s provisions; and (3) assets recognized from costs to obtain or fulfill a contract with a customer.
Effective Date and Transition

For public entities, the proposal would be effective for reporting periods (fiscal and interim) beginning after December 15, 2016. The following three alternative adoption dates will be available to nonpublic entities:

- The effective date for public entities.
- Annual reporting periods beginning after December 15, 2016, including interim periods thereafter (i.e., same initial year of adoption as that for public entities, but nonpublic entities would be allowed to postpone adoption of the ASU during interim reporting periods in that year).
- Annual reporting periods beginning after December 15, 2017, including interim periods therein (i.e., one year deferral).

Entities would not be permitted to early adopt the standard, although entities reporting under IFRSs would have the option of doing so. Further, entities would have the option of using either a retrospective transition approach (with certain practical expedients) or a modified approach to apply the new standard. Entities that choose retrospective application would also consider the requirements in ASC 250. According to the February 20, 2013, summary of Board decisions, under the modified approach, an entity would recognize “the cumulative effect of initially applying [the revenue standard] as an adjustment to the opening balance of retained earnings . . . at the date of initial application.” Under the modified approach, the proposed guidance would apply to contracts for which the entity has remaining performance obligations to fulfill as of the effective date but would not apply to contracts that were completed (i.e., the entity has no remaining performance obligations to fulfill) before the effective date. In the year of adoption, entities would also be required to disclose an explanation of the impact resulting from the adoption of the ASU as well as the financial statement line item and respective amount that are directly affected by the standard’s adoption.

The standard setters have acknowledged that because the proposed revenue standard will replace a significant amount of authoritative literature, there may be a need for interpretive guidance. This could be particularly relevant for industries that currently apply specialized revenue guidance under U.S. GAAP (e.g., software, construction contracts, power purchase agreements, real estate). As part of the revenue implementation initiative, the AICPA has formed a number of industry-specific task forces to identify challenging implementation issues under the new guidance and to develop frameworks for assessing the issues with a goal of minimizing diversity in practice when the new rules are implemented. The P&U and oil and gas industries have established task forces as part of the initiative.

Leases Project

Overview

On May 16, 2013, the FASB and IASB issued a revised joint ED on lease accounting. The ED, released by the FASB as a proposed ASU, introduces a new accounting model that would require entities to record substantially all leases in the statement of financial position. The proposal was issued primarily to address stakeholders’ concerns about off-balance-sheet financing arrangements for lessees and is expected to improve the transparency of financial statement reporting about leases. If finalized, the proposed ASU would substantially converge the FASB’s and IASB’s accounting models for lease arrangements.

Key Provisions

Scope

The scope of the proposed guidance is fairly consistent with current U.S. GAAP but will not be limited to depreciable assets. For example, inventory arrangements could be within the scope of the proposal but would not be expected to qualify very
often. There are also several scope exceptions, most of which are also consistent with current U.S. GAAP. These include rights related to minerals and natural resources, biological assets, and intangibles.

**Definition of a Lease**

The revised ED defines a lease as “a contract that conveys the right to use an asset (the underlying asset) for a period of time in exchange for consideration.” When determining whether a contract contains a lease, entities should assess whether (1) the contract is based on a specified asset and (2) the lessee obtains the right to control the asset for a particular period.

Under the proposal, a leased asset must be specifically identifiable either explicitly (e.g., by a specific serial number) or implicitly (e.g., the only asset available to satisfy the lease contract). An arrangement does not have a specified asset if the lessor has substantive substitution rights to fulfill the contract through the use of alternative assets. In addition, a specified asset could be a physically distinct portion of a larger asset (e.g., one floor of a building). However, a capacity portion of a larger asset that is not physically distinct (e.g., a percentage of a pipeline) would not be a specified asset under the proposal.

Under the proposed guidance, it is unclear whether ancillary use agreements or easements, which allow the asset owner to continue using the underlying asset without any meaningful loss in its rights of use at the level of the entire underlying asset, would be considered leases of a specified asset. In comment letters, several P&U companies, as well as the EEI, have requested additional clarification of the “specified asset” guidance related to these arrangements (e.g., the ancillary use of a transmission utility pole).

The definition of control or “right to use” is consistent with the way control is assessed under the proposed revenue standard and consolidation literature. A contract would be deemed to convey the right to control the use of an identified asset if the customer has the ability to direct, and derive benefits from, the use of that asset. Benefits from use would include direct and indirect economic gain stemming from use of the asset (e.g., renewable energy credits, or secondary physical output, such as steam). One of the most significant changes to the definition of a lease is that the ability to specify the output from the use of the asset (e.g., dispatch rights of a generating facility) would not, in and of itself, indicate that the customer has the ability to direct the use of the asset. Rather, the entity would need to be able to make decisions about the inputs and processes used to produce such output. This decision is likely to affect whether gas supply contracts and power purchase arrangements constitute leases.

**Lessee Accounting**

The proposed accounting for lessees is based on a right-of-use (ROU) model, which results in the recognition of all leases (except certain short-term leases) as a lease obligation and ROU asset in the lessee’s statement of financial position. The boards agreed on two different lease classification approaches that would be applied to determine a lessee’s subsequent accounting for the ROU asset — (1) the financing lease approach (i.e., Type A leases) and (2) the straight-line-expense approach (i.e., Type B leases). A lessee would determine which method to apply on the basis of the nature of the underlying asset (something other than property or property, respectively) and the lease terms.

**Lessor Accounting**

The proposed model would require lessors to classify leases similarly to the way lessees classify them (i.e., as either Type A leases or Type B leases). Type A leases would be accounted for under the receivable-and-residual approach, which requires the lessee to (1) derecognize the leased asset, (2) recognize a lease
receivable for its right to lease payments over the lease term, and (3) recognize the expected value of the residual asset at the end of the lease. Type B leases would be accounted for under the operating lease approach, which would closely mirror current operating lease accounting for lessors.

**Specific Industry Considerations**

**Power Purchase Agreements**

Under current guidance, a power purchase agreement (PPA) is accounted for as a lease if the off-taker (1) agrees to buy all, or substantially all, of the output(s) of a specified generating facility and (2) pays for the output(s) under pricing terms that are neither fixed per unit nor indexed to market prices. However, the proposed definition of a lease focuses on whether the off-taker has control of the specified generating facility. That is, an arrangement would not be considered a lease solely on the basis of the pricing and the extent of outputs purchased under the contract. P&U companies would have to determine whether a PPA gives the off-taker control of an identified generating facility because the off-taker has the ability to direct the use, and derive the benefits from the use, of the facility.

The ED indicates that a customer that is involved in the design of a specified asset may have the ability to direct the asset’s use, given that the customer may be predetermining, before lease commencement, how the asset is to operate and run in order to derive economic benefits from the use of the asset. However, the ED does not indicate (1) how involved in the asset’s design the customer would need to be to demonstrate that it has the ability to direct the asset’s use or (2) how to consider the customer’s involvement in design together with other ongoing decisions in an off-take agreement.

**Transportation and Storage Contracts**

Existing contracts to transport or store gas or other fuel products would need to be evaluated under the proposed definition of a lease. Currently, a contract for a portion of a pipeline’s transport or storage capacity is not precluded from being a lease. Under the proposed lease standard, however, a capacity portion of a larger asset would have to be physically distinct or substantially all of the larger asset’s capacity to be considered a specified asset. Given that pipeline and storage contracts vary significantly in structure (e.g., in terms of contracting for the rights to a percentage of an asset’s capacity or benefits), P&U companies would need to evaluate their contracts to determine whether they should account for them under the guidance on leases, revenue recognition, or derivatives.

P&U companies currently may structure agreements for electricity off-take, or to satisfy commodity transportation and storage needs, to avoid on-balance-sheet accounting under either derivative or capital lease guidance. Those structures may not offer the same accounting benefits once the proposed lease model is in effect.

**Other Accounting and Measurement Considerations**

For a lease or a contract that contains lease components, the ED contains several other accounting and measurement considerations that could affect entities in the P&U industry.

**Lease Classification**

If a single lease contract or a component of a lease contract gives a P&U company the right to use more than one asset (e.g., a lease PPA for a natural gas power plant contains both building/real estate and a turbine), the entity would have to determine the primary asset in the arrangement. That determination would dictate the lease classification and income statement profile. The notion of “integral equipment” under current accounting would not affect the conclusion of whether an asset is property or nonproperty for lease classification purposes under the proposed guidance.
In-Substance Fixed Lease Payments

Like current GAAP, the proposal would require entities to include in-substance fixed lease payments structured as variable or contingent payments in the measurement of the lease liability (for lessees) or receivable (for lessors). Accordingly, P&U companies would need to evaluate their contracts to determine whether those agreements include in-substance fixed lease payments (e.g., in-substance minimum payments based on an agreement’s default provisions).

Grandfathering Under EITF Issue 01-8

P&U companies may have PPAs, other off-take agreements, or fixed-asset leases that were executed before May 2003. Companies were not required to reassess those contracts when the guidance in EITF 01-8 (currently ASC 840-10-15) on determining whether an arrangement contains a lease became effective. However, under the ED, all outstanding contracts would need to be evaluated in light of the proposed new definition of a lease. That is, there would be no grandfathering under the proposed guidance, even for contracts entered into before May 2003.

Consideration of Other U.S. GAAP

The proposed guidance would supersede the guidance in ASC 980-840 on leases of regulated entities. It is thus unclear whether regulated P&U companies that currently apply ASC 980-840 to lease contracts would need to evaluate such contracts under the proposed lease guidance and without the benefit of a regulatory accounting overlay. This could affect the timing of expense recognition for financial reporting purposes. Lease expense that is currently recognized on a straight-line basis in accordance with the accounting requirements in ASC 980-840 (i.e., in a manner consistent with the approach used for rate-making purposes) may need to be recorded in accordance with the ED’s general lease classification requirements, regardless of the lease classification requirements in ASC 840.

While fewer off-take arrangements in the P&U industry would be expected to meet the ED’s definition of a lease, this change to ASC 980 could significantly affect the financial reporting for other lease contracts entered into by regulated P&U companies. In comment letters to the FASB, several P&U companies, as well as the EEI, have expressed concerns about removing ASC 980-840, recommending that the guidance be put back into U.S. GAAP.

Next Steps

The boards received more than 630 comment letters on the ED, which are currently being analyzed. Redeliberations began in November of 2013 and are expected to continue into 2014. A final standard could be issued sometime in 2014 but is not expected to be effective any sooner than January 1, 2017 (for calendar-year December 31, 2017, reporting periods).

See Deloitte’s May 17, 2013, Heads Up for more information about the revised ED and Deloitte’s December 6, 2013, Heads Up for further discussion of comment-letter feedback received by the boards.

Financial Instruments Projects

The FASB and IASB have struggled to converge their guidance on accounting for financial instruments (AFI). The boards’ AFI project is divided into three major components: classification and measurement, impairment, and hedge accounting. Although the boards have converged key elements of their classification and measurement models, they appear to be divided on impairment and have not worked together on hedge accounting from the beginning. The status of each component of the FASB’s AFI project, including select industry considerations, is discussed below.
Classification and Measurement

Background

On February 14, 2013, the FASB released for public comment a proposed ASU\(^1\) on the recognition, classification, measurement, and presentation of financial instruments. Comments on the proposal were due by May 15, 2013.

Under the FASB’s and IASB’s proposals, entities would be required to classify a financial asset into one of the following three categories on the basis of the asset’s contractual cash flow characteristics and the business model in which it is managed: (1) amortized cost, (2) FV-OCI, or (3) FV-NI. Financial assets would be classified and measured on the basis of their contractual cash flow characteristics and the business model in which those assets are managed. In earlier deliberations the boards had tentatively decided that a financial asset would meet the requirements of the contractual cash flow characteristics assessment if the contractual terms of the instrument “give rise on specified dates to cash flows that are solely payments of principal and interest [SPPI] on the principal amount outstanding.”

The proposed ASU identifies three distinct business models in which an asset may be held and managed:

- A business model that has the objective of holding the assets to collect contractual cash flows (“hold-to-collect”). Financial assets that meet the SPPI criterion and are held in a hold-to-collect business model are accounted for at amortized cost.

- A business model that has the objective of both holding financial assets to collect contractual cash flows and selling financial assets (“hold-and-sell”). In other words, the entity has not determined whether it expects to hold or sell the assets. Financial assets that meet the SPPI criterion and are held in a hold-and-sell business model are accounted for at FV-OCI or, optionally, at FV-NI.

- A business model with an objective that is not consistent with (1) or (2) above. Financial assets that are held in a business model that is neither hold-to-collect nor hold-and-sell are accounted for at FV-NI.

Under the proposed ASU, embedded features in a hybrid financial asset would no longer be analyzed for bifurcation from the host contract. Instead, entities would be required to classify hybrid financial assets in their entirety on the basis of the contractual cash flow characteristics criterion and the entity’s business model.

The boards had also tentatively decided that:

- Financial liabilities would be accounted for at amortized cost with certain exceptions.

- Equity investments would be accounted for at FV-NI unless (1) they result in consolidation, (2) the equity method of accounting applies, or (3) the investment does not have a readily determinable fair value and the entity has elected to apply a practicability exception.

- The existing unconditional fair value option for financial instruments would be replaced with a conditional option.\(^2\)

---

\(^1\) See Deloitte’s February 14, 2013, and August 2, 2013, Heads Up newsletters for an overview of the proposed ASU and a summary of feedback from stakeholders, respectively.

\(^2\) The proposal states that under this option, an entity may irrevocably elect to account for the following instruments at FV-NI:

1. “[A] group of financial assets and financial liabilities for which both of the following conditions are met:
   a. The entity manages the net exposure relating to the financial assets and financial liabilities (which may be derivative instruments subject to [ASC] 815) on a fair value basis.
   b. The entity provides information on a net exposure basis to its management.”

2. “[A] hybrid financial liability provided that neither of the following conditions exists:
   a. The embedded derivative or derivatives do not significantly modify the cash flows that otherwise would be required by the contract
   b. It is clear with little or no analysis when a similar hybrid instrument is first considered that separation of the embedded derivative or derivatives is prohibited.”

In addition, an entity may irrevocably elect to account for an instrument that qualifies for the FV-OCI classification at FV-NI.
Recent Deliberations

At its December 18, 2013, board meeting, the FASB decided to abandon the SPPI test that would have been required as part of the proposed contractual cash flow assessment for determining the classification and measurement of financial assets. The FASB discussed the complexity associated with the proposed contractual cash flow test and noted that requiring an SPPI test would be swapping known complexity (i.e., the bifurcation guidance in ASC 815-15) for unknown complexity (SPPI). The FASB tentatively decided to retain the requirement to bifurcate financial assets under the “clearly and closely related” guidance in ASC 815-15 on assessing whether an embedded derivative feature should be bifurcated from a hybrid financial asset. As a result of this decision, the FASB’s and IASB’s models for classifying and measuring financial instruments are substantially diverged.

Next Steps

The FASB directed the staff to analyze whether — in the determination of the classification and measurement of (1) a host contract that remains after bifurcation of embedded features, (2) hybrid financial assets with embedded features that do not require bifurcation, and (3) financial assets that are not within the scope of ASC 815 — the contractual cash flow characteristics test should be based solely on the “clearly and closely related” criterion in ASC 815-15 or developed further, the category an entity uses to classify and measure financial instruments could change. It remains unclear whether and, if so, how the FASB or IASB will address industry concerns about how P&U companies with nuclear and other decommissioning obligations should account for decommissioning trusts.

