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January 2013

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. To help you meet these challenges, we are pleased to present our 11th annual Accounting, Financial Reporting, and Tax Update. 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.

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, we have included a section that discusses the Board’s proposals and have highlighted nuances that could affect our industry.

This year’s update addresses timeless considerations as well as new guidance. We hope you find it to be a useful resource, and we welcome your feedback. Please also visit us at www.deloitte.com for more information. Special reference is made to our Heads Up newsletter issued December 11, 2012, covering highlights from the 2012 AICPA Conference on Current SEC and PCAOB Developments.

As always, we encourage you to contact your Deloitte team for additional information and assistance.

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Section 1
Industry Developments
Outlined below are some of the issues and trends that have affected entities in the power and utilities (P&U) industry that are not addressed in the rest of this publication.

Merger and Acquisition Activity

The volume of merger and acquisition activity in the P&U industry was down significantly in 2012 when compared with 2011. Though new activity slowed, the industry did see the closing of a number of previously announced mergers. Some of the more significant transactions that closed in 2012 include the following:

- **Duke Energy Corporation and Progress Energy Inc.** — On July 2, 2012, Duke Energy Corporation confirmed the closing of its merger with Progress Energy Inc. Progress Energy Inc. has become a wholly owned direct subsidiary of Duke Energy, creating the country’s largest electric utility (as measured by enterprise value, market capitalization, generation assets, customers, and numerous other criteria).

- **Energy Transfer Equity L.P. (ETE) and Southern Union Company (SUG)** — On March 26, 2012, ETE announced the completion of its merger with Southern Union. Southern Union will continue to operate as a wholly owned subsidiary of ETE.

- **Exelon Corporation and Constellation Energy Group Inc.** — On March 12, 2012, Exelon Corporation and Constellation Energy Group Inc. completed their merger. The new company retains the Exelon name.

- **Kinder Morgan Inc. and El Paso Corp.** — On May 24, 2012, Kinder Morgan Inc. announced the completion of its acquisition of El Paso Corp. This acquisition makes Kinder Morgan one of the largest midstream companies in North America.

- **Northeast Utilities and NSTAR** — On April 10, 2012, Northeast Utilities announced that its merger with NSTAR was complete. NSTAR will operate as a subsidiary of Northeast Utilities.

Significant merger activity announced in 2012 included the following:

- **NRG Energy Inc. and GenOn Energy Inc.** — The merger agreement was announced on July 22, 2012, with a transaction value of $3.9 billion. On December 14, 2012, NRG Energy Inc. and GenOn Energy Inc. announced the merger was complete, creating one of the largest competitive power generators in the country.

- **Fortis Inc. and CH Energy Inc.** — On February 21, 2012, Fortis Inc. announced that it had entered into an agreement to acquire CH Energy Inc. for $65 per common share in cash, for an aggregate price of $1.5 billion, including the assumption of $500 million of debt.

Mergers and acquisitions can be an intermediate-term strategy to gain financial scale and flexibility for required investments and may provide cost reductions. Many expect mergers and acquisitions will continue as the industry reacts to environmental compliance requirements, the impacts of low natural gas prices, and in some cases, the need to moderate customer rate increases.

See Deloitte’s *A Roadmap to Accounting for Business Combinations and Related Topics* for specific discussion and considerations regarding the accounting for mergers and acquisitions.

The Future of Nuclear

After the 2011 Fukushima Daiichi nuclear disaster, the increased cost and regulatory delays associated with constructing nuclear facilities caused a number of companies to postpone or formally cancel the construction of new nuclear power plants. In addition, entities have experienced increased costs associated with design assessment and compliance for existing units. Some significant developments in 2012 included the following:

1 For a list of abbreviations used in this publication, see Appendix A.
On August 30, 2012, judges from the NRC’s Atomic Safety and Licensing Board held that UniStar Nuclear Operating Services LLC and Calvert Cliffs 3 Nuclear Project LLC could not build a third unit at the Calvert Cliffs nuclear power plant in Maryland. The judges ruled that the applicants could not receive a combined license to build and operate an Areva EPR at Calvert Cliffs because the applicants are 100 percent owned by a foreign corporation.

On August 28, 2012, Exelon notified the NRC that it would withdraw its early site permit application for a proposed site in Victoria, Texas, since low natural gas prices and economic and market conditions made construction of a new merchant nuclear power plant in a competitive market uneconomical.

A few companies are continuing the construction of new nuclear facilities. Some of the current construction projects include:

- **Vogtle Electric Generating Plant Units 3 and 4** — In February 2012, the NRC issued construction and operating licenses for two new nuclear power reactors at the Vogtle plant located in eastern Georgia, which is operated by Georgia Power, a subsidiary of the Southern Company. As of October 2012, the construction project was approximately one-third complete. Units 3 and 4 are expected to begin commercial operation in 2016 and 2017, respectively.

- **Virgil C. Summer Nuclear Generating Station Units 2 and 3** — In March 2012, the NRC approved the construction license for the two proposed reactors at the Summer plant, which is located in South Carolina. Two-thirds of the Summer plant is owned by the operator, a subsidiary of SCANA Corp., and the remaining one-third is owned by the South Carolina Public Service Authority. Units 2 and 3 are expected to begin commercial operation in 2017 and 2018, respectively.

- **Tennessee Valley Authority Watts Bar Unit 2** — In April 2012, the Tennessee Valley Authority board of directors approved continuing the construction of the unit, with revised estimates for the budget and timeline. (Estimated completion of the project is now 2015.) After this unit completes its first fuel load, the Tennessee Valley Authority plans to begin construction on the Bellefonte Nuclear Plant Unit 1 in Alabama.

In October 2012, Dominion Resources Inc. announced plans to close and decommission its Kewaunee Power Station in Wisconsin in the second quarter of 2013 despite having received a 20-year extension to its operating license that was previously set to expire in December 2013. In a statement, Dominion’s president and CEO attributed the decision to economic reasons, such as the low price of natural gas. Kewaunee is the first U.S. nuclear reactor to close since 1998.

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

**Rate-Case Activity**

Rate-case activity continued at a significant level in 2012. The elevated level of rate-case activity in recent years 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 due to the economy and customer conservation. In 2012, the return on equity (ROE) percentages set by regulators began trending lower than historical amounts, with average ROEs going below 10 percent. For the 21 electric-rate cases settled in the second and third quarter of 2012, the average ROE was 9.87 percent. For the 14 gas-rate cases filed in 2012, the average ROE was 9.75 percent. Notwithstanding 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

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, increased supplies, combined with the slowdown in demand resulting from the recent economic events, have sent North American gas prices down dramatically.

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 rates of growth in the demand for regional gas, the advent of new natural gas infrastructure, and evolving gas flows may also contribute to changes in regional basis.

Gas prices in the eastern United States, which have historically been among the highest in North America, could be reduced by increased supplies from shale gas production in the region. Such regional shale gas production in the eastern United States could depress prices in the regions that have historically produced gas. With significant shale gas production out of Haynesville and Eagle Ford, the Gulf region is projected to continue to have plentiful production and remain one of the regions with the lowest gas prices in North America.

The sustained low natural gas prices in the United States are now making it economical to export liquefied natural gas (LNG) to Europe and Asia. See Deloitte’s report, Exporting the American Renaissance: Global Impacts of LNG Exports from the United States, for more information. As a result of the high costs of constructing a liquefaction plant and transporting an LNG tanker, a spread would be required of at least $3.00/MMBtu to Europe and over $4.00/MMBtu to Asia, and the current spreads are well above that level. Consequently, entities have had an increased interest in constructing LNG export facilities. The construction and operation of LNG facilities must be approved by the FERC. The following LNG export facilities were approved or proposed to the FERC in 2012:


- *Cheniere Energy Inc.: Corpus Christi liquefaction project* — On August 31, 2012, Cheniere Energy Inc. filed an application with the FERC for authorization to construct and operate a natural gas liquefaction and export plant and LNG import facilities with regasification capabilities at a site near Corpus Christi, Texas. The majority of the project will be located in areas previously evaluated and assessed by the FERC in 2005 in association with an LNG import facility that was not constructed because of changes in global market conditions.

- *Freeport LNG Development L.P.* — On June 29, 2012, Freeport LNG filed an application with the FERC for authorization to site, construct, and operate natural gas liquefaction and export facilities at and adjacent to its existing LNG terminal near Freeport, Texas.

- *Southern Union’s Trunkline LNG Co. project* — On March 30, 2012, Trunkline LNG filed a statement of intent to file an application with the FERC for authorization to site, construct, and operate natural gas liquefaction facilities located near the existing Trunkline LNG import terminal near Lake Charles, Louisiana. The formal application for FERC authorization is expected to be filed no later than March 2013.

- *Jordan Cove Energy Project L.P.* — On February 29, 2012, Jordan Cove requested that the FERC initiate a prefiling review of its proposal to locate liquefaction facilities at the Coos Bay, Oregon, site of its previously certified LNG import terminal.

- *Cameron LNG* — In April 2012, Cameron LNG, an affiliate of Sempra LNG, requested that the FERC initiate a prefiling review of its proposal to locate liquefaction and export facilities near its current terminal in Hackberry, Louisiana. The formal application for FERC authorization was filed on December 7, 2012.

- *Dominion Cove Point LNG* — In June 2012, Dominion submitted a request to the FERC to initiate a prefiling review of its proposal to locate liquefaction facilities for exporting LNG at its existing Cove Point LNG terminal on the Chesapeake Bay in Lusby, Maryland. The formal application for FERC authorization is expected to be filed in April 2013.
• **Oregon LNG** — In July 2012, Oregon LNG submitted a request to the FERC to initiate a prefiling review of its proposed project to convert Oregon LNG’s pending LNG terminal and pipeline in Warrenton, Oregon, into a bidirectional LNG terminal and pipeline. The formal application for FERC authorization is expected to be filed in the first quarter of 2013.

Only one LNG export project has been approved by the FERC so far, and it is unclear whether additional projects will be approved. 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.

With significant influence from federal policies, the exportation (as well as other uses) of the North American shale gas supply will continue to affect the industry.

**Future of Coal Power Plants**

Because of regulatory requirements and market dynamics, including low natural gas prices, the rising cost of coal, and reduced demand for electricity, the P&U industry continued to see announcements of plans to retire coal plants. Recent reports suggest that the current infrastructure will decrease by almost 30,000 MW of capacity by 2016.

Regulatory requirements for coal plants were established by the EPA’s Mercury and Air Toxics Standards (MATS), which were finalized in December 2011 and set standards to limit toxic air emissions. In August 2012, a federal appeals court vacated the EPA’s CSAPR, which would have set limits on emissions from power plants in 28 eastern states via a new cap-and-trade program. While current regulatory requirements may be less restrictive than originally believed, additional requirements may come in the future.

Decreases in spot and forward natural gas prices as the cost of replacement power and projected energy margins decrease may have a greater impact on the economics in the decision to retrofit versus retire coal units. Recent studies have indicated that a $1/MMBtu decrease in the current forward gas prices could more than triple the current projected plant retirements.

Regulations may have an even more significant effect on the construction of new coal power plants. In March 2012, the EPA proposed its Carbon Pollution Standard for New Power Plants. To meet the emission rates proposed by the standard, coal power plants would need to incorporate technology, such as carbon capture and storage, to reduce emissions. If this proposed regulation becomes effective, no new coal power plants are likely to be constructed in the United States.

As regulations and market conditions change, entities must continue to evaluate the economics of coal plants and the impacts on financial accounting.
Section 2
SEC Update
This section summarizes recent SEC rulemaking and interpretive guidance that may affect companies in the P&U industry.

Proxy, Risk, Compensation, and Corporate Governance Guidance Updates

SEC Staff Issues Small Entity Compliance Guide on Listing Standards for Compensation Committees

On July 12, 2012, the SEC staff issued a compliance guide for small public entities (that are not smaller reporting companies as defined in Regulation S-K, Item 10(f)) that provides interpretive guidance on implementing Section 10C of the Securities Exchange Act of 1934 (the “Exchange Act”). Specifically, the guide addresses (1) disclosure requirements related to compensation consultant conflicts of interest and (2) the requirement that securities exchanges establish minimum listing standards related to issuers’ compensation committees.

SEC Staff Issues Guidance on Shareholder Proposals

On October 18, 2011, the SEC’s Division of Corporation Finance released Staff Legal Bulletin No. 14F, which provides the staff’s views on shareholders’ eligibility to submit proposals in a company’s proxy access materials under Rule 14a-8 of the Exchange Act. The legal bulletin addresses the following topics:

- Which “types of brokers and banks . . . constitute ‘record’ holders under Rule 14a-8(b)(2)(i).” Under this provision, a beneficial owner must submit a record holder’s written statement that the beneficial owner (i.e., the shareholder) is eligible to submit a proposal.
- Some “[c]ommon errors shareholders can avoid when submitting proof of ownership to companies.”
- A shareholder’s “submission of revised proposals.”
- “Procedures for withdrawing no-action requests for proposals submitted by multiple proponents.”
- The SEC’s “new process for transmitting Rule 14a-8 no-action responses by email.”

On October 16, 2011, the SEC’s Division of Corporation Finance released Staff Legal Bulletin No. 14G, which provides information for companies and shareholders about Exchange Act Rule 14a-8. This bulletin includes information about various topics, such as:

[The parties that can provide proof of ownership under Rule 14a-8(b)(2)(i) for purposes of verifying whether a beneficial owner is eligible to submit a proposal under Rule 14a-8; the manner in which companies should notify proponents of a failure to provide proof of ownership for the one-year period required under Rule 14a-8(b)(1); and the use of website references in proposals and supporting statements.]

Activities Related to Requirements Under the Dodd-Frank Act

Certain provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) require the SEC to take specific action, such as make rules or conduct studies related to various areas of financial regulation. The discussion below summarizes recent SEC activities in connection with these requirements.
SEC Issues Final Rule on Risk Management and Operations of Clearing Agencies

On October 22, 2012, the SEC issued a final rule on the risk management and operations of clearing agencies. The rule requires clearing agencies to “establish, implement, maintain and enforce written policies and procedures reasonably designed to”:

- “[M]easure [their] credit exposures to [their] participants at least once a day.”
- Use margin requirements to limit their credit exposures to participants by using risk-based models and parameters, which should be reviewed at least monthly.
- Maintain sufficient financial resources to withstand, at a minimum, a default by the participant family to which they have the largest exposure in extreme but plausible market conditions (and a default by the two participant families to which they have the largest exposures for security-based swap clearing agencies).
- Provide for an annual model validation by a qualified person who is free from influence of the persons responsible for the development or operation of the models being validated.

The final rule became effective on January 2, 2013. This rule may affect P&U companies, or their subsidiaries, that have trading activities or that enter into derivative positions to hedge fluctuations in fuel prices to limit risk.

SEC Approves Proposals for Swap Dealers and Major Swap Participants

On October 18, 2012, the SEC issued a proposed rule that outlines capital, margin, and segregation requirements that make the derivative markets fairer, more efficient, and more transparent. Among other things, the proposed rule outlines:

- How much capital dealers in security-based swaps need to hold.
- When and how these dealers need to collect collateral, or margin, to protect against losses from counterparties.
- How these dealers segregate and protect funds and securities held for customers.

Comments on the proposed rule are due January 22, 2013.

SEC Finalizes Rule Defining Key Swap-Related Terms

In accordance with Title VII of the Dodd-Frank Act, on July 19, 2012, the SEC and CFTC jointly adopted a final rule that further defines the terms “swap,” “security-based swap,” and “security-based swap agreement” (collectively referred to as “product definitions”); defines “mixed swaps”; and describes recordkeeping requirements related to security-based swap agreements. While the final rule retains the statutory definitions of swaps and security-based swaps, it also discusses how such definitions apply to common financial products. For example, because of constituents’ concerns, the final rule (1) excludes forward contracts from the definitions of a “swap” and “security-based swap” and (2) also considers insurance and foreign exchange products, total return swaps, credit default swaps, and consumer and commercial agreements, contracts, and transactions. In addition to the final rule, the SEC posted a summary entitled, “The Regulatory Regime for Security-Based Swaps,” on its Web site.

SEC Issues Final Rule on Disclosing Payments Made by Issuers Engaged in Resource Extraction

On August 22, 2012, the SEC issued a final rule implementing Section 1504 of the Dodd-Frank Act. Under Section 1504, issuers that are (1) required to file an annual report with the SEC and (2) engaged in commercial resource extraction of oil, natural gas, and minerals must disclose certain payments made to the federal government or foreign national or subnational governments. The final rule’s disclosure requirements apply to domestic issuers (including smaller reporting companies), foreign issuers, their subsidiaries, and other entities controlled by such extractive issuers. The final rule requires extractive issuers to annually file with the SEC a newly created Form SD that would include, as an XBRL exhibit, the required payment information.
Extractive issuers must file Form SD with the SEC no later than 150 days after their fiscal year-end and must comply with the final rule’s disclosure requirements for fiscal years ending after September 30, 2013. For an extractive issuer whose fiscal year began before September 30, 2013, disclosures in the first report will need to include only those payments made after September 30, 2013, through the end of the issuer’s fiscal year.

Registrants in the P&U industry should pay particular attention to the disclosure requirements of the final rule. Some P&U registrants with oil and gas operations could meet the definition of an “extractive issuer” and need to disclose such payments made to governments. Implementation of the final rule may be challenging for numerous reasons, including the following:

- The final rule would apply not only to registrants but also to their subsidiaries as well as other entities that the registrant has an interest in and accounts for as an equity method investment. There are also questions about whether oil field services issuers and commodity traders should be included in the scope of the final rule.
- The payment threshold is low. Any payment in excess of $100,000 (individually or in the aggregate) must be disclosed.
- The disclosure requirements are very detailed. The final rule specifies that project-level disclosures are required. While the final rule notes that the term “project” is intentionally undefined, it also notes that the term is commonly understood and indicates that “project level” would generally refer to “contract level.” In addition, the required disclosures include (1) various types of payments and (2) the countries, governments, and currencies associated with such payments.

The SEC staff is compiling implementation-related questions and considering whether to issue interpretive guidance.

**SEC Issues Final Rule on Conflict Minerals**

On August 22, 2012, the SEC narrowly approved issuance of a long-awaited final rule implementing Section 1502 of the Dodd-Frank Act. Section 1502 requires issuers to annually disclose a description of the measures employed to “exercise due diligence on the source and chain of custody of such [conflict] minerals” that originate in the Democratic Republic of Congo (DRC) and adjoining countries.

Under the final rule, all SEC registrants must assess whether they use conflict minerals and whether such conflict minerals are “necessary to the functionality or production” of either (1) products they manufacture or (2) products that they have contracted to third parties for manufacture. If these conditions are met, registrants must conduct a reasonable country-of-origin inquiry to determine the source of the conflict minerals. The rule also requires registrants to perform, when applicable, reasonable due diligence to classify their conflict minerals as (1) “DRC conflict free,” (2) “not DRC conflict free,” or (3) “DRC conflict undeterminable.” Each classification has different reporting requirements. Registrants must file a newly created Form SD with the SEC on a calendar-year basis (regardless of their fiscal year-ends) beginning with the first calendar year ending December 31, 2013. Form SD is due on May 31, 2014, and on May 31 each year thereafter.

Because the final rule applies to issuers that manufacture products or contract third parties to manufacture products on the issuers’ behalf, it may appear that the final rule may not apply to P&U registrants. However, P&U registrants should be sure to evaluate all revenue streams to determine whether the final rule applies to them because there is no materiality threshold for the use of conflict minerals.

The SEC staff is compiling implementation-related questions and considering whether to issue interpretive guidance.

**SEC Staff Issues Report on Implementing Organizational Reform Recommendations**

On March 30, 2012, the SEC staff issued a report on implementing its organizational reform recommendations. The document is the second in a series of four SEC reports to the U.S. Congress under Section 967(c) of the Dodd-Frank Act.
SEC Issues Final Rule on Mine Safety Disclosure Requirements

On December 21, 2011, the SEC issued a final rule on disclosures about mine safety that completes the Commission’s required rulemaking under Section 1503 of the Dodd-Frank Act. The final rule is based on the safety and health requirements under the Federal Mine Safety and Health Act of 1977 and requires registrants (including foreign private issuers (FPIs)) to periodically disclose mine safety violations and related information, regardless of materiality. Under the new rule, registrants “that are operators, or that have a subsidiary that is an operator, of a coal or other mine” located in the United States are required to disclose, in their periodic reports to the SEC, “health and safety violations, orders and citations, related assessments and legal actions, and mining-related fatalities.”

The final rule became effective on January 27, 2012.

The Jumpstart Our Business Startups Act

President Obama signed the Jumpstart Our Business Startups Act (the “JOBS Act”) into law on April 5, 2012, to increase American job creation and economic growth by improving access to the public capital markets for emerging growth companies (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 (1) to reduce financial statements presented (from three to two years), (2) to reduce periods that would be presented for selected financial data, (3) the option to adopt new or revised accounting standards (issued after April 5, 2012) on the basis of nonpublic company transition periods, and (4) to forego obtaining an attestation report for ICFR.

Title I of the JOBS Act amends the Securities Act of 1933 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). On May 11, 2012, the SEC announced that it implemented an enhanced e-mail system that allows EGCs and eligible FPIs to submit a draft registration statement to the SEC staff in a secure manner, allowing the staff to provide these entities with confidential review comments. Detailed instructions for the submission process are available on the SEC’s Web site.

To address certain implementation issues and considerations related to the JOBS Act, the SEC staff has been posting and will continue to post FAQs on its Web site. The FAQs discuss various topics related to EGCs (Title I), crowdfunding (Title III), and Exchange Act registration and deregistration (Titles V–VI) and include responses to questions about the following:

- Determining whether an issuer qualifies for EGC status.
- Understanding how certain provisions of the JOBS Act interact with existing SEC rules and regulations related to small entities, issuers of asset-backed securities, and FPIs.
- Applying certain of the financial reporting and disclosure accommodations available to EGCs (e.g., deferral of the adoption of new and revised accounting standards).
- Submitting draft financial statements.
- The definition of an EGC.

SEC Issues Proposed Rule on General Solicitation and Advertising

On August 29, 2012, the SEC issued a proposed rule that, if finalized, would implement Section 201(a) of the JOBS Act. The primary impacts of the proposed rule include:

- Removal of the prohibition on general solicitation and general advertising for securities offered under Rule 506, provided that issuers “take reasonable steps to verify that the purchasers of the securities are accredited investors.” The proposed rule would also amend Form D so that issuers could indicate whether they elect to apply the revised Rule 506 exception to registration.
• Amendments to Rule 144A to permit the offering of securities to investors that are not qualified institutional buyers (QIBs) as long as the securities are ultimately sold to investors that the seller reasonably believes are QIBs.

The comment period on the proposed rule ended on October 5, 2012, and the SEC staff is currently assessing the comments received. As of the date of this publication, the SEC had not yet issued a final rule.

Incorporation of IFRSs Into U.S. Reporting System

See Section 3 for a discussion of recent SEC developments related to IFRSs.

Financial Reporting Manual Updates

The FRM, issued by the SEC’s Division of Corporation Finance, contains SEC staff interpretations of various rules and regulations. The following updates were made to the FRM in 2012.

• October update (contains changes made as of June 30, 2012) — In addition to certain minor editorial revisions, changes include clarifications regarding (1) proxy statement requirements related to business dispositions, (2) auditor association with “from inception” amounts in development stage companies, and (3) PCAOB auditor and other reporting requirements related to reverse mergers.

• July update (contains updates made as of March 31, 2012) — In addition to certain minor editorial revisions, changes included clarifications related to the (1) Form 8-K requirements for the age of financial statements and (2) discussion of pro forma information in MD&A.

• April update (contains changes made as of December 31, 2011) — Noteworthy changes included (1) updates to reflect the guidance in ASU 2011-12; (2) treatment of “related businesses” under the significance tests in Regulation S-X, Rule 3-05; (3) Form 8-K reporting topics, including (a) pro forma requirements for dispositions representing discontinued operations and (b) non-GAAP measures; (4) scaled disclosures in a registration statement and Form 8-K; and (5) interim financial statement requirements for FPIs.

• January update (contains changes made as of September 30, 2011) — Changes were related to (1) auditor association requirements for development-stage companies, (2) “requests to provide less than full financial statements upon acquisition of ‘less than substantially all’ of an entity,” (3) reporting requirements for businesses acquired through step acquisitions, (4) subsidiary guarantee release provisions, and (5) various updates to Topic 6 for newly effective requirements of Final Rule 33-8959 on foreign issuer reporting enhancements.