Impairment

Background

After years of separately and jointly deliberating various impairment models, the FASB and IASB have each released their third of three formal proposals on recognizing credit losses on financial assets, with the FASB issuing its proposed ASU in December 2012 and the IASB issuing its ED in March 2013. The boards’ proposed impairment models differ in many respects (one of the more notable differences is impairment loss timing and loss recognition, as detailed below). However, both proposed models (1) are based on a concept of expected credit losses (i.e., all contractual cash flows that the entity does not expect to collect) rather than incurred losses and (2) would apply regardless of the form of the asset (e.g., loan vs. debt security).

Impairment Loss Timing and Loss Recognition

The FASB’s proposed model is based on a single-measurement approach in which the impairment allowance reflects the estimate of current expected credit losses (i.e., all contractual cash flows that entities do not expect to collect over the expected term of the asset). All expected credit losses are recognized at initial recognition, except for PCI assets.

In contrast, the IASB’s proposed model is based on a dual-model approach in which the impairment allowance is generally measured at an amount equal to either of the following:

- 12-month expected credit losses.
- Lifetime expected credit losses if, as of the reporting date, the credit risk has increased significantly since initial recognition.3

3 Exceptions are made for (1) trade receivables without a significant financing component, (2) trade receivables with a significant financing component and lease receivables for which an entity elected the simplified approach, and (3) purchased and originated credit-impaired assets.

4 If there is objective evidence of an asset’s impairment, the asset would be included in this category.
For instruments with low credit risk, an allowance equal to 12 months of expected credit losses would be measured regardless of whether there has been a significant increase in credit risk. See Deloitte’s November 7, 2013, journal entry for more information about the IASB’s clarifications of several aspects of its impairment model, including instruments with low credit risk.

Next Steps

In December, the FASB staff presented to the Board four alternative paths forward, along with feedback from investors on how they analyze impairment losses and how they view the Board’s proposed CECL impairment model. On the basis of investors’ feedback and the staff analysis presented, the Board ultimately decided to continue to develop and refine its proposed CECL model. The other three alternatives discussed at the meeting included developing (1) a gross-up model, (2) a truncated model, or (3) a model similar to that being developed by the IASB.

See the FASB’s December 18, 2013, Board Meeting Handout for more information about the four alternatives discussed by the Board. The IASB has also made further refinements to its proposed impairment model at its October, November, and December 2013 meetings.

The boards are not expected to issue final guidance on this topic until 2014. No effective date has been set, but constituents generally indicated that they would need at least two to three years to implement a final standard (i.e., if a standard is finalized in 2014, it should be effective no earlier than 2017).

See Deloitte’s August 20, 2013, Heads Up for additional details about the boards’ impairment proposals.

Hedge Accounting

IASB Developments

In November 2013, the IASB issued amendments to IFRS 9 that introduce a new “general hedge accounting model.”5 The new model, which is described in Chapter 6 of IFRS 9, significantly differs from the current hedge accounting model in IAS 39 in a number of ways, including in the following respects:

- Eligibility of hedging instruments.
- Accounting for the time value component of options and forward contracts.
- Eligibility of hedged items.
- Designation of components of nonfinancial items as hedged items.
- Qualifying criteria for applying hedge accounting.
- Modification and discontinuation of hedging relationships.
- Extension of the fair value option.
- Additional disclosures.

For P&U companies, a notable difference between the new model and the current IAS 39 model is that the new model permits an entity to hedge certain nonfinancial risk components. Risk components of nonfinancial items that are separately identifiable and reliably measurable may be hedged. For instance, an energy company with a commodity exposure at a

5 The new general hedge accounting model does not address the macro hedging issues that the IASB is currently discussing. A DP on the IASB’s macro hedge accounting model is expected to be issued in the first quarter of 2014.
particular delivery point may choose to hedge only the commodity price risk associated with price volatility at a liquid trading hub and may elect not to hedge the locational basis difference between the hub location and the delivery point. This guidance differs from the current guidance in both IFRSs and U.S. GAAP, under which an entity is required to focus on the all-in exposure when attempting to hedge nonfinancial risks. P&I companies generally support this change because it puts them on a more level playing field with financial institutions, which tend to have more financial exposures that are eligible for component hedging.

The IASB’s new hedge accounting model is currently available for adoption if an entity also adopts all the other provisions of IFRS 9. For more information on the IASB’s new hedging model, see Deloitte’s November 26, 2013, *Heads Up.*

The new hedge accounting model in IFRS 9 is a significant departure from current practice under both IFRSs and U.S. GAAP and is intended to better align the accounting framework with entities’ risk management activities. As proposed in the May 2010 ED, the FASB’s approach makes fewer changes to existing hedge accounting requirements than the IASB’s approach. Both boards, however, have agreed on certain changes, such as removing the requirement to retrospectively assess whether a hedging relationship is effective, eliminating the ability to voluntarily dedesignate a hedging relationship, introducing qualitative considerations in the evaluation of hedging relationship effectiveness, and disallowing an assumption of perfect effectiveness in hedging relationships.

**FASB Developments**

The FASB has not spent significant time during 2013 on the hedging phase of its financial instruments project, and it is unclear to what extent the provisions of the IASB’s new model will affect the FASB’s future discussions. The FASB did, however, consider two limited amendments to its hedge accounting guidance during the year.

On July 17, 2013, the FASB issued *ASU 2013-10*, which amends ASC 815 to include the Fed Funds Effective Swap Rate (also referred to as the Overnight Index Swap Rate) as an eligible benchmark interest rate for hedge accounting in the United States, in addition to UST and LIBOR. The ASU also removes restrictions on an entity’s ability to designate different benchmark interest rates as the hedged risk for similar hedges. The ASU applies prospectively to qualifying new hedging relationships entered into on or after July 17, 2013, and to hedging relationships redesignated on or after that date.

In addition, on November 25, 2013, the FASB endorsed for final issuance an alternative proposed by the PCC regarding the U.S. GAAP hedge accounting requirements for private companies. The endorsed alternative will allow private companies that are not financial institutions to apply, in certain circumstances, a simplified hedge accounting method to hedging relationships involving variable-rate debt and a pay-fixed, receive-floating interest rate swap. The simplified approach assumes no hedge ineffectiveness in the hedging relationship, thereby resulting in an income statement impact similar to what would have occurred had the private company simply entered into a fixed-rate borrowing. In addition, the simplified approach (1) allows private companies to measure the hedging interest rate swap at its settlement value, rather than at fair value, (2) gives private companies more time to put hedge documentation in place, and (3) provides certain private companies with relief from fair value measurement disclosure requirements. The endorsed alternative is effective for reporting periods beginning after December 15, 2014; early adoption is permitted.

**Balance Sheet Offsetting**

**Background**

In December 2011, the FASB issued *ASU 2011-11* (subsequently codified in ASC 210-20), which established new disclosure requirements regarding the nature of an entity’s rights of setoff and related arrangements associated with its financial instruments and derivative instruments and their potential effect on the entity’s financial position. Further, in January 2013, the FASB clarified the scope of the ASU 2011-11 offsetting disclosure requirements by issuing *ASU 2013-01* (also codified in ASC 210-20).
The requirements are effective for all entities for fiscal years beginning on or after January 1, 2013, and interim periods within those annual periods.

**Scope**

ASU 2013-01 limits the scope of the offsetting disclosure requirements to the following instruments or transactions:

- “Recognized derivative instruments accounted for in accordance with [ASC] 815, including bifurcated embedded derivatives . . . repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are offset in accordance with either [ASC] 210-20-45 or [ASC] 815-10-45.”

- “Recognized derivative instruments accounted for in accordance with [ASC] 815, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either [ASC] 210-20-45 or [ASC] 815-10-45.”

The amendments clarify that only derivatives accounted for in accordance with ASC 815, including bifurcated embedded derivatives, are within the scope of the disclosure requirements. Instruments that meet the definition of a derivative in ASC 815 but that are subject to one of the scope exceptions under ASC 815 are outside the scope of the disclosure requirements.

**Required Disclosures**

Under ASC 210-20-50-3 and 50-4, an entity must disclose, at a minimum, the following information “in a tabular format, separately for assets and liabilities, unless another format is more appropriate”:

a. The gross amounts of those recognized assets and . . . liabilities

b. The amounts offset in accordance with the guidance in [ASC] 210-20-45 and [ASC] 815-10-45 to determine the net amounts presented in the statement of financial position

c. The net amounts presented in the statement of financial position [i.e., (a)–(b)]

d. The amounts subject to an enforceable master netting arrangement or similar agreement not otherwise included in (b) [along with the] amounts related to financial collateral (including cash collateral)

e. The net amount after deducting the amounts in (d) from the amounts in (c).

Amounts shown for items (a) through (c) should be grouped by type of instrument or transaction; however, amounts shown for items (c) through (e) may be shown by type of instrument or by counterparty. Also, the amounts reported for item (c) must be reconciled to amounts presented in the statement of financial position, and the total amount disclosed for item (d) cannot exceed the amount shown for item (c) for a given financial instrument.

P&U companies that did not previously elect to offset their commodity derivative positions in accordance with ASC 210-20 are likely to be more significantly affected. To meet the requirements in item (d) above, P&U companies that previously did not have the necessary infrastructure in place now must separately identify, track, and disclose fair value amounts of both derivatives and cash collateral subject to MNAs or other similar agreements.

ASU 2013-01 permits entities to include in their tabular offsetting disclosures all other recognized derivatives accounted for in accordance with ASC 815 to facilitate reconciliation to individual line item amounts in the statement of financial position. Therefore, it is likely that P&U companies would combine their ASC 815-10-50 tabular disclosures with the new balance sheet offsetting disclosures required by ASU 2011-11.

An entity also must describe the rights of setoff associated with its recognized financial instruments subject to an enforceable MNA or similar agreement disclosed in item (d) above, including the nature of those rights. The tabular and
qualitative disclosure requirements are minimum requirements; an entity may need to supplement these disclosures with additional qualitative disclosures to fully describe the effect of the rights of setoff and related arrangements on the entity’s financial instruments and derivatives and its financial position.


**Transition**

The disclosure guidance must be applied retrospectively for any period presented that begins before the date on which the entity initially adopts the requirements.

**Accumulated Other Comprehensive Income**

**Introduction**

On February 5, 2013, the FASB issued ASU 2013-02, which contains new disclosure requirements for items reclassified out of accumulated other comprehensive income (AOCI). The ASU is intended to help entities improve the transparency of changes in other comprehensive income (OCI) and income statement effects of significant items reclassified out of AOCI. It does not amend any existing requirements for reporting net income or OCI in the financial statements. Both public and nonpublic entities that report items of OCI are affected by the ASU (however, the interim disclosure requirements and effective date differ depending on whether an entity is public or nonpublic).

**Overview of the ASU**

ASU 2013-02 requires entities to disclose additional information about reclassification adjustments, including (1) changes in AOCI balances by component and (2) significant items reclassified out of AOCI.

**Changes in AOCI Balances by Component**

Under the ASU, an entity must disaggregate the total change for each component of AOCI (e.g., unrealized gains or losses on available-for-sale securities or foreign-currency items) and separately present amounts related to (1) reclassification adjustments and (2) current-period OCI. Both before-tax and net-of-tax presentations are acceptable provided that the requirements in ASC 220-10-45-12 are met. An entity can present these required disclosures either on the face of the financial statements or separately in the notes.

ASU 2013-02 does not address the presentation of information about an entity’s noncontrolling interest (NCI). Information about changes in AOCI (see ASC 220-10-45-14A) should reflect amounts of OCI attributable to the parent, since AOCI represents an accumulation of amounts for the parent only. Current-period OCI attributable to an entity’s NCI would be accumulated in the entity’s NCI balance sheet line item and thus would not be included in AOCI. However, because ASU 2013-02 is silent on the presentation of OCI information about NCI, an entity would not be precluded from separately disclosing information about components of OCI for an entity’s NCI.

**Significant Items Reclassified Out of AOCI**

ASU 2013-02 requires entities to provide information (i.e., amount and income statement line item affected) about significant items reclassified out of AOCI by component. Entities whose significant reclassification adjustments are reclassified in their entirety to the income statement in a reporting period (e.g., the effective portion of a gain or loss on a gas futures contract designated as a cash flow hedge, once the hedged forecasted sales transaction affects income) have the option of presenting such information either (1) on the income statement or (2) in a separate footnote to the financial statements. However, if one or more significant reclassification adjustments are partially reclassified from AOCI to both the
income statement and the balance sheet (e.g., amortization of defined benefit pension and other employee benefit cost components), an entity must separately disclose such information in its footnotes.

An entity that elects to present information in its income statement would include the reclassification before-tax amount in parentheses for the line item affected. The aggregate tax amount attributed to the significant reclassification adjustments included on the face of the income statement would be presented parenthetically on the income tax expense (benefit) line.

If an entity elects or is required to present the information in its footnotes, the total of the reclassification adjustments by component must be the same as the total by component presented in the changes in AOCI by component disclosure. Either before-tax or net-of-tax presentation is acceptable. However, for significant partial reclassifications, an entity would refer to the footnote disclosure that contains information about the impact of the reclassifications. The ASU does not amend the guidance on determining which components of AOCI are reclassified partially and which are reclassified entirely.

ASC 220-10-45-17 does not address the presentation of information about significant amounts reclassified from an entity’s NCI balance sheet line item to the income statement. However, an entity may elect to disclose information about the income statement effects of significant reclassification adjustments that include an NCI portion. Doing so would be consistent with presenting consolidated net income (i.e., an entity view) and attributing an amount to NCI in accordance with ASC 810-10. If an entity presents income statement effects that include an NCI amount, it may disclose the (1) aggregate NCI amount related to all the significant reclassification adjustments or (2) NCI amount affecting each income statement line item. Regardless of how NCI is presented in this disclosure (i.e., the income statement effects of significant reclassification adjustments), if at all, the subtotal of amounts reclassified by component for this disclosure must be consistent with the reclassification adjustments presented in the changes in AOCI balances by component. Therefore, a reconciliation showing the amounts attributable to NCI may be necessary.

**Interim-Period Reporting**

In their interim financial statements, public entities are required to present information about both (1) changes in AOCI balance by component and (2) significant items reclassified out of AOCI. The ASU amended the guidance in ASC 270-10-50-1, which requires public entities that report summarized financial data in interim reporting periods to present this information for both the current quarter and the current year-to-date periods. Therefore, under the ASU, the two disclosures above should be presented for both quarter-to-date and year-to-date periods.

Nonpublic entities are only required to disclose the disaggregated changes in AOCI balances by component in their interim financial statements (i.e., they are not required to disclose the income statement lines affected by reclassification adjustments).

**Effective Date and Transition**

For public entities, the ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. Nonpublic entities have a one-year deferral (i.e., for nonpublic entities, the ASU is effective for fiscal years beginning after December 15, 2013, and interim and annual periods thereafter). Early adoption is permitted. The amendments in the ASU should be applied prospectively.
Liquidation Basis of Accounting

Overview

On April 22, 2013, the FASB issued ASU 2013-07, which is intended to increase the consistency and comparability of financial statements prepared under the liquidation basis of accounting. Before the ASU’s issuance, there was limited guidance on this topic under U.S. GAAP. The ASU applies to both public and nonpublic entities; however, investment companies regulated under the Investment Company Act of 1940 are excluded from its scope.

The ASU requires an entity to use the liquidation basis of accounting to present its financial statements when it determines that liquidation is imminent, unless the entity’s liquidation plan is the same as the plan specified in an entity’s governing documents created at its inception. According to the ASU, liquidation would be considered imminent in either of the following situations:

a. A plan for liquidation has been approved by the person or persons with the authority to make such a plan effective, and the likelihood is remote that any of the following will occur:
   1. Execution of the plan will be blocked by other parties (for example, those with shareholder rights)
   2. The entity will return from liquidation.

b. A plan for liquidation is imposed by other forces (for example, involuntary bankruptcy), and the likelihood is remote that the entity will return from liquidation.

An entity’s liquidation plan differs from the plan specified in its governing documents if the entity must dispose of its assets for a value other than fair value.

When applying the liquidation basis of accounting, an entity would initially measure its assets to reflect the amount it expects to receive in cash or other consideration. In certain circumstances, if the expected consideration to be collected approximates the fair value of an asset, the entity may measure the asset at fair value. Under the liquidation basis of accounting, the entity would be required to recognize and measure previously unrecognized assets that it intends to sell during the liquidation (e.g., trademarks). The entity would present — separately from the measurement of the assets or other items anticipated to be sold in liquidation — the expected aggregate liquidation and disposal costs to be incurred during the liquidation process. To measure liabilities (excluding accruals recorded in liquidation for disposal costs and ongoing expenses), the entity would use other applicable U.S. GAAP adjusted for changes in assumptions resulting from its decision to liquidate (e.g., a change in the timing of payments); however, the entity’s liabilities should not be reduced on the basis of the assumption that the entity will be legally released from its obligation. In addition, the entity would estimate and accrue the expected future costs and income to be incurred or realized during the course of liquidation, such as payroll expense or “income from preexisting orders that the entity expects to fulfill during liquidation,” if and when the entity has a reasonable basis for estimating these amounts. The entity would remeasure all balances as of each subsequent reporting period.

Presentation and Disclosures

Under the ASU, an entity must present, at a minimum, (1) a statement of net assets in liquidation and (2) a statement of changes in net assets in liquidation. In addition to presenting disclosures required under U.S. GAAP that are relevant to a user’s understanding of the liquidation basis financial statements, an entity is also required to disclose certain other information related to the liquidation as specified in ASC 205-30-50-2.

Effective Date and Transition

The ASU applies to entities that determine that liquidation is imminent during annual reporting periods beginning after December 15, 2013, and interim reporting periods therein. Early adoption is permitted. The ASU’s guidance is to be applied prospectively from the date liquidation is imminent. If an entity is reporting on the liquidation basis of accounting as of the
Emerging Issues Task Force

Proposal on Accounting for Investments in Qualified Affordable Housing Projects

Background

In April 2013, the FASB issued a proposed ASU based on EITF Issue 13-B that would make it easier for investments in affordable housing projects to qualify for the effective yield method under ASC 323-740. Currently, if certain criteria are met, an entity may elect under ASC 323-740 to (1) amortize the original cost of an investment in a manner that creates a constant yield and (2) present this amortization net with related tax credits and other tax benefits in the provision for income taxes in the income statement. At its September 2013 meeting, the EITF made tentative decisions that would (1) simplify the amortization method an entity uses and (2) further modify the criteria that must be met before an entity can elect to use this simplified amortization and presentation alternative for investment in affordable housing projects. The EITF also discussed whether it should further expand the types of tax credit investments that would qualify for the same favorable income statement presentation, ultimately deciding to defer that decision and to request that the staff perform additional work to determine whether there could be unforeseen consequences resulting from such an expansion in scope.

Currently, ASC 323-740 permits entities to elect to use the effective yield method to account for certain investments in affordable housing projects. Under this method, an entity (1) recognizes related tax credits as received, (2) amortizes the original cost of the investments in a manner that results in a constant effective yield over the period during which credits are received, and (3) presents both the credits and amortization net within the entity’s provision for income taxes. These limited-partnership investments are otherwise accounted for under the cost or equity method. For an entity to apply the effective yield method under the current guidance in ASC 323-740, the investment must be an equity investment in a limited partnership that passes low-income housing tax credits (LIHTC) through to investors and for which (1) the availability of such credits is guaranteed by a creditworthy party, (2) the investor’s projected yield is positive solely on the basis of the benefits or “cash flows” from the tax credits, and (3) the investor is a limited partner for both legal and tax purposes with liability limited to its capital investment. Entities must elect to apply the effective yield method to qualifying investments.

While the market size and volume for these investments have increased in recent years, fewer LIHTC investments are qualifying for the effective yield method because, some believe, the conditions are too restrictive. It is rare, for example, for investors in LIHTC projects to obtain a third-party guarantee that the related tax credits will be available, which is one of the conditions for applying the effective yield method. Further, it is not always the case that the cash flows from tax credits alone result in positive yield, which is another condition. Sometimes, a combination of both tax credits and other tax benefits is needed to achieve positive yield.

The FASB added this Issue to the EITF’s agenda not only to address these concerns but also to consider whether the guidance in ASC 323-740 should instead be eliminated, since some believe that the net presentation of investment amortization with the related tax credits in the provision for income taxes makes it difficult to analyze the investment’s performance.

Key Provisions

Under the EITF’s final consensus related to LIHTC, entities are permitted to make an accounting policy election to apply a proportionate amortization method to LIHTC investments if the following conditions are met:6

6 Quoted from the EITF’s September 13, 2013, meeting minutes.

• “It is probable that the tax credits allocable to the investor will be available.”
• “The investor does not have the ability to exercise significant influence over the operating and financial policies of the limited liability entity, and substantially all of the projected benefits are from tax credits and other tax benefits.”

• “The investor’s projected yield based solely on the cash flows from the tax credits and other tax benefits is positive.”

• “The investor is a limited liability investor in the [limited liability entity] for both legal and tax purposes, and the investor’s liability is limited to its capital investment.”

In addition, other transactions between the investor and the limited liability entity would not preclude an investor from accounting for LIHTC investments by using the proportionate amortization method provided that all of the following conditions are met:

7 (a) [The reporting entity is in the business of entering into those [other] transactions
(b) [Those transactions are consistent with an arm’s-length transaction at market terms]
(c) [The reporting entity does not acquire] the ability to exercise significant influence over the operating and financial policies of the limited liability entity.

Finally, the EITF reached a final consensus that:

• Does not prescribe where an entity would present investments accounted for under the proportionate amortization method in its statement of financial position.

• Requires an entity to evaluate its eligibility to use the guidance in this Issue "(a) based on facts and conditions that exist at the time of the initial investment or (b) upon a change in the nature of the investment or in the relationship with the limited liability entity that could result in the reporting entity no longer meeting the conditions to be able to use the guidance in the [Issue]."

• Requires an entity to test LIHTC investments accounted for under the proportionate amortization method for impairment when it is more likely than not that the investment will not be realized through the realization of tax credits and other tax benefits, and to measure an impairment loss as the amount by which the carrying amount of an investment exceeds its fair value.

• Requires an entity to disclose information that “enable[s] users of financial statements to understand the nature of the investments in qualified affordable housing tax projects, the financial statement effect of those investments, and the related tax credits.”

Effective Date and Transition

For public entities, the guidance would be effective for fiscal years beginning after December 15, 2014, and interim periods therein. For nonpublic entities, the guidance would be effective for annual periods beginning after December 15, 2014, and interim and annual periods thereafter. Early adoption is permitted. Entities that applied the effective yield

7 See footnote 6.
8 During its September 2013 meeting, the EITF tentatively decided that LIHTC investments would be combined with other DTAs; however, after FASB staff research and outreach revealed that these investments do not have all the characteristics of DTAs and that such classification could have negative consequences for entities that must meet regulatory capital requirements, the Task Force decided not to require entities to classify tax credit investments accounted for under the proportionate amortization method as DTAs.
method to account for LIHTC investments would be permitted to continue to do so, but only for investments already accounted for under the effective yield method. Otherwise, an entity would be required to apply the guidance retrospectively to all periods presented.

Next Steps

The FASB ratified the final consensus at its December 11, 2013, meeting and is expected to issue a final ASU in January 2014. The scope of the FASB’s ratification of this final consensus will be limited to LIHTC investments. However, the FASB directed the staff to perform preagenda decision research on the applicability of EITF Issue 13-B to other types of tax credit investments, not just investments in qualified affordable housing projects. The results of that research will be presented to the Board at a later date. On the basis of those results, the Board will decide whether to address this issue and, if so, whether to add it to the FASB’s or the EITF’s agenda.

Proposal on Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward or Tax Credit Carryforward Exists

Background and Key Provisions

In July 2013, the FASB issued ASU 2013-11, which is based on EITF Issue 13-C and requires entities to present an unrecognized tax benefit (UTB), or a portion of a UTB, in the financial statements as a reduction to a deferred tax asset (DTA) (i.e., net) for an NOL carryforward, a similar tax loss, or a tax credit carryforward except when:

- An NOL carryforward, a similar tax loss, or a tax credit carryforward is not available as of the reporting date under the governing tax law to settle taxes that would result from the disallowance of the tax position.
- The entity does not intend to use the DTA for this purpose (provided that the tax law permits a choice).

If either of these conditions exists, entities should present a UTB in the financial statements as a liability and should not net the UTB with a DTA.

Additional recurring disclosures are not required because the ASU does not affect the recognition or measurement of uncertain tax positions under ASC 740.

See Deloitte’s July 22, 2013, Heads Up and Section 9 for more information about the ASU.

Effective Date and Transition

The ASU’s amendments are effective for public entities for fiscal years beginning after December 15, 2013, and interim periods within those years. Nonpublic entities may wait until fiscal years, and interim periods within those years, beginning after December 15, 2014, to adopt the amendments. Early adoption is permitted for all entities. The amendments should be applied to all UTBs that exist as of the effective date; however, entities may also choose to apply the amendments retrospectively.
Other Accounting Projects

**Discontinued Operations**

On April 2, 2013, the FASB issued a proposed ASU that would substantially converge the definition of a discontinued operation under ASC 205-20 with that under IFRS 5.

The proposal would also expand the disclosure requirements for disposals, including disclosures about individually material components that do not qualify as discontinued operations. In addition to promoting convergence, the proposed guidance is intended to address concerns that (1) “too many disposals of assets qualify for discontinued operations presentation under the current definition, resulting in financial statements that are not decision useful” and (2) the “continuing involvement criterion is difficult to apply and does not result in consistent application.”

The FASB met in November 2013 to discuss comments on the proposal, which were due in August 2013. The Board made tentative decisions about various aspects of the proposal.

**Definition of a Discontinued Operation**

The Board tentatively decided to modify the definition of a discontinued operation to specify that a component or a group of components of an entity should be reported as a discontinued operation if the following criteria, as outlined in the meeting’s Summary of Board Decisions, are met:

1. The component or group of components has been disposed of, or is classified as held for sale, together as a group in a single transaction
2. The disposal of the component or group of components represents a strategic shift that has (or will have) a major effect on an entity’s financial results. A strategic shift includes a disposal of:
   a. A separate major line of business,
   b. A separate major geographical area of operations, or
   c. A combination of parts of (a) or (b) that make up a major part of an entity’s operations and financial results.

Further, the Board “decided that an acquired business that is classified as held for sale on the date of acquisition also should be reported as a discontinued operation.”

The Board also tentatively decided to (1) remove language about a single coordinated plan from the definition of a discontinued operation because it was confusing and (2) add examples to clarify what may constitute a major line of business or major geographical area of operations.

Under current guidance, a sale of property often qualifies for treatment as a discontinued operation because the property frequently qualifies as a component of an entity. Under the proposed ASU, however, such sales are not likely to qualify for discontinued operations treatment unless they represent a plan to dispose of a major line of business, a separate major geographical area of operations, or a combination of the two and have a major financial effect on the entity. Accordingly, fewer sales are expected to qualify as a discontinued operation under the proposal. However, even if a sale does not qualify, the proposal requires entities to provide certain disclosures if the disposal is deemed “individually material.”

**Presentation**

The Board tentatively decided to require entities to reclassify assets and liabilities as discontinued operations for all periods presented in their financial statements.
Disclosures

The proposed guidance requires entities to disclose additional information about discontinued operations. In addition, the Board believes that fewer disposals of components of an entity would be reported as discontinued operations under the proposed guidance and that financial statement users therefore would have less information about such disposals. As a result, the proposal expands the disclosure requirements for individually material components that do not meet the proposed definition of a discontinued operation. See the appendix of Deloitte’s April 3, 2013, Heads Up for a discussion of these additional disclosures grouped by entity type (i.e., public and nonpublic).

At its November 6, 2013, meeting, the Board tentatively decided to keep many of the proposed ASU’s disclosure requirements; however, it decided to (1) modify the requirements related to equity method investments and nonpublic entities, (2) eliminate the requirements related to the balance sheet and statement of operations reconciliation for amounts by major class for individually material disposals and disclosure of financing cash flows, and (3) remain silent on how to disclose multiple disposals (material and immaterial) in the aggregate.

As indicated in the November 13 Summary of Board Decisions, the Board decided that for “an equity method investment that meets the definition of a discontinued operation, an entity should disclose summarized information about assets, liabilities, and results of operations of the investee if that information was disclosed in financial reporting periods prior to the disposal.” In addition, the final standard will include additional examples to clarify how to apply the guidance to disposals of equity method investments or wholly owned subsidiaries when an entity retains an equity method investment.

Continuing Involvement

Although the FASB removed the current continuing-involvement criterion from the proposed definition of a discontinued operation, disclosure about such status would still be required. The proposal’s examples of continuing involvement include (1) a supply and distribution agreement, (2) a financial guarantee, (3) an option to repurchase a discontinued operation, and (4) an equity method investment.

Scope

The proposed guidance applies to all recognized noncurrent assets and to all disposal groups of an entity. The proposal would remove the current scope exceptions for certain assets, such as goodwill and equity method investments. The FASB notes that removing these scope exceptions would (1) improve convergence of U.S. GAAP and IFRSs and (2) result in the use of the proposed definition to evaluate all disposals to determine whether they would qualify for presentation as discontinued operations.

Other than for entities that dispose of certain equity method investments, whose disposals could now qualify as discontinued operations, the FASB expects the effect of such scope changes to be limited.

Transition and Effective Date

The Board tentatively decided that entities would apply the new guidance prospectively. Public companies would apply it to annual periods beginning on or after December 15, 2014, and interim periods therein. Nonpublic entities would apply it to annual periods ending on or after December 15, 2015, and interim periods thereafter.

Next Steps

The Board directed the staff to draft a final standard for vote by written ballot.
**Going Concern**

On June 26, 2013, the FASB issued a proposed ASU that would provide guidance on determining when and how to disclose going-concern uncertainties in the financial statements. Under the proposal, management would be required to perform interim and annual assessments of an entity’s ability to continue as a going concern within 24 months of the financial statement date. An entity would have to disclose uncertainties about such an ability if (1) it is “more likely than not” (MLTN) — that is, a likelihood of more than 50 percent — that it will not be able to meet its obligations within 12 months of the financial statement date or (2) it is “known or probable that the entity will be unable to meet its obligations within 24 months after the financial statement date.” Although the proposed ASU applies to all entities, a public entity would also have to assess whether there is “substantial doubt” about its ability to continue as a going concern and, if so, would need to provide specific disclosures. Comments on the proposed ASU were due by September 24, 2013.

**Background**

Under U.S. GAAP, an entity’s financial reports reflect its assumption that it will continue as a going concern until liquidation is imminent. However, before liquidation is deemed imminent, an entity may have uncertainties about its ability to continue as a going concern. Because there are no specific U.S. GAAP requirements related to disclosing such uncertainties, auditors are responsible for assessing the nature, timing, and extent of an entity’s disclosures on the basis of applicable auditing standards. Such application has resulted in diversity in practice, which the proposal aims to alleviate.