Division of Corporation Finance Disclosure Topics

SEC Issues Disclosure Guidance on European Sovereign Debt Exposures

On January 6, 2012, the SEC’s Division of Corporation Finance issued CF Disclosure Guidance: Topic No. 4. While the SEC staff notes that “[t]his guidance is not a rule, regulation or statement of the Securities and Exchange Commission,” it contains detailed information regarding the disclosures that the SEC generally expects registrants to provide.

The SEC issued this guidance because of the lack of transparent, comparable information associated with European sovereign debt exposures, which has raised concerns about the adequacy of registrants’ disclosures for investors.

The SEC staff highlighted that in “determining which countries are covered by this guidance, registrants should focus on those experiencing significant economic, fiscal and/or political strains such that the likelihood of default would be higher than would be anticipated when such factors do not exist.” It is the SEC staff’s view that disclosures should be provided (1) separately by country, (2) segregated between sovereign and non-sovereign exposures, and (3) separated by financial
statement category. These categories will be aggregated together to determine the gross funded exposure. In addition, the staff has recommended that registrants consider providing separate disclosure of the gross unfunded commitments made. Finally, under this guidance, the staff has recommended that registrants “provide information regarding hedges in order to present an amount of net funded exposure.”

Specifically, the SEC highlights that registrants should consider disclosures that are relevant and appropriate on the basis of their particular facts and circumstances.

SEC Issues Disclosure Guidance Addressing Cybersecurity Reporting Considerations

On October 13, 2011, the SEC’s Division of Corporation Finance issued CF Disclosure Guidance: Topic No. 2 which highlights its views on disclosure considerations related to cybersecurity risks and cyber incidents. The guidance was issued in response to an increase in cybersecurity incidents, some of which have caused certain companies to incur significant remediation and other costs for (1) direct damages to the company (both real and reputational), (2) impacts on the company’s customers, and (3) increased protection from future cybersecurity attacks. Cybersecurity risks and cyber incidents may therefore constitute material risks, known trends, or uncertainties that a registrant should consider disclosing in SEC filings. Specifically, the staff’s guidance addresses considerations related to disclosure and the level of disclosure (1) in a registrant’s MD&A and financial statements, (2) related to risk factors and legal proceedings, and (3) in connection with disclosure controls and procedures.

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 on 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.

Loss Contingencies

While loss contingencies are not unique to the P&U industry, there has been an increase in comments received by utility companies related to this topic as the SEC staff has renewed its focus on the sufficiency of the related disclosures. Areas of focus include the following:

• If a registrant identifies that an accrual is necessary because a loss contingency is both probable and estimable, the staff has also asked the registrant to provide the factors it considered in providing an estimate of the reasonably possible range of loss in excess of the amounts it has accrued. If a registrant cannot estimate a range of loss, the staff has requested that the registrant provide a statement that such an estimate cannot be made at the present time.

• If a settlement has occurred in the most recent quarterly period, the SEC staff will look to prior-period filings to ensure that the disclosures were adequate and that users were provided proper early warnings about potential charges or charges that may have been taken in a current-period filing.

ASC 450 indicates that if the likelihood of an unfavorable outcome is determined to be at least reasonably possible but less than probable, or if the amount of probable loss cannot be reasonably estimated, accrual would be inappropriate. However, entities should include disclosures about the nature of the contingency and an estimate of the possible loss, or range of possible loss, or state that such an estimate cannot be made. Furthermore, the SEC staff has indicated that in this regard, nonspecific disclosure indicating that the outcome of a matter may be material to future results of operations or cash flows does not satisfy the criteria in ASC 450.
Debt Covenants

In recent SEC comments, the staff has asked registrants to disclose both quantitative and qualitative information about the status of their compliance with financial covenants and other covenants and debt instruments. For example, the staff has noted that the discussion in MD&A about the status of covenant compliance should (1) describe what an indenture’s covenants are and (2) illustrate what the actual ratios are, especially if the registrant is close to tripping the covenant.

Comments Specific to the P&U Industry

SEC comments relevant to companies in the P&U sector have focused on the following topics:

- Subsidiary and equity investee dividend restrictions.
- Accounting for the impact of rate making.
- Renewable energy certificates.


Other SEC Matters

SEC Issues Guidance About the Foreign Corrupt Practices Act

On November 14, 2012, the SEC and Department of Justice (DOJ) jointly issued A Resource Guide to the Foreign Corrupt Practices Act. The guide provides information to help registrants comply with the often complex requirements of the Foreign Corrupt Practices Act (FCPA). It also describes the statutory requirements, hypothetical scenarios, examples of enforcement actions, and applicable case law and DOJ opinion releases. The guide details (1) who and what is covered by the FCPA’s anti-bribery and accounting provisions, (2) the definition of a “foreign official,” (3) what constitutes proper and improper gifts and travel and entertainment expenses, (4) the nature of facilitating payments, (5) how successor liability applies in an M&A context, (6) considerations that promote an effective corporate compliance program, and (7) different types of civil and criminal resolutions that are available to registrants.

New Disclosure Requirements for Issuers Engaged in Sanctionable Activities With Iran and Syria

On August 10, 2012, President Obama signed into law the Iran Threat Reduction and Syria Human Rights Act of 2012 (the "Iran-Syria Act"). The Iran-Syria Act amends Section 13 of the Exchange Act to require issuers to disclose information about any instance in which they or their affiliates engaged in “sanctionable activities” (i.e., activities prohibited by the Iran-Syria Act).

Issuers that have engaged in sanctionable activities must disclose the following information in their annual or quarterly filings with the SEC:

- The nature and extent of the activity.
- The gross revenues and profits, if any, that are attributable to the activity.
- Whether the issuer intends to continue the activity.

The SEC is required to report registrants engaged in sanctionable activities to the president (and other members of Congress). The president will decide whether sanctions should be brought against the registrant within 180 days after the report is filed.
While the SEC has not yet proposed or finalized related rules because the new disclosure requirements are “self-executing,” the rules are effective for quarterly and annual reports filed on or after February 6, 2013. See Deloitte’s December 11, 2012, Heads Up, for more information on this topic.

**SEC Staff Issues Guidance on Legal and Tax Opinions in Registered Offerings**

On October 14, 2011, the SEC issued Staff Legal Bulletin No. 19, which provides the staff’s views on legal and tax opinions filed as part of a registered security offering. Specifically, the legal bulletin addresses (1) requirements for filing these opinions, (2) the SEC’s perspective on “the required elements for these opinions and the staff’s practices in reviewing them,” and (3) “the filing of consents to include these opinions in registration statements.”

**SEC Posts Draft EDGAR Filer Manual Updates**

The SEC periodically issues final rules to facilitate updates to the EDGAR filing manual. In 2012, the SEC posted updates in March, June, August, and October. Some noteworthy changes include:

- The EDGAR system will no longer support the 2009 U.S. GAAP XBRL taxonomy. Interactive data files that use this taxonomy will not be accepted by the system. Calendar-year-end filers should consider this change when preparing their second-quarter Form 10-Q filings.

- The EDGAR system will support confidential draft registration statement submissions made by EGCs and FPIs that are eligible under the JOBS Act or the Division of Corporation Finance’s policies.

Other changes, including a link to a complete listing of XBRL taxonomies that are supported by the EDGAR system, are described on the Information for EDGAR Filers page on the SEC’s Web site.
Section 3
International Financial Reporting Standards
The potential adoption of IFRSs remains a topic of interest for many companies in the P&U industry as the FASB works on convergence efforts and the SEC considers whether to mandate the standards for U.S. companies.

**SEC Update**

In November 2008, the SEC issued a proposed IFRS roadmap outlining milestones that could potentially lead to mandatory transition to IFRSs in the United States. The proposed roadmap sought input from U.S. constituents on (1) the use of IFRSs by U.S. issuers, (2) the SEC’s overall approach and considerations, (3) proposed technical amendments to the SEC’s rules and regulations, (4) standard setting under IFRSs, and (5) other topics.

Since the SEC issued the proposed roadmap, there has been additional discussion about the benefits and issues of “adopting,” “endorsing,” or “condorsing” IFRSs in the United States. Most recently, on July 13, 2012, the SEC staff issued its final report, *Work Plan for the Consideration of Incorporating IFRSs Into the Financial Reporting System for U.S. Issuers*. In the report, the staff made the following key comments:

- **Development of IFRSs** — Globally, IFRSs are generally perceived to be high-quality standards.
- **Interpretive process** — The IASB needs to improve the quality and the timeliness with which interpretations are issued.
- **Global application and enforcement** — There is diversity in application of IFRSs globally. Regulators in various jurisdictions need to work cooperatively to foster consistent application and enforcement of IFRSs.
- **Governance of the IASB** — The SEC staff approves of the structure of the IASB and the IASB’s independence but believes the best approach may be for the FASB to endorse IFRSs (rather than adopt IFRSs on a wholesale basis) to protect U.S. capital markets.
- **Status of funding** — More work must be done to stabilize the funding mechanism for the IASB.
- **Investor understanding** — Investors do not have “uniform” education on accounting issues under IFRSs.

The final report does not include a staff recommendation or provide a sense of what the SEC’s next steps may be in relation to IFRSs. Although the work plan is now completed, the final staff report acknowledges that “additional analysis and consideration of this threshold policy question is necessary before any decision by the Commission concerning the incorporation of IFRSs into the financial reporting system for U.S. issuers can occur.”

While the SEC has yet to make final decisions about whether and, if so, when and how to incorporate IFRSs into the financial reporting system for U.S. issuers, the report suggests that it is unlikely that the United States will be moving to IFRSs anytime soon. In a recent speech, SEC Chairman Elisse Walter stated that she believes the United States “will get there,” when speaking of adoption of IFRSs in some manner, but she did not confirm the timing. She also said that adopting IFRSs must be in the best interest of the U.S. investing public. So, while the final report issued by the staff does not clearly lay out a plan for adoption of IFRSs, it does appear that there is support for the general globalization of accounting standards, and it is also clear that, in the opinion of the SEC staff, IFRSs are best suited to accomplish that goal.

**The Modified Convergence Strategy**

The convergence of U.S. GAAP and IFRSs remains a key goal for the boards. The IASB released an updated work plan in October 2012 outlining revised estimates for its various projects. A number of projects have been deferred and the expected timing of other projects was more precisely defined. The projects that are closest to being finalized are the leases, revenue, and various financial instruments projects. Deadlines for finalization of IFRSs on leases were not explicitly stated in the work plan (although there is a hope that the leases standard will be finalized during 2013); however, the IASB expects to issue the final revenue recognition standard in the first half of 2013.

*Section 7* highlights some of the potential changes to U.S. GAAP as a result of the boards’ convergence efforts that may be of interest to P&U companies. However, U.S. GAAP would not necessarily converge with IFRSs because of these changes.
Key IFRS Agenda Items

As discussed above, the SEC has not been clear about whether or how the United States may adopt IFRSs. However, the ongoing IASB standard-setting activities will affect the SEC’s ultimate decision. Some of the topics being addressed in IASB standard setting that will be of particular interest to the SEC, FASB, and companies in the P&U sector are discussed below.

Financial Instruments

The guidance under IFRSs and U.S. GAAP on accounting for financial instruments is conceptually similar but the requirements in some areas differ. For instance, the definition of a derivative differs under the two accounting frameworks and consequently the contracts within the scope of derivative accounting will differ. Furthermore, even though the guidance is similar or the same in some areas, the lack of interpretative guidance in IFRSs may result in a different application of that guidance in practice. For example, under U.S. GAAP there are a significant number of interpretive issues on energy transacting that are not specifically addressed in IFRSs.

The boards have a joint project on their active agenda to improve the existing accounting guidance on financial instruments in IFRSs and U.S. GAAP. Although the financial instruments project is a joint project, the boards have adopted different strategies. While the FASB issued a comprehensive ED on classification and measurement, impairment, and hedge accounting in May 2010, the IASB is addressing the project in phases.

Classification and Measurement

In November 2009, the IASB issued IFRS 9, which requires entities to classify and measure financial assets on the basis of their business models and the assets’ contractual terms. In October 2010, the IASB amended IFRS 9 to retain the existing classification and measurement guidance for financial liabilities, with the exception that entities must present, in OCI, the changes in fair value of financial liabilities designated at fair value through profit or loss that are attributable to changes in the entities’ own credit risk. This phase had been completed, but 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 insurance project as well as the FASB’s model on the classification and measurement of financial instruments. The IASB has deferred the mandatory effective date of both the 2009 and 2010 versions of IFRS 9 to annual periods beginning on or after January 1, 2015, because it issued a new version of IFRS 9, which was exposed for public comment in November 2012.

General Hedging

The IASB issued an ED in December 2010 and a staff draft of the hedging model in September 2012. The general hedging model will replace the guidance under IAS 39 and cover just the general hedging requirements because the IASB is currently working on a macro hedging DP to address more detailed hedging programs. Changes made by the IASB to IAS 39, or to its original ED issued in 2010, are related to the following topics:

- **Hedging instruments** — Under IAS 39, a financial instrument was generally the only item eligible to be designated as a hedging instrument. Under the new rule, any item currently reported at fair value through profit or loss would be eligible as a hedging instrument regardless of whether it is a financial instrument. In addition, the staff draft also allows time value of options to be deferred, whereas today entities would typically run those items through the profit and loss.

- **Hedged items** — Under the ED, the IASB permits components of a nonfinancial item to be designated as a hedgeable item. This is a significant departure from IAS 39 guidance, under which only components of financial items could be designated as hedged items. In addition, the IASB is now allowing items that include derivatives or “aggregate exposures” to be designated as hedged items. This is also a significant departure from the guidance under IAS 39, which did permit derivatives to be hedged items. Finally, the IASB has proposed allowing companies to hedge groups and net positions. This would allow a company 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 a quantitative analysis both prospectively and retrospectively 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, there is no quantitative requirement to show there is an “economic relationship” between the hedged item and the hedge instrument. Instead, companies can complete an analysis of whether a hedge relationship exists either qualitatively (if the hedging relationship is clear) or quantitatively (for more complex hedging relationships).

• **Modifying or discontinuing a hedging relationship** — Under IAS 39, changes made to 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 ED removes the redesignation requirement in certain circumstances. In addition, the ED 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 ED creates new disclosure requirements to help users of the financial statements understand an entity’s use of hedging. These disclosures include information about:
  
  o The entity’s risk management strategy.
  
  o How the hedges will affect future cash flows.
  
  o How the hedges affect the balance sheet and the statement of equity.

**Impairment**

In this project, 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 to consider not only past and current information but also possible future events in determining impairment losses. The expected loss model and variations thereof have not been received favorably by constituents. In the first quarter of 2013, the IASB plans to expose for public comment 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 loss model, which it exposed for public comment in fourth quarter of 2012. For further discussion on this topic, see Section 7.

**Regulatory Assets and Liabilities**

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 followed similar accounting principles 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 one-year 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, and (4) proceeding with IFRS adoption (with some companies writing off regulatory balances, and some retaining them). 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, the IFRIC proposed a project on a narrow group of issues that ultimately delayed work on a 2009 international ED. On the 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 DP on these issues (targeting issuance in the second half of 2013) 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). Since 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 a variety of different regulatory regimes and the related accounting issues, not just the cost-of-service model commonly employed in North America and certain other countries.

On December 17, 2012, the IASB tentatively decided to develop an interim standard that permits some grandfathering of existing U.S. GAAP recognition and measurement accounting policies for those rate-regulated entities that have not transitioned to IFRS (primarily a benefit for Canadian entities). This interim standard would include presentation and disclosure requirements designed to assist users in understanding the effects of rate regulation. It is expected that the IASB will publish an ED with a 120-day comment period for the interim standard during the first quarter of 2013. The IASB expects to resume deliberations on its comprehensive project on rate-regulated activities during the second quarter of 2013 and publish a DP during the second half of 2013.

**Lease Accounting and Revenue Recognition Accounting**

See Section 7.

**Emissions Trading Schemes**

The IASB added an emissions trading scheme project to its agenda in October 2005. The Board added this project because of the increasing international use (or planned use) of schemes designed to achieve reduction of greenhouse gases through the use of tradable permits and because there was a risk of diverse accounting practices for such schemes after the withdrawal of IFRIC 3, which would sacrifice the comparability and usefulness of financial statement information.

In December 2007, the IASB began working jointly with the FASB on the project, and the two boards made tentative decisions on some of the main issues, including the recognition of assets and liabilities when an entity receives emission allowances (EAs) from the scheme administrator for no monetary consideration; however, many issues have not been discussed. Further, some aspects of the tentative decisions reached (primarily, up-front recognition of an emissions obligation for an entire compliance period upon the grant of related allowances, and measuring both allowances and the compliance obligation at fair value through profit and loss each reporting period) have been controversial and contrary to prevailing industry practice. In November 2010, the boards postponed this project after amending the timetables for other joint projects.

In May 2012, the IASB indicated that it would give priority to the project again as part of its ongoing deliberations on its three-year agenda consultation process, having received recent encouragement from French and Australian standard setters to move forward given the critical stages of their respective emission regulation schemes and their lack of related accounting guidance. The Australian and French accounting standards boards issued their own respective DPs to spur international discussion of the issues. Notably, the positions in the French paper are relatively consistent with those raised by the EEI in its April 2011 whitepaper on accounting for emissions (provided to the FASB’s staff at its request), particularly on the more controversial aspects of the tentative decisions mentioned above. Specifically, both the EEI and French papers appear consistent in advocating different measurement models for allowances that contemplate the business intent of the entity (i.e., “compliance” vs. “trading” models) as well as in believing that the obligating event for emission liability recognition is the act of emitting, not in becoming subject to the entirety of a scheme’s requirements simply because allowances were granted up front. The Australian paper also appears to indicate a belief that the emission of carbon is the obligating event for liability recognition purposes. However, the paper does directly provide a view on a preferred measurement model for the assets/allowances (and acknowledges that the classification of the allowances would potentially drive measurement and presentation).
Section 4
Industry Accounting 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 because such accelerated depreciation (which may be embedded in accumulated depreciation) represents a regulatory liability under U.S. GAAP. Therefore, if the regulator orders or agrees to an adjustment to reduce this regulatory liability, there are no restrictions on the reversal of the excess reserves under U.S. GAAP. The reversal of the regulatory liability should occur 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 previously recorded accumulated cost of removal. Accordingly, a negative cost of removal amortization is 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 theoretically excess “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 result in net depreciation expense being 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 was 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 are deferred for future recovery by the regulator 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. Regulatory lag is defined as the delay between a change in a regulated entity’s costs and a change in rates as ordered by the 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. Characterizing a rate decision as a phase-in plan or protection from the impact of regulatory lag requires a great deal of judgment and is based on the individual utility’s facts and circumstances.

**Purchase Accounting**

In December 2007, the FASB completed the second phase of its business combination project, which constituted a major overhaul of the accounting rules for business combinations and noncontrolling interests. This resulted in the FASB’s issuance of the guidance later codified in ASC 805 and ASC 810, which substantially elevated the role of fair value and dramatically changed the way companies account for business combinations and noncontrolling interests. In addition, the FASB issued new guidance on fair value measurement, including the measurement of assets and liabilities as of the acquisition date, which was later codified in ASC 820.

**Regulated Utility Considerations**

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 the utility 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 820-35-10 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. (Note that in June 2010, the FASB issued a proposed ASU that, among other things, 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 to which it is subject and by agreements that restrict the asset and transfer with it 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 attaches to the individual asset.
- The mechanism for recovery and whether the asset or liability is subject to rate recovery.
- 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:
  - Regulatory approval is required before the sale or disposition of utility assets.
  - The gain on the sale of a regulated asset is required to be shared with the regulated customers.
  - Use of the asset is restricted to public purposes.
While there may be differences in professional judgment regarding evaluation of the above factors, the recording of regulated property assets by using the predecessor’s carrying value to estimate the fair value of regulated assets in a business combination is generally viewed to be acceptable because either regulation attaches to the assets or entity regulation is so pervasive that the regulation 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 discounting of such assets by the acquired entity, 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.

**Normal Purchase Normal Sale 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 to the contract, or otherwise reach an outcome that indicates that it no longer is probable that the contract will result in physical delivery.

A contract that no longer qualifies for the NPNS exception 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 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 continued economic downturn.
- 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., 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

Developments in regulatory proceedings 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 in which the framework is applied in circumstances specific to 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 provide additional evidence about conditions that existed as of the date of the balance sheet, including the estimates inherent in the process of preparing financial statements. Type 1 subsequent events are recognized in the financial statements. Type 2 subsequent events are those that provide evidence about conditions that did not exist as of the date of the balance sheet but arose after that date. Type 2 subsequent events are not recognized in the financial statements, but 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 resolution of that loss contingency occurs 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.

Reversing 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 would also be appropriate if the liability 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. If a loss contingency event...
had not occurred as of the balance sheet date, but occurs 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.

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.” 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?

Regulated Utility Considerations

ASC 980 does not specifically address subsequent events unique to the P&U industry. Accordingly, entities should use the general guidance outlined 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 about conditions that existed as of the balance sheet date).

The examples below illustrate how regulated utilities might apply the guidance to typical subsequent events. Companies should give appropriate consideration to their particular facts and circumstances when applying the guidance outlined above.

Subsequent-Event Examples

Fuel Order Issued After the Balance Sheet Date

On July 15, 2011, 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, 2010, to December 31, 2010. 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, 2011, 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, and B 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 payer. 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 the court order constituted a change in legal status but not the realization of a gain and concluded 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. 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 a reasonable estimate of the amount of the disallowance can be made, 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 these terms. Utility D concluded that the ruling constituted additional significant objective evidence and that the associated impairment analysis previously performed was revised accordingly as a result of this Type 1 subsequent event. In other cases, post-balance-sheet events other than a final order from a regulator may constitute significant objective evidence.

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 would 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 determined it would 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 continue to operate and the likelihood that its regulator would have continued to allow recovery of the deferred costs was probable. 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 related to 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 they were willing to settle the case if F would forgo the remaining amortization of the storm damage costs. While F disagreed strongly with the intervenor 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 was probable 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, it was probable its regulator would have continued to allow recovery of the deferred costs over the remaining two years.

Companies clearly 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 prudence review in the current regulatory process.

Plant Abandonments and Disallowances of the Costs of Recently Completed Plants

ASC 980-360 provides guidance on the 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 or under-construction asset will be abandoned, the associated cost should be “removed from construction work-in-process or plant-in-service.” ASC 980-360 further provides 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. ASC 980-360 outlines the specific guidance.

SAB Topic 10E states that losses recorded pursuant to ASC 980-360 should not be reported as an extraordinary item. In addition, ASC 980-360 also implies that extraordinary item treatment of losses from abandoned assets is precluded. When a utility follows 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 not 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, typically an asset that will be retired in the near future and much earlier than its previously expected retirement date 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 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 abandonment date (early retirement date). Determining what constitutes an abandonment is a matter of judgment. Below are factors to consider in evaluating whether a plant is being abandoned:

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

Entities 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, in response to the federal appeals court’s decision to vacate CSAPR or for other reasons, reconsider a previous conclusion that an asset abandonment was probable. Specifically, a regulated asset that was probable of abandonment in a prior period may no longer be probable of abandonment. A regulated utility may have also recorded an abandonment loss in an earlier period when abandonment became probable. Based on these general facts, we believe it would be reasonable for the regulated utility to reclassify the carrying amount of the asset back into 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 reversing 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. If an unregulated affiliate transfers the recently completed plant costs to the rate-regulated utility, and such costs are then subject to the provisions of ASC 980-10, an impairment determination should be made under ASC 980-360 when the transfer is recorded.

There is no specific guidance in ASC 980-360 or ASC 360-10-35 defining a “recently completed plant” or specific guidance in ASC 980-340 defining a “newly completed plant.” It is reasonable to conclude that both terms should have the same definition. 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.
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.

Disallowances of costs for plants that are not recently completed are recognized in accordance with U.S. GAAP as applied by enterprises in general. An explicit, but indirect, disallowance occurs when no return or a reduced return is permitted on all or a portion of the new plant. In the case of indirect disallowances, 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 to the recorded plant amount, and the difference 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.