The proposed ASU extends the responsibility for performing the going-concern assessment from auditors (as required under current auditing standards) to management and contains guidance on how to perform a going-concern assessment and when going-concern disclosures would be required under U.S. GAAP.

**Key Provisions of the Proposed ASU**

**Disclosure Thresholds**

As noted above, an entity would be required to disclose information about its potential inability to continue as a going concern when either:

- **a.** It is **more likely than not** that the entity will be unable to meet its obligations within **12 months** after the financial statement date. . . . [or]
- **b.** It is **known or probable** that the entity will be unable to meet its obligations within **24 months** after the financial statement date. [Emphasis added]

In applying the disclosure threshold outlined in (a) and (b) above, entities would be required to evaluate all conditions and events (including positive and mitigating conditions) except for management’s plans that are outside the ordinary course of business. In addition, the proposed ASU indicates that the MLTN threshold is not intended to be a “formula-based likelihood calculation”; rather, it is a “benchmark” in the determination of whether disclosures are required. The proposal provides examples of events that suggest that an entity may be unable to meet its obligations.

Under current auditing standards, an auditor is required to evaluate the adequacy of going-concern disclosures after concluding that there is substantial doubt about the entity’s ability to continue as a going concern for a reasonable period of time. Accordingly, the MLTN threshold may result in an entity’s having to disclose uncertainties about its ability to continue as a going concern earlier than is required under current practice.

---

9 In accordance with ASC 205-30, once liquidation is deemed imminent, an entity must apply the liquidation basis of accounting.
10 PCAOB AU Section 341A.
11 PCAOB AU Section 341A.02.
12 The proposal defines actions that are “outside the ordinary course of business” as those “of a nature, magnitude, or frequency that are inconsistent with actions customary in carrying out an entity’s ongoing business activities.” The proposal also provides examples of management’s plans that are outside the ordinary course of business.
In addition, a public entity would be required to evaluate whether there is substantial doubt about its ability to continue as a going concern. Unlike the disclosure threshold outlined above, the substantial-doubt assessment takes into account management’s plans outside the ordinary course of business. Nonpublic entities would not be required to perform the substantial-doubt assessment.

**Time Horizon**

In each reporting period (including interim periods), an entity would be required to assess its ability to meet its obligations as they become due for up to 24 months after the financial statement date. For the 12 months after the financial statement date, the entity would assess whether it is MLTN that it would not be able to meet its obligations. For the period beyond 12 months, the entity would consider only information about events or conditions whose impact on the entity’s going-concern presumption is “known or probable.”

The proposal’s assessment period is longer than that in current auditing literature, which requires auditors to “evaluate whether there is substantial doubt about an entity’s ability to continue as a going concern for a reasonable period of time, . . . not to exceed one year beyond the date of the financial statements being audited” (emphasis added).

**Disclosure Content**

If an entity triggers the MLTN threshold, it would be required to provide footnote disclosures similar to those required by current auditing literature. The proposal indicates that these disclosures would describe the following:

a. Principal conditions and events that give rise to the entity’s potential inability to meet its obligations
b. The possible effects those conditions and events could have on the entity
c. Management’s evaluation of the significance of those conditions and events [and any mitigating factors]
d. Mitigating conditions and events
e. Management’s plans that are intended to address the entity’s potential inability to meet its obligations.

The proposal explains that these disclosures may change over time as new information becomes available.

In addition, if a public entity determines that there is substantial doubt about its ability to continue as a going concern within 24 months after the financial statement date, the entity would be required to disclose that it has such doubt by using specific wording described in the proposal.

**Effective Date and Transition**

The guidance in the proposal would be applied prospectively for reporting periods after the final standard’s effective date, which has not yet been established.

---

13 According to the proposal, substantial doubt “exists when information about existing conditions and events . . . indicates that it is known or probable that an entity will be unable to meet its obligations as they become due within 24 months after the financial statement date.”

14 PCAOB AU Section 341A.02.

15 PCAOB AU Section 341A.10.

16 Under the proposal, if an SEC filer “determines that there is substantial doubt about its going concern presumption, the entity shall disclose that determination in its financial statements through the use of the phrase there is substantial doubt about the entity’s ability to continue as a going concern within 24 months after the financial statement date or similar wording that includes the terms substantial doubt, and ability to continue as a going concern or ability to prepare financial statements under the going concern presumption.”
Private-Company Standard Setting

The Private Company Council (PCC), which was formed in late 2012, works jointly with the FASB to improve the accounting standard-setting process for private companies.

Private-Company Decision-Making Framework

The PCC and FASB have worked together to develop a private-company decision-making framework (PCDMF) for identifying and evaluating U.S. GAAP alternatives (i.e., exceptions or modifications) for private companies. On April 15, 2013, the FASB and PCC jointly issued an invitation to comment on an updated version of the PCDMF that was initially proposed in a discussion paper issued by the FASB staff in July 2012. Like the initial framework, the draft PCDMF identified the following five areas in which alternatives for private companies might be considered: (1) recognition and measurement, (2) disclosures, (3) presentation, (4) effective date, and (5) transition. For more information, see Deloitte’s April 25, 2013, Heads Up. The FASB’s and PCC’s consideration of comments received on the draft PCDMF resulted in only minor revisions and, on December 23, 2013, the FASB and PCC jointly issued a final PCDMF.

Definition of a Public Business Entity

The PCC and FASB have also considered the specific types of entities that would be eligible to adopt accounting alternatives developed under the PCDMF. In connection with establishing the scope of the PCDMF, the FASB issued for comment a proposed ASU that would (1) amend the Codification Master Glossary to add and define the term “public business entity” (PBE) under U.S. GAAP and (2) clarify what other types of entities, in addition to PBEs, would be outside the scope of the PCDMF once it is finalized. Defining a PBE is central to establishing which entities will be eligible to elect the accounting alternatives being developed by the PCC. On the basis of the definition originally proposed, an entity would be deemed a PBE if it met any one of five specific criteria, such as filing financial statements with the SEC. For more information, see Deloitte’s August 19, 2013, Heads Up.

During redeliberations, the FASB discussed feedback received and agreed to make certain clarifying changes to the criteria proposed. On December 23, 2013, the FASB issued ASU 2013-12, which defines a PBE. For more information, see Deloitte’s December 24, 2013, journal entry.

Proposed Alternatives for Private Companies

After the creation of the PCDMF, the PCC developed — and the FASB endorsed and issued for public comment — four proposed ASUs that contain U.S. GAAP alternatives for private companies:

- **Goodwill** — This proposal outlines an alternative method of accounting for goodwill that would (1) permit an entity to amortize goodwill, (2) require a test for impairment only upon the occurrence of a triggering event, and (3) simplify the way the impairment test is performed. During redeliberations, the PCC voted to retain the proposed amortization requirements and permit goodwill to be amortized over a period of 10 years but specified that a shorter period could be used if this period was appropriate under the circumstances. In addition, the PCC voted to revise the level at which goodwill is tested and give entities the option to test it at either the entity level or the reporting unit level. The PCC reaffirmed the proposal’s effective date (i.e., 2015 for calendar-year companies, with early adoption permitted) and transition (i.e., prospectively applied to existing and future goodwill balances). The FASB endorsed the final proposal at its November 25 meeting and is expected to issue a final ASU in the first quarter of 2014.

- **Interest rate swaps** — This proposal provides two alternative methods of accounting for certain interest rate swaps: the simplified hedge accounting approach and the combined instruments approach. During redeliberations, the PCC voted to approve the simplified hedge accounting approach with minor scope adjustments and clarifications and agreed on certain transition and implementation guidance. The PCC also decided to eliminate the combined-instruments approach from the current proposal and consider it separately after the FASB staff
performs additional research. The PCC reaffirmed the proposal’s effective date (i.e., 2015 for calendar-year companies, with early adoption permitted) and transition requirements (i.e., modified retrospective or full retrospective). The FASB endorsed the final proposal at its November 25 meeting and is expected to issue a final ASU in the first quarter of 2014.

- **Identifiable intangible assets acquired in a business combination** — This proposal would permit an entity to recognize fewer intangibles in a business combination and would simplify the measurement of some intangibles that continue to be recognized. The PCC received input from constituents that this proposal would not result in substantial reductions in cost or complexity for financial statement preparers. Further, the PCC discussed whether recognizing any intangible assets separately from goodwill gives users of private-company financial statements decision-useful information. As a result, the PCC directed the FASB staff to research alternatives that would subsume most, if not all, intangible assets into goodwill and to consider what enhanced disclosures would be warranted in such case. The PCC is expected to discuss the alternatives related to this proposal at its January 2014 meeting.

- **Consolidation of variable interest entities** — This proposal would give an entity the option of not applying the VIE consolidation guidance to certain interests in lessor entities that are under common control. The PCC recently redeliberated this proposal and made minor amendments as well as voted on an effective date (i.e., 2015 for calendar-year companies, with early adoption permitted) and transition requirements (i.e., full retrospective). However, the PCC is expected to continue deliberating concerns raised regarding the scope of this proposal at its January 2014 meeting before requesting final endorsement from the FASB.

For more information, see Deloitte’s July 9, 2013, and August 27, 2013, Heads Up newsletters. Final ASUs on accounting alternatives for goodwill and interest-rate swaps are expected to be issued in early January 2014. It is expected that an entity could early adopt these alternatives, when issued, in any interim and annual period for which financial statements are not yet issued.
Section 8
FERC Enforcement Activities
In November 2013, FERC’s (the “Commission’s”) Office of Enforcement (“FERC Enforcement”) issued its 2013 Report on Enforcement (the “2013 Report”). According to the 2013 Report, FERC seeks to balance its (1) obligation to keep nonpublic investigation matters confidential and (2) efforts to inform the public of the activities of FERC Enforcement staff. The 2013 Report provides information about FERC Enforcement activities, including its auditing and monitoring of data reported by companies under its jurisdiction and its surveillance and analysis of individual conduct in wholesale natural gas and electricity markets. The report notes that in fiscal year 2014, FERC Enforcement will continue to focus on its previously established priorities:

- “Fraud and market manipulation.”
- “Serious violations of the [r]eliability [s]tandards.”
- “Anticompetitive conduct.”
- “Conduct that threatens the transparency of regulated markets.”

FERC Enforcement developed these priorities to further the two primary goals of FERC’s strategic plan:

- To ensure that “rates, terms, and conditions of jurisdictional services are just, reasonable, and not unduly discriminatory or preferential.”
- To promote “the development of a safe, reliable, and efficient energy infrastructure that serves the public interest.”

The report further notes that in fiscal year 2013, FERC Enforcement “opened 24 new investigations while bringing 29 to closure with no action, a settlement, or a formal enforcement proceeding.”

**Highlights**

In fiscal year 2013, FERC resolved an investigation that resulted in its largest settlement to date for violations of the Commission’s anti-manipulation rule and its rule barring the provision of inaccurate and misleading information to regional transmission organizations and independent system operators (RTOs/ISOs). The settlement included a $435 million civil penalty, $34 million in disgorgement of profits against the trading entity, and an additional $18 million against individual traders involved in the manipulation.

FERC approved 19 separate settlement agreements resolving pending investigations or pending proceedings on orders to show cause. These settlements resulted in payments of more than $304 million in civil penalties and disgorgement of over $141 million plus interest. Three of the settlements were for open-access transmission tariff violations, three were for violations of the reliability standards, four were for violations of natural gas open-access transportation rules, two were for violations of regulations related to market-based rate authority, one was for violations of hydropower license provisions, and six were for violations of the Commission’s regulations prohibiting manipulation in natural gas and electric markets.

Note that, in prior years, FERC Enforcement facilitated the Commission’s review of notices of penalty filed by NERC, which reflect the activity by the eight Regional Entities (REs) enforcing the reliability standards. In March 2013, FERC’s Office of Electric Reliability (OER) took full leadership of the Commission’s internal process of review, and FERC Enforcement remains involved in reviewing notices of penalty but only on an as-needed basis.

In fiscal year 2013, the number of self-reports continued to decrease: 75 new self-reports were filed, compared with 89 in fiscal year 2012 and 107 in fiscal year 2011. FERC Enforcement closed 94 pending self-reports, many from fiscal year 2012 and fiscal year 2011, but still has 42 pending reports from fiscal year 2013. In fiscal year 2013, RTO/ISO violations accounted for a significant portion of self-reports. While the number of self-reports has decreased, FERC Enforcement noted that it “continues to encourage the submission” of self-reports and that it views these reports “as evidence of a company’s commitment to compliance.”
FERC Enforcement was involved in the proposed, and now final, rule on the coordination between natural gas and electricity markets. This rule allows for the sharing of nonpublic information on the basis of reliability but with stipulations on the access and use of this information. The Commission has stated that this type of information sharing is necessary to enhance reliability but emphasized that there is a risk of market manipulation if certain safeguards are not implemented to prevent the misuse of the information.

Activities by Enforcement Division

FERC Enforcement has four divisions: Investigations, Audit, Market Oversight, and Analytics and Surveillance. Each division’s recent activities are discussed below.

Investigations

FERC’s Division of Investigations (DOI) directed the Commission’s secretary to issue 12 notices of alleged violations and opened a total of 24 investigations. Of the 24 investigations opened, eleven involve market manipulation or false statements to the Commission or an RTO/ISO, four involve tariff violations, eight involve violations of reliability standards, one involves standards of conduct, and one involves natural gas open-access transportation rules.

In July 2013, the Commission approved a bidding-practices settlement between FERC Enforcement and a company. The investigation, which arose from referrals by the Market Monitoring Units of the California Independent System Operator Corporation and the Midcontinent (formerly Midwest) Independent System Operator Inc., focused on bidding strategies over almost two years and found that the company violated the Commission’s anti-manipulation rule when it engaged in 12 manipulative bidding schemes in CAISO and MISO. The settlement resulted in $285 million in civil penalties, $124 million in disgorgement to CAISO ratepayers, and $1 million in disgorgement to MISO.

Further, in July 2013, FERC Enforcement reached a settlement resulting from an October 2012 order to show cause and notice of penalty issued by the Commission. As indicated in the 2013 Report, the order alleged that the company “engaged in loss-generating trading of next-day, fixed-price physical electricity on the Intercontinental Exchange with the intent to benefit financial swap positions at primary electricity trading points in the western United States.” The resulting $435 million civil penalty assessed is the largest ever assessed by the Commission to date; the Commission also assessed $18 million against traders.

In August 2013, the Commission issued an order to show cause that alleged violations of the Commission’s anti-manipulation rule in connection with “trading . . . of next-day, fixed-price natural gas at the Houston Ship Channel.” FERC Enforcement found the practices “uneconomic and part of a manipulative scheme to increase the value of . . . financial position based on Houston Ship Channel natural gas prices.” A $28 million civil penalty, as well as disgorgement of $800,000 in profits, is proposed by the order.

In addition, FERC Enforcement reached, and the Commission approved, several settlement agreements with regulated entities. The fiscal year 2013 settlements encompassed a wider range of violation types than in the previous year. In addition to market manipulation and natural gas transportation, which were the primary focus of the fiscal year 2012 settlements, fiscal year 2013-settled violations included market-based rate violations and violations of reliability standards.
FERC Enforcement received self-reports from various market participants, including power marketers, electric utilities, natural gas companies, and RTOs/ISOs. FERC Enforcement’s penalty guidelines continue to stress how important it is to self-report and offers credits that significantly mitigate penalties when such reports are made. In fiscal year 2013, RTO/ISO violations accounted for a significant portion of self-reports received.

Audits

In fiscal year 2013, the Division of Audits and Accounting (DAA) within FERC Enforcement:

- Completed 29 audits of public utilities, natural gas pipelines, and storage companies (financial and nonfinancial).

- Completed reliability oversight audits of the Electric Reliability Organization (ERO) and REs and conducted compliance audits of registered entities with staff from the OER’s Division of Compliance and Division of Reliability Standards and Security.

The ERO and RE audits “included budgeting formulation, administration, and execution, and resources used to achieve program results” and resulted in 98 recommendations.

The audits of registered entities were selected on the basis of risk-based criteria related to their strategic location, relative size, and the scope of reliability responsibilities for which they were registered. These audits resulted in 56 recommendations.

The 2013 report includes the following additional information about the DAA’s activity:

In FY2013, [the] DAA reviewed 225 Commission filings. These filings included requests for accounting approval, certificate authorizations, mergers and acquisitions, security and debt applications, and rate filings. Also, DAA provided informal guidance on 73 inquiries related to various aspects of Commission accounting, financial reporting, and record retention regulations. These inquiries were received from jurisdictional entities, industry stakeholders, and consultants, as well as questions arising through the Commission’s Compliance Help Desk, Office of External Affairs, Enforcement Hotline, and other offices within the Commission.

Audit Findings

Below are some of the areas in which the DAA has identified consistent patterns of noncompliance over the past several years (quotes are from the 2013 Report):

"Formula Rate Matters. DAA rigorously examines the accounting that populates formula rate recovery mechanisms that are used in determining billings to wholesale customers. In recent formula rate audits, DAA observed certain patterns of noncompliance in the following areas:

- Merger Goodwill — including goodwill in the equity component of the capital structure absent Commission approval;

- Depreciation Rates — using state-approved, rather than Commission-approved, depreciation rates;

- Merger Costs — including merger consummation costs (e.g., internal labor and other general and administrative costs) without Commission approval;

- Tax Prepayments — incorrectly recording tax overpayments which are not applied to a future tax year’s obligation as a prepayment leading to excess recoveries through working capital;

- Asset Retirement Obligation (ARO) — including ARO amounts in formula rates, without explicit Commission approval;
• Below-the-Line Costs — attempting to move below-the-line costs into formula rates (e.g., lobbying, charitable contributions, fines and penalties, and compromise settlements arising from discriminatory employment practices); and

• Improper Capitalization — seeking to include in rate base (and earn a return on) costs that should be expensed.”

**Example Findings**

[The Company] incorrectly recorded $X in payments resulting from compromise settlements in above-the-line accounts, rather than below-the-line, as required.

[The Company] incorrectly recorded $X in charitable contributions and lobbying costs in above-the-line accounts, rather than below-the-line, as required.

“Transmission Incentive. Commission orders granting incentives to specific transmission projects requires increased rigor in the proper accounting of costs to ensure that such incentives are only applied for projects approved. DAA noted instances in which cost allocation mechanisms improperly assigned costs to incentive projects, thereby permitting a greater return than warranted. Additionally, in some audits, the controls over directly assigning costs to specific work orders for approved transmission projects were inadequate, resulting in certain costs being improperly assigned to incentive transmission projects.”

**Example Finding**

[The Company] improperly allocated construction overhead costs to transmission incentive projects recorded in Account 107, Construction Work in Progress — Electric, that were not applicable to such projects. As a result of this misallocation, [the Company] overbilled its wholesale transmission customers $X million for the excessive return it collected on construction overheads improperly allocated to transmission incentive projects.

“Regulatory Assets. DAA noted instances in which regulatory assets reported in financial statements are not supported by a probable rate action of a regulator to permit recovery of a previously incurred cost in future rates. DAA is concerned that jurisdictional entities are neither making a proper initial assessment of the probability for recovering costs deferred as a regulatory asset nor making periodic reassessments to ensure existing regulatory assets remain probable for future rate recovery.”

**Example Finding**

[The Company] provided insufficient justification for inclusion of its Environmental Costs Regulatory Asset in Account 182.3, Other Regulatory Assets, as the USofA requires.

In addition to the above, selected significant or recurring comments include:

**Centralized Service Company Reporting.** As stated on FERC’s Web site, “Form No. 60 is an annual regulatory support requirement under 18 CFR 369.1 for centralized service companies. The report is designed to collect financial information from centralized service companies subject to the jurisdiction of [FERC].” Audits have identified multiple cases in which companies did not properly complete the form in accordance with its general and schedule instructions. In some cases, companies were required to resubmit the form.
Example Findings

[The Company] did not report the amount of convenience payments made in 2010 on behalf of each associate company in its 2010 and 2011 FERC Form No. 60 filings. Also, [the Company] failed to make adequate disclosures in its notes to financial statements in its 2010 and 2011 FERC Form No. 60 filings.

[The Company] did not maintain its books using the Commission’s accounts, and could only convert from its own accounts to the Commission’s accounts on an annual basis, which posed challenges to audit staff’s analysis and testing. Also, [the Company’s] processes for reporting did not ensure all costs were included in the correct functional expense categories for FERC Form No. 60 purposes.

Transactions With Associated (Affiliated) Companies, FERC Form 1, Page 429. The instructions on page 429 required public utilities to disclose nonpower goods and services provided by, or received from, affiliated companies during the calendar year, including descriptions of these goods or services, affiliate names, accounts used to record the transactions, and amounts charged. In evaluating compliance with these instructions, audit staff identified several reporting errors.

Example Finding

[The Company] did not report complete and accurate information in its FERC Form No. 1 for transactions with affiliated companies for 2010 and 2011. Specifically, it improperly aggregated transactions above the reporting threshold amount and reported only one of three cost allocation methods used to determine transaction amounts. [The Company] also incorrectly reported the account charged or credited for transactions with affiliates.

Natural Gas Pipeline Activity Accounting. FERC identified improper accounting for activity on natural gas pipelines, including shipper imbalances and cash-outs, fuel tracker activity, line pack, and penalties. Findings often led companies to change their methods of recording the transactions to conform to the USofA.

Example Finding

During its review of [the Company] accounting, audit staff noted that the Company made no entries when an imbalance due to or from another party under an Operational Balancing Agreement (OBA) occurred on its system. Because [the Company] has OBAs at all points, the Company explained it assumed it did not need to make any entries to reflect the imbalance. In Order No. 581, the Commission revised Account 806, Exchange Gas, to include debits or credits for the cost of gas in unbalanced transactions, including those where gas is delivered to another party in exchange, load balancing, or no-notice transportation transactions. Imbalances managed through OBAs fall within this definition.

According to the USofA, companies must account for the value of gas in unbalanced transactions in Account 806, Exchange Gas, with contra entries to Account 174, Miscellaneous Current and Accrued Assets, or Account 242, Miscellaneous Current and Accrued Liabilities. Consequently, when imbalances occur on its system, [the Company] should record entries to Account 806 with contra entries to either Account 174 or Account 242.

Market Oversight

According to the 2013 report, the Division of Energy Market Oversight (Market Oversight) “administers, analyzes, and ensures compliance with” FERC’s filing requirements, reviewing submissions for:

- Nine annual report series.
- Seven quarterly report series, including the Electric Quarterly Report (EQR).
During fiscal year 2012, FERC proposed a new process for filing EQRs that would use either a Web-based interface or an XML format. On October 10, 2013, the Commission informed all public and nonpublic utilities that they should postpone filing EQRs for the third quarter of 2013 until the Web-based approach is available.

**Analytics and Surveillance**

In an effort to restore and enhance the analytic capability of its Enforcement office, FERC created the Division of Analytics and Surveillance (DAS) in February 2012. The DAS “develops surveillance tools, conducts surveillance, and analyzes” physical natural gas and electricity markets and transactions. To conduct surveillance of the natural gas and electric markets and to analyze the behavior of individual market participants, the Commission issued Order No. 771 and a Notice of Inquiry on Enhanced Natural Gas Market Transparency.

Regarding Order No. 771, the 2013 Report states:

> This final rule grants the Commission access, on a non-public and ongoing basis, to the complete electronic tags (e-Tags) used to schedule the transmission of electric power interchange transactions in wholesale markets. The rule requires e-Tag authors and Balancing Authorities to take appropriate steps to ensure Commission access to the e-Tags by designating the Commission as an addressee on the e-Tags. In addition, the rule requires that e-tag information be made available to RTOs/ISOs and their Market Monitoring Units, upon request to e-Tag Authors and Authority Services, subject to appropriate confidentiality restrictions.

Regarding the Notice of Inquiry on Enhanced Natural Gas Market Transparency, the 2013 Report states:

> In [this notice of inquiry], the Commission sought comments on what changes, if any, should be made to its regulations under the natural gas market transparency provisions of § 23 of the Natural Gas Act (NGA). [Footnote omitted] Specifically, the Commission is considering the extent to which quarterly reporting of every natural gas transaction within the Commission’s NGA jurisdiction that entails physical delivery for the next day (i.e., next day gas) or for the next month (i.e., next month gas) would provide useful information for improving natural gas market transparency. To that end, the Commission also sought comments in response to a series of specific questions related to: (1) which data elements should be reported and how; (2) possible public dissemination of any data reported; (3) the scope of such a reporting requirement; and (4) the burden of such reporting on market participants.

**Other Developments**

During fiscal year 2013, FERC continued to focus on market manipulation. FERC’s strategic plan linked deterring companies from market manipulation to its goal of monitoring efficient provision of energy services. Funding for FERC Enforcement has increased over the past two years, from $42.5 million in fiscal year 2012 to $42.6 million in fiscal year 2013. FERC Enforcement has requested a budget of $42.3 million for fiscal year 2014.

During fiscal year 2013, FERC’s role under the Dodd-Frank Act has continued to remain uncertain. For example, the Dodd-Frank Act mandated that FERC and the CFTC sign a Memorandum of Understanding (MoU) by January 2011 to coordinate potentially overlapping jurisdictions. The agencies missed the mandated deadline, and as of the date of this publication, no new Dodd-Frank MoU is in place.
Section 9
Income Tax Update
Normalization — Deferred Investment Tax Credit and Excess Deferred Taxes (Depreciation Study)

In August 2013, the IRS published PLR 201107002, which addresses the rates at which (1) deferred investment tax credits (ITCs) may be amortized under the Option 2 ITC normalization requirements and (2) excess deferred federal income taxes (EDFIT) may be amortized under the average rate assumption method (ARAM). The taxpayer performed a depreciation study in conjunction with a rate case filing. The revised depreciation rates reflected extensions in the lives of assets and formed the basis of regulatory depreciation expense in the rate case filing. However, after rates had become effective, the taxpayer discovered that it had inadvertently failed to extend the ITC amortization periods and the ARAM amortization of EDFIT to correspond to the extended depreciable lives. The practical effects of these errors were to provide lower rates to customers by flowing through ITC and EDFIT tax benefits as a reduction of regulatory tax expense more rapidly than prescribed by the normalization requirements. The taxpayer represented that it would correct its ITC amortization rates and EDFIT amortization rates in its next rate case filing.

The IRS exercised its discretion not to apply the ITC recapture sanction or to disallow continued use of accelerated depreciation because the error was inadvertent and the commission neither insisted on this treatment nor addressed these matters in the rate case. The IRS indicated that orders concerning this matter that are finalized by the commission after the date of this ruling are not necessarily subject to the same analysis. Further, the IRS indicated that the ruling is based on the representations submitted by the taxpayer and is only valid if those representations are accurate. Specifically, this ruling is expressly conditioned on the taxpayer’s correcting its ITC amortization rates and EDFIT amortization rates in its next rate case filed before the commission.

Normalization — Deferred Investment Tax Credit (Formula Rates)

In May 2013, the IRS issued a set of similar private letter rulings related to the amortization of accumulated deferred investment tax credit (ADITC) under Option 2. Under Option 2, ADITC may not reduce the rate base but the related amortization may reduce the regulatory tax provision no more rapidly than ratably over the regulatory lives of the assets. Ratably is defined as the period used to compute the taxpayer’s regulated depreciation expense. Regulations stipulate that this depreciation expense must be determined on the basis of the period in which the assets are used by the taxpayer, without reduction for salvage value or other items. Note that Option 1 taxpayers may not reduce regulatory tax expense for ITC amortization but may reduce rate base by ADITC as long as the rate base reduction is restored no less rapidly than ratably over the regulatory lives of the assets.

PLR 201318004 involves a formula rate structure used for wholesale generation activities, and PLRs 201318005 and 201318006 involve a formula rate structure used for electric transmission services. The formula rate templates were approved by the commission. Use of formula rates allows for annual self-executing adjustments to rates to reflect increases and decreases in costs and investments since the prior year. The formula rates incorporate a calculation of both rate base and tax expense and reflect the ADITC balance and ITC amortization.

In the rulings, the Option 2 taxpayers determined that for several years they had been applying the Option 1 approach in setting their formula rates even though they had elected to apply the Option 2 normalization requirements. The effect of the erroneous treatment of ADITC in the formula rate templates was a reduction in customer rates. At the time the ruling requests were filed, the taxpayers had not made formula filings with the corrected templates, but the taxpayers indicated that they would do so in their next annual filings.
The commission did not specifically address these matters in rate cases involving the taxpayers and did not issue orders on this matter during the periods in which ADITC was erroneously treated in the templates. The commission did not insist on the errors. The rulings noted that the taxpayers acted upon discovery of these errors and adjusted their templates so that the templates would reflect the same amounts as if no errors had occurred when filed. The IRS exercised its discretion not to disallow or recapture ITC. The IRS indicated that its analysis would not necessarily apply to rate orders finalized after the dates of the rulings.

Normalization — Amortization of Deferred Investment Tax Credit (Carryforwards)

In July 2012, the IRS published PLR 201230021, which addresses when an Option 2 utility may begin reducing regulatory tax expense for amortization of deferred ITCs that are not realized in the tax year in which the plant is placed in service and instead are carried forward for use in a subsequent year.

Pursuant to the Option 2 ITC normalization rules of former IRC Section 46(f)(2), a utility may not reduce rate base or its allowed return for unamortized ITCs but may reduce regulatory tax expense by amortizing ITCs at a rate no more rapid than ratably over the life of the property used for regulatory depreciation purposes. Specifically, Regulation Section 1.46-6(g)(2) indicates that what is “ratable” is determined by considering the period actually used to compute the taxpayer’s regulated depreciation expense for the property for which a credit is allowed. The IRS previously ruled that if any portion of ITC that is carried forward is amortized in a period before this portion of the credit is actually used as an offset against federal income tax, the ITC normalization requirements would be violated, but that straight-line amortization of the investment credit over the remaining regulatory life of the asset at the time the credit is used for federal income tax purposes would not violate the normalization rules.

The utility began amortizing ITCs associated with a plant placed in service during a tax year because it expected to use the ITCs in that tax year as of the month the plant was placed in service. Because of the extension of bonus depreciation later in the year, the utility ultimately was unable to use the ITC on its consolidated tax return for the year the plant was placed in service. However, the utility inadvertently did not adjust ITC amortization recorded that year in its regulatory books of account or the tax estimates used in a rate proceeding occurring during the period within the deadlines prescribed by the commission for introducing new or revised information into a rate proceeding.

The IRS exercised its discretion not to apply the ITC recapture or disallowance sanctions because the error was inadvertent, and the commission neither ordered the treatment nor was aware of the mistake. The IRS ruled that the commission must allow the utility taxpayer to request a reduction of its ITC amortization in its next appropriate rate proceeding because the utility inadvertently amortized ITC that had not yet been used as an offset against federal tax liability on its consolidated tax return. The IRS indicated that the private letter ruling will be null and void if any of its prescribed conditions are not met.