Accounting for Renewable Energy Certificates

The development of carbon markets worldwide has created a host of challenges for companies — and of these challenges, the accounting for transactions in these markets is perhaps one of the least understood. 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 undertaking efforts that capture or reduce carbon emissions. Electricity suppliers demonstrate compliance by redeeming RECs with the applicable regulatory or governmental body. They typically accumulate RECs through some combination of internal renewable energy generation, through purchase contracts with third-party owners of renewable energy facilities, or through transactions in secondary markets. Because of (1) the various mechanisms by which electricity suppliers obtain RECs, (2) uncertainties about how many RECs will ultimately be required for any annual or other compliance period, and (3) 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 leasing and derivative accounting guidance. The asset type, accounting value, and shortfall provisions should be assessed for all RECs, whether generated internally or acquired through transactions with third parties. The discussion below focuses on these areas of particular interest in connection with REC accounting. See Section 10 for additional discussion of revenue recognition accounting considerations related to RECs.

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 contracts such as these under ASC 840 to determine whether they contain a lease.¹

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 liability for capital leases) and (3) classification in the statement of cash flows (e.g., principal payments on capital lease obligations within financing activities).

¹ 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.
With respect to determining 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 under ASC 840, views differ about whether associated RECs are also considered outputs in the determination of whether a contract contains a lease. A clearly defensible policy 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 RECs should not be considered outputs because RECs are not produced or generated by operation of the PP&E but instead are generated by governmental or regulatory action. Under this view, RECs are considered an attribute of the PP&E and not an output of the PP&E. That is, RECs represent a marketable benefit of the PP&E; however, because RECs are “produced or generated” by law or regulation (like tax benefits) and are not physically produced by the PP&E, they are not considered an output in the determination of whether an arrangement contains a lease.

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. Proponents of this view believe 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 the purchaser is taking more than a minor amount of the output or other utility that will be produced or generated by the PP&E.

Whether RECs are considered an output in the determination of whether the arrangement contains a lease is critical 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, which may be difficult in situations in which there are bundled pricing terms (i.e., the individual products do not have discrete prices).

While either view of outputs described above is currently acceptable, companies should give appropriate consideration to the particular facts and circumstances of the contract (e.g., the stand-alone marketability of the RECs) and should apply the above guidance consistently.

**Derivative Considerations**

Entities should distinguish between the accounting for the actual REC 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 similar to 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 similar to contracts to buy, sell, or exchange other goods (e.g., forward contracts to purchase electricity). A derivative contract must be reported at fair value each reporting period, subject to certain scope exceptions (e.g., the NPNS exception).

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1 Economic attributes that are not both (1) generated by the facility’s production process and (2) separately marketable are generally not considered outputs in the determination of whether an arrangement contains a lease. 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.
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, RECs may be combined in some contracts with the purchase or sale of energy; energy is generally considered RCC. See Section 5 for additional discussion of derivative considerations 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, there is currently no authoritative accounting literature from either the FASB or the IASB on this topic or on emission allowances. In the meantime, many companies have developed accounting policies in the absence of explicit authoritative guidance. See Section 7 for additional discussion of the boards’ joint emissions trading schemes project.

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

**Asset Type**

The majority of 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 held are inventory or intangibles, entities may consider how they have historically used the RECs, their prospective intent, and the accounting ramifications of each accounting model. In fact, 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 transferred between pools.

Aside from the apparent balance sheet classification difference (both specific line item and short vs. long term), the two widely used models might affect financial statements differently with respect to:

- Timing and presentation of amortization or cost of sales expenses.
- Statement of cash flows classification of both purchases and sales of RECs in investing or operating.
- 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 some method of allocating costs of acquisition or costs of production 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 RECs are consumed by an entity 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 purchase 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.

For RECs from internal renewable generation sources, entities may use multiple accounting models to determine the carrying value. Three such models are described below.\(^3\)

**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 minimal costs allocated to RECs because it generally costs no more to produce RECs (e.g., relatively insignificant certification costs). As a result, 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, one may consider electricity and RECs to be joint products. Under the joint product allocation method, the cost of production is fully allocated between electricity and RECs and generally based on their relative fair values. This method results in more cost allocated to the RECs and less cost allocated to electricity than under the incremental cost method and, therefore, backloads expense recognition (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 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 accelerated or decelerated cost recognition relative to the previous two methods.

**Accounting Value Summary**

Each of the three methods to determine the accounting value of internally generated RECs is supportable, depending on the applicable facts and circumstances. Entities should consider the unique environment in each jurisdiction. Deloitte has issued interpretive guidance on the joint product and by-product allocation methods that entities may find useful in evaluating the alternatives; this guidance can be found in 330-10-30 (Q&A 06) in Deloitte’s FASB Accounting Standards Codification Manual.\(^4\) 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 subject to lower of cost or market inventory or amortized intangible impairment considerations.

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\(^1\) The accounting value models described in this section are applicable to RECs accounted for as “inventory.” ASC 350-30-30 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.

\(^2\) Deloitte’s FASB Accounting Standards Codification Manual is available on Technical Library: Deloitte’s Accounting Research Tool. For more information, including subscription details and an online demonstration, visit [www.deloitte.com/us/techlibrary](http://www.deloitte.com/us/techlibrary).
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, diversity exists with respect to the timing of recognition of a liability. Some support recognition of a liability only when the entity’s RECs have been exhausted, while others believe that consideration of expected shortfalls should be recognized throughout the compliance period in accordance with the guidance in 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.

EPA’s Cross-State Air Pollution Rule

Background

On August 21, 2012, a federal appeals court vacated the EPA’s CSAPR, which would have set limits on emissions from power plants in 28 states in the eastern half of the United States via a new cap-and-trade program. The court has instructed the EPA to draft regulations to replace CSAPR, which may take years to finalize, and to retain the CAIR until a replacement to the CSAPR has been finalized.

The EPA originally issued the CSAPR on July 6, 2011, which would have required more than 1,050 coal-, natural gas-, and oil-fired electric power plants in 28 states in the eastern half of the United States to reduce sulfur dioxide (SO2) and nitrous oxide (NOX) emissions via a new cap-and-trade program for emission allowances. The rule would have also required every affected state to adopt federal implementation plans (FIPs). The CSAPR would have ultimately replaced the CAIR, which the EPA issued in 2005. According to the EPA, the CSAPR’s overall purpose was to protect the health of American citizens by reducing air pollution that damages the ozone and results in the emission of fine particles. Effectively, the new rule would have been a means to enforce the requirements of the NAAQS.

On October 5, 2012, the EPA filed a petition for an en banc hearing that would include the full bench of judges serving the U.S. Court of Appeals for the District of Columbia Circuit as opposed to the three-judge panel that vacated CSAPR on August 21, 2012. Industry observers do not believe the en banc hearing is likely to overturn the August 21, 2012 ruling, but the ultimate outcome is uncertain.

Legislative History

Congress enacted the Clean Air Act (CAA) in 1963 to research and regulate the effects of air pollution nationally. In 1970 and 1977, Congress greatly expanded the CAA to require the development of both federal and state regulations on industrial and mobile pollution (i.e., pollution caused by vehicle engine emissions). In 1990, amendments to the CAA required governments to establish regulations addressing pollution related to acid rain, ozone depletion, and toxic air pollution. These amendments also (1) increased enforcement authority, (2) established a national permit program for stationary sources, and (3) established new auto gasoline reformulation requirements.

The “good neighbor provision” in the CAA requires every state to operate its emissions policies responsibly and limit the adverse impact of pollution on neighboring states. Under this provision, states must institute a state implementation plan (SIP) that would:

[C]ontain adequate provisions [that would prohibit] any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will . . . contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard.

The CSAPR was designed to implement the good neighbor provision for the regulation of SO2 and NOX and would have required certain upwind states to establish measures to prevent the emission of pollution across state lines that would “contribute significantly to nonattainment” of the NAAQS by neighboring states. The rule’s overall goal was to reduce SO2
and NOX emissions and pollution in downwind states. Certain aspects of the rule were to take effect January 1, 2012, with full implementation by 2014.

Court Challenges

After the CSAPR’s issuance, various stakeholders, including states, local governments, industry groups, and labor organizations, challenged its legality for numerous reasons. On December 30, 2011, just days before the rule was to take effect, the CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit to give the judges more time to consider its merits. On August 21, 2012, the court ruled 2–1 to vacate the CSAPR.

While it addressed numerous points, the majority opinion cited two primary reasons for vacating the rule:

- The EPA exceeded its authority under the CAA by mandating that a state reduce its emissions beyond its level of significant contribution. The CSAPR does not properly account for an upwind state’s proportional contribution to a downwind state’s nonattainment of the NAAQS because it does not take into consideration (1) contributions by other upwind states or (2) the downwind state’s independent contribution to its own nonattainment.

- The EPA overstepped its authority by imposing FIPs on states that were identified as upwind states. Upon its adoption of any EPA emissions standard, a state must be given the opportunity to initiate and execute a SIP before the EPA mandates a FIP. Under the CSAPR, however, the EPA executed a FIP when it implemented the rule, thereby violating the CAA.

Return to CAIR

The court has instructed the EPA to act “expeditiously” in drafting and finalizing a rule to replace the CSAPR. In addition, the court has directed the EPA to retain the CAIR until a replacement rule has been enacted. Therefore, companies are now operating under CAIR until a replacement is enacted, or further instructions are provided as a result of the EPA’s October 5th petition.

The CAIR’s cap-and-trade system, which covers 27 eastern states and the District of Columbia, allows the states to meet their individual emissions budgets by employing either of two compliance options: (1) requiring power plants to participate in an EPA-administered interstate cap-and-trade system that caps emissions in two stages or (2) undertaking measures of their own choosing. Immediately after the court vacated the CSAPR, the trading prices for 2012 NOX annual and seasonal allowances and 2012 SO2 allowances for the CAIR program increased slightly (although allowance prices remain low relative to those of several years ago). CAIR SO2 allowances in particular are plentiful and are trading at low prices. As a practical matter, the cost for a power producer to comply with the CAIR SO2 emission requirements is not expected to be significant. The October 5th petition filed by the EPA did not significantly affect trading of CAIR or CSAPR allowances. As of the date of this publication, industry observers note the emission markets remain in a holding pattern amid the legislative uncertainty.

Impact on Electric Power Producers

In response to the court’s decision to vacate the CSAPR, some electric power producers that had previously decided to abandon, or that may have temporarily idled, a power plant pending the outcome of the CSAPR ruling are reconsidering those plans. In addition, some power producers are considering delaying the implementation of certain SO2 and NOX emission control solutions that had been planned in response to the CSAPR requirements until those controls are needed for the Mercury and Air Toxics Standards (MATS) rule compliance, discussed immediately below, or until the EPA issues a replacement rule. Even though the CSAPR has been vacated, other federal and state regulations, including the CAIR, the MATS rule, the NAAQS, and regional haze rules, still curtail excessive emissions and air pollution. U.S. companies, including electric power plants, should familiarize themselves with changes to such regulations.
EPA’s Mercury and Air Toxics Standards

The EPA issued MATS on December 16, 2011, to set a national standard for mercury emissions and to regulate power plant emissions of mercury, acid gases, and nonmercury metallic toxic pollutants. The MATS rule is intended to (1) prevent emission into the air of about 90 percent of the mercury from coal burned in power plants, (2) reduce acid gas emissions from power plants by 88 percent, and (3) reduce SO2 emissions from power plants by 41 percent. Unlike the CSAPR or CAIR, the MATS rule is not a cap-and-trade program; no EAs are involved. If a specific plant emits more mercury or other toxins than are permitted, that plant is not allowed to operate.

Under the MATS rule, companies must make reductions starting in the first quarter of 2015. Power producers are expected to employ available technologies to reach the prescribed mercury targets, including selective catalytic reduction (SCR) with flue-gas desulfurization, activated carbon injection (ACI), ACI with fabric filter, and lectrostatic precipitators. For more information on the MATS rule, including information on targets, penalties, and technologies expected to be used to address other toxics, see the EPA’s Web site.

Thinking Ahead

The EPA is certain to continue monitoring air pollution nationally and to issue rules as needed to reduce toxic emissions in states where power plants are located as well as neighboring states. Power and utility companies should continue to evaluate different strategies to reduce emissions (including SO2 and NOX) to comply with state and EPA air-quality guidelines, including CAIR and the MATS rule. These strategies should take into account natural gas prices, CAIR allowance prices, as well as other economic factors, and they could potentially include (1) early retirement of certain plants, (2) retrofitting of existing plants with emissions reduction equipment, (3) changing the fuel mix of generating units, (4) seasonal operation of or temporarily idling plants, or (5) designing flexible dispatch plans. Although the industry is expected to achieve reductions of certain toxins without too much difficulty and, in many cases, with existing equipment (as would be the case with NOX), the reduction of other toxics (e.g., SO2) might present greater challenges.

Accounting Considerations

Emission Allowances

Intangible Asset Model

The court’s ruling to vacate CSAPR is not expected to directly result in accounting consequences in the third or fourth quarter of 2012 as it relates to EAs accounted for as intangible assets. Since the court stayed the implementation of CSAPR in December 2011, the decision of the court to vacate CSAPR in August 2012 (pending the outcome of the EPA’s petition) does not result in a triggering event pursuant to ASC 360-10-35-21. Companies accounting for CAIR EAs as intangible assets may have recorded an impairment of intangible assets in the third quarter of 2011 when CSAPR was enacted. Reversal of previously recognized impairment is prohibited.

However, companies should continuously evaluate the impact of operational plans stemming from changing regulations on the accounting model applied to EAs. Strategies that include (1) early retirement of certain plants, (2) retrofitting of existing plants with emissions reduction equipment, (3) changing the fuel mix of generating units, (4) seasonal operation or temporarily idling plants, or (5) designing flexible dispatch plans, could result in a change in the accounting model applied to EAs and under some circumstances result in impairment.

To the extent that a company’s accounting policy includes emission allowances expected to be used in plant operations in a power plant asset group, companies should carefully evaluate the extent to which EAs are included in the asset group specifically considering the aforementioned strategies. Depending on specific facts and circumstances, including the type of EA (CAIR, CSAPR, Acid Rain), the continued assertion that such allowances may be assumed held for use amid such strategies may no longer be appropriate. In the event the allowances are no longer held for use due to such strategies, an impairment may be present due to the high likelihood that the carrying cost of the EAs (including CSAPR, CAIR, and Acid Rain Allowances) exceed the fair value of the allowances given the low trading prices of the allowances amid the legislative uncertainty.
Inventory Model

A similar conclusion is expected with respect to EAs treated as inventory that are carried at the lower of cost or market due to a slight increase in the market prices of CAIR EAs subsequent to the court’s ruling. The lower of cost or market consideration should be applied to inventories at each reporting period. EAs carried in a trading portfolio would typically be subject to frequent turnover so that their value should approximate fair value at the end of each reporting period. ASC 330 provides guidance on the application of lower of cost or market analysis which is generally a comparison to net realizable value. If the EA inventory is to be used in the production of electricity, the net realizable value would generally be based on the estimated amount realizable from the sale of the electricity reduced by other costs of generation and sale of the electricity. If the EA inventory is to be sold rather than used in the generation of electricity, the carrying value would generally be compared to the amount realizable through existing firm sales commitments or expected sales prices (which may be market prices at the balance sheet date). Absent a clear decline in market prices of EAs, a company would not likely have a lower of cost or market impairment for its trading EAs.

Long-Lived Asset Impairments

The accounting considerations and potential impact of MATS and the court decision to vacate CSAPR may differ depending on whether (1) the generating units are rate regulated (and within the scope of ASC 980) or (2) the units are not subject to cost-based regulation. Further, the accounting considerations and potential impact will differ for companies which previously recognized an impairment or abandonment resulting from the enactment of CSAPR. Please refer to the Impairment Considerations section.

Rate-Case Settlements

A utility company files a rate case with its regulatory commission on a periodic basis. This may be due to requirements of the regulatory commission that the utility company file a new rate case or because the utility company has chosen to request new rates. The rate-case process when fully litigated in front of the regulatory commission is often a long process and may last 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. 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. The regulatory commission can then review and vote on the settlement agreement. The advantage of a settlement agreement is that it reduces the time 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 related to the types of currently-incurred costs that are to be recovered or information about the recovery of previously incurred costs that are deferred as regulatory assets. As such, a settled rate case requires a significant amount of judgment by a utility company to determine the appropriate accounting. Below are areas that utility companies should consider when determining how to account for a rate-case settlement.

- A utility company should consider preparing a hypothetical settled revenue requirement calculation based on the initially-filed rate case, filed testimony and responses to intervenor requests, discussions with intervenors and the regulator, and the settlement agreement. The hypothetical settled revenue requirement calculation may require input from the regulatory department, accounting, legal and management and will require a significant amount of judgment depending on the level of detail in the settlement agreement. The hypothetical settled revenue requirement calculation should be prepared with sufficient detail to allow parties to understand the significant judgments and allocations made in the calculations.
Specific considerations may include (1) the estimated capital structure ratio and cost of capital components; (2) a determination of how costs previously deferred will be recognized for both the amount of costs and the duration of recovery; and (3) whether any regulatory assets should be written off as they are no longer collectible.

The judgments about the capital structure ratio and cost of capital components will impact the amount of allowance for funds used during construction (debt and equity) 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 to future periods for costs recovered in future rates.

A utility company may consider weighting the evidence used in its professional judgments to determine the hypothetical settled rate requirement calculation similar to that used to determine whether a regulatory asset is probable of recovery. 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 and 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 for 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 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 non-regulated. 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.

An electric utility that is subject to traditional, cost-based rate regulation and uses various sources of generation to fulfill its service obligation would illustrate a grouping concept. 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 hydro-electric 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 making 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 attributable directly 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 provide evidence on 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, and management may in this case operate the assets on a fleet basis. The determination would also depend on whether management makes operating decisions on a plant basis, or undertakes a strategy to maintain 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. To illustrate, 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 from other assets.

- **The entity’s distribution characteristics, such as regional distribution centers, local distributors, or individual plants** — Consideration may be given to how the entity manages outages and maintenance across its assets. If management adjusts output at one plant to compensate for an outage at another, this may be indicative of interdependent cash flows. By contrast, if each plant is managed individually and there is little coordination across 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, the purchase of fuel for plants using a common fuel source may be performed and 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** — Consideration may be given to how the entity operates its assets. The more an entity provides 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 dispatch its fleet depending on market conditions, cash flows may be considered interdependent. Likewise, if a group of plants are committed to serve an ISO and dispatch decisions are controlled by the ISO, this may be indicative of more interdependence among the assets. Another consideration would be the ability of an entity to dispose of or deactivate an individual plant and whether this would impact the operation of other plants.

An entity should consider each of the relevant characteristics and make an informed judgment about its asset grouping. Determining the lowest level of identifiable cash flows requires considerable judgment and identification and assessment of 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.
Accounting for Section 1603 Treasury Grants

The American Recovery and Reinvestment Act of 2009 (the “Recovery Act”) was passed by Congress in 2009 and created the 1603 Treasury Program to encourage entities to develop renewable energy projects by offering cash incentives in the form of production tax credits, ITC, or cash grants. Under the Recovery Act, eligible companies make an election as to whether or not they would like to receive production tax credits, ITC, or cash grants.

The Recovery Act initially stipulated that regulated entities needed to treat cash grants under the normalization rules, meaning that the benefits of the grants could not be passed back to customers faster than the book depreciable life of the plant. However, in late 2011, Congress passed the National Defense Authorization Act for Fiscal Year 2012 (NDAA). NDAA eliminated the normalization provisions associated with the cash grants.

Historical industry practice has been to account for government grants by analogy to IAS 20; however, recent discussions with the SEC have indicated that the SEC would permit companies to establish an accounting policy that would account for the cash grants by analogy to ASC 450, and more specifically the guidance within ASC 450 related to gain contingencies, which would allow companies to recognize revenue related to cash grants when they are realizable, and not necessarily over the life of the property related to the grant.

This ability to recognize revenue when the grants are determined to be realizable under ASC 450 would allow regulated entities to establish regulatory liabilities at the point of realization if the company’s regulatory body requires this benefit to be flowed back to regulators. The period of time over which the regulatory liability could be flowed back to ratepayers would not be restricted under this approach.

Lease Classification Considerations

The lease classification test under ASC 840-10-25-1(d) (commonly referred to as the “90 percent test”) requires that:

- The present value at the beginning of the lease term of the minimum lease payments, excluding that portion of the payments representing executory costs such as insurance, maintenance, and taxes to be paid by the lessor, including any profit thereon, equals or exceeds 90 percent of the excess of the fair value of the leased property to the lessor at lease inception, over any related investment tax credit retained by the lessor and expected to be realized by the lessor.

Entities have questioned whether or not cash grants under the 1603 Treasury program, which are elected in lieu of ITC, should be adjusted for in the calculation of the 90 percent test in the same manner as the guidance requires an adjustment to be made for ITC. The guidance under ASC 840-10-25-1(d) requires entities to determine for purposes of the 90 percent test the lessor’s net investment in a lease. When entities elect economically similar benefits in lieu of ITC, cash grants would be accounted for within the 90 percent test in the same manner as ITC in determining the lessor’s net investment in the lease.
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 accounting and reporting for energy contracts, derivatives, as well as risk management efforts.

**Rulemaking Under the Dodd-Frank Act**

The Dodd-Frank Act divides regulatory authority over swap agreements between the CFTC and the SEC. The SEC has regulatory authority over “security-based swaps,” while the CFTC has primary regulatory authority and certain rulemaking obligations for all other swaps, including energy and agricultural swaps. The CFTC has established final rules for compliance, and effective dates vary depending on the category of the company or asset. Current compliance deadlines range from immediate adoption to adoption after 270 days with phase-in requirements. As effective dates draw near, several rule sets are still pending. Note also that courts have vacated certain rules before their effective date (e.g., the CFTC’s position limits rules).

The new OTC derivative regulations created by the CFTC have broad implications for energy companies. Definitions of certain terms, such as “hedging activity,” “swap,” “swap dealer,” “end user,” and “substantial position in swaps,” and how these items are quantified and reported are significant to all entities that transact in commodities or energy products. Title VII of the Dodd-Frank Act, which addresses the use of certain derivatives, significantly affects energy companies that use derivatives to manage commodity price risk.

Broadly, the Dodd-Frank Act:

- Extends CFTC regulatory authority to swaps (as defined by the CFTC).
- Establishes central clearing and exchange trading for swaps (an exception to the centrally cleared requirement is allowed for those entities that elect to take an end-user exception for certain transactions).
- Mandates data collection and publication to enhance market transparency.
- Establishes capital and margin requirements as financial safeguards.
- Amends trading practices to enhance market integrity.
- Requires disclosure of payments by oil, gas, and mining companies to foreign governments. (See Deloitte’s September 27, 2012, *Heads Up* for further details on Section 1504.)

**Entity and Transaction Designation**

Under the new OTC regulations, each entity will be classified as a swap dealer (SD), major swap participant (MSP), non-SD, or non-MSP. An entity’s classification is determined on the basis of volume of swap activity, counterparty composition, and the entity’s purpose for transacting. Entities are required to perform a self-assessment and register accordingly with the CFTC. SD and MSP classifications must be monitored and self-reported quarterly. Nonfinancial firms may claim an exemption on transactions in which swaps are used for hedging under accounting or economic standards. For those entities whose swap activity is primarily associated with hedging operational commercial risks, many transactions may be excluded from the notional value calculation that determines an entity’s classification.

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1 Security-based swaps are based on a single security or loan or a narrow-based group or index of securities (including any interest therein or the value thereof) or events related to a single issuer or issuers of securities in a narrow-based security index. Security-based swaps are included in the definition of “security” under the Exchange Act and the Securities Act.

2 The CFTC and SEC share authority over “mixed swaps,” which are security-based swaps that also have a commodity component.

3 The term “swap dealer” refers to any entity that (1) holds itself out as a dealer in swaps, (2) makes a market in swaps, (3) regularly enters into swaps with counterparties as an ordinary course of business for its own account, or (4) is commonly known in the trade as a dealer or market maker in swaps with activity surpassing $8 billion. (In the future, this threshold may decrease to $3 billion.)

4 Firms register with the CFTC through the National Futures Association.
The Dodd-Frank Act affords entities an end-user exception that may be applied on a deal-by-deal basis. The end-user exception is not a classification like SD or MSP but rather addresses the requirement that all swaps must be cleared unless the entity can demonstrate that the deal has certain characteristics of a hedge. The CFTC rules therefore include two similar yet distinct rulemaking areas relevant to swaps that hedge or mitigate commercial risk:

- **Entity classification** — The final entity classification rule allows transactions that hedge or mitigate commercial risk to be excluded from the notional value calculation used to determine whether an entity is classified as an SD or MSP.

- **End-user exception** — A swap that qualifies for the end-user exception is not required to be centrally cleared. However, the end-user exception is not available to SDs or MSPs.

Transactions that hedge or mitigate commercial risk include deals that (1) qualify as a hedge under CEA rules, (2) qualify for hedge accounting treatment under ASC 815, or (3) are economically appropriate to the reduction of risks in the conduct and management of a commercial enterprise (e.g., potential change in value to asset, liabilities, or services).

While few energy companies are expected to be classified as SDs or MSPs, all entities subject to the Dodd-Frank Act will be required to perform a number of new activities, including the following:

- **Reporting and recordkeeping:**
  - Retention and reporting of preexecution, execution, and postexecution transaction information including orders, executions, and oral and written communications; all indexed to the transaction.
  - Data kept for the entire existence of a swap and five years after the swap’s termination or expiration.
  - Data must be “readily accessible,” and records must be retrievable by the recordkeeping counterparty within five business days.

- **Compliance with exchange rules:**
  - Adherence to reporting and recordkeeping when derivative activity occurs.
  - Adherence to margin and collateral requirements for transactions executed on the exchange platforms.
  - Adherence to trade practices, such as increased self-surveillance and antifraud protection activities.

- **Application of end-user exception:**
  - Processed at time of transaction.
  - Pre- and post-execution documentation and controls.

**Swap Definition**

Entities should work with their legal counsel to establish company policy for transactions on the basis of their specific facts and circumstances. Company policies for defined swaps would generally include (1) foreign currency forwards and swaps, (2) forward rate agreements, (3) commodity options, and (4) certain transportation contracts. Since the CFTC has limited jurisdiction over forward contracts, swaps would generally not include forward contracts in nonfinancial commodities. However, the current rule is ambiguous regarding physical positions with embedded optionality. Finally, Brent crude oil contracts are expected to be excluded because of the 1990 CFTC interpretation that the 15-day Brent system crude oil contract is a forward.

While the CFTC has issued a proposed order to exempt specific RTO/ISO transactions, the order is not yet final and interpretations of the order vary. The order would apply narrowly to exempt:

- Financial transmission rights.
• Energy transactions.
• Forward-capacity transactions.
• Reserve or regulation transactions.

**Effects on Transacting**

It is expected that the broad definition of “swap” and related regulatory uncertainty will result in a shift to increased physical transacting. Such shifts may affect liquidity in certain markets and thereby affect entities’ ability to execute or value certain energy transactions. In addition, contract reviewers will need to pay particular attention to embedded derivatives that entities include in the structuring of physical deals in the hope of qualifying for the end-user exception. Swap customers will most likely turn to the futures markets to avoid uncertain and onerous compliance requirements. The Intercontinental Exchange Inc. and Chicago Mercantile Exchange will list its OTC derivatives as futures instead of swaps, which may result in less complicated derivative valuations but significantly different collateral requirements.

Although the CFTC is working aggressively to finalize the implementation rules, only 41 of the 60 rules have been completed. In addition, the U.S. District Court threw out the CFTC’s recently enacted position limits rules just two weeks before their scheduled effective date, holding that the CFTC failed to establish that position limits are necessary and appropriate to curb excessive speculation in the commodity markets. The CFTC intends to appeal this decision.

Despite the uncertainties and pending implementation questions, the Dodd-Frank Act is expected to affect the commodity transacting lifecycle in many ways, which include:

• Modifications to the deal entry process to comply with recordkeeping requirements.
• Potential acceleration of the confirmation process to provide increased accuracy before reporting.
• Capture of legal entity identifiers, and categorical designation for all counterparties under the Dodd-Frank Act.
• Development of capabilities to capture primary economic terms and comply with reporting timeframe requirements.
• Recording of retention requirements.
• Increased complexity of reporting transactions across borders and business units, requiring internal coordination.

For more information, refer to Deloitte’s whitepaper, “An Interpretation of the ‘Hedge or Mitigate Risk’ Criteria and the Impact to Compliance With the Dodd-Frank Act.” Information about the Dodd-Frank Act is also available on the CFTC’s Web site.

**Market Activity**

**Coal and Natural Gas**

The increased availability of U.S. shale gas is affecting domestic and foreign energy production and related market strategies, including regulatory reform and the use of coal plants on the dispatch curve.

**Environmental Regulations**

In August 2012, the U.S. Court of Appeals for the D.C. Circuit vacated the EPA’s CSAPR, which would have set strict limits on emissions for power plants in the eastern United States via a new cap-and-trade program. The standards were expected to significantly reduce the demand for “dirtier” Illinois- and Appalachian-based coals and increase the demand for PRB products, which in turn would have most likely accelerated the retirement of older coal-fired plants. While the EPA revises the CSAPR in response to the court’s directive, the current (more lenient) regulations under the CAIR remain in effect.
This “stay of execution” has provided P&U companies more time to consider their compliance strategies and long-term generation mixes.

**Natural Gas Prices Drive Coal Decisions**

The low price of natural gas continues to affect the economics of coal generation. The schedule for coal generator retirement or retrofitting has accelerated. Shifts in market and regulatory conditions have resulted in the retirement of about 30,000 GW of capacity from coal-fired plants by 2016.5 Companies are evaluating existing coal contracts and, at times, modifying contract terms to adjust for lower demand levels. Coal inventories may increase as forward demand weakens, triggering consideration of lower of cost or market (LCM) analysis and possible resulting impairments.

Companies with coal transactions related to trading and marketing or procurement 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 an entity makes about its business strategy or operations. With the availability of low-cost natural gas, key coal assets may not run as previously forecasted. Thus, companies are making strategic decisions to shift sourcing supplies or, in some cases, retrofit coal plants to gas generation, which could mean existing coal contracts may not result in physical delivery of all contracted volumes. Net settlement, deferrals, and contract modifications require companies to revisit certain assertions to determine whether the existing accounting elections remain appropriate.

- **Impairment of coal generation assets, coal inventories, or both** — Coal generation may be displaced as natural gas prices remain low, which could have implications for the economic useful life of generation assets. Similarly, lower demand and resulting market prices expose coal inventories to LCM adjustments.

**ERCOT and California**

In December 2010, the Electric Reliability Council of Texas (ERCOT) transitioned from a zonal to a nodal market, which resulted in a refined approach to the delivery of electricity in Texas and allowed the market to provide more precise pricing signals for participants. The transition was also designed, in part, to encourage additional investment in generation and transmission to ensure that there is a sufficient supply of power to meet current and expected future load. Generation investors have voiced concerns that a lack of long-term contracting with buyers, low market heat rates, and low natural gas prices have contributed to a challenging investment environment in ERCOT. In response, ERCOT recently raised its system-wide offer cap from $3,000/MWh to $4,500/MWh (staged to go to up to $9,000/MWh over next few years) to provide a higher potential return to investors. This fundamental change to the market could affect transaction strategies in ERCOT, especially as market participants digest the impact of these changes. Similarly, the regulatory uncertainty associated with the cap-and-trade emissions programs (e.g., AB 32) in California Independent Service Operator (CAISO) may influence transacting strategies in the forward markets because companies may be hesitant to transact until they are more certain of the future market structure.

**Hedge Accounting**

The use of hedge accounting continues to be a hot topic in the energy industry, particularly in the P&U sector. Companies need to consider FASB guidance on hedge accounting as they manage risks associated with fluctuating market prices and dynamics. Perhaps the most significant challenge for companies that use hedge accounting is to show that the hedging relationship, both at inception and on an ongoing basis, will be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. In other words, the risks associated with the hedging instrument (i.e., forward prices) should be highly correlated to the risks associated with the hedged item. In accordance with ASC 815-20-35-2,

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6 Effective August 1, 2012.
companies can assess the effectiveness of a fair value or cash flow hedge relationship on the basis of “regression or other statistical analysis of past changes in fair values or cash flows as well as on other relevant information.” A relationship that can no longer be considered highly effective ceases to qualify for hedge accounting and should be discontinued. Energy companies continually question whether the effort associated with applying hedge accounting is worth the outcome or whether more time should be spent educating analysts and designing appropriate non-GAAP measures to account for the unrealized changes in derivative fair value.

**Day-Ahead Versus Real-Time Pricing in Power Markets**

It is common in the P&G industry for companies with generation assets and load-serving obligations to employ hedge accounting to minimize the risk of cash flow variability associated with changes in the price of electricity. Companies have traditionally managed this risk by employing hedge accounting relationships that use OTC contracts to offset the amounts ultimately received on sales of power to the power pool. However, hedging relationships that have historically exhibited high correlation may deteriorate with changing market conditions. Low natural gas prices in the United States; environmental regulations increasing the costs of coal generation in PJM, MISO, and NEPOOL; and transitions by ISOs from zonal to nodal pricing formats (e.g., ERCOT) may disrupt previously effective regressions. One such example presented itself in the PJM power pool. Because of the volatile nature of the real-time market power pool, asset owners have typically bid their generation assets in the day-ahead market. Accordingly, the most effective hedge instrument would settle against the day-ahead market. The forecasted sales of electricity are generally scheduled to deliver in the PJM day-ahead market, but, however, the financial hedge instrument generally settles on the basis of the price quoted in the PJM real-time market,

thus introducing some level of ineffectiveness in the hedge relationship. Historically, companies have determined that this disconnect was not significant enough to drive relationships outside of the bounds of hedge effectiveness, but recently, companies have found that the effectiveness of these relationships has disintegrated because of certain conditions in the PJM marketplace, including the following:

- **Low natural gas prices driving a shift in the generation mix in the region** — Because coal prices have remained high while natural gas prices have decreased throughout the region, the generation asset mix has shifted toward dispatching natural gas on a regular basis instead of coal-fired units. Thus, coal units are dispatched to meet the peak demand levels within the real-time market while natural gas generation will fill base load generation needs. Since coal has historically been considered the base load fuel in the region, a shift toward natural gas affects the development of the locational marginal pricing (LMP) in the real-time and day-ahead markets.

- **Increased use of demand response program** — In recent years, PJM has increased its use of the demand response program, which requires large consumer and industrial (C&I) customers to scale back their load in the real-time market so that PJM can balance its supply and demand in the region. The program has driven increased volatility between the day-ahead and real-time prices.

While ASC 815-20-55-68 through 55-70 permit various methods to be used to assess the effectiveness of a hedge relationship, entities that operate in power markets should be sure to understand the inputs of their hedge assessments to determine the effectiveness of any hedge relationship. All methods, including dollar-value offset, regression, or another statistical analysis, require the use of professional judgment. Entities should monitor the markets in which they are hedging so that they can respond to changing market conditions that may affect the effectiveness of their cash flow or fair value hedge relationships.

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8 PJM's day-ahead market is a forward market in which hourly LMPs are calculated for the next operating day on the basis of generation offers, demand bids, and scheduled bilateral transactions.

9 PJM's real-time market is a spot market in which current LMPs are calculated at five-minute intervals on the basis of actual grid operating conditions. The real-time prices are posted on the PJM Operational Data page on the PJM Web site. Transactions are settled hourly; invoices are issued to market participants monthly.
Multiple-Element Arrangements

The production and delivery of electricity often involves multiple products and services, including electricity, capacity, various ancillary services, and RECs. Although electricity procurement is typically the primary purpose of a contract, contracts will frequently combine electricity with one or more of these additional products and services, often referred to as bundled contracts.

Because there is no ASC guidance that specifically addresses the accounting for bundled contracts, diversity in practice has developed in the P&U industry. However, a few predominant accounting models have emerged, each of which can be complex and require entities to consider whether the various elements in the contract should be accounted for separately or together. Entities should consider these factors during the initial contract assessment and ultimate financial statement recognition upon settlement.

Contract Assessment

Entities should assess bundled contracts under ASC 810, ASC 815, and ASC 840. However, the primary complexities associated with bundled 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).” Within bundled arrangements, nonlease elements are typically (1) products that are not considered outputs or other utilities that will be produced or generated by a power plant or (2) services. There is currently diversity in practice regarding whether certain elements within a bundled contract are considered a unit of output, including RECs. However, if a reporting entity asserts that a REC is not a “unit of output,” the portion of the contract associated with RECs would need to be separately assessed as a derivative under ASC 815. In addition, in accordance with ASC 840-10-15-19, the contract price should be allocated between the leasing and nonleasing elements on a relative fair value basis unless one of the elements of the contract requires ongoing fair value accounting treatment (i.e., if the element is a bifurcated embedded derivative), in which case the element requiring fair value treatment would be recorded at its fair value and all other elements would be accounted for on a relative fair value basis.

- **Derivative accounting** — The derivative considerations depend on whether the agreement was deemed to contain a lease with nonlease elements, as follows:

  1. **Lease with nonlease elements** — To the extent that an element in a bundled arrangement (e.g., an REC) is considered to be a nonlease element, entities would need to assess it to determine whether that portion of the contract meets the definition of a derivative. In practice, companies typically conclude that the market for RECs is insufficiently active for RECs to be readily convertible to cash. However, as the market continues to develop, RECs could become readily convertible to cash in future periods. Reporting entities can conditionally elect the NPNS scope exception in anticipation of increased activity in the REC market.

  2. **Nonlease** — If the contract does not contain a lease, an entity must assess it under ASC 815 in its entirety. ASC 815 does not provide explicit guidance on how to assess the various elements within a bundled contract. Accordingly, diversity in practice has developed, yielding the following models:

    a. **Hybrid or multiple element model** — An entity assesses each element in the contract to determine whether it meets the criteria of a derivative. Therefore, the contract could contain derivative and nonderivative elements. For example, in a forward contract for electricity and RECs, the electricity element of the contract would most likely be considered a derivative whereas the REC element may not (under the view that RECs are not readily convertible to cash). For valuation purposes, only the elements of the contract that meet the derivative criteria should be shown at fair value. Note that any derivative elements that are identified and recorded should generally not result in any inception gain or loss being recorded.
Rather, an entity should offset the value attributable to the derivative contract by allocating an offsetting amount to the cost basis of the other elements in the contract (which is similar to the accounting that would be achieved if the derivative were accounted for as a bifurcated embedded derivative).

b. **Embedded derivative model** — In this model, the contract is comprised 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:

i. **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 application of this view is fairly common in practice, we also believe that there is accounting risk in this approach and that reporting entities should consult with their auditors about whether it continues to be an accepted practice.

ii. **Nonderivative host** — In this view, the host is defined as the portion of the contract that does not meet the criteria of a derivative. 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 (noted in (1) above).

In practice, entities determine 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 use under the quantitative approach. For example, an entity might consider whether the elements were produced from the same asset (e.g., electricity and RECs were both produced by the same facility). Accordingly, there could be a higher likelihood that the qualitative approach would result in a conclusion that the host and potential embedded derivative are clearly and closely related. We believe that either approach has merit and that some combination of both approaches should be considered in any assessment of whether an embedded derivative is deemed to be clearly and closely related to the host contract. Reporting entities should consult with their auditors to determine which approach is most appropriate given their specific facts and circumstances.

**Financial Statement Recognition Upon Settlement**

Because most elements in a bundled contract cannot be “stored” (i.e., electricity, capacity, and ancillary services), settlement amounts associated with these elements are typically recognized immediately in the income statement. RECs, however, can be stored. Accordingly, entities may need to allocate the bundled contract settlement price between the various contract elements. For example, a company that purchases RECs for resale or in excess of any regulatory requirements would have stored RECs. In these instances, the contract price should be allocated between the two elements on the basis of the relative fair values of the various elements at the inception of the contract (regardless of whether the company has elected to classify such RECs as inventory or intangible assets).
Although it is not directly related to the settlement associated with bundled arrangements, the applicable accounting associated with RECs generated, but not sold, by a reporting entity should be considered. Specifically, if the reporting entity has elected to classify such RECs as inventory, it is required to assign a value based on the estimated production cost under ASC 330. However, if the reporting entity has elected to classify such RECs as intangible assets, the RECs would be treated as internally developed intangibles, which are precluded from being capitalized under ASC 350.

Because there is no ASC guidance on the accounting for bundled contracts, companies should develop and consistently apply an accounting policy that best reflects the economics of their bundled contract portfolio and related operating activities in their financial statements. Also, companies should consider the potential impacts of the leases and revenue recognition convergence projects on the accounting for bundled contracts. For example, contracts that are deemed to contain a lease under current guidance may no longer meet the definition of a lease under the criteria outlined in the leases convergence project. In addition, as part of the revenue recognition project, the FASB will provide explicit guidance on multiple-element arrangements, which could affect current revenue recognition practices.

See Section 7 of this publication and Deloitte’s September 27, 2012, and November 15, 2011, Heads Up newsletters for information about the leases and revenue recognition projects.
Section 6
Fair Value Measurements
Market Activity

In accordance with ASC 820, a fair value measurement should incorporate “assumptions that market participants would use in pricing the asset or liability.” Since 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 (see discussion in Section 5).
- ERCOT nodal pricing caps (see discussion in Section 5).
- 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. Since FTRs are typically considered derivative instruments under ASC 815, we encourage companies to consider the effects of this underfunding in valuing their FTRs.

Fair Value Measurements

In May 2011, the FASB issued ASU 2011-04, which resulted in various amendments to ASC 820. These changes include minor amendments to measurement principles (e.g., consideration of offsetting credit and market risks) and expanded disclosure requirements including those related to Level 3 fair value measurements. (For more information about the ASU’s amendments, see Deloitte’s May 13, 2011, Heads Up.) The guidance in the ASU was effective for interim and annual periods beginning after December 15, 2011, for public companies.

The primary impact of the adoption of the ASU on the P&U industry appears to have been associated with the expanded fair value measurement disclosure requirements for Level 3 fair value measurements. Some of these expanded disclosure requirements include:

- 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)).

The example disclosures in ASU 2011-04 are not specific to the P&U industry. Accordingly, management was required 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.”¹ 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 to be “significant” to their Level 3 measurements.

¹ ASU 2011-04 Basis for Conclusions paragraph BC86.
• **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.

Section 7
Accounting Standards Codification Update
Revenue Recognition Proposals

In November 2011, the FASB and IASB jointly issued a revised ED on revenue recognition, which retains the core five-step model from the June 2010 ED but modifies the application of individual steps. Since then, the boards have received comments from numerous constituents (including member company representatives of the EEI and AGA) and have been redeliberating the revised proposals. We expect that the boards will issue a final standard in the first half of 2013 with an effective date no earlier than January 1, 2016. If the boards adopt the final standard on a full retrospective basis (with certain optional transition reliefs), an SEC filer that reports three years of financial information may need to implement the finalized guidance as early as January 1, 2014.

The revised ED’s core principle is that “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.” The ED lists five key steps for recognizing revenue for contracts within the proposal’s scope:

• “Identify the contract with a customer.”
• “Identify the separate performance obligations [(POs)] in the contract.”
• “Determine the transaction price.”
• “Allocate the transaction price to the separate [POs] in the contract.”
• “Recognize revenue when (or as) the entity satisfies a [PO].”

Scope and Customer Contract Identification

The proposals would apply to all of an entity’s contracts with customers, with certain exceptions for contracts within the scope of other standards (e.g., lease contracts or insurance contracts). A contract can be written, verbal, or implied, and the proposed guidance provides specific criteria for entities to consider in determining whether a contract exists. Notably, if both parties can unilaterally terminate the contract before either party’s performance without penalty, a contract does not exist.

Forward energy sales with a defined term and enforceable performance provisions would be within the scope of the revenue proposals as long as they are not subject to other accounting guidance (i.e., derivative or lease accounting). While both parties must be able to terminate without penalty before performance begins for the agreement to be outside of the proposal’s scope, some view many tariff-regulated sales as “stand ready” obligations instead of contracts with defined forward terms. However, entities need to analyze all sales channels and customer classes because some regulated sales (perhaps sales to commercial and industrial customers) may involve standalone contracts or tariff provisions that effectively obligate performance on both parties for a defined time period (i.e., minimum volume stipulations or other pricing provisions that create enforceable obligations).

Contract Modifications

Companies in the industry occasionally enter into blend-and-extend contracts. A company might enter into a blend-and-extend contract when a fixed-price forward power sales contract has two years of delivery term (performance) remaining, the forward price of power has declined since it originally executed the contract, and the customer seeks to take advantage of the more favorable current forward price environment. As a result, the parties agree to extend the remaining two years of the contract by adding an additional two years and blending the lower market price of the extension period with the current fixed price of the premodification forward term. The inherent fair value of the remaining contract term prior to modification is therefore blended (deferred) into the additional two-year extension. Revenue for periods already delivered is not affected by the pricing or economics of the modification.
In October 2012, the boards redeliberated the revised ED’s proposals on accounting for contract modifications. Under the proposals, when a contract modification does not meet the criteria to be accounted for separately from the original contract, the accounting depends on a number of considerations. Importantly, entities would need to determine whether the remaining POs in the modified contract are distinct from the PO(s) that were already satisfied prior to the modification. If so, a cumulative adjustment to earnings would generally not be required. Otherwise, an entity would update its measure of progress toward completion for any POs that are satisfied over time but only partially satisfied upon modification, which could result in a cumulative earnings catchup.

Participants in the industry expressed concerns about both the original and revised EDs’ guidance on accounting for contract modifications. In particular, companies were concerned that cumulative earnings adjustments could be required for blend-and-extend contract modifications, which economically relate only to undelivered (forward) obligations. This concern is premised on the view that a contractual commitment to provide energy over a defined forward term represents a “single, continuously satisfied” PO. However, staff agenda papers appeared to indicate that contracts involving repetitive deliveries of goods or services would generally not be subjected to cumulative catch-up accounting upon modification since each individual unit of service or individual good is distinct. While potentially helpful as it relates to contract modification accounting, this view seems to conflict with the boards’ recent conclusions that repetitive delivery or service contracts do not contain POs that are “distinct in context of the contract” and are therefore satisfied over time (see further discussion above). As such, the boards need to provide further clarification to resolve this apparent inconsistency and thus conclude that forward energy sales would not require cumulative catch-up accounting upon modification when the economics underlying the modification are entirely forward-looking.

Separate from the guidance on contract modifications, the boards also proposed that if a contract contained a significant financing component, an entity would need to separately account for the TVOM, as discussed above. Whether or not the guidance on modifications would ultimately require a cumulative P&L catchup for a traditional blend-and-extend contract, the industry will need to address the possible financing implications of such modifications. Specifically, it is generally acknowledged that when the seller’s realization of the fair value of the premodified contract has been deferred (“blended”) into the extended term, this would appear to put such arrangements at risk of requiring separate accounting for the TVOM. See the discussion of the TVOM above.

Identify Separate Performance Obligations

An entity’s determination of whether a PO represents a separate unit of accounting (i.e., is “distinct”) from other promised goods and services in a contract, and the manner in which POs are satisfied (i.e., at a “point in time” vs. “over time”) has important consequences in applying the proposed revenue model. These two topics were the primary subjects of the EEI and AGA’s discussions with the boards earlier this year, particularly how they relate to forward fixed-price energy sales and perceived effects on contract price allocation (discussed further below). During the summer, the boards made tentative decisions to revise certain aspects of their proposals relative to this step of the model, specifically for contracts involving so-called “repetitive” or “consecutive” deliveries of the same good or service multiple times over a period of time (e.g., a three-year contract to supply energy continuously).

Guidance in the Revised ED

In the revised ED, the boards note that a PO is distinct if (1) the entity regularly sells it separately or the customer can benefit from the good or service on its own or together with resources that are readily available and (2) the PO did not meet the criteria to require bundling into a single accounting unit. It further notes that such POs would be satisfied at “points in time” if the “satisfied over time” criteria are not met. The boards suggest that the prevailing industry view is that forward contracts to deliver commodities involve multiple distinct POs that are satisfied at points in time (i.e., each forward delivery period is a separate PO). The revised ED further notes that, as a practical expedient, otherwise distinct POs could be combined and accounted for together (removing the need to allocate contract pricing to each separately) if they have the “same pattern of transfer.” Some entities believe this practical expedient should apply to repetitive deliveries of the same, distinct product or service delivered multiple times during a period (“consecutive” deliveries). Some industry constituents asserted that this application of the practical expedient could help entities avoid having to separately allocate a fixed contract price to each
forward delivery period (for each individual sales agreement) on the basis of the inception forward curve. These entities also asserted that this interpretation may avoid the potential negative consequences of a single PO satisfied over a period (e.g., potential cumulative catchups to earnings upon contract modification and complying with certain disclosure requirements).

Current Tentative Guidance

The boards clarified the guidance on identifying separate POs during their deliberations this summer. The tentative guidance requires an entity to account for a good or service as a separate PO when it is (1) capable of being distinct (i.e., the customer can benefit from the good or service on its own or with other readily available resources) and (2) distinct in the context of the contract (the boards provided indicators to assist entities in making such a determination). The boards removed the practical expedient to combine otherwise distinct POs into a single PO. If a good or service is part of a series of consecutively delivered goods or services that represent POs satisfied over time (in accordance with paragraph 35 of the revised ED) and that use the same method for measuring progress toward completion, it is not distinct in the context of the contract (and thus, may need to be combined with other POs).

The boards also restated the criteria for determining if a PO is satisfied over time including (but not limited to) the following:

- For “pure services contracts,” the customer “receives and consumes the benefits of the entity’s performance as the entity performs [and another] entity would not need to “substantially reperform the work the entity has completed to date.”
- “The entity’s performance creates or enhances an asset (for example, work in process) that the customer controls as the asset is created or enhanced.”
- “The entity’s performance does not create an asset with an alternative use to the entity,” the “entity has a right to payment for performance completed to date, and it expects to fulfill the contract as promised.” When evaluating whether an asset has “alternative use” to the entity, an entity should consider at contract inception the effects of contractual and practical limitations on its ability to readily direct the promised asset to another customer.

The boards appear to have heard the concerns raised by industry constituents earlier this year on price allocation. The boards’ tentative decisions indicate that they now view a forward energy contract as a single PO that is continuously satisfied over time (the FASB even uses forward energy sales contracts in its July meeting Staff Paper on this topic). Notwithstanding, the revised criteria for determining that a PO is satisfied over time may require further clarification in the final standard to ensure its intended application to forward energy sales. For example, the criteria focused on the customer’s simultaneous receipt and consumption of the benefits of the seller’s performance is specifically intended to apply only to “pure services contracts.” The industry initially viewed forward commodity contracts as containing distinct POs that are satisfied at points in time because energy commodities are products (not services) with physical properties, transfer characteristics, and standalone value because of entities’ ability to market them separately (further, energy commodities other than electricity can generally be stored and thus may not immediately be “consumed” by a customer upon transfer). Alternatively, the criteria for sales of assets, which focuses on an entity’s right to payment for performance completed to date, may be helpful in viewing forward energy sales as being satisfied over time, particularly because it appears focused on sales of assets that an entity does not “create.” However, this criteria also requires that the asset sold does not have an “alternative use” to the seller, whereas energy commodities are fungible, have standalone value, and are thus generally able to be redirected to another party. While potentially incurring a loss to redirect the asset to another party may represent a “practical” limitation on the seller’s ability to redirect, entities may need to undertake related analysis to conclude whether this criteria is met.

The original and revised EDs’ provisions for the recognition of losses on onerous contracts and the accounting for contract modifications involve unique consequences for POs that are satisfied over time. Such consequences include potential upfront loss recognition for certain contracts deemed “onerous” and cumulative P&L catchup for certain modifications (discussed further below). While the boards decided to remove the onerous contract provision proposed in the revised ED (a broadly supported move across industries), the effect on modifications of forward energy contracts is still unclear. Thus, companies in the P&U industry are encouraged to monitor developments on contract modification accounting for POs satisfied over time.
The above discussion (and the energy example in the boards’ summer agenda paper) presumes a simplistic contract to consecutively deliver only a series of the same energy product or service over a period of time (i.e., a firm plain-vanilla forward to deliver gas or electricity). Entities will need to closely evaluate the final guidance on separating potentially distinct POs and allocating the transaction price to those POs for sales contracts that involve the delivery of multiple products and services (e.g., “full requirements” or bundled energy combined with capacity, congestion management, ancillaries, renewable energy credits, or asset management services) or provide for delivery in a nonuniform manner.

**Determine the Transaction Price**

Entities generally refer to “variable consideration” when the contract price is not fixed. The boards tentatively extended the definition of variable consideration to include instances in which the contractual price of a good or service is fixed but the amount is not fixed as a result of an uncertain event (e.g., an outcome-based fee). In November 2012, the boards also clarified the objective for “constraining” the cumulative amount of revenue entities may recognize for contracts containing variable consideration, and moved the constraint guidance to step three in the proposed model. Under the clarified objective, revenue would only be included in the transaction price when an entity has a “high level of certainty” that the amount of revenue recognized would not be subject to future reversals.

This step of the model would appear relatively simple for straightforward energy sales (e.g., firm forwards with wholly fixed pricing). However, industry constituents were concerned with the requirement to estimate transaction price variability upfront, which may affect the amounts recognized in applying the last step of the model as well as certain disclosure requirements. In particular, they were concerned that the requirement to estimate upfront (and then subsequently adjust) the price used for market-priced contracts for recognition purposes seemed unnecessary since revenues would ultimately be driven by then-current market (spot) pricing upon delivery.

The boards are contemplating both price- and event-driven variability that could ultimately affect the transaction price. Further, if a sale of an energy commodity represents a PO that is satisfied over time, the revised ED’s guidance on measuring progress towards completion of such POs indicates that one method (i.e., the output method) may allow an entity to recognize revenue on the basis of billed amounts as long as such amounts correspond “directly with the value to the customer of the entity’s performance completed to date.” Therefore, while further clarification is still warranted, the boards’ proposals may not have a major impact on contracts with either fully fixed or fully market-based pricing because there would generally be no true-ups expected in an approach whereby entities record revenues on the basis of either the fixed contract price or then-current market price multiplied by volume upon delivery, respectively (as is generally current practice for such contracts). However, entities will need to consider variability arising from uncertain or contingent events in light of this guidance (for example, adjustments to predetermined unit-pricing that are based on production exceeding or falling below contractually-specified minimum or maximum volumetric bands), which may be particularly impactful to certain sectors of the energy industry, such as the marketing sector. Further, it is unclear how contracts with stepped pricing, partially fixed and partially variable pricing, or other forms of energy pricing that create variability (such as formula rate, plant-linked, and heat-rate based pricing structures) should be subjected to the price determination and recognition constraint guidance.

**Time Value of Money**

The boards recently deliberated the revised ED’s proposals on adjusting the transaction price for the time value of money (TVOM). The revised ED proposed that entities should adjust the transaction price to reflect the TVOM if the contract included a “significant financing” element. While the ED’s focus seemed to be on situations involving significant time lag between performance and payment, it also noted that a significant financing element could exist when “the promised amount of consideration differs from the cash selling price of the promised goods or services.” Entities in the P&U industry were concerned that fixed price forward sales could be viewed as containing embedded financing (i.e., for commodity deliveries in early periods when strip pricing exceeds market pricing, the seller receives an in-kind “loan” that is subsequently repaid with higher value in-kind commodities on the back end).
During recent deliberations, the boards expressed their belief that comment letter respondents appear to be putting too much weight on only one of the ED’s factors for evaluating if a significant financing component might exist in a contract (i.e., instances involving significant time lag between advance (or deferred) cash payments and performance/delivery). Further, the boards indicated that in some such instances, there may not necessarily be an explicit or implicit intent to finance (for example, when timing of delivery is at a customer’s discretion or the advance or deferred payment is clearly for reasons other than financing, such as certain retainages on a long-term contract). The boards did tentatively decide to retain the optional practical expedient to avoid accounting for the TVOM when the time period between payment and performance is one year or less.

The outcome of the boards’ recent deliberations has been received favorably by entities in the P&U industry. The view that a sale of forward energy represents a “single” PO that is satisfied over time would also seem to support the view that the strip price (“promised consideration”) equals the “cash selling price” of each delivery under the PO. However, constituents in other industries in which traditional advance or deferred payment schemes are more common continue to anticipate that complying with the ED’s TVOM provisions could be complex. Finally, as discussed below, the application of the TVOM requirements to “blend-and-extend” contract modifications may prove difficult. Therefore, companies in the energy industry are encouraged to continue monitoring the guidance on the TVOM through to the final standard.

Lease Proposals

The boards have spent the last two years addressing comments on the August 2010 leases ED. During this time, they have made a number of significant changes to their proposed guidance, including significant changes to the proposed accounting model in the past year. The boards substantially concluded redeliberating the guidance at their September 2012 meeting and are expected to expose for public comment a revised ED, with a 120-day comment period, in the first quarter of 2013. On the basis of this timeline, a final standard is expected to be issued in late 2013, with an effective date no earlier than annual reporting periods beginning January 1, 2016. The boards tentatively decided that entities could apply a modified retrospective transition approach or a full retrospective transition approach. Under either approach, an SEC filer that reports three years of financial information may need to implement the finalized guidance as early as January 1, 2014.

The boards reaffirmed the ED’s overall model in which all leases within the scope of the proposed guidance are treated as financing transactions and are recognized on the balance sheet as a right-of-use (ROU) asset. The boards spent a significant amount of effort revisiting the definition of a lease, variable lease payments, the expense recognition pattern for lessees, and the accounting for lessors. Although the changes to the proposed guidance in these areas have been seen as largely positive for the industry, it is important for entities to monitor the boards’ future decisions since these decisions may change before the issuance of the final standard. The following sections summarize the boards’ decisions to date on the leases project. See Deloitte’s September 27, 2012, Heads Up for further details on the project.

Definition of a Lease

The ED defined a lease as “a contract in which the right to use a specified asset (the underlying asset) is conveyed, for a period of time, in exchange for consideration.” The boards decided that 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). In addition, the boards decided that 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.

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 would not, in and of itself, automatically mean 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 or processes used to produce such output. This decision is likely to affect whether gas supply contracts and power purchase arrangements constitute leases. Further, the boards decided that the grandfathering provisions of EITF 01-08 will not be carried forward (i.e., entities will need to assess whether all contracts meet the revised definition of a lease).
The boards also decided that when an asset is used to perform services for a customer, the customer and supplier must assess whether the use of the asset is separable from the services provided to the customer. If the use of the asset is separable, the arrangement may contain a lease. The boards will provide indicators for entities to use in determining whether the asset is separable.

The boards’ decisions related to unit-contingent PPAs and take-or-pay arrangements have been positively received by the industry. Under current accounting requirements, some PPAs are accounted for as leases because the majority of plant output combined with pricing that is not fixed or the market price per unit of output is typically enough to trigger lease accounting. Under the current tentative proposals, many such arrangements might not meet the definition of a lease going forward. The boards’ PPA examples appear to have been directly influenced by the industry’s comments on the August 2010 ED and subsequent targeted outreach. However, constituents should continue to monitor the boards’ discussions related to finalizing the definition of a lease and refining the application examples because such changes could affect an entity’s determination of whether an arrangement contains a lease. In particular, some industries have questioned whether the examples in the boards’ earlier agenda paper that are used to formulate their tentative lease definition model are consistently applied (i.e., PPAs vs. drilling rigs vs. vessel time charters). Therefore, any resolution of such inconsistencies could affect the ultimate application of the final lease definition to PPAs.

**Initial Measurement**

Under the ROU approach, a lessee would recognize (1) an asset for the right to use the underlying asset and (2) a liability to make lease payments. Both would be initially measured at the present value of the lease payments. Any initial costs (e.g., legal fees, consultant fees, commissions paid) that are directly attributable to negotiating and arranging the lease would be included in the ROU asset. A lessee would also include lease incentives in the initial measurement of the ROU asset (i.e., receipts from the lessor would reduce the ROU asset).

The boards decided to define “lease term” as “the noncancellable period for which the lessee has contracted with the lessor to lease the underlying asset, together with any options to extend or terminate the lease when there is a significant economic incentive for an entity to exercise an option to extend the lease, or for an entity not to exercise an option to terminate the lease.”

Further, the boards decided that a lessee’s calculation of its ROU asset and lease obligation would include fixed lease payments. Variable lease payments would generally not be included. Accordingly, entities would recognize lease payments that are based on performance or usage of an underlying asset as an expense when they are incurred rather than include them in the initial measurement. Only those variable payments that are (1) based on an index or rate or (2) in-substance fixed lease payments (e.g., the lease contains disguised fixed lease payments) should be included in the measurement.

Financial statement preparers generally supported the boards’ move away from a requirement to include expected variable lease payments in the calculation of the ROU asset and lease obligation. However, other constituents are concerned that leases could be structured to minimize the amounts reflected on the balance sheet. Accordingly, the boards may receive comments that focus on the identification of situations in which a lease is structured solely to enable the exclusion of rental payments from the ROU asset and lease liability (i.e., “abusive” situations in which there is no economic reason for the contingent rental provision other than the avoidance of recording the payments or the escalation of payments as a liability). It is unclear how or whether the boards will address variable payment structures that are not abusive by design but nonetheless relate to “virtually certain” amounts (i.e., variability driven by usage or sales but for which there is relative certainty as to a minimum or expected amount, such as is the case for some PPAs tied to wind or solar energy production that are supported by statistical studies at high confidence intervals).

**Subsequent Measurement: Expense Recognition Pattern**

A lessee would use the effective-interest method to subsequently measure the liability to make lease payments. Regarding the ROU asset, respondents to the ED noted that the proposal’s subsequent measurement requirements did not reflect the economics of all types of leases. They indicated that entities would more appropriately account for certain types of leases (e.g., leases of real estate) by using a straight-line expense recognition pattern. Accordingly, the boards settled on two different approaches for lessees: a straight-line expense (SLE) approach and the interest and amortization (I&A) approach.
A lessee would determine which method to apply on the basis of whether it acquires and consumes a "more-than-insignificant portion" of the underlying asset.

In addition, the boards decided that entities could use the nature of the underlying asset as a practical expedient to determine whether the lessee acquires and consumes a more-than-insignificant portion of the underlying asset. Specifically, under the practical expedient and provided certain criteria are met, a lessee can assume that it does not acquire and consume a more-than-insignificant portion of the underlying asset if the underlying asset is "property," which is defined as "land or a building — or part of a building — or both."

For leases accounted for under the SLE approach, the amortization of the ROU asset would be calculated as the difference between the total straight-line lease expense (total undiscounted lease payments divided by the lease term) and the interest expense related to the lease liability for the period. Effectively, amortization of the ROU asset would be a "plug" for the difference between total straight-line expense and amortization of the lease liability using the effective interest rate method. The amortization of the ROU asset and the interest expense would be combined and presented as a single amount within the income statement. In addition, the boards decided that the expense recognition pattern for leases accounted for under the SLE approach must be straight-line, regardless of whether this is the pattern of consumption for the underlying asset.

Given the expectation that the SLE approach would generally apply to leases of real estate, the benefit of straight line accounting would be limited within the P&U industry. Therefore, concerns from industry constituents related to having different expense recognition patterns for GAAP accounting versus regulatory accounting will likely still exist (e.g., impact on cost recovery, rate base). There are also concerns with how entities should apply the proposed practical expedient. Specifically, some in the industry have questioned whether "in-substance" real estate would constitute real estate (a power plant generally meeting "in-substance" real estate criteria). This may be relevant when unit-contingent transactions (i.e., tolling arrangements) meet the definition of a lease (which earlier staff agenda papers on the lease definition model discussed above indicated could be the case, particularly if the buyer provides the fuel input).

Accounting for Financial Instruments Proposals

The boards have noticeably struggled to reach converged requirements on the accounting for financial instruments (AFI) project. The AFI project is divided into three major components: classification and measurement, impairment, and hedge accounting. The boards converged key elements of their classification and measurement models in 2012; however, they appear to be divided on impairment and have not worked together on hedge accounting from the beginning. The FASB released a proposed ASU1 on impairment in December 2012 and expects to issue a proposed ASU on the classification and measurement components of the AFI project during the first quarter of 2013; however, there is no clear timeline for the FASB’s hedge accounting component. The status of each component of the FASB’s AFI project, including select industry considerations, is discussed below.

Classification and Measurement

The boards modified their original 2010 proposals wherein fair value through net income (FV-NI) treatment was considered the “default” classification for all financial instruments unless strict qualifying criteria were met. Since then, the boards have modified the criteria for both amortized cost and fair value through OCI (FV-OCI) treatment, generally relaxing the originally proposed requirements for both. The criteria for amortized cost and FV-OCI relate to both the cash flow characteristics of the underlying instruments and the business model an entity employs for managing such instruments. FV-NI treatment is now viewed as a “residual” category for instruments that do not meet the criteria for amortized cost or FV-OCI.

Amortized Cost

The criteria for amortized cost treatment depend on whether the financial instrument in question is an asset or a liability. For financial liabilities, amortized cost is the presumed classification unless the instrument is a derivative, a short sale, or one that will be transacted at fair value. The “cash flow characteristics” and “business model” criteria for financial instruments to qualify for amortized cost treatment must be met, as follows:

- **Cash flow characteristics** — The asset’s contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest (P&I), interest being consideration for (1) time value of money and (2) credit risk.
- **Business model** — The asset is held to collect contractual cash flows.

The FASB intends to provide additional application guidance in its final standard describing activities consistent with a “held to collect” business model. In meetings held during the third quarter of 2012, the FASB indicated that “[s]ales of financial assets as a result of significant credit deterioration would be consistent with the objective of amortized cost classification if such sales are to maximize the collection of contractual cash flows through sales rather than through cash collection. Sales for other reasons should be very infrequent.”

It is expected that an entity’s own debt will generally continue to qualify for amortized cost treatment.

Fair Value Through Other Comprehensive Income

The criteria for FV-OCI treatment apply to financial assets only and involve a cash flow characteristic and business model assessment, as follows:

- **Cash flow characteristics** — Same as for amortized cost treatment (i.e., “debt-like” instruments).
- **Business model** — The asset is held to collect (contractual cash flows) and to sell.

The FASB also intends to provide application guidance for activities that would be consistent with the business model for FV-OCI. The Board has tentatively decided that “[f]inancial assets classified at FVOCI may be held for collection of contractual cash flows or sold. That is, management may hold the assets for an unspecified period of time or sell the assets to meet certain objectives.” Also, financial assets that are “held for sale at initial recognition would not be consistent with the primary objective of amortized cost or FVOCI classification” and would be measured at FV-NI.

Deloitte’s 2012 E&R publication noted that certain restricted investment vehicles such as pension plans or asset retirement obligation funds (i.e., nuclear decommissioning trusts) may not be able to continue receiving FV-OCI treatment because of the cash flow characteristics test limiting the application to debt or debt-like instruments. Both the EEI and AGA raised this issue in their comment letters on the AFI project as well. Entities with these types of investments should continue to monitor the Board’s decisions.

There appears to be a subtle difference between (1) the ability to hold to collect and sell (for FV-OCI purposes) and (2) the intention to hold for sale at the outset (which would trigger FV-NI treatment). For the former, an objective of the business model would presumably be “maximizing returns” (a phrase used in previous deliberations), while for the latter, an entity may be focused on “speculation” (or opportunistic trading). Entities should be prepared to comment on the sufficiency of any application guidance in the Board’s revised ED, because without clear guidance, they may have difficulty justifying one position over the other.

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2 FASB’s Accounting for Financial Instruments, Summary of Decisions Reached to Date During Redeliberations, as of December 12, 2012.
3 See footnote 2.
4 See footnote 2.
Fair Value Through Net Income

As noted above, this category is a “residual” classification in that financial assets that fail the amortized cost and FV-OCI assessments would be measured at FV-NI.

Other Classification and Measurement Items

Investments in equity securities are accounted for by FV-NI unless they are measured at cost under a practicability exception for nonmarketable (private) equity instruments (now available to both private and public filers) or the equity method of accounting (retained except when an entity’s strategy is “held for sale” at the outset, subject to certain indicators). A fair value option (FVO) is provided but only for (1) hybrid financial liabilities (unless the embedded feature does not significantly change the instrument’s cash flows and management can determine with little analysis that it would not be bifurcated) or (2) for groups of financial assets and financial liabilities held to manage the entity’s net exposure on a fair value basis. The FASB also tentatively decided that reclassifications would be required when an entity’s business model changes (which should be very infrequent) and measured as of the last day of the reporting period in which such changes occur.

Impairment

In its proposed ASU, the FASB asks for feedback on its current expected credit loss (CECL) model for accounting for the impairment of financial assets by April 20, 2013. Unlike the current impairment models under U.S. GAAP, the proposed CECL model is a single impairment approach for financial assets measured at amortized cost or FV-OCI that would apply regardless of the form of the asset (e.g., loan versus debt security). Under the CECL model, a reporting entity would recognize an impairment allowance equal to the current estimate of expected credit losses (i.e., all contractual cash flows that the entity does not expect to collect) for financial assets as of the end of the reporting period.

Through June 2012, the boards jointly deliberated a three-bucket impairment model for financial assets. However, after constituents expressed significant concerns that the joint model could be difficult to understand, operationalize, and audit, the FASB decided to separately develop an alternative impairment model. Because it did not receive similar feedback from its constituents, the IASB tentatively decided to continue deliberations of the jointly developed model and has recently concluded those deliberations. However, the boards may resume joint deliberations after they receive comments on their respective proposals. The IASB plans to issue an ED on impairment in the first quarter of 2013.

The FASB’s abandonment of the three-bucket model is a significant departure from the converged approach previously undertaken with the IASB on the impairment proposals.

Scope

The CECL model would apply to all financial assets measured at amortized cost or FV-OCI; however, in certain limited circumstances, a practical expedient would be permitted (as discussed below). Reinsurance receivables that result from insurance transactions within the scope of ASC 944, trade and lease receivables, and loan commitments not measured at FV-NI would be included in the model’s scope.

Expected Loss Approach

Under the current impairment models in U.S. GAAP (often referred to as incurred loss models), an impairment allowance is recognized only after a loss event (e.g., default) has occurred or its occurrence is probable. The CECL model, however, does not include a recognition threshold. Rather, at the end of each reporting period, the impairment allowance is recognized on the basis of expected credit losses (i.e., contractual cash flows not expected to be collected). Further, the CECL model would not prescribe a unit of account (e.g., an individual asset or a group of financial assets) to be used in the measurement of credit impairment.

These two categories (amortized cost and FV-OCI) stem from the FASB’s project on the classification and measurement of financial instruments. For more information about the FASB’s tentative decisions on classification and measurement, see Deloitte’s September 24, 2012, Heads Up.
Under the proposed ASU, credit impairment would be recognized as an allowance — or contra-asset — rather than as a direct write-down of the amortized cost basis of a financial asset. An entity would, however, write off the carrying amount of a financial asset if “the entity [ultimately] determines that it has no reasonable expectation of future recovery. The allowance for [the] expected credit losses shall be reduced by the amount of the financial asset balance written off. Recovery of a financial asset previously written off shall be recognized by recording an adjustment to the allowance for expected credit losses only when consideration is received.”

If financial assets are measured at FV-OCI and the practical expedient\(^6\) is not used, the estimate of expected credit losses would be recognized in earnings\(^7\) and presented as a contra-asset that reduces the amortized cost of the asset, while a change in fair value resulting from noncredit components would be recognized in OCI.

Both the FASB’s and the IASB’s proposed impairment models are based on expected credit losses and may address some constituents’ concerns that recognition of incurred losses is “too little, too late.”

In addition, the CECL model would replace the current guidance under U.S. GAAP (ASC 310-30, formerly SOP 03-3\(^8\)) on the accounting for purchased credit-impaired (PCI) assets. Under the model, entities would use the same approach to estimating expected credit losses for PCI financial assets that they do for originated and non-PCI assets. The CECL model would also add explicit nonaccrual accounting guidance under which a financial asset would be placed on nonaccrual status “when it is not probable that the entity will receive substantially all of the principal or substantially all of the interest.”

### Measurement of Expected Credit Losses

The proposed ASU requires the estimate of current expected credit losses to:

- Incorporate the TVOM.

- Reflect all “internally and externally available information considered relevant in making the estimate. That information includes information about past events, including historical loss experience with similar assets, current conditions, and reasonable and supportable forecasts and their implications for expected credit losses.”

- Reflect at least two possibilities: (1) that a credit loss exists and (2) that no credit loss exists. A probability-weighted calculation that includes more than these two possibilities is not required but may be used. Furthermore, the estimate would not represent a best- or worst-case scenario or the entity’s best point estimate of expected credit losses.

- Reflect “how credit enhancements (other than those that are freestanding contracts) mitigate expected credit losses.”\(^9\)

Although the estimate of expected credit losses must incorporate multiple possible outcomes and the TVOM, entities would not be required to perform a discounted cash flow analysis for individual securities at the end of each reporting period. A number of measurement approaches satisfy the requirements of the CECL model and could therefore be used by entities to develop an estimate of expected credit losses. Some alternatives specifically mentioned in the proposed ASU include “loss-rate methods, roll-rate methods, probability-of-default methods, and a provision matrix method using loss factors.” The FASB also notes in the proposed ASU that using the fair value of collateral (less estimated costs to sell) for collateral-dependent loans implicitly satisfies the requirements.

In addition, for loan commitments within the proposal’s scope, an entity would be required to “estimate [expected] credit losses over the full contractual period over which the entity is exposed to credit risk [under an unconditional] present legal obligation to extend credit.” Such an estimate would take into account both the likelihood that funding will occur and the expected credit losses on commitments to be funded.

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\(^6\) See discussion below in **Practical Expedient**.

\(^7\) In addition, the FASB decided that foreign-currency gains and losses on foreign-currency-denominated debt securities classified at FV-OCI would also be recognized in earnings.

\(^8\) AICPA Statement of Position 03-3, Accounting for Certain Loans or Debt Securities Acquired in a Transfer.

\(^9\) The proposed ASU states, “A freestanding contract is entered into either: (a) Separate and apart from any of the entity’s other financial instruments or equity transactions (b) In conjunction with some other transaction and is legally detachable and separately exercisable.”
**Practical Expedient**

The FASB also provided a practical expedient for financial assets measured at FV-OCI under which entities would not be required to record an impairment allowance for such assets if both of the following conditions are met:

- The fair value of the financial asset exceeds its amortized cost.
- The amount of expected credit loss for the financial asset is insignificant.

**Effective Date and Transition**

The proposed ASU would require entities to record a cumulative-effect adjustment to the statement of financial position as of the beginning of the first reporting period in which the guidance is effective. An effective date for the final guidance has not yet been proposed.

**Hedge Accounting**

The FASB has not redeliberated its May 2010 ED’s proposals on hedge accounting, or its February 2011 request for comment on the IASB’s December 2010 ED. Instead, the Board is focusing on the classification and measurement and impairment components of the AFI project. However, the industry favored the IASB’s comprehensive proposals on a general hedge accounting model over the FASB’s targeted May 2010 improvements because the IASB’s model sought to broadly align hedge accounting requirements with an entity’s risk management practices. Application of hedge accounting under both accounting frameworks today is optional and is seen as an exception to the normal recognition and measurement requirements, rather than as a means of portraying how an entity manages risk. As a result, today’s hedge accounting requirements have been viewed as “rules-based” and disconnected from an entity’s risk management activities. The objective of the IASB’s revised hedge accounting requirements is to address these criticisms by focusing on how an entity manages its risks.

The IASB recently published a staff draft on its general hedge accounting model in anticipation of final IFRS guidance on hedge accounting by the end of 2012. The IASB is still discussing its so-called “macro hedge accounting” (open portfolio) model with a DP currently expected in the second quarter of 2013. It is expected that the FASB will consider the IASB’s revised guidance when they come back to this portion of the AFI project. The salient features of the IASB’s general hedge accounting model are summarized below.

**Effectiveness Assessment**

Both boards’ proposals sought to simplify the rigid quantitative requirements inherent in both IFRSs and U.S. GAAP today. The FASB’s May 2010 ED proposals introduced a “reasonably effective” threshold that would replace the current 80 to 125 percent effectiveness threshold under current GAAP, while the IASB proposed similar requirements that have since been clarified to respond to constituent concerns around an expectation of “optimal effectiveness.” Under the IASB’s current proposals, there should be “an economic relationship between the hedged item and hedging instrument,” “the effect of credit risk [should] not dominate the value changes that result from that economic relationship,” and the hedge ratio should reflect the actual quantity of hedging instrument used to hedge the actual quantity of hedged item (provided that the ratio weightings are not imbalanced in a way that creates hedge ineffectiveness that could result in an outcome inconsistent with the objective of hedge accounting). Entities may need to support their conclusions with a qualitative or quantitative assessment of the economic relationship, depending on the complexity of the hedging relationship (i.e., it may be sufficient to perform a qualitative analysis to conclude that an economic relationship exists when the critical terms (e.g., timing, amounts, rates) of the hedging instrument and the hedged item match, while it may be necessary to perform a quantitative analysis when a hedging instrument introduces significant basis risk that is not present in the hedged item).

**Risk Component Hedging**

Under current IFRSs and U.S. GAAP, an entity may hedge a component of certain financial risks (such as hedging the benchmark interest rate component of variable rate debt interest payments), but may not do so for nonfinancial risks.
As a result, entities are sometimes unable to apply hedge accounting to nonfinancial items (such as hedging the NYMEX component of an all-in market priced commodity purchase at a locational basis point) or are forced to designate hedged items in a way that is contrary to how they manage the particular risk. This may result in hedge ineffectiveness that is inconsistent with their risk management activities. The FASB’s May 2010 ED did not propose any change in this regard, while the IASB’s proposals allow component hedging for financial as well as nonfinancial risks provided the hedged risks are “separately identifiable and reliably measurable.” Under the IASB’s proposals, such risk components need not be “contractually specified” in order to be “separately identifiable,” although judgment is required in such circumstances. Such judgments may consider existing market pricing practices and application guidance is expected in the final standard.

**Discontinuing Hedge Accounting**

Under current IFRSs and U.S. GAAP, an entity must discontinue hedge accounting when the hedging relationship no longer qualifies for hedge accounting (i.e., is no longer “highly effective” or the forecasted transaction is no longer “probable” of occurring), but may voluntarily discontinue (dedesignate) a hedging relationship at will. Under both boards’ initial proposals, voluntary discontinuation would be prohibited. However, the IASB since clarified in its proposals (as noted in last year’s publication) that hedge discontinuance would be required not only when the relationship ceases to qualify, but also when a change in an entity’s risk management objective or strategy related to the hedge relationship has occurred. The IASB also proposed separate “rebalancing” requirements which would otherwise avoid the need to dedesignate and redesignate a hedge in response to certain changes in market conditions or hedging (volumetric) ratios, provided such changes are consistent with an entity’s risk management strategy and do not create an imbalance or resulting ineffectiveness in the hedge relationship that is inconsistent with the objective of hedge accounting. The IASB also intends to provide application guidance to clarify these concepts. It is possible that such guidance would mitigate the effect of the “prohibition” on voluntary dedesignation. This is an important issue for the industry given the variety of hedge strategies that involve voluntary dedesignations during the term of a hedge relationship (e.g. stack-and-roll hedging, proxy hedge).

Companies are encouraged to familiarize themselves with the IASB’s detailed proposals and monitor domestic developments on hedge accounting requirements by the FASB since the IASB’s model could significantly increase entities’ ability to avail themselves of hedge accounting by reducing the complexity and risk of applying hedge accounting.

**FASB Disclosure Framework**

On July 12, 2012, the FASB issued a DP to obtain feedback from stakeholders on its project to develop a framework to make financial statement disclosures “more effective, coordinated, and less redundant.” The DP identifies aspects of the notes to the financial statements that need improvement and explores possible ways to improve them. If implemented, some of the ideas in the DP could significantly change the Board’s process for creating disclosure requirements in future standards and could potentially alter disclosure requirements in existing standards.

Comments on the DP were due November 16, 2012. Both the EEI and AGA submitted comments in response to the DP. The DP is organized into seven chapters that contain questions for respondents. Chapters 2 through 4 focus on the core thought process of the DP (i.e., the Board’s decisions process, disclosure flexibility, and disclosure relevance), and relevant industry considerations associated with these chapters are discussed further below. For information on the other chapters including the scope of the project (Chapter 1), format and organization of the notes to the financial statements (Chapter 5), interim financial statement disclosures (Chapter 6), and other matters, including costs and consequences of disclosure requirements (Chapter 7), see Deloitte’s July 17, 2012, Heads Up.

**The Board’s Decision Process (Chapter 2)**

Chapter 2 of the DP contains 27 “decision questions” that the Board would potentially use in future standard-setting projects as part of its conceptual framework. The decision questions broadly cover (1) “general information about the reporting entity as a whole,” (2) “information about line items” in the financial statements, and (3) “information about other events and conditions that can affect an entity’s prospects for future cash flows.” Separately, the DP asks respondents whether the 27 decision questions encompass “all [relevant] information appropriate for notes to financial statements,”
whether such decision questions “identify information that is not appropriate for notes,” and whether the decision questions would be “better applied by reporting entities instead of the Board.”

Industry constituents have indicated that the decision questions appear to encompass relevant information for the notes but also encompass information that is potentially beyond the scope of the traditional financial reporting conceptual framework. In particular, some have noted that the questions appear to be so focused on information that “could potentially” affect a user’s assessment of an entity’s “prospects for future cash flows” that the resulting disclosures could incorporate inherently forward-looking information that is beyond the scope of faithfully reporting information about an entity’s historical financial performance and current financial position. Further, the DP only mentions that reducing volume is a “desired outcome” of the Board’s decision process, not a stated objective; many within the industry feel that reducing the volume of irrelevant information should be a stated project objective. Finally, there appears to be a preliminary consensus within the industry that the decision questions would be better applied by the Board (vs. individual entities) in its own standard-setting process, given the current legal and regulatory environment in the United States in which entity’s typically default to maximum disclosure as opposed to exercising judgment that may later be subject to challenge. Some within the industry believe this concern may be balanced by the Board’s implementing “flexible” disclosure requirements, as further discussed below, in relation to Chapter 3 of the DP.

Making Disclosure Requirements Flexible (Chapter 3)

The Board notes that a main cause of unnecessary volume in the notes to the financial statements is that entities tend to provide each piece of information in a disclosure required by an ASC topic when they have an account balance or transaction related to that topic. The DP includes an example of disclosures about a defined benefit pension plan that has been curtailed and about which an entity would probably include all the disclosures required by ASC 715-20 in the notes to its financial statements regardless of the potential impact on future cash flows of the plan. The Board identified “disclosure selectivity” as a possible solution, stating that it “may be the single best way to reduce volume” and increase a user’s ability to find the relevant information needed in the notes to the financial statements. To achieve disclosure selectivity, the Board may consider a number of options, including an extreme possibility of removing all specific disclosure requirements in the FASB Accounting Standards Codification and replacing those requirements with their decision process and a broad disclosure standard that reporting entities would then use to determine the relevant footnote disclosures in their financial statements. However, the Board recognizes that given the U.S. legal and regulatory environment, this approach could create challenges including inconsistent application that could affect the comparability of information in the notes to the financial statements. Other potential solutions proposed included establishing “minimum” and “expanded” requirements, or a “tiered” scale of requirements, which entities would then apply on the basis of their facts and circumstances.

Industry constituents appear to support flexibility in applying disclosure requirements. Because of the U.S. legal and regulatory environment, industry participants broadly believe that such disclosure requirements should include sufficiently detailed application guidance to enable entities to support their judgments.

Reporting Entities’ Decisions About Disclosure Relevance (Chapter 4)

If the Board adopts an approach that offers flexibility in complying with disclosure requirements, reporting entities will need additional guidance to help them determine what information is relevant. Although the DP discusses materiality, it “does not add anything new to existing literature or practice for deciding whether an amount [a disclosure] is material.” However, the DP explores an approach under which a disclosure would be relevant “if it would be expected to change users’ assessments of prospects for future cash flows by a material amount.” A reporting entity would consider a list of disclosures for an ASC topic and decide whether to include some, all, or none of the disclosures depending on what it determines to be relevant or material.

The decision process focuses on whether disclosures could affect a user’s assessment of an entity’s “prospects for future cash flows.” Industry constituents have indicated that it may be difficult for accounting and financial reporting professionals to determine what may influence a user’s assessment of prospects for future cash flows. Industry preparers note that the function of accounting and financial reporting has traditionally been to faithfully and accurately reflect factual information about an entity’s historical performance and current financial position and not to predict or provide “forward-looking” information (which may be more in line with a user’s mission). Further, there is a feeling that current disclosure requirements
and the framework outlined within the DP appear to be focused simply on whether users want or desire certain information (whether factual or forward-looking), but not on why it is needed and, if needed, how it is used (and therefore expected to be relevant in influencing investing, lending and credit decisions). For example, there are extensive disclosure requirements that exist today for derivatives and fair value measurements, which must be applied to many forward commodity instruments that do not qualify for alternative (non-derivative) accounting treatment even if their effect on future cash flows is primarily to economically fix purchase or sales pricing arising from an entity’s core operations. Further, for regulated entities, the realized value of such instruments may be recoverable via fuel causes or other regulatory mechanisms and thus have very little effect on the entity’s future net cash flows. Some in the industry feel that such fact patterns illustrate how the underlying instruments’ effect on future net cash flows is either nil or so straightforward that today’s related disclosure requirements are not meaningful (i.e., would not make a difference on a user’s assessment of future cash flows) and therefore should not be fully applied in such circumstances.

Other Accounting Guidance

The following is an update on other select domestic or joint FASB/IASB projects that have either recently been closed for comment, recently finalized and issued, or are near finalization.

ASU 2011-11: Balance Sheet Offsetting Disclosures

The primary differences between IFRSs and U.S. GAAP offsetting presentation requirements are that (1) netting is elective under U.S. GAAP but not under IFRSs and (2) IFRSs requires the right of offset to be unconditional and that there be an intent to settle net or simultaneously, while U.S. GAAP allows exceptions on both accounts for derivatives. The boards were unable to agree on a converged offsetting presentation model and instead issued converged disclosure requirements in December 2011. Under U.S. GAAP, this guidance was issued by the FASB in ASU 2011-11. These new disclosure requirements are effective for annual periods beginning on or after January 1, 2013, and interim periods within those annual periods (i.e., effective for the first quarter 2013 filings of calendar public filers).

In brief, the new guidance requires reporting of both gross and net information (including reconciliation to recognized balance sheet amounts and disaggregation of amounts that are currently offset vs. amounts eligible to be netted which are not). The original scope of the ASU 2011-11 offsetting disclosure included all of an entity’s financial instruments and derivative instruments and related cash collateral receivables and payables, that were either offset in the balance sheet or subject to an enforceable master netting arrangement or similar agreement. As discussed below, in January 2013, the FASB voted to further narrow the scope of the disclosure requirements. Because the scope of the disclosure requirements includes instruments that an entity may not have elected to offset in the past, those entities that do not currently elect to offset may be most affected by the new disclosure requirements. Those entities will need to assess the sufficiency of their existing systems and may need to put in place systems or calculation tools and related 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 nonaccounting systems or processes (i.e., credit and margining); however, entities implementing new offsetting processes to comply with the disclosure requirements should not assume that such information will be sufficiently complete and accurate (or subject to the same financial control rigor from a Sarbanes-Oxley perspective) to satisfy the disclosure requirements without sufficient involvement and assessment from the accounting organization. For further information on the details of the requirements, see Deloitte’s December 20, 2011, Heads Up on the ASU.

In November 2012, the FASB issued a proposed ASU to address preparers’ concerns about the scope of the disclosure requirements in ASU 2011-11. The proposed amendments would limit the scope of ASU 2011-11 to the following recognized instruments that are either offset in the balance sheet or subject to enforceable master netting arrangements or similar agreements: (1) derivatives accounted for in accordance with ASC 815, including bifurcated embedded derivatives;10 (2) repurchase agreements and reverse repurchase agreements; and (3) securities lending and securities borrowing transactions.11 The proposal received broad support, and the FASB expects to issue the final ASU soon. The amendments

10 Instruments that meet the definition of a derivative but qualify for one of the ASC 815 scope exceptions would be excluded from the scope of the final ASU.
11 For more information about the FASB’s proposal to clarify the scope of ASU 2011-11, see Deloitte’s November 29, 2012, Heads Up.
have the same effective date as ASU 2011-11. We expect this will alleviate constituents’ concerns that instruments such as trade receivable and payable balances including but not limited to those arising under derivative master netting arrangements that are not eligible to be offset in the statement of financial position under existing netting requirements in ASC 815 would be subject to the ASU 2011-11 disclosure requirements.

**Proposed ASU: Disclosures About Liquidity and Interest Rate Risk**

In June 2012, the FASB issued a proposed ASU that would amend ASC 825 and require reporting entities to provide new qualitative and quantitative disclosures about liquidity and interest rate risk. Under the proposal, (1) all entities would disclose information about their liquidity risk and (2) “financial institutions” would also disclose information about their interest rate risk (“financial institutions” broadly includes insurance companies and entities’ whose primary business activity is to generate and earn interest income). For nonfinancial institutions (i.e., all other companies), the ASU proposed additional tabular disclosures of “expected financial cash flow obligations” and “available liquid funds.” The proposal did not have an effective date, although the FASB intends to establish one in future deliberations.

Both the EEI and AGA authored comment letters on the proposals, broadly supporting the project’s objective of providing users with better information about an entity’s liquidity risk, but also asserting that the proposals, as written, were not likely to achieve that objective. Concerns were raised that (1) the proposals would create unnecessary overlap with existing SEC MD&A and certain GAAP disclosures, (2) the scope of the tabular requirements was not clear (and in some cases did not make sense), and (3) certain aspects of the measurement and presentation requirements would misrepresent how entities economically view and manage their liquidity risks. Currently, it is unclear how or when the Board will revisit this project, as the proposals for financial institutions also did not receive broad support within the financial services sector. Industry participants are encouraged to continue to monitor the project.

**Accounting for Emissions Trading Schemes**

As noted in Section 3, the joint emissions trading schemes project was paused in late 2010. However, the IASB may reactivate the project to provide needed IFRS guidance at the request of French and Australian accounting standard setters and discussed making it a “priority” project as part of their three-year agenda consultation process. Since the project was previously approached jointly with the FASB, it remains to be seen whether the FASB will reengage if the IASB reactivates the project. As noted in Section 3, the boards’ previous tentative decisions could result in a drastically different accounting model from today’s prevailing practice in the United States, and the FASB has expressed interest in direct engagement from the industry going forward (the EEI authored a whitepaper in 2011 at the FASB’s request). Further industry monitoring of this project is encouraged.

**Accounting for Rate-Regulated Activities**

As noted in Section 3, the IASB has recently given priority to reactivating its comprehensive 2009 project to address the lack of international accounting guidance for RRAs, authoring a DP on the issues while researching differing regulatory regimes and aligning with its conceptual framework project. In its comments on the SEC’s May 2011 staff paper on a possible method of IFRS incorporation in the United States, the industry has encouraged domestic regulators and standard setters to work together with the IASB in the event it proceeds with an international project, given the long history and familiarity with accounting for RRAs in the United States. While there is some question about whether the United States will move to IFRSs any time in the near future (see SEC Update in Section 3), the FASB also previously indicated in the summer of 2011 (during deliberations of the revenue project and impact on specialized utility guidance for alternative revenue programs) that the guidance in ASC 980 could be a potential topic for future convergence standard setting with the IASB. Therefore, while the international project is still in its early stages and the outcome is uncertain, it is possible that the existing ASC 980 guidance could change whether or not the United States moves to IFRSs. Therefore, industry participants are encouraged to stay engaged on this project and monitor further developments.
In November 2012, the FERC’s Office of Enforcement (“FERC Enforcement”) issued its 2012 Report on Enforcement. According to the report, the FERC seeks to balance (1) its obligation to keep nonpublic investigation matters confidential and (2) its efforts to inform the public of the activities of the FERC Enforcement staff. The 2012 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 FY2013, FERC Enforcement will continue to focus on its previously established priorities for FY2010, FY2011, and FY2012, which include the following:

- Fraud and market manipulation.
- Serious violations of the reliability standards.
- Anticompetitive conduct.
- Conduct that threatens the transparency of regulated markets.

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

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

**Highlights**

In March 2012, the FERC reached a settlement agreement with the trading arm of a major utility that included a $135 million penalty and sanctions against individual employees of the company. The FERC described this as the largest fine by FERC Enforcement since 2005. Recently, the FERC issued a show cause order that could result in a $435 million penalty for a major financial institution and sanctions for certain employees. The alleged infraction involves loss-generating trading to benefit financial swap positions. In November 2012 (after the close of FY2012), the FERC issued a show cause order threatening to revoke the market-based rate authority of the energy trading arm of a major financial institution to trade electric power products. In another action against a financial institution energy trading shop, the FERC issued a show cause order to threaten penalties of under $2 million because of allegations of market manipulation and submitting inaccurate information. The targeted firm is contesting the matter.

The FERC approved nine settlement agreements in FY2012 and FY2011, compared with six in FY2010. These settlements resulted in payments totaling over $148 million in civil penalties and disgorgement of over $119 million plus interest. FERC Enforcement reached three settlements concerning violations of FERC regulations regarding market manipulation, false or misleading reporting, or both. FERC Enforcement also settled three cases concerning natural gas pipeline open access violations. Settlements of violations of electric reliability standards declined from two to one. The FERC also reached one settlement on an open access transmission tariff (OATT) violation (compared to two in FY2011) and one settlement related to a violation of market-based rate authority (unchanged from FY2011).

FERC Enforcement also processed 45 notices of penalty filed by the NERC, in which regional entities proposed approximately $6.5 million in penalties. In FY2011, FERC settlements totaled roughly $3 million in civil penalties and disgorgement of approximately $2.7 million plus interest.

The number of self-reports filed in FY2012 declined 17 percent from the previous year. There were 33 self-reports of OATT violations in FY2012, down from 37 in FY2011. In both years, this was the most common type of violation self-reported. NGPA 311 transportation was the second most common self-reported violation, with 11 cases in FY2012 compared with one case in FY2011. The third most commonly self-reported violations were the Certificate and ISO/RTO violations, with six cases each in FY2012, compared to one and zero cases, respectively, in FY2011.
Activities by Enforcement Division

FERC Enforcement has four divisions: Investigations, Audit, Market Oversight, and Analytics and Surveillance. The FERC created Analytics and Surveillance in February 2012 as part of an increased commitment to preventing market manipulation. Each division’s recent activities are discussed below.

Investigations

The FERC Division of Investigations (DOI) opened 16 investigations in FY2012, compared with 12 investigations in FY2011. Of the 16 investigations opened by FERC DOI:

- Eleven cases related to market manipulation or false statements to the FERC or RTO/ISO.
- Two cases related to tariff violations and manipulation.
- Two cases related to violations of market-based rate authority.
- One case addressed a violation of Section 203 of the Federal Power Act (FPA), which mandates FERC oversight and approval of any mergers or acquisitions in the utilities sector.

In May 2012, in a joint effort with the NERC staff, the FERC DOI staff concluded an investigation of the cause of the September 8, 2011, blackouts in parts of Southern California, Arizona, and northern Baja California, Mexico. The staffs outlined 27 recommendations to system operators. Also in May 2012, the staffs concluded a joint investigation of the power outages that followed an October 2011 snowstorm in New England and the mid-Atlantic. The staffs outlined mitigating steps and techniques for utilities.

During FY2012, the FERC DOI staff also investigated entities suspected of having violated the Commission’s Anti-Manipulation Rule. In March 2012, the FERC DOI reached a $245 million settlement with the trading arm of a major utility over charges of manipulation by the utility in the New York ISO markets. The fine was the largest levied by the FERC since 2005, involving a $135 million penalty and a disgorgement of $110 million in ill-gotten gains.

In July 2012, FERC DOI issued show cause orders threatening penalties against three companies and an individual, alleging that the entities had manipulated markets by providing fraudulent load baselines to the ISO New England day-ahead load response program. A consulting company and two manufacturers incurred civil penalties of $7.5 million, $4.4 million, and $13.5 million, respectively, and one company has been ordered to disgorge about $2.8 million. In addition, the managing director of the consulting firm faces a penalty of $1.25 million. All four subjects deny violations.

Also in July 2012, the FERC investigated possible market manipulation by a financial trading operation concerning transactions for California and Midwest electricity markets. The case is currently being disputed. In September 2012, the Commission threatened penalties to another financial institution’s trading arm for approximately $1.5 million, alleging that its traders had engaged in manipulation and provided false information with regard to electricity trades in the California ISO markets between January and March 2010.

In April 2012, the FERC DOI charged another financial institution and four of its traders with market manipulation violations on the basis of trades executed in electricity markets in the western United States between November 2006 and December 2008. The Commission concluded its investigation in October 2012, imposing a $435 million civil penalty and ordering the bank to disgorge $34.9 million plus interest in unjust profits. In addition, the four individual traders have been assessed fines totaling $18 million. All three of these financial institutions are contesting the FERC penalties.
Audits

In FY2012, the Division of Audits (DA) within FERC Enforcement:

- Completed 44 audits of public utilities, natural gas pipelines, and storage companies (financial and nonfinancial).
- Completed 15 reliability oversight audits, jointly undertaken with the Office of Electric Reliability, to observe audits by regional entities and to provide on-site feedback of the audit resources, methods, techniques, and technical rigor.

Furthermore, the FERC DA staff’s oversight of audits performed by regional reliability entities influenced FERC recommendations to the NERC on the appropriate application of audit techniques and the interpretation of standards.

During FY2012, the FERC DA staff continued to promote transparency through its audit process, its review of company compliance programs, and its industry outreach. The staff increased the specificity of its audit reports to enable entities to become better informed about compliance efforts and procedures.

Building on initiatives from FY2010, the FERC continued multiobjective probes in the natural gas pipeline sector. In FY2012, the DA staff evaluated a pipeline operator for compliance with North American Energy Standards Board (NAESB) standards, FERC Form No. 2 filing requirements, select reporting requirements pursuant to Commission regulations, and the operator’s FERC gas tariff. The audit revealed 10 instances of noncompliance, largely related to accounting and reporting errors, and the FERC DA staff proposed 32 recommendations to the pipeline operator.

The FERC DA staff continued to engage in discussions with the SEC staff concerning the potential incorporation of IFRSs into the financial reporting system of publicly traded U.S. companies. See Section 3 for additional information.

In June 2012, the FERC issued a Notice of Proposed Rulemaking for certain aspects of its regulation regarding market-based rates, services requirements under the OATT, and accounting and reporting requirements for energy storage assets. The Commission is currently soliciting comments from industry and regional entities.

Market Oversight

The Division of Energy Market Oversight (Market Oversight) administers, analyzes, and ensures compliance with the FERC’s filing requirements, reviewing submissions for:

- Nine annual report series.
- Seven quarterly report series, including the Electric Quarterly Report (EQR).

It also observes and reports on energy markets relevant to FERC jurisdictional responsibilities to identify market events and trends, as well as anomalies that may require FERC attention.

In FY2011, the FERC did not revoke any market-based rate authorizations. During FY2012, the FERC revoked the market-based rate authority and terminated the electric market-based rate tariffs of eight public utilities when the utilities failed to comply with EQR filing requirements by the appropriate deadline.

During FY2012, the FERC proposed a new process for filing EQRs that would use either a Web-based interface or an XML format. If adopted by the Commission, staff changes to the filing process are planned to take effect with the 2013 third-quarter EQR. The new process is currently awaiting approval.

In addition, the FERC amended the instructions of Form No. 6 to clarify that oil pipeline operators report interstate barrel and barrel-mile data only, rather than a combination of interstate and intrastate data. This change has been approved by the Commission and is currently in effect.
Analytics and Surveillance

In an effort to restore and enhance the analytic capability of the FERC Enforcement office, the FERC created the Division of Analytics and Surveillance (DAS) in February 2012. The division develops surveillance tools, conducts surveillance, and analyzes physical natural gas and electricity markets and transactions. Two final rules issued by FERC Enforcement during FY2012 enhanced the DAS’s surveillance abilities by adding new data sources:

- Order No. 760 requires each jurisdictional ISO/RTO to electronically submit to the FERC data related to the markets administered by these entities.
- Order No. 768 requires electricity market participants that have previously been excluded from FERC jurisdiction and have more than a de minimis market presence to submit EQRs. The rule also revises the existing EQR filing requirements for all interstate electricity market participants to incorporate additional data fields, such as the trade date, rate type, and whether a broker was used to complete a transaction.

During FY2012, the DAS Electric Surveillance Branch reported conducting monthly screens of electricity markets to identify any financial transmission rights positions that benefited from persistent locational marginal price spreads. The staff also gained access to new electricity market data sources in order to develop and improve its surveillance capabilities. Since the establishment of DAS, the division has participated in more than 20 investigations with the FERC DOI staff, most of which have involved alleged violations of tariff provisions or allegations of manipulation in the natural gas and electricity markets.

FERC Order No. 1000 — Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

Order No. 1000 amends the FERC’s electric transmission planning and cost allocation requirements for public utility transmission providers. The Order requires that all public utility transmission owners create a list of projects approved for mandatory regional cost allocation. It specifies that transmission owners must consider transmission needs for the integration of renewable resources and other public policy requirements in the regional planning process. The Order makes transmission business available to new entrants by eliminating provisions that give preference to incumbent utilities in the construction of new regional projects. The Order revises the rules for transmission cost recovery by requiring all public utility transmission owners to file regional cost allocation methods that assign cost responsibility for regional transmission projects in a manner that is “roughly commensurate” with the benefits of the projects. The Order establishes a two-stage compliance process that requires a range of stakeholders to agree on complex issues that will affect investment in and cost recovery for billions of dollars of new transmission investments.

Other Developments

During FY2012, the FERC focused on market manipulation. The FERC’s strategic plan linked deterring market manipulation to its goal of monitoring efficient provision of energy services. Funding for FERC Enforcement has increased over the past two years, from $41 million in FY2011 to $42.5 million in FY2012. FERC Enforcement has requested a budget of $42.8 million for FY2013.

During FY2012, the FERC’s role under the Dodd-Frank Act remained uncertain. For example, the Dodd-Frank Act mandated that the 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, there is no new Dodd-Frank MoU in place. The lack of a new agreement creates regulatory uncertainty. For example, for the organized markets of RTOs and ISOs, some transactions such as congestion revenue rights (CRRs) (congestion hedging devices for electric power transactions) could be subject to regulations by both agencies. The RTOs and ISOs filed a petition with the CFTC in February 2012 to seek exemption from CFTC oversight with regard to certain transactions that are regulated by the
FERC or the Public Utility Commission of Texas. In August 2012, the CFTC issued a proposed order granting an exemption for FTRs, forward capacity transactions, and other transactions. While the exemption has provided some guidance on regulatory oversight in post-Dodd-Frank electricity markets, the FERC and the CFTC have yet to agree on other potential areas of regulatory overlap. FERC Order No. 741, which was issued in October 2010 to improve credit risk conditions in the organized markets, began to take effect in the spring of 2012 as RTOs and ISOs began to put new credit risk management policies into place. The issuance of Order No. 741 and its subsequent compliance efforts were seen as actions related to the Dodd-Frank Act.

In 2011, the Department of Energy (DOE) proposed transferring some electric transmission siting authority over identification of national corridors to the FERC. State regulators and some members of Congress opposed this idea, and in October 2012, the DOE announced that it would retain control over these siting decisions. However, the DOE did note that it would maintain “enhanced cooperation” with the FERC in preparing transmission congestion studies and reviewing proposed electric transmission projects.

Regulatory uncertainty persists for some aspects of the FERC’s jurisdiction. The FERC’s focus on pursuing suspected cases of market manipulation illustrates the need for improved document management, records retention, and compliance governance. Industry leaders should work to enhance compliance programs and adopt strategies that will help companies prepare for future FERC Enforcement initiatives.
Section 9
Income Tax Update
Health Care Legislation Eliminates Tax Deduction Related to Medicare Part D Subsidy

The comprehensive health care legislation enacted in March 2010 changed the tax law related to the Medicare Part D subsidy available to employers offering retiree prescription drug coverage that is at least as valuable as Medicare Part D coverage. The Medicare subsidy is accrued for financial reporting purposes on an actuarial basis (i.e., amounts expected to be received with respect to past service costs) sooner than it is received as a reimbursement for expenditures. Neither the accrual nor the receipt of this subsidy is taxable. The buildup of the accrued Medicare subsidy is normally recorded as an embedded receivable offsetting the unfunded OPEB liability.

Before the 2010 tax law change, the Medicare subsidy resulted in a permanent book/tax difference because an employer was allowed a tax deduction for the full OPEB obligation (i.e., the deduction was not reduced by the subsidy) and the receipt of the subsidy was not (and still is not) taxable. A deferred tax asset was recorded for the future tax deduction related to the presubsidy amount of the obligation, and a deferred tax liability was not required for the subsidy receivable.

The tax law change eliminated the tax deduction for the portion of the prescription drug costs for which an employer receives a Medicare Part D subsidy for taxable years beginning after December 31, 2012. Thus, the book/tax difference for the Medicare subsidy became a temporary book/tax balance sheet difference requiring deferred tax liability recognition for the Medicare receivable (or reduction of the existing deferred tax asset for the net-of-subsidy unfunded OPEB liabilities).

While this tax deduction has been eliminated for 2013, the rules related to accounting for income taxes require the expected income tax expense to be recorded in the period of enactment of the tax law change. Thus, an entity should have estimated the amount of retiree prescription drug costs to be funded by the Medicare subsidy before 2013 to calculate the deferred tax adjustment in the period of enactment. This estimate should have been revisited periodically before the prospective effective date of the tax law change and should be adjusted as appropriate as of the end of 2012. Regulated enterprises may defer recognition of this deferred tax expense as a regulatory asset until rate recovery occurs in appropriate circumstances. Entities should reassess in later periods the decision to record or not to record a regulatory asset in the period of the tax law change to take into account subsequent regulatory developments. As would be the case with other costs for which rate recovery is sought, regulatory actions involving other utilities in a given jurisdiction may indicate the likelihood of rate recovery of specific costs by all utilities in such jurisdiction. Further, it is possible to record a regulatory asset in a subsequent period for a cost recognized as an expense in an earlier period if the likelihood of rate recovery later satisfies the ASC 980 requirements.

In accordance with ASC 740, the deferred tax expense associated with adjusting the deferred tax assets and liabilities because of a change in tax law is recognized as tax expense in continuing operations in the period the change in tax law is enacted, even if the tax benefits had previously been recorded as a component of OCI. Many regulated enterprises recorded a regulatory liability for the permanent tax benefit expected to be realized for the portion of the Medicare subsidy receivable recorded as OCI (or reduced the regulatory asset for postretirement benefit costs recorded as OCI). For this component of the Medicare subsidy tax benefit that will not be realized because of the 2010 tax law change, it would normally be appropriate to reduce the regulatory liability (or increase the regulatory asset) attributable to the OCI component rather than recognize deferred tax expense in continuing operations.
Normalization — Amortization of Deferred Investment Tax Credit (Depreciation Studies)

In February 2011, the IRS published PLR 201107002, which discusses the rate at which deferred investment tax credits may be amortized under Option 2. The IRS addressed a situation in which a taxpayer extended the depreciable life of certain assets as a result of depreciation studies in three years but did not extend the period over which ADITC was amortized. The practical effect of this error was to lower rates and, thus, to flow the ITC to customers more rapidly than if the amortization period had correctly been extended as well. The company realized the error when preparing its financial statements for a subsequent year and immediately notified its commissions of the error.

The IRS exercised its discretion not to apply the ITC recapture or disallowance sanctions because the error was inadvertent, and the commissions neither ordered the treatment nor were aware of the mistake. The IRS indicated that its analysis would not apply to rate orders finalized after the date of the ruling.

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 investment tax credit when the ITC is not realized in the tax year the plant is placed in service and instead is carried forward for utilization 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 ITC but may reduce regulatory tax expense by ITC amortization at a rate no more rapidly than ratably over the life of the property used for regulatory depreciation purposes. Specifically, Regulation Section 1.46-6(g)(2) provides that what is “ratable” is determined by considering the period of time actually used in computing the taxpayer’s regulated depreciation expense for the property for which a credit is allowed. The IRS has previously ruled that if any portion of ITC that is carried forward is amortized in a period before such portion of the credit is actually used as an offset against federal income tax, the ITC normalization requirements would be violated and that the straight-line amortization of the investment credit over the remaining regulatory life of the asset at the time the credit is utilized for federal income tax purposes would not violate the normalization rules.

The utility began amortizing ITC associated with plant placed in service during a tax year because it anticipated using the ITC 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 not able 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 this 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 commissions neither ordered the treatment nor were 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 provided that the private letter ruling will be null and void and will have no effect if any of its prescribed conditions do not occur.
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 that 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 rate 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 liability and rate base.

The American Taxpayer Relief Act of 2012

The President signed the American Taxpayer Relief Act of 2012 (the “Act”) into law on January 2, 2013. Among other things, the Act extends through 2013 an array of temporary business and individual tax provisions. Please see Deloitte’s Financial Reporting Alert for a discussion of the Act’s income tax accounting implications.
Section 10
Renewable Energy
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 Recovery Act in February 2009. The Recovery Act extended the placed-in-service date requirement for IRC Section 45 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., 2012 wind production at 2.2 cents) multiplied by kWh generated during each of the first 10 years of operation. In January 2013, the American Taxpayer Relief Act of 2012 (the “Relief Act”) extended the eligibility of wind resource generation facilities with construction beginning before the end of 2013 to qualify for PTCs.

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 election to claim an ITC in lieu of a PTC is made separately for each facility on the tax return for the year the property is placed in service, in accordance with IRS Notice 2009-52. 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. For property expected to require more than two years to complete, the ITC can be claimed on qualified progress expenditures (QPEs). Regulated public utility property is eligible for the energy credit, including the ITC in lieu of the PTC, and the historical ITC normalization requirements for regulated entities apply to such property. The Relief Act amended the credit termination date rules for most PTC-eligible facilities for which ITC is elected and extended the termination date for wind resource generation facilities. Renewable energy facilities eligible for 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 (the “2010 Act”) 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.

A key difference between ITCs and Section 1603 grants, and a primary reason for enactment of the Section 1603 grants, is that the Section 1603 grants are not subject to the limitations that apply to ITCs on the basis of tax liability or tentative minimum tax. Section 1603 grants are similar to ITCs in other respects (e.g., recapture). Partnerships and LLCs treated as pass-through (nontaxable) entities are eligible for Section 1603 grants unless one of the partners or members is a governmental entity or tax-exempt organization (which is more restrictive than the ITC rules).

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.
Updated Program Guidance and Frequently Asked Questions

The Treasury issued program guidance, general FAQs, and “Begun Construction” FAQs. The Begun Construction FAQs clarify eligibility requirements for properties placed in service after December 31, 2011 (i.e., the construction of such properties must have begun in 2009, 2010, or 2011). Significant provisions from the Begun Construction FAQs are summarized below:

The FAQs clarify eligibility requirements for properties placed in service after December 31, 2011 (i.e., the construction of such properties must have begun in 2009, 2010, or 2011). Significant provisions from the FAQs are summarized below:

• For projects placed in service after December 31, 2011, to be considered grant-eligible, “physical work of a significant nature” must have started in 2009, 2010, or 2011 (i.e., beginning of construction). No dollar threshold is specified for this requirement, and “any physical work on the specified energy property will be treated as the beginning of construction . . . even if [it] relates to only a small part of the facility.” The Treasury acknowledges that physical work of a significant nature can consist of either onsite construction. The Treasury will consider disruptions in the work schedule that are beyond the applicant’s control (e.g., unusual weather or a site at which work can only be performed during certain seasons) in the determination of whether an applicant has undertaken a continuous program of construction.

• Applicants may meet the beginning-of-construction requirement on the basis of the 5 percent safe harbor threshold by demonstrating that costs incurred during 2009, 2010, and 2011 meet or exceed 5 percent of the total eligible project costs. Applicants seeking to use the safe harbor provisions may apply the safe harbor rule to the total estimated eligible costs. However, upon final submission of the application, the applicant must demonstrate that the costs incurred before December 31, 2011, meet or exceed 5 percent of total actual eligible costs upon completion of the project. Accordingly, if a project incurs significant cost overruns during construction after December 31, 2011, but after it applied for safe harbor, the project may fail to meet the 5 percent safe harbor threshold on the basis of the actual costs. Consequently, the entire project may be deemed ineligible as a result of its having incurred insufficient costs to qualify under the safe harbor provisions before 2011. If cost overruns void an applicant’s safe harbor eligibility, the applicant is permitted to bifurcate the project into asset groups such that one unit of property complies with the 5 percent safe harbor requirements and the other unit of property is excluded from the final grant eligibility. An applicant should bifurcate the project on the basis of physical assets and follow the same cost allocation method used in the original informational application.

• In evaluating the 5 percent safe harbor provision, applicants may rely on statements by suppliers regarding the amount of costs that have been paid or incurred on their behalf by the supplier with respect to property to be manufactured, constructed, or produced under a binding written contract. The economic performance rules of IRC Section 461(h) (see Treas. Regs Section 1.461-1(a)(1) and (2)) apply in the determination of when costs have been incurred by the supplier. The supplier may use any reasonable method to allocate the costs it incurs among the units of property manufactured, constructed, or produced under a binding written contract for multiple units. The reasonableness of the method depends on all relevant facts and circumstances. Finally, if components are manufactured for the supplier by a subcontractor, 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 one-half months from the date of payment (supplier’s payment to subcontractor) is considered to be provided by the payment date.

• The deadline for new applications to receive Section 1603 grants under either the “physical work of a significant nature” or the 5 percent safe harbor provision of the Recovery Act for properties with placed-in-service dates after December 31, 2011 (collectively, the “Begun Construction provisions”), was October 1, 2012. 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 if the taxpayer follows 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, and (3) occasional delays in receiving cash.

**Accounting for Grant-Eligible ITC 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 Section 1603 grants could be accounted for as either a tax credit or a grant, as discussed below. ITCs that are not eligible for conversion to a Section 1603 grant (e.g., an ITC related to construction that began after 2011) would be subject to the accounting under ASC 740-10.

Some believe that entities would opt for Section 1603 grants in lieu of an ITC when such election is available because generally it would be economically advantageous to do so. However, in certain circumstances it may be economically disadvantageous to elect the Section 1603 grants in lieu of an ITC. For example, in some states, Section 1603 grants could be subject to state income taxation under existing state tax law or amendments enacted in response to the Recovery Act, whereas the ITC and other federal tax credits would not be taxable. If an entity claims the ITC instead of the Section 1603 grants because the Section 1603 grants would be less economically favorable than the ITC, there may be a basis for accounting for the ITC under existing tax credit literature rather than as a grant. Entities should determine what constitutes "less economically favorable" on a case-by-case basis and should take into account all available facts. If an entity elects a Section 1603 grant after initially claiming the ITC, its initial ITC accounting should be converted to grant accounting when the ITC is recaptured and converted to a Section 1603 grant.

It is unclear how to account for an ITC eligible for Section 1603 grants. 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 used IAS 20 in practice because there is no specific guidance under U.S. GAAP 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 rather 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 rather 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.

**Day 1 Deferred Tax Entries**

Entities may use either of two acceptable methods to account for the day 1 deferred income tax impact of the book/tax basis differences associated with the grant accounting:

1. **Method 1** — Account for the offset to the deferred tax asset as a reduction to the book basis of the related property. This method would be analogous to ASC 740-10-25-51, which states that “the tax effect of asset purchases that are not business combinations in which the amount paid differs from the tax basis of the asset shall not result in immediate income statement recognition.” In addition, as noted in ASC 740-10-55-171 through 55-182, entities should use the simultaneous equations method to calculate the reduction to the book basis and the related deferred tax asset. This method is considered preferable in such cases.

2. **Method 2** — Recognize the offset to the deferred tax asset as a reduction of income tax expense. Entities would use this method if they conclude that the simultaneous equations method does not apply to grant-eligible ITCs or the Section 1603 grant and that ASC 740 generally supports income statement recognition of the offset to deferred tax assets and liabilities. This is consistent with ASC 740-10-55-183 through 55-188 as well as ASC 740-10-55-76 and 55-203 through 55-204. If an entity chooses this method, it should consider recognizing,
in accordance with ASC 270-10 and ASC 740-270, the impact of the income tax expense reduction in its estimated annual effective tax rates for interim financial statements. Regulated entities should record a regulatory liability instead of an immediate reduction of tax expense if the requirements of ASC 980-405-25-1 are satisfied. The regulatory liability is a temporary difference requiring a deferred tax asset computed in accordance with the simultaneous equations method (i.e., tax-on-tax gross-up).

The method used should generally be consistent with any historical accounting policy for similar initial basis differences. See considerations for a rate-regulated plant in the Rate-Regulated Entities section below.

**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 such Section 1603 grant election would be made 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 (the NDAA) 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 that 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 an income statement gain.

**Accounting for PTCs**

When an entity claims PTCs (instead of ITC 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 deferred tax assets for PTC carryforwards to determine whether a valuation allowance is necessary.
Structuring Project Arrangements and the Resulting Accounting and Tax Implications

The use of renewable energy tax benefits, including PTCs and accelerated depreciation, can be challenging for some renewable energy businesses. Because of start-up activities, current economic conditions, changing tax rules or circumstances (e.g., eligibility for bonus depreciation), or better than expected resource generation (e.g., wind, solar), an entity may be unable to take advantage of all the renewable energy tax benefits available. To address this challenge, entities often look for ways to monetize the value of their tax benefits and avoid the measurement considerations in ASC 740-10 associated with such benefits.

One means of addressing the challenge is for companies to enter into partnerships, or other structured arrangements, with “green” investors or investors looking to reduce their tax liability. Such arrangements, often referred to as “partnership flip structures” or “tax equity structures” (herein referred to as “structures”), give both the renewable energy businesses and investors opportunities to maximize benefits and returns on investments.

Motivation for Structures

The motivation for renewable energy businesses to enter into structures is simple — the arrangements allow them to monetize renewable energy tax benefits that otherwise might be lost or delayed because of insufficient taxable income. By entering into structures and allocating renewable energy tax benefits to investors, businesses are able to generate positive cash flow immediately by receiving cash in exchange for the benefits. In addition, these structures allow businesses to avoid the administrative burden and scrutiny associated with analyzing renewable energy tax benefits under ASC 740-10.

The early years of a renewable energy project often do not generate sufficient taxable income to take advantage of the tax benefits. Consequently, these businesses are typically unable to use such tax benefits and would have to analyze the likelihood of using any of the deferred tax benefits in accordance with ASC 740-10-30-2.

For investors, participating in structures offers several benefits: (1) an attractive return on investment, (2) tax benefits that can be used to offset taxable income or income tax liability, and (3) the opportunity to market themselves as being environmentally friendly.

Investors in structures are typically entities with available cash for investing opportunities and high tax liabilities. Before the credit crisis, these investors were typically investment banks and insurance companies, but new types of investors are now exploring this option. Such investors have similar characteristics (i.e., available cash for investing opportunities and the ability to use tax benefits). In addition, foreign investors have become more active in renewable energy structures in the United States, using these investments to enter the U.S. market. Renewable energy businesses have explored various funding options, but the most common approach is for the investor to invest cash upon inception of the arrangement. Such investors typically carry a large tax liability as a result of strong operating performance that increases taxable income. Investing in structures allows them to offset high tax liabilities and receive an attractive after-tax return on their investment. In addition, such investors are often predisposed to marketing themselves as “green,” and by entering into structures, they are able to advertise themselves as being environmentally friendly and focused on renewable energy alternatives.

Features of Traditional Structures

Structures contain certain features that allow investors to receive favorable tax treatment. A common arrangement is a tax partnership in which the renewable energy business and investor hold partnership interests in a renewable energy project. Under this arrangement, the investor purchases an interest for cash and is allocated a majority of the tax benefits (e.g., PTCs, accelerated depreciation) for some defined period. Typically, at the end of the period, the renewable energy business has the option, but not the requirement, to repurchase all of the investor’s partnership interest as of the option exercise date. The investor’s interest typically flips down from 99 percent to 5 percent before repurchase, which makes the repurchase less expensive than it would be in a sale leaseback deal. This arrangement allows both the renewable energy business and the investor to maximize the renewable energy tax benefits. The renewable energy business monetizes unused tax credits and tax depreciation, while the investor receives tax benefits to offset its tax liability.
One variable of structures is the timing of the cash receipts from an investor. An investor typically would make an up-front cash payment upon the formation of the partnership to coincide with the commercial operation of the renewable energy project. The amount of cash is meant to capture the expected tax benefits the investor will receive throughout the life of the structure.

The features of traditional structures described above are consistent with those described in the IRS’ Revenue Procedure ("Rev. Proc.") 2007-65. Rev. Proc. 2007-65, issued in October 2007, provides a safe harbor for partnership arrangements by identifying the economic terms that must be present in structures. Key economic terms described in Rev. Prov. 2007-65 include:

- Throughout the life of the structure, the renewable energy business has at least a 1 percent interest in partnership income, gains, deductions, losses, and credits (including PTCs).
- Throughout the life of the structure, the investor has at least a 5 percent interest in partnership income and has gains equal to at least 5 percent of its largest such interest.
- The investor’s allocation of renewable energy tax benefits cannot be guaranteed.
- Upon the project’s being placed into service, the investor has at least a 20 percent unconditional investment in the partnership.
- At least 75 percent of the investor’s capital contributions are fixed and determinable.
- The partnership has to bear operational risk (e.g., wind availability), and no party can guarantee the availability of wind.
- The investor may not hold an option that allows it to force the renewable energy business to purchase its partnership interest (i.e., a put option); however, the renewable energy business may have the ability, but not the requirement, after five years from COD to repurchase the investor’s tax partnership interest at fair market value (i.e., a call option).
- The renewable energy business cannot lend to, or guarantee, the investor’s investment in the partnership.

As long as the safe harbor provisions in Rev. Proc. 2007-65 are met, the IRS will not challenge the validity of the partnership for federal income tax purposes or the allocation of renewable energy tax benefits. In addition, although the features described in Rev. Proc. 2007-65 are explicitly applicable to wind partnerships with production tax credits, the features are often copied in structures for other tax credits, such as solar and biomass.

### Accounting and Reporting Considerations for Traditional Structures

As discussed above, renewable energy businesses often establish a partnership, and sell a portion of the partnership interest to an investor, to monetize the tax benefits generated by the renewable energy project. The primary asset of such partnership is commonly the renewable energy project (i.e., the wind farm or solar project). Therefore, the renewable energy business would need to consider whether a sale of a portion of such partnership interest is within the scope of the real estate accounting guidance. ASC 360-20-15-3 provides guidance on determining whether a transaction is within the scope of real estate sales guidance. It states, in part:

The guidance in this Subtopic applies to the following transactions and activities:

a. All sales of real estate, including real estate with property improvements or integral equipment. The terms property improvements and integral equipment as they are used in this Subtopic refer to any physical structure or equipment attached to the real estate that cannot be removed and used separately without incurring significant cost.

   Examples include an office building, a manufacturing facility, a power plant, and a refinery.

b. Sales of property improvements or integral equipment subject to an existing lease of the underlying land should be accounted for in accordance with paragraphs 360-20-40-56 through 40-59.

c. The sale or transfer of an investment in the form of a financial asset that is in substance real estate.
On the basis of the guidance in ASC 360-20-15-4 through 15-8, a renewable energy project is typically considered integral equipment; therefore, the sale of the related partnership interest is within the scope of ASC 360-20-15-3. ASC 360-20 explains that two criteria must be met if an entity uses the full accrual method to recognize profit when real estate (or in substance real estate) is sold: (1) the profit must be determinable and (2) the earnings process must be substantially complete. ASC 360-20-40-3 states, in part:

Profit shall be recognized in full when real estate is sold, provided that both of the following conditions are met:

a. The profit is determinable, that is, the collectibility of the sales price is reasonably assured or the amount that will not be collectible can be estimated.

b. The earnings process is virtually complete, that is, the seller is not obliged to perform significant activities after the sale to earn the profit.

If the structure does not qualify for profit recognition by the full accrual method because it does not meet all of the criteria described in ASC 360-20-40-5, a renewable energy business must account for the sale of the partnership interest under another method described in ASC 360-20-40-28 through 40-64. Primarily because of the repurchase option held by the renewable energy business (described in Features of Traditional Structures above), a renewable energy business is most likely to account for a sale of a partnership interest in a renewable energy project by using a method other than the full accrual method (e.g., deposit, financing, leasing, profit-sharing). In selecting such method, a renewable energy business must consider the specific facts and circumstances, including the substance and economics of the structures.

Regardless of the method a renewable energy business uses to account for the sale of partnership interests, it should consider the effects on the balance sheet, the income statement, and the cash flows statement to ensure that the accounting and disclosures are appropriate and consistent.

In addition, a renewable energy business should consider the guidance in ASC 815-15 to determine whether its call option to repurchase the investor’s membership interest after a certain date at the then fair market value represents an embedded derivative within the partnership agreement that requires bifurcation.

The accounting and reporting considerations discussed above are from the perspective of the renewable energy business. However, investors would need to determine whether a structure constitutes equity or a debt security. If an investor concludes that a structure constitutes equity with no readily determinable fair value, it would then need to determine whether it exercises significant influence over the investee in accordance with ASC 323-10, which would require the application of equity method accounting. If however, an investor concludes that a structure constitutes a debt security, it would classify and account for it in accordance with ASC 320-10.

Both renewable energy businesses and investors need to evaluate structures under ASC 810 to determine which party is required to consolidate the entity that is the subject of such structures.

**Hypothetical Liquidation at Book Value**

Depending on the accounting treatment of the features of structures (described in Features of Traditional Structures above) from the perspective of both the renewable energy businesses and the investors, it may be necessary to allocate income/loss and cash distributions to a renewable energy business and its investors at varying percentages at different points in time or upon the occurrence of certain events. Applying the traditional equity method under ASC 323-10 in this context is generally challenging because the traditional equity method allocates income on the basis of ownership percentages for simple equity structures and does not adequately incorporate the complexities of tax equity structures.

Often companies look to the guidance in ASC 970-323 to assist with determining the appropriate GAAP equity and income/loss allocation method to apply in structures. ASC 970-323-35-17 indicates that arrangements with features similar to those found in structures should be “analyzed to determine how an increase or decrease in net assets of the venture (determined in conformity with GAAP) will affect cash payments to the investor over the life of the venture and on its liquidation.” In practice, the application of this provision often translates into the use of a more detailed equity method accounting process called the hypothetical liquidation at book value (HLBV) method.
In contrast to the traditional equity method prescribed in ASC 323 which is based on allocation of income based on ownership percentages, HLBV is a balance sheet oriented approach to determine the allocation of GAAP equity and income/loss. The HLBV method allocates GAAP income/loss to each investor on the basis of the change during the reporting period of the amount each investor is entitled to in a liquidation scenario, which effectively determines how better (or worse) off the investor is at the end of the period as compared to the beginning of the period.

It is common for renewable energy businesses and their investors to use the HLBV method to allocate GAAP equity and income/loss on the basis of features of structures described in the partnership or LLC agreements. Because features in structures are generally dominated by the value of the tax benefits being monetized, applying the HLBV method to allocate GAAP equity and income/loss in structures would often incorporate tax concepts. Further, the underlying mechanics of the HLBV method are highly dependent on the terms of the partnership or LLC agreement and any interpretations thereof, which at times, involve the use of judgment. Thus, entities should be cognizant that applying HLBV in the context of structures is not a “one size fits all” approach and should tailor the components and mechanics incorporated in the calculation to the facts and circumstances of each structure.

Deferred Tax Considerations

Renewable energy businesses typically elect to be taxed as a partnership at the federal income tax level (i.e., a flow-through entity), and the federal income tax liabilities are passed through to the members of the partnership. Accordingly, the tax related activity would not be reflected in the financial statements of the renewable energy business if it is a pass-through entity for tax purposes.

Investors in structures are often entities with significant federal income tax liabilities; therefore, the features in structures are designed such that these investors would receive a majority (if not all) of the tax benefits generated by the renewable energy project. Temporary and permanent differences resulting from investment in structures are expected to arise, and investors need to consider the related income tax effects in accordance with ASC 740. Investors in structures should also be cognizant of unique tax considerations associated with flow-through entities. Such considerations include adjusting the tax basis of the investment by the investor’s distributed share of income, deductions, credits, and other items from pass-through entities (reported by a flow-through entity in IRS Schedule K-1 (Form 1065)), as well as recognizing any resulting income tax payable in their financial statements.

Lastly, because equity method investments are presented as a single consolidated amount on the financial statements in accordance with the equity method of accounting, the tax effects attributable to basis differences are not presented separately on the investor’s financial statements as individual current or deferred tax assets and liabilities — rather, such tax effects would become a component of this single consolidated amount on the financial statements.

Put Options and Withdrawal Rights

One of the variations to the features found in traditional structures is the existence of withdrawal rights, or in limited cases, a put option for the tax equity investors. Because of regulatory requirements, certain investors must be able to demonstrate an ability to exit certain types of investments (e.g., structures discussed herein) at a specified time (usually 10 years after inception of the deal). One way for the investors to demonstrate such ability is by holding a put option in the structures. The exercise price of the put option (1) may be the lower of a fixed amount or the fair market value of the investor’s partnership interest at the exercise date and (2) does not provide an economic incentive for the investor to exercise it.

A variation on a put option in structures is the presence of withdrawal rights, which are based on traditional common law or state law and represent the rights afforded to investors to withdraw from partnerships. The features of the exercise price for withdrawal rights are similar to those for put options. Withdrawal rights, however, are different from put options in that (1) withdrawal rights are not based on a regulatory requirement and (2) the only recourse for investors holding withdrawal rights is to the project assets (i.e., renewable energy facilities) as opposed to other partners (i.e., other investors, renewable energy business) or other third parties.
Accounting Considerations

As discussed above, accounting for the sale of the partnership interest to an investor is based on facts and circumstances. Nevertheless, the existence of a put option (or withdrawal right) within a partnership agreement should be analyzed to determine whether the substance and economics of the arrangement is more like equity or liability. The guidance in ASC 480 might be helpful in such analysis. In addition, renewable energy businesses should look to the guidance in ASC 815-15 to determine whether a put option (or withdrawal right) represents an embedded derivative within the partnership agreement that requires bifurcation.

Tax Implications

IRS Rev. Proc. 2007-65 in conjunction with Announcement 2009-69 (which amended certain provisions in Rev. Proc. 2007-65) is the primary guidance issued by the Treasury on wind structures to date. As discussed above, put options are prohibited under the safe harbor provisions of Rev. Proc. 2007-65. The industry has typically looked to relevant case law to determine whether the investor’s interest in structures containing put options is more like debt or equity. Entities should consider consultation with their tax advisers in making such determination.

Accounting for Traditional Structures Under IFRS

One difference between U.S. GAAP and IFRS relates to the potential application of ASC 360-20 to traditional structures under U.S. GAAP (discussed above in Accounting and Reporting Considerations for Traditional Structures). No equivalent accounting guidance is currently available under IFRS. When entities apply ASC 360-20 under U.S. GAAP, the ultimate accounting of the investor’s interest in a traditional structure may result, for example, in equity (as opposed to liability) treatment.

A common feature in a traditional structure is the requirement for available cash to be distributed to the members of the partnership. Cash distributions are contingent upon the availability of cash, but are not required when cash is not available. Depending on the specific facts and circumstances, such a contingent feature may allow for an equity classification under ASC 480.

IAS 32, paragraph 19, states that “if an entity does not have an unconditional right to avoid delivering cash or another financial asset to settle a contractual obligation, the obligation meets the definition of a financial liability.” IAS 32, paragraph 25, further states, in part, that a financial instrument that may require “the entity to deliver cash . . . in the event of the occurrence or non-occurrence of uncertain future events (or on the outcome of uncertain circumstance (that are beyond the control of both the issuer and the holder of the instrument)” does not give such entity the unconditional right to avoid delivering cash. One example provided in IAS 32, paragraph 25, is a situation in which the settlement of a contractual obligation is contingent upon future level of revenues. In the context of structures, available cash is highly dependent upon production volume, hence, amount of revenues generated.

Given the above considerations, none of the parties involved in structures has the unconditional right to avoid cash distributions (i.e., cash distributions are required once cash is available). Therefore, similar features in traditional structures are likely to result in a liability classification of the investor’s partnership interest under IAS 32.

U.S. GAAP and IFRS also differ in their treatment of tax credits in traditional structures, such as PTCs. ASC 740-10 requires investors (typically taxable entities for federal income tax purposes) to record tax credits earned as a component of deferred or current federal income tax expense on their financial statements. As discussed above, renewable energy businesses often elect to be taxed as pass-through entities for federal income tax purposes; therefore, their financial statements would generally not include such tax credits as a component of deferred or current federal income tax expense. In contrast, because IAS 12 excludes the accounting for tax credits from its scope and most entities have accounted for tax credits on the basis of their nature and substance under IFRS, tax credits may be recorded outside of the tax accounts.

While there are significant differences in the accounting for traditional structures under U.S. GAAP and IFRS, entities should consider all relevant facts and circumstances in determining the appropriate accounting under each framework.
Appendixes
## Appendix A — Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>ACI</td>
<td>activated carbon injection</td>
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<tr>
<td>AcSB</td>
<td>Canadian Accounting Standards Board</td>
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<tr>
<td>AFI</td>
<td>accounting for financial instruments</td>
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<tr>
<td>AGA</td>
<td>American Gas Association</td>
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<tr>
<td>AICPA</td>
<td>American Institute of Certified Public Accountants</td>
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<tr>
<td>ASC</td>
<td>FASB Accounting Standards Codification</td>
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<td>ASU</td>
<td>FASB Accounting Standards Update</td>
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<td>Btu</td>
<td>British thermal unit</td>
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<td>C&amp;I</td>
<td>consumer and industrial</td>
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<td>CAA</td>
<td>Clean Air Act</td>
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<td>CAIR</td>
<td>Clean Air Interstate Rule</td>
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<td>CAQ</td>
<td>Center for Audit Quality (affiliated with the AICPA)</td>
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<td>C&amp;DIs</td>
<td>SEC Compliance and Disclosure Interpretations</td>
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<td>CAISO</td>
<td>California Independent Service Operator</td>
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<td>CD&amp;A</td>
<td>compensation discussion and analysis</td>
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<td>CECL</td>
<td>current expected credit loss</td>
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<td>CEO</td>
<td>chief executive officer</td>
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<td>CFTC</td>
<td>Commodity Futures Trading Commission</td>
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<td>CME</td>
<td>Chicago Mercantile Exchange</td>
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<td>CRR</td>
<td>congestion revenue rights</td>
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<td>CSAPR</td>
<td>Cross-State Air Pollution Rule</td>
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<td>DA</td>
<td>FERC’s Division of Audits</td>
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<td>EDGAR</td>
<td>SEC’s Electronic Data Gathering, Analysis, and Retrieval System</td>
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<td>EEI</td>
<td>Edison Electric Institute</td>
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<td>EGC</td>
<td>emerging growth company</td>
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<td>EITF</td>
<td>Emerging Issues Task Force</td>
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<td>EPA</td>
<td>Environmental Protection Agency</td>
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<tr>
<td>EQR</td>
<td>Electric Quarterly Report</td>
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<td>ERCOT</td>
<td>Electric Reliability Council of Texas</td>
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<td>Abbreviation</td>
<td>Description</td>
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<td>FAQs</td>
<td>frequently asked questions</td>
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<td>FASB</td>
<td>Financial Accounting Standards Board</td>
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<td>FCPA</td>
<td>Foreign Corrupt Practices Act</td>
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<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<tr>
<td>FIFO</td>
<td>first-in first-out</td>
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<tr>
<td>FIP</td>
<td>federal implementation plan</td>
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<tr>
<td>FPI</td>
<td>foreign private issuer</td>
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<td>FRM</td>
<td>SEC’s Division of Corporation Finance Financial Reporting Manual</td>
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<td>FTR</td>
<td>financial transmission rights</td>
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<td>FV-NI</td>
<td>fair value through net income</td>
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<td>FV-OCI</td>
<td>fair value through other comprehensive income</td>
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<td>FVO</td>
<td>fair value option</td>
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<td>GAAP</td>
<td>generally accepted accounting principles</td>
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<td>GW</td>
<td>gigawatt</td>
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<td>HLBV</td>
<td>hypothetical liquidation at book value</td>
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<td>I&amp;A</td>
<td>interest and amortization</td>
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<td>IAS</td>
<td>International Accounting Standards</td>
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<td>International Accounting Standards Board</td>
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<td>ICE</td>
<td>Intercontinental Exchange Inc.</td>
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<td>ICFR</td>
<td>internal control over financial reporting</td>
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<td>International Financial Reporting Interpretations Committee</td>
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<td>IFRS</td>
<td>International Financial Reporting Standard</td>
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<tr>
<td>IPO</td>
<td>initial public offering</td>
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<tr>
<td>IRC</td>
<td>Internal Revenue Code</td>
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<td>Internal Revenue Service</td>
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<td>ISO</td>
<td>Independent System Operator</td>
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<td>investment tax credit</td>
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<td>JOBS Act</td>
<td>Jumpstart Our Business Startups Act</td>
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<td>kWh</td>
<td>kilowatt hour</td>
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<td>LCM</td>
<td>lower of cost or market</td>
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<tr>
<td>LIFO</td>
<td>last-in first-out</td>
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<td>LLC</td>
<td>limited liability company</td>
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<td>LMP</td>
<td>locational marginal pricing</td>
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<td>LNG</td>
<td>liquefied natural gas</td>
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<td>M&amp;A</td>
<td>mergers and acquisitions</td>
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<td>MATS</td>
<td>Mercury and Air Toxics Standards</td>
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<td>MISO</td>
<td>Midwest Independent Transmission System Operator Inc.</td>
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<td>MD&amp;A</td>
<td>Management’s Discussion and Analysis</td>
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<td>Abbreviation</td>
<td>Description</td>
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<td>MoU</td>
<td>Memorandum of Understanding</td>
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<td>MSP</td>
<td>major swap participant</td>
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<td>MWh</td>
<td>milliwatt hour</td>
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<td>NAAQS</td>
<td>National Ambient Air Quality Standards</td>
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<td>NAESB</td>
<td>North American Energy Standards Board</td>
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<td>NEPOOL</td>
<td>New England Power Pool</td>
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<td>NERC</td>
<td>North American Electric Reliability Corporation</td>
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<td>NGPA</td>
<td>Natural Gas Policy Act</td>
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<td>NOX</td>
<td>nitrous oxide</td>
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<td>NPNS</td>
<td>normal purchase normal sale</td>
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<td>NRC</td>
<td>Nuclear Regulatory Commission</td>
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<td>NYMEX</td>
<td>New York Mercantile Exchange</td>
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<td>OATT</td>
<td>Open Access Transmission Tariff</td>
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<tr>
<td>OCI</td>
<td>other comprehensive income</td>
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<tr>
<td>OPEB</td>
<td>other postemployment benefits</td>
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<tr>
<td>OTC</td>
<td>over the counter</td>
</tr>
<tr>
<td>OTTI</td>
<td>other than temporary impairment</td>
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<tr>
<td>P&amp;I</td>
<td>principal and interest</td>
</tr>
<tr>
<td>P&amp;L</td>
<td>profit and loss</td>
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<td>P&amp;U</td>
<td>power and utilities</td>
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<td>PCAOB</td>
<td>Public Company Accounting Oversight Board</td>
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<td>PJM</td>
<td>Pennsylvania, Jersey, Maryland Power Tool</td>
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<td>PLR</td>
<td>IRS private letter ruling</td>
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<td>PO</td>
<td>performance obligation</td>
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<td>PPA</td>
<td>power purchase agreement</td>
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<td>PP&amp;E</td>
<td>property, plant, and equipment</td>
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<td>PRB</td>
<td>Powder River Basin</td>
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<td>PTC</td>
<td>production tax credit</td>
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<td>QIB</td>
<td>qualified institutional buyer</td>
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<td>QPE</td>
<td>qualified progress expenditure</td>
</tr>
<tr>
<td>RCC</td>
<td>readily convertible to cash</td>
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<td>REC</td>
<td>renewable energy certificate</td>
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<tr>
<td>Rev. Proc.</td>
<td>IRS Revenue Procedure</td>
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<td>ROE</td>
<td>return on equity</td>
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<td>ROU</td>
<td>right of use</td>
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<td>RRA</td>
<td>rate-regulated activities</td>
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<td>RTO</td>
<td>Regional Transmission Organization</td>
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<td>Abbreviation</td>
<td>Description</td>
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<tr>
<td>SAB</td>
<td>SEC Staff Accounting Bulletin</td>
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<td>SCR</td>
<td>selective catalytic reduction</td>
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<td>SD</td>
<td>swap dealer</td>
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<tr>
<td>SEC</td>
<td>Securities and Exchange Commission</td>
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<tr>
<td>SIC</td>
<td>Standing Interpretations Committee</td>
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<tr>
<td>SIP</td>
<td>state implementation plan</td>
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<tr>
<td>SO2</td>
<td>sulfur dioxide</td>
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<tr>
<td>TVOM</td>
<td>time value of money</td>
</tr>
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<td>VIE</td>
<td>variable interest entity</td>
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<tr>
<td>XBRL</td>
<td>eXtensible Business Reporting Language</td>
</tr>
<tr>
<td>XML</td>
<td>eXtensible Markup Language</td>
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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.

**CAQ Literature**

CAQ Alert #2011-04, “SEC Staff Reminds Auditors of Requirement to Sign EDGAR Audit Reports”

**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*

**SEC Literature**


- Final Rules, Interim Final Rules, Proposed Rules, and Interpretive Releases:
  - Final Rule No. 33-8959, *Foreign Issuer Reporting Enhancements*
  - Final Rule Nos. 33-9286 and 34-66019, *Mine Safety Disclosure*
  - Final Rule No. 34-67716, *Conflict Minerals*
  - Final Rule No. 34-67717, *Disclosure of Payments by Resource Extraction Issuers*
  - Final Rule No. 34-68080, *Clearing Agency Standards*
  - Final Rule No. 33-9136, *Facilitating Shareholder Director Nominations*

Final Rule No. 33-9175, *Disclosure for Asset-Backed Securities Required by Section 943 of the Dodd-Frank Wall Street Reform and Consumer Protection Act*

Final Rule No. 33-9176, *Issuer Review of Assets in Offerings of Asset-Backed Securities*

Final Rule No. 33-9178, *Shareholder Approval of Executive Compensation and Golden Parachute Compensation*

Final Rule No. 33-9245, *Security Ratings*


Interim Final Rule No. 33-9231, *Exemptions for Security-Based Swaps*

Interim Final Rule No. 33-9232, *Extension of Temporary Exemptions for Eligible Credit Default Swaps to Facilitate Operation of Central Counterparties to Clear and Settle Credit Default Swaps*

Interim Final Rule No. 34-64832, *Amendment to Rule Filing Requirements for Dually-Registered Clearing Agencies*

Proposed Rule No. 33-9354, *Eliminating the Prohibition Against General Solicitation and General Advertising in Rule 506 and Rule 144A Offerings*

Proposed Rule No. 34-68071, *Capital, Margin, and Segregation Requirements for Security-Based Swap Dealers and Major Security-Based Swap Participants and Capital Requirements for Broker-Dealers*


Proposed Rule No. 33-9143, *Short-Term Borrowings Disclosure*

Proposed Rule No. 33-9199, *Listing Standards for Compensation Committees*

Proposed Rule No. 34-63236, *Prohibition Against Fraud, Manipulation, and Deception in Connection With Security-Based Swaps*

Proposed Rule No. 34-63346, *Regulation SBSR — Reporting and Dissemination of Security-Based Swap Information*

Proposed Rule No. 34-63347, *Security-Based Swap Data Repository Registration, Duties, and Core Principles*

Proposed Rule No. 34-63549, *Disclosure of Payments by Resource Extraction Issuers*

Proposed Rule No. 34-64140, *Incentive-Based Compensation Arrangements*

Proposed Rule No. 34-64148, *Credit Risk Retention*


Proposed Rule No. 34-65355, *Prohibition Against Conflicts of Interest in Certain Securitizations*

Interpretive Release No. 33-9144, *Commission Guidance on Presentation of Liquidity and Capital Resources Disclosures in Management’s Discussion and Analysis*
• Forms:
  o Form 8-K, “Current Reports”: Item 4.01, “Changes in Registrant’s Certifying Accountant”
  o Form 10-K, “General Form of Annual Report”
  o Form 10-Q, “Quarterly Report Pursuant to Sections 13 or 15(d)” of the Exchange Act
  o Form S-8, “Initial Registration Statement for Securities to Be Offered to Employees Pursuant to Employee Benefit Plans”

• Regulation C, “Registration”:
  o Rule 430B, “Prospectus in a Registration Statement After Effective Date”
  o Rule 433, “Conditions to Permissible Post-Filing Free Writing Prospectuses”

• Regulation FD, “Fair Disclosure”

• Regulation S-K:
  o Item 304, “Changes in and Disagreements With Accountants on Accounting and Financial Disclosure”
  o Item 401, “Directors, Executive Officers, Promoters and Control Persons”
  o Item 402, “Executive Compensation”
    – Item 402(b), “Executive Compensation: Compensation Discussion and Analysis”
    – Item 402(t), “Executive Compensation: Golden Parachute Compensation”
  o Item 601, “Exhibits