Normalization — Deferred Tax Consistency Requirement

In June 2012, the IRS published PLR 201223014, which discusses the application of the consistency requirement of the deferred tax and depreciation normalization rules to the construction costs of a power plant that exceeded the public utility commission’s preapproved overall “cost cap” and were treated less favorably in setting rates than the costs that did not exceed the cost cap. In accordance with the commission’s preapproval, if amounts expended exceeded the cost cap, amounts would be recoverable only if the utility demonstrated to the public utility commission’s satisfaction that the amounts were reasonable and prudent.

Actual construction costs exceeded the cost cap. In subsequent rate proceedings, the utility demonstrated that the amounts incurred in excess of the cost cap were reasonable and prudent. The commission ultimately approved full recovery of costs (regulatory depreciation expense) and rate base inclusion for the full cost of the plants but allowed different rates of return for the portion of the unrecovered plant costs not exceeding the cost cap and the portion exceeding the cost cap. The commission allowed zero return on costs exceeding the cost cap.
The IRS held that while the commission did not allow the utility to earn a return on the portion of the cost of the plant that exceeded the cost cap, IRC Section 168(i)(9)(B) does not require that every element of the cost of a project included in ratable base earn a uniform rate of return. Thus, the IRS ruled that the regulatory treatment satisfies the normalization rules requiring consistent ratemaking and regulatory accounting treatment of estimates or projections of tax expense, depreciation expense, deferred tax liabilities (DTLs), and rate base.

**Presenting an Unrecognized Tax Benefit When Tax Carryforwards Exist**

In July 2013, the FASB issued ASU 2013-11 in response to a consensus reached at the EITF’s June 11, 2013, meeting. The ASU provides guidance on financial statement presentation of a UTB when a net operating loss (NOL) carryforward, a similar tax loss, or a tax credit carryforward exists. The FASB’s objective in issuing the ASU was to eliminate diversity in practice resulting from a lack of existing guidance on this topic in U.S. GAAP.

Under the ASU, an entity must present a UTB, or a portion of a UTB, in the financial statements as a reduction to a DTA for an NOL carryforward, a similar tax loss, or a tax credit carryforward except when either of the following conditions is met:

- An NOL carryforward, a similar tax loss, or a tax credit carryforward is not available as of the reporting date under the governing tax law to settle taxes that would result from the disallowance of the tax position.
- The entity does not intend to use the DTA for this purpose (provided that the tax law permits a choice).

If either of these conditions exists, an entity should present a UTB in the financial statements as a liability and should not net the UTB with a DTA. New recurring disclosures are not required because the ASU does not affect the recognition or measurement of uncertain tax positions under ASC 740. Further, the ASU does not affect the amounts public entities disclose in the tabular reconciliation of the total amounts of UTBs because the tabular reconciliation presents the gross amounts of UTBs.

The ASU’s amendments are effective for public entities for fiscal years beginning after December 15, 2013, and interim periods within those years. Nonpublic entities may wait until fiscal years, and interim periods within those years, beginning after December 15, 2014, to adopt the amendments. Early adoption is permitted for all entities. The amendments should be applied to all UTBs that exist as of the effective date. Entities may choose to apply the amendments retrospectively to each prior reporting period presented.

ASU 2013-11 is codified as ASC 740-10-45-10A and 45-10B and amendments to ASC 740-10-45-11 through 45-13.

**The American Taxpayer Relief Act of 2012**

President Obama signed the American Taxpayer Relief Act of 2012 (the “Relief Act”) into law on January 2, 2013. Among other things, the Act extends through 2013 an array of temporary business and individual tax provisions. The following are two of the Act’s provisions relevant to many P&U companies:

- The credit for certain research and experimentation expenses expired at the end of 2011. The Act retroactively extended the credit through the end of 2013. Under ASC 740, the effects of new legislation are recognized upon enactment, which in the U.S. federal jurisdiction is the date the president signs a tax bill into law. Although many of the extenders are effective retroactively for 2012, entities should only consider currently enacted tax law as of the balance sheet date in determining current and deferred taxes. For calendar-year-end reporting entities, this means that both the retroactive tax effects for 2012 and the tax effects for 2013 will be recognized in the 2013 financial statements.
The Act amended IRC Section 168(i)(9)(A)(ii) to clarify that the amount of tax depreciation referenced to compute the amount of DTL, which may offset rate base or be treated as zero-cost capital when regulated rates are set, must respect all elections made by the taxpayer under IRC Section 168 (e.g., the election not to claim bonus depreciation).

Accounting for the Tangible Property Regulations

In September 2013, the U.S. Department of the Treasury and the IRS released final regulations (the “Final Regulations”) that provide guidance on amounts paid to acquire, produce, or improve tangible property, as well as rules for materials and supplies and proposed regulations addressing dispositions and general asset accounts. In addition, in April 2013, the IRS released Rev. Proc. 2013-24, which contains elective safe harbor definitions of units of property and major components taxpayers may use to determine whether expenditures to maintain, replace, or improve steam or electric power generation property must be capitalized. The Final Regulations are generally effective for taxable years beginning on or after January 1, 2014. In addition, taxpayers are permitted to early adopt provisions in the Final Regulations for taxable years beginning on or after January 1, 2012. The government expects to issue procedural guidance pursuant to which taxpayers will be granted automatic consent to change their accounting methods to comply with the Final Regulations.

P&U companies will most likely be required to change tax accounting methods to comply with the Final Regulations. Further, many of the method changes will need to be applied retrospectively (i.e., with a cumulative catch-up adjustment referred to as a “481(a) adjustment”) and will affect an entity’s temporary differences and related deferred taxes under ASC 740. For example, some amounts previously taken as deductions may need to be capitalized into the tax basis of property upon transition, resulting in a positive 481(a) adjustment (i.e., increasing taxable income). In general, positive 481(a) adjustments are included in taxable income over four tax years beginning with the year of change and negative 481(a) adjustments are deducted in a single year’s U.S. federal income tax return. However, all 481(a) adjustments resulting from method changes to the safe harbor guidance of Rev. Proc. 2013-24 must be recognized in full in the year of change. A DTL is required for positive 481(a) adjustments and a DTA is required for negative 481(a) adjustments. Note that any DTL for a positive 481(a) adjustment that must be reported in taxable income is separate and distinct from any resulting DTL with respect to a book-tax basis difference in the related underlying asset (e.g., depreciable plant).

For purposes of applying ASC 740, the Final Regulations are viewed as new tax law. Although the Final Regulations are not effective until January 1, 2014, ASC 740-10-25-47 requires that the effect of a change in tax law be recognized as of the enactment date. The recognition of the effects of a change in tax law requiring a change in tax accounting method is discussed in ASC 740-10-55-58 through 55-63, which illustrate that the effect of a change in tax law on DTAs and DTLs should be reflected as of the enactment date regardless of a later effective date. An entity that is required to change its tax accounting methods to comply with the Final Regulations should account for the effect of the tax law changes on the tax accounts in the interim and annual period in which the Final Regulations were issued. At this time, the entity would generally reflect both of the following (along with appropriate disclosures):

- The deferred tax effects of the estimated Section 481(a) temporary difference(s) that will be created when it files one or more Forms 3115 (application for a change in accounting method) to request the accounting method changes along with a corresponding adjustment to its temporary differences related to the affected property.

- Updates to the liability for UTBs related to any uncertainty in the application of the Final Regulations.

In addition, an entity may need to consider changes to DTAs and DTLs (including the timing of future reversals) resulting from the Final Regulations in determining whether a valuation allowance is needed for the entity’s DTAs. Power and utility companies operating in regulatory jurisdictions that employ the flow-through method of accounting for certain deferred taxes would need to consider the scope of historical flow-through accounting practices and any special rulemaking applicable to accounting method changes to reflect the appropriate effects of the accounting method change(s) on tax-related regulatory assets and liabilities.
In a classified balance sheet, the current/noncurrent classification of a DTL for the estimated Section 481(a) adjustment would be based on the expected reversal date of that temporary difference, which would be affected by the period in which the entity intends to adopt the Final Regulations. For example, a calendar-year taxpayer not affected by the safe harbor electric generation guidance of Rev. Proc. 2013-24 whose adoption of the Final Regulations would have been effective on January 1, 2014, would include 25 percent of any taxable Section 481(a) adjustment (or 100 percent of any deductible Section 481(a) adjustment) in its current taxable income for 2014; thus, 25 percent of the related DTL (or 100 percent of a related DTA) as of December 31, 2013, would be classified as current.

Some entities may find it challenging to determine the impact of the Final Regulations on their interim and year-end financial reporting because of both the timing of the issuance date and uncertainty regarding the interpretation of some aspects of implementation (until the additional procedural guidance is issued). ASC 740-10-25-14 states that the measurement of a tax position should “be based on management’s best judgment given the facts, circumstances, and information available at the reporting date.” Although additional analysis of existing information would not typically constitute new information for purposes of adjusting prior estimates, if subsequent administrative guidance (e.g., procedural guidance regarding the Final Regulations, safe harbor guidance for gas distribution and transmission plant) changes the initial assessment of the impact of the Final Regulations on DTAs and DTLs, changes resulting from that additional guidance would be accounted for in the period in which the additional guidance becomes available.
Section 10

Renewable Energy
Section 10 — Renewable Energy: Production Tax Credits, Investment Tax Credits, and Treasury Grants

Production Tax Credits, Investment Tax Credits, and Treasury Grants

Introduction

To create jobs and promote economic growth during the credit crisis, President Obama signed into law the American Recovery and Reinvestment Act (the “Recovery Act”) in February 2009. The Recovery Act extended the placed-in-service date requirement for PTCs for wind resource generation facilities through December 31, 2012, and for certain other renewable generation facilities through December 31, 2013. PTCs are calculated by using stated rates (e.g., 2013 wind production at 2.3 cents) multiplied by kWh generated during each of the first 10 years of operation. In January 2013, the Relief Act extended the PTC eligibility to wind resource generation facilities with construction beginning before January 1, 2014.

The energy credit under IRC Section 48 is an ITC available for certain renewable energy facilities placed in service through specified dates. ITCs are calculated by using stated rates (e.g., 30 percent for wind and solar electric generation property) multiplied by the tax basis of the eligible property. The Recovery Act provides an irrevocable election under IRC Section 48(a)(5) that allows entities to claim an ITC instead of a PTC for most PTC-eligible facilities placed in service after December 31, 2008, as long as no PTC has been claimed for such property. The depreciable tax basis of the property is reduced by 50 percent of any ITC claimed, and the ITC is subject to recapture if the related property is sold or otherwise ceases to operate within five years of being placed in service. The Relief Act amended the credit termination date rules for most PTC-eligible facilities for which an ITC is elected.

Renewable energy facilities eligible for an ITC include solar electric generation property and combined heat and power system property placed in service before January 1, 2017, as well as wind resource generation facilities, closed-loop biomass facilities, open-loop biomass facilities, geothermal energy facilities, landfill gas facilities, municipal waste facilities, hydropower facilities, and marine and hydrokinetic renewable energy facilities with construction beginning before January 1, 2014.

Section 1603 of the Recovery Act allows the Treasury secretary to provide a grant in lieu of an ITC (a “Section 1603 grant”) for renewable generation property, including public utility property. The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 extended certain provisions in Section 1603 of the Recovery Act by one year to allow the Treasury secretary to continue to provide a Section 1603 grant as long as construction began by December 31, 2011, and the facility is placed in service before the ITC placed-in-service date that otherwise applies to such property (e.g., before December 31, 2012, for wind generation facilities; December 31, 2013, for other PTC-eligible property; and December 31, 2016, for solar generation facilities). The deadline for submitting new Section 1603 grant applications was October 1, 2012.

In July 2009, the Treasury published Payments for Specified Energy Property in Lieu of Tax Credits Under the American Recovery and Reinvestment Act of 2009 (the “program guidance”) and FAQs on Section 1603. The Treasury also issued “Began Construction” FAQs, which clarify eligibility requirements for properties placed in service after December 31, 2011 (e.g., the construction of such properties must have begun in 2009, 2010, or 2011).
Applicants that submitted an initial application with the Treasury before October 1, 2012, under the Begun Construction provisions are required to file an updated application within 90 days after the energy property is placed in service. Applicants should be aware that the Treasury will not accept any final applications filed after 90 days. Like initial applications, all final applications with an eligible cost basis of $1 million or more must also include a certification from independent accountants. The Treasury will accept either an agreed-upon procedures report prepared by an independent accountant in accordance with AICPA AT Section 201 or an examination report on the schedule of eligible costs paid or incurred (depending on whether the taxpayer applies the cash method or accrual method) in accordance with AICPA AT Section 101.

The program guidance, FAQs, and instructions for preparing an agreed-upon procedures report are available on the Treasury Department’s Web site. Renewable energy providers should be aware that the Treasury’s recent intense scrutiny of qualifying costs has resulted in (1) longer review periods, (2) more frequent challenges to applications, (3) occasional delays in receiving cash, and (4) sequestration of awards. As communicated via a message on sequestration on the Treasury’s Web site, every award given to a Section 1603 grant applicant on or after October 1, 2013, and on or before September 30, 2014, will be reduced by 7.4 percent, irrespective of when the application was received by the Treasury. The sequestration reduction rate will be applied unless or until a law is enacted that cancels or otherwise affects the sequester, at which time the sequestration reduction rate is subject to change.

**Changes to PTC and ITC Eligibility Under the Relief Act**

In May 2013, the IRS issued Notice 2013-29, which “provides guidelines and a safe harbor to determine when construction has begun” on facilities that are eligible to receive a PTC, or an ITC in lieu of a PTC, in accordance with credit termination dates amended by the Relief Act (the construction of the facility must begin before January 1, 2014). Eligible facilities include wind facilities, closed-loop biomass facilities, open-loop biomass facilities, geothermal facilities, landfill gas facilities, trash facilities, hydropower facilities, and marine and hydrokinetic facilities (no changes were made to the requirements for solar ITCs). Although the guidelines for determining when construction has begun under Notice 2013-29 are similar to those under the Section 1603 grant guidance, one difference is that Notice 2013-29 does not contain any construction-start-date requirements or placed-in-service-date requirements. However, under Notice 2013-29, the taxpayer must maintain a continuous program of construction for the facility (the “continuous-construction test”) to satisfy the requirements for the physical work test and must make continuous efforts to advance toward completion of the facility (the "continuous-efforts test") to satisfy the condition for the safe harbor. The following is a summary of significant provisions of Notice 2013-29:

- **Notice 2013-29** states that “[c]onstruction of a qualified facility begins when physical work of a significant nature begins.” Physical work of a significant nature would include “[b]oth on-site and off-site work (performed either by the taxpayer or by another person under a binding written contract).” However, such work “does not include preliminary activities [such as] planning or designing, securing financing, exploring, researching, obtaining permits, licensing, conducting surveys, environmental and engineering studies, clearing a site, test drilling of a geothermal deposit, test drilling to determine soil condition, or excavation to change the contour of the land (as distinguished from excavation for footings and foundations).” As with the Section 1603 grant guidance, removal of existing turbines and towers should be excluded from the definition of preliminary activities.

- A taxpayer is in a safe harbor from the beginning-of-construction requirement if it is able to demonstrate that it (1) has incurred at least 5 percent of the project’s total estimated eligible costs before January 1, 2014, and (2) has made “continuous efforts to advance towards completion of the facility” in the absence of disruptions that are beyond the taxpayer’s control (e.g., severe weather conditions, licensing and permitting delays, inability to obtain specialized equipment). Notice 2013-29 further states:

> If the total cost of a facility that is a single project comprised of multiple facilities (as described in section 4.04(2)) exceeds its anticipated total cost, so that the amount a taxpayer actually paid or incurred with respect to the facility before January 1, 2014, is less than five percent of the total cost of the facility at the time the facility is placed in service, the [safe harbor threshold] is not fully satisfied. However, [the safe harbor threshold] will be satisfied and

---

1 In September 2013, the IRS issued Notice 2013-60 to clarify the requirements of Notice 2013-29.
the PTC or ITC may be claimed with respect to some, but not all, of the individual facilities (as described in section 4.04(1)) comprising the single project, as long as the total aggregate cost of those individual facilities is not more than twenty times greater than the amount the taxpayer paid or incurred before January 1, 2014.

- In evaluating the 5 percent safe harbor provision, taxpayers may rely on suppliers’ statements regarding costs that the supplier has paid or incurred on the taxpayer’s behalf for property to be manufactured, constructed, or produced under a binding written contract. In determining when it has incurred costs, the supplier may consult the economic performance rules in IRC Section 461(h) (see Treas. Regs. Section 1.461-1(a)(1) and (2)). The supplier may use any reasonable method (the method’s reasonableness depends on the facts and circumstances) to allocate the costs it incurs among the units of property manufactured, constructed, or produced under a binding written contract for multiple units. If a subcontractor manufactures components for the supplier, the cost of those components is incurred only when the components are provided to the supplier (not when the subcontractor pays or incurs the costs). In the determination and allocation of costs, property that the supplier reasonably expects to receive from a subcontractor within three and a half months from the date of payment (supplier’s payment to subcontractor) is considered to be provided by the payment date.

IRS Notice 2013-60, which clarifies Notice 2013-29, states that a facility placed in service before January 1, 2016, will meet the requirements for the continuous construction test (by way of passing the physical work test) or the continuous efforts test (by way of passing the 5 percent safe harbor test). Taxpayers are advised to carefully document their physical work and the physical work of their contractors that occur before January 1, 2014, if they are relying on the physical work test or their costs incurred before January 1, 2014, if they are relying on the 5 percent safe harbor test.

**Accounting for Grant-Eligible ITCs and Section 1603 Grants**

A Section 1603 grant should be accounted for as a grant and not as a tax credit. An ITC eligible for a Section 1603 grant could be accounted for as either a tax credit or a grant. ITCs that are not eligible for conversion to Section 1603 grants (e.g., ITCs related to construction that began after 2011) would be subject to the accounting requirements of ASC 740-10.

It is unclear how to account for an ITC eligible for a Section 1603 grant. In practice, the related balances have been deferred on the balance sheet, either as a reduction to the book property basis or as a deferred credit (not as a deferred tax credit). Such accounting is consistent with IAS 20. Entities have applied IAS 20 in practice because there is no specific U.S. GAAP guidance on accounting for government grants. The benefit should be recognized over the book life of the property. When the property balance is reduced, the income statement credit should not be recorded as a reduction of income tax expense but as a reduction to depreciation and amortization. When a deferred credit is recorded, the income statement credit should not be recorded as an increase to revenues but should be reflected as an increase to other income or as a reduction of depreciation and amortization.

See [Rate-Regulated Entities](#) below for a discussion of the possible application of ASC 450 (rather than IAS 20) to a grant for a rate-regulated plant.

**Grant-Eligible ITC Claimed on QPEs**

An ITC claimed during the construction period for property that is eligible for the Section 1603 grant should be deferred until the property is placed in service because it is presumed that this Section 1603 grant would be elected when the property is placed in service and the ITC is recaptured. No deferred income tax benefit should be reflected in the income statement until the year the property is expected to be placed in service.

**Section 1603 Grants on Property Owned by Partnerships and LLCs**

Section 1603 grants received by both nontaxable and taxable partnerships and LLCs must be recognized in the separate financial statements of such entities in accounts other than income tax accounts, as described above.
Applicability to Pass-Through Entities

The accounting described above for grant-eligible ITCs and Section 1603 grants also applies to pass-through entities. In addition, because the benefits of the ITC accrue to the taxable members of a pass-through entity, to the extent that the grant-eligible ITC is accounted for as a grant, such taxable members should recognize deferred income taxes for any book/tax basis differences.

Rate-Regulated Entities

The Recovery Act initially stipulated that rate-regulated entities must apply the normalization rules to Section 1603 grants, meaning that the benefits of the grants could not be passed back to customers faster than a plant’s book depreciable life. However, in late 2011, the National Defense Authorization Act for Fiscal Year 2012 eliminated the normalization provisions associated with cash grants. Accordingly, a regulator can reduce rates for the grants faster than the life of the property without violating the normalization rules.

In addition, when rate-regulated entities account for the grant proceeds as a reduction of plant or as a deferred credit, they should be aware that if the regulator flows back the deferred grant for rate purposes more rapidly than the deferred amount is recognized in income under GAAP, the excess rate reduction (a timing difference between GAAP and rate-making) does not qualify as a regulatory asset and income statement volatility would result.

Entities have historically accounted for government grants by analogizing to IAS 20. As noted in the section above, this method involves recording the grant proceeds as a reduction of plant or as a deferred credit. However, we are aware of one recent situation in which the SEC staff indicated it would not object to a company’s establishment of an accounting policy under which it would account for the cash grants by analogy to ASC 450 and, more specifically, to its guidance on gain contingencies. In this specific case, the power plant that qualified for the Section 1603 grant was part of the company’s rate-regulated operations. Because the regulator would require the benefits from the Section 1603 grant to reduce customer rates, the Section 1603 grant qualifies under the gain contingency recognition rules of ASC 450 and the benefit would be recorded as a regulatory liability rather than an income statement gain.

Accounting for PTCs

When an entity claims PTCs (instead of ITCs or Section 1603 grants), the PTCs claimed will continue to be recognized as a reduction of income tax expense in the year in which the eligible kWh generation occurs. Entities must assess any DTAs for PTC carryforwards to determine whether a valuation allowance is necessary.

Start-Up Versus Development Costs and Timing of Capitalization

Fundamental to renewable energy developers’ business activities is the development of new renewable energy generation facilities (individually, a project). A typical project has three stages: start-up, development (ordinarily, construction phase to achieving commercial operation), and late-stage development (the post-commercial-operation stage). As further discussed below, certain milestones must be accomplished before an entity decides to construct a project.

Various costs are incurred at each development stage. The primary determination related to these costs is whether to treat them as expense or capital items and, if capital items, when capitalization of such costs should commence and cease. In making this determination, entities should look to the guidance in ASC 720-15, 360-20, 360-970, 805-10, and 835-20.

ASC 720-15 requires that start-up costs be expensed as incurred and broadly defines such costs as “those one-time activities related to any of the following:

a. Opening a new facility
b. Introducing a new product or service
c. Conducting business in a new territory

d. Conducting business with an entirely new class of customers . . . or beneficiary

e. Initiating a new process in an existing facility

f. Commencing some new operation.”

Business initiation costs are components of start-up costs — they are incurred in the normal course of starting a business or a project and should be expensed as incurred. Generally, business initiation costs consist of costs incurred for activities pertaining to bid preparation, internal analysis, legal research and early-stage engineering, maintaining a development office, and organizing new legal entities.

Development costs are costs incurred before acquisition or construction of a project is initiated but after the decision to initiate such a transaction has been made. In general, development costs are capitalizable as long as they are related to a specific project and management concludes that the project’s construction and completion are probable. The probability conclusion should be based on the achievement of milestones or a combination of milestones and the entity’s historical experience. These milestones may include the receipt of permits or approvals from governmental agencies and the execution of significant project agreements such as power purchase agreements, construction loan agreements, and agreements to acquire significant project components (e.g., turbine supply agreements). Examples of potentially capitalizable development costs include project acquisition fees, costs of obtaining permits and licenses, professional fees, and internal costs related to contract negotiation.

Construction costs are necessary costs incurred to prepare an asset that is ready for its intended use. Virtually all costs incurred in a project’s construction phase are capitalizable. Capitalization should cease on the commercial operation date. Potentially capitalizable construction costs may include EPC contractor fees; interest paid to third parties; test power costs and the related income (for short periods); internal costs directly related to the project; property tax incurred during the construction period; bonuses paid to the development team; and, in certain circumstances, development fees.

Certain late-stage development activities are likely to continue to take place after a project achieves commercial operation and may last up to a couple of years after the post-commercial-operation stage begins. Costs associated with late-stage development generally are related to employee training to operate and maintain the project, equipment fine-tuning, and contract negotiation concerning project operation. These costs are generally not capitalizable.

The determination of whether a cost exhibits characteristics of a start-up cost rather than a development cost is based on the relevant facts and circumstances. Certain costs may appear to be related to a specific project but may not need to be incurred for an entity to construct the project or achieve its commercial operation. These costs should not be capitalized as part of project costs. Examples include, but are not limited to, power market studies, professional fees related to accounting and tax services, legal fees associated with the execution of a power purchase agreement, and allocation of administrative/corporate overhead.

Certain circumstances throughout the development stages may call into question whether any or all of the capitalized project costs are recoverable. ASC 360-10-35-21 gives examples of such circumstances. Entities should look to the guidance in ASC 360-10 in determining whether capitalized project costs are impaired and thus warrant an immediate write-off. To test for recoverability, an entity should compare future cash flows from the use and ultimate disposal of the project (i.e., cash inflows to be generated by the project less cash outflows necessary to obtain the inflows) with the carrying amount of the project (i.e., cumulative capitalized project costs plus estimated costs of completing construction and achieving commercial operation). Impairment exists when the expected future nominal (undiscounted) cash flows, excluding interest charges, are less than the project’s carrying amount.
Entities should develop a capitalization policy in accordance with the aforementioned considerations and should apply this policy consistently to all of their projects. A best practice for capitalization policies is to incorporate entity-specific considerations, including factors affecting management’s judgment about properly accounting for start-up and development costs. At a minimum, entities should consider incorporating the following into their capitalization policy:

- Milestones in each development stage to establish the event (or a combination of events) that triggers the commencement and cessation of capitalization.
- The types of costs that qualify as capitalized project costs.
- An event (or a combination of events) that triggers a review to determine whether capitalized costs are impaired.
Appendixes
## Appendix A — Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AcSB</td>
<td>Canadian Accounting Standards Board</td>
</tr>
<tr>
<td>ADITC</td>
<td>accumulated deferred investment tax credit</td>
</tr>
<tr>
<td>AFI</td>
<td>accounting for financial instruments</td>
</tr>
<tr>
<td>AICPA</td>
<td>American Institute of Certified Public Accountants</td>
</tr>
<tr>
<td>AOCl</td>
<td>accumulated other comprehensive income</td>
</tr>
<tr>
<td>ARAM</td>
<td>average rate assumption method</td>
</tr>
<tr>
<td>ASC</td>
<td>FASB Accounting Standards Codification</td>
</tr>
<tr>
<td>ASU</td>
<td>FASB Accounting Standards Update</td>
</tr>
<tr>
<td>Btu</td>
<td>British thermal unit</td>
</tr>
<tr>
<td>C&amp;DIs</td>
<td>SEC Compliance and Disclosure Interpretations</td>
</tr>
<tr>
<td>CAISO</td>
<td>California Independent Service Operator</td>
</tr>
<tr>
<td>CECL</td>
<td>current expected credit loss</td>
</tr>
<tr>
<td>CEO</td>
<td>chief executive officer</td>
</tr>
<tr>
<td>CFTC</td>
<td>Commodity Futures Trading Commission</td>
</tr>
<tr>
<td>CO₂</td>
<td>carbon dioxide</td>
</tr>
<tr>
<td>CSAPR</td>
<td>Cross-State Air Pollution Rule</td>
</tr>
<tr>
<td>DAA</td>
<td>FERC’s Division of Audits and Accounting</td>
</tr>
<tr>
<td>DAS</td>
<td>FERC’s Division of Analytics and Surveillance</td>
</tr>
<tr>
<td>DG</td>
<td>distributed generation</td>
</tr>
<tr>
<td>DOE</td>
<td>U.S. Department of Energy</td>
</tr>
<tr>
<td>DOI</td>
<td>FERC’s Division of Investigations</td>
</tr>
<tr>
<td>DP</td>
<td>discussion paper</td>
</tr>
<tr>
<td>DTA</td>
<td>deferred tax asset</td>
</tr>
<tr>
<td>DTL</td>
<td>deferred tax liability</td>
</tr>
<tr>
<td>EBITDA</td>
<td>earnings before interest, taxes, depreciation, and amortization</td>
</tr>
<tr>
<td>ED</td>
<td>exposure draft</td>
</tr>
<tr>
<td>EDFIT</td>
<td>excess deferred federal income taxes</td>
</tr>
<tr>
<td>EDGAR</td>
<td>SEC’s Electronic Data Gathering, Analysis, and Retrieval system</td>
</tr>
<tr>
<td>EEI</td>
<td>Edison Electric Institute</td>
</tr>
<tr>
<td>EGC</td>
<td>emerging growth company</td>
</tr>
<tr>
<td>EIA</td>
<td>U.S. Energy Information Administration</td>
</tr>
<tr>
<td>EITF</td>
<td>Emerging Issues Task Force</td>
</tr>
<tr>
<td>EPA</td>
<td>Environmental Protection Agency</td>
</tr>
<tr>
<td>EPC</td>
<td>engineering, procurement, construction</td>
</tr>
<tr>
<td>EQR</td>
<td>Electric Quarterly Report</td>
</tr>
<tr>
<td>ERCOT</td>
<td>Electric Reliability Council of Texas</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
</tr>
<tr>
<td>--------------</td>
<td>-------------</td>
</tr>
<tr>
<td>ERO</td>
<td>Electric Reliability Organization</td>
</tr>
<tr>
<td>FAQs</td>
<td>frequently asked questions</td>
</tr>
<tr>
<td>FASB</td>
<td>Financial Accounting Standards Board</td>
</tr>
<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
</tr>
<tr>
<td>FRM</td>
<td>SEC’s Division of Corporation Finance Financial Reporting Manual</td>
</tr>
<tr>
<td>FTR</td>
<td>financial transmission rights</td>
</tr>
<tr>
<td>FV-NI</td>
<td>fair value through net income</td>
</tr>
<tr>
<td>FV-OCI</td>
<td>fair value through other comprehensive income</td>
</tr>
<tr>
<td>GAAP</td>
<td>generally accepted accounting principles</td>
</tr>
<tr>
<td>IAS</td>
<td>International Accounting Standards</td>
</tr>
<tr>
<td>IASB</td>
<td>International Accounting Standards Board</td>
</tr>
<tr>
<td>ICE</td>
<td>Intercontinental Exchange Inc.</td>
</tr>
<tr>
<td>ICFR</td>
<td>internal control over financial reporting</td>
</tr>
<tr>
<td>IFRIC</td>
<td>International Financial Reporting Interpretations Committee</td>
</tr>
<tr>
<td>IFRS</td>
<td>International Financial Reporting Standard</td>
</tr>
<tr>
<td>IPO</td>
<td>initial public offering</td>
</tr>
<tr>
<td>IRC</td>
<td>Internal Revenue Code</td>
</tr>
<tr>
<td>IRS</td>
<td>Internal Revenue Service</td>
</tr>
<tr>
<td>ISO</td>
<td>Independent System Operator</td>
</tr>
<tr>
<td>ITC</td>
<td>investment tax credit</td>
</tr>
<tr>
<td>kWh</td>
<td>kilowatt hour</td>
</tr>
<tr>
<td>LCM</td>
<td>lower of cost or market</td>
</tr>
<tr>
<td>LIBOR</td>
<td>London Interbank Offered Rate</td>
</tr>
<tr>
<td>LIHTC</td>
<td>low-income housing tax credits</td>
</tr>
<tr>
<td>LLC</td>
<td>limited liability company</td>
</tr>
<tr>
<td>LNG</td>
<td>liquefied natural gas</td>
</tr>
<tr>
<td>LP</td>
<td>limited partnership</td>
</tr>
<tr>
<td>MATS</td>
<td>Mercury and Air Toxics Standards</td>
</tr>
<tr>
<td>MISO</td>
<td>Midcontinent (formerly Midwest) Independent Transmission System Operator Inc.</td>
</tr>
<tr>
<td>MD&amp;A</td>
<td>Management’s Discussion and Analysis</td>
</tr>
<tr>
<td>MLP</td>
<td>master limited partnership</td>
</tr>
<tr>
<td>MLTN</td>
<td>more likely than not</td>
</tr>
<tr>
<td>MMBtu</td>
<td>million Btu</td>
</tr>
<tr>
<td>MNA</td>
<td>master netting arrangement</td>
</tr>
<tr>
<td>MoU</td>
<td>Memorandum of Understanding</td>
</tr>
<tr>
<td>MSP</td>
<td>major swap participant</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
</tr>
<tr>
<td>--------------</td>
<td>-------------</td>
</tr>
<tr>
<td>MW</td>
<td>megawatt</td>
</tr>
<tr>
<td>MWh</td>
<td>megawatt hour</td>
</tr>
<tr>
<td>NCI</td>
<td>noncontrolling interest</td>
</tr>
<tr>
<td>NERC</td>
<td>North American Electric Reliability Corporation</td>
</tr>
<tr>
<td>NOL</td>
<td>net operating loss</td>
</tr>
<tr>
<td>NPNS</td>
<td>normal purchase normal sale</td>
</tr>
<tr>
<td>NRC</td>
<td>Nuclear Regulatory Commission</td>
</tr>
<tr>
<td>NYMEX</td>
<td>New York Mercantile Exchange</td>
</tr>
<tr>
<td>OBA</td>
<td>Operational Balancing Agreement</td>
</tr>
<tr>
<td>OCI</td>
<td>other comprehensive income</td>
</tr>
<tr>
<td>OER</td>
<td>FERC’s Office of Electric Reliability</td>
</tr>
<tr>
<td>P&amp;U</td>
<td>power and utilities</td>
</tr>
<tr>
<td>PBE</td>
<td>public business unit</td>
</tr>
<tr>
<td>PCAOB</td>
<td>Public Company Accounting Oversight Board</td>
</tr>
<tr>
<td>PCC</td>
<td>FASB’s Private Company Council</td>
</tr>
<tr>
<td>PCDMF</td>
<td>private-company decision-making framework</td>
</tr>
<tr>
<td>PCI</td>
<td>purchased credit-impaired</td>
</tr>
<tr>
<td>Plc</td>
<td>public limited company</td>
</tr>
<tr>
<td>PJM</td>
<td>represents RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia</td>
</tr>
<tr>
<td>PLR</td>
<td>IRS private letter ruling</td>
</tr>
<tr>
<td>PPA</td>
<td>power purchase agreement</td>
</tr>
<tr>
<td>PP&amp;E</td>
<td>property, plant, and equipment</td>
</tr>
<tr>
<td>PTC</td>
<td>production tax credit</td>
</tr>
<tr>
<td>PV</td>
<td>photovoltaic</td>
</tr>
<tr>
<td>Q&amp;A</td>
<td>question and answer</td>
</tr>
<tr>
<td>QIB</td>
<td>qualified institutional buyer</td>
</tr>
<tr>
<td>QPE</td>
<td>qualified progress expenditure</td>
</tr>
<tr>
<td>RCC</td>
<td>readily convertible to cash</td>
</tr>
<tr>
<td>RE</td>
<td>Regional Entities</td>
</tr>
<tr>
<td>REC</td>
<td>renewable energy certificate</td>
</tr>
<tr>
<td>Rev. Proc.</td>
<td>IRS Revenue Procedure</td>
</tr>
<tr>
<td>RFI</td>
<td>request for information</td>
</tr>
<tr>
<td>RFS</td>
<td>renewable fuel standards</td>
</tr>
<tr>
<td>RIN</td>
<td>renewable identification number</td>
</tr>
<tr>
<td>ROE</td>
<td>return on equity</td>
</tr>
<tr>
<td>ROU</td>
<td>right of use</td>
</tr>
<tr>
<td>RTO</td>
<td>Regional Transmission Organization</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
</tr>
<tr>
<td>--------------</td>
<td>------------------------------</td>
</tr>
<tr>
<td>RRA</td>
<td>rate-regulated activities</td>
</tr>
<tr>
<td>SAB</td>
<td>SEC Staff Accounting Bulletin</td>
</tr>
<tr>
<td>SD</td>
<td>swap dealer</td>
</tr>
<tr>
<td>SEC</td>
<td>Securities and Exchange Commission</td>
</tr>
<tr>
<td>SPPI</td>
<td>solely payments of principal and interest</td>
</tr>
<tr>
<td>TVA</td>
<td>Tennessee Valley Authority</td>
</tr>
<tr>
<td>USofA</td>
<td>FERC's Uniform System of Accounts</td>
</tr>
<tr>
<td>UST</td>
<td>U.S. Department of Treasury</td>
</tr>
<tr>
<td>UTB</td>
<td>unrecognized tax benefit</td>
</tr>
<tr>
<td>VIE</td>
<td>variable interest entity</td>
</tr>
<tr>
<td>XBRL</td>
<td>eXtensible Business Reporting Language</td>
</tr>
<tr>
<td>XML</td>
<td>eXtensible Markup Language</td>
</tr>
</tbody>
</table>

The following is a list of short references for the Acts mentioned in this publication:

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Act</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dodd-Frank Act</td>
<td>The Dodd-Frank Wall Street Reform and Consumer Protection Act</td>
</tr>
<tr>
<td>JOBS Act</td>
<td>Jumpstart Our Business Startups Act</td>
</tr>
<tr>
<td>NGA</td>
<td>Natural Gas Act of 1938</td>
</tr>
<tr>
<td>Relief Act</td>
<td>American Taxpayer Relief Act of 2012</td>
</tr>
<tr>
<td>Securities Act</td>
<td>Securities Act of 1933</td>
</tr>
</tbody>
</table>
Appendix B — Titles of Standards and Other Literature

The titles of the standards and other literature referred to in this publication are available from the sources below.

**FASB Literature**

For titles of *FASB Accounting Standards Codification* references, see Deloitte’s “Titles of Topics and Subtopics in the *FASB Accounting Standards Codification*.”

See the FASB’s Web site for the titles of:

- Accounting Standards Updates.
- Exposure documents open for comment.
- Exposure documents issued for public comment (archive).
- Pre-Codification literature (Statements, Staff Positions, EITF Issues, and Topics).
- Concepts Statements.

**International Standards**

See Deloitte’s IAS Plus Web site for the titles of:

- International Accounting Standards (IAS).
- International Financial Reporting (IFRIC) Interpretations.
- Standing Interpretations Committee (SIC) Interpretations.

IASB Exposure Draft, *Rate-regulated Activities*

**PCAOB Literature**

- Auditing Standard 16, *Communications With Audit Committees*

**SEC Literature**

- Final Rules, Interim Final Rules, Proposed Rules, and Interpretive Releases:
  - Final Rule No. 33-9414, *Disqualification of Felons and Other “Bad Actors” from Rule 506 Offerings*
  - Final Rule No. 33-9415, *Eliminating the Prohibition Against General Solicitation and General Advertising in Rule 506 and Rule 144A Offerings*
  - Final Rule No. 34-67716, *Conflict Minerals*
  - Final Rule No. 34-67717, *Disclosure of Payments by Resource Extraction Issuers*
  - Final Rule No. 34-68668, *Lost Securityholders and Unresponsive Payees*
  - Proposed Rule No. 33-9452, *Pay Ratio Disclosure*
  - Proposed Rule No. 33-9470, *Crowdfunding*
  - Proposed Rule No. 34-70277, *Credit Risk Retention*
- Forms:
  - Form 8-K, “Current Reports”: Item 4.01, “Changes in Registrant’s Certifying Accountant”
  - Form 13H, “Large Trader Registration Information Required of Large Traders Pursuant To Section 13(h) of the Securities Exchange Act of 1934 and Rules Thereunder”
  - Form 20-F
  - Form 40-F
  - Form D, “Notice of Exempt Offering of Securities”
  - Form S-3, “Registration Statement Under the Securities Act of 1933”
  - Form SD, “Specialized Disclosure Report”
- Regulation D, “Rules Governing the Limited Offer and Sale of Securities Without Registration Under the Securities Act of 1933”:
  - Rule 501, “Definitions and Terms Used in Regulation D”
  - Rule 506, “Exemption for Limited Offers and Sales Without Regard to Dollar Amount of Offering”
- Regulation FD, “Fair Disclosure”
- Regulation S-K:
  - Item 402(c), “Executive Compensation: Summary Compensation Table”
- Regulation S-X:
  - Rule 3-05, “Financial Statements of Businesses Acquired or to Be Acquired”
  - Rule 3-09, “Separate Financial Statements of Subsidiaries Not Consolidated and 50 Percent or Less Owned Persons”
  - Rule 3-14, “Special Instructions for Real Estate Operations to Be Acquired”
  - Rule 4-08(g), “General Notes to Financial Statements: Summarized Financial Information of Subsidiaries Not Consolidated and 50 Percent or Less Owned Persons”
- SEC Staff Accounting Bulletins:
  - Topic 10.E, “Classification of Charges for Abandonments and Disallowances”
- Division of Corporation Finance:
  - Financial Reporting Manual (FRM)
- Securities Exchange Act of 1934 Rules:
  - Rule 17Ad-17, “Lost Securityholders and Unresponsive Payees”
Appendix C — Deloitte Specialists and Acknowledgments

U.S. Energy & Resources Contacts

**John McCue**  
U.S. Industry Leader, Energy & Resources  
Deloitte Consulting LLP  
+1 216-830-6606  
jmccue@deloitte.com

**Sampat Prakash**  
U.S. Consulting Industry Leader, Energy & Resources  
Deloitte Consulting LLP  
+1 713-982-2723  
sapprakash@deloitte.com

**Brad Seltzer**  
U.S. Tax Industry Leader, Energy & Resources  
Deloitte Tax LLP  
+1 202-220-2050  
bseltzer@deloitte.com

**Bill Graf**  
U.S. AERS Advisory Industry Leader, Energy & Resources  
Deloitte & Touche LLP  
+1 312-486-2673  
wgraf@deloitte.com

**Charlie Muha**  
U.S. AERS Audit Industry Leader, Energy & Resources  
Deloitte & Touche LLP  
+1 704-887-1541  
cmuha@deloitte.com

**Jed Shreve**  
U.S. FAS Industry Leader, Energy & Resources  
Deloitte Financial Advisory Services LLP  
+1 713-982-4393  
jshreve@deloitte.com

U.S. Power & Utilities Contacts

**John McCue**  
U.S. Sector Leader, Power & Utilities  
Deloitte Consulting LLP  
+1 216-830-6606  
jmccue@deloitte.com

**Reid Miller**  
U.S. Consulting Sector Leader, Power & Utilities  
Deloitte Consulting LLP  
+1 612-397-2673  
remiller@deloitte.com

**Bill Graf**  
U.S. AERS Audit Sector Leader, Power & Utilities  
Industry Professional Practice Director, Power & Utilities  
Deloitte & Touche LLP  
+1 312-486-2673  
wgraf@deloitte.com

**James Barker**  
Deputy Industry Professional Practice Director, Power & Utilities  
Deloitte & Touche LLP  
+1 203-761-3550  
jabarker@deloitte.com

**Clint Carlin**  
U.S. AERS Advisory Sector Leader, Power & Utilities  
Deloitte & Touche LLP  
+1 713-982-2840  
ccarlin@deloitte.com

**Brad Seltzer**  
U.S. Tax Sector Leader, Power & Utilities  
Deloitte Tax LLP  
+1 202-220-2050  
bseltzer@deloitte.com

**Tom Kilkenny**  
Deputy Industry Professional Practice Director, Power & Utilities  
Deloitte & Touche LLP  
+1 414-977-2530  
tkilkenny@deloitte.com
**Acknowledgments**

We would like to thank the following Deloitte professionals for contributing to this document:

- Erin Abreu
- Kyle Arthur
- James Barker
- Will Bible
- Derek Bradfield
- Lynne Campbell
- Diane Castro
- Jeff Craft
- Mark Crowley
- Joe DiLeo
- Geri Driscoll
- George Fackler
- Trevor Farber
- Jason Gambone
- Bill Graf
- Amanda Hargrove
- Lauren Hegg
- Karen Higgins
- David Horn
- Brad Humpal
- Elisabeth Indriani
- Paul Josenhans
- Tom Keefe
- Tom Kilkenny
- Steve Koesters
- Tim Kolber
- Christopher Lee
- Eric Lukas
- Wendy Meredith
- Erin Meyer
- Matthew Moore
- Anthony Mosco
- Charles Muha
- Patrick Ngako
- Ejituru Okorafor
- Jeanine Pagliaro
- Matt Parker
- Taylor Paul
- Heath Poindexter
- Sean Prince
- Joe Renouf
- Brad Seltzer
- Liesbeth Simons
- Scott Streaser
- Teresa Thomas
- Rick Tiwald
- Abe Varghese
- Abhinetri Velanand
- Jason Weaver
- Russell Wright
- Tim Wilhelmy
- Karen Wiltzie
- Dave Yankee
Appendix D — Other Resources and Upcoming Events

Subscribe
To receive practical insights from Deloitte via e-mail, including newsletters, thoughtware alerts, and webcast invitations, visit www.deloitte.com/us/subscriptions.

Dbriefs
We invite you to participate in Dbriefs, live webcasts from our Energy & Resources practice, which offer valuable insight into important developments affecting your business. These monthly webcasts feature discussions by Deloitte professionals and industry specialists on critical issues that affect your business. Subscribe to receive notifications about future Dbriefs webcasts at www.deloitte.com/us/dbriefs.

Events
Deloitte Energy Conference — Washington, DC
May 13–14, 2014
For more information, please contact: EnergyConference@deloitte.com.

Utility Industry Book/Tax Differences
March 25–26, 2014
For more information, please contact: USEnergyTaxSeminars@deloitte.com.

Alternative Energy Seminar — Dallas, TX
September 29–October 1, 2014
For more information, please contact: AlternativeEnergy@deloitte.com.

Deloitte Energy Accounting, Financial Reporting and Tax Update — Chicago, IL
December 2014
For more information, please contact: USEnergyFallSeminars@deloitte.com.

Deloitte Energy Transacting Accounting — Chicago, IL
December 2014
For more information, please contact: USEnergyFallSeminars@deloitte.com.

Deloitte Financial Reporting for Taxes: Rate-Regulated Utilities
December 2014
For more information or to schedule this seminar at your company, please contact USEnergyTaxSeminars@deloitte.com.

Social Media
Stay current with research and insights from the Deloitte Center for Energy Solutions by following us on Twitter @Deloitte4Energy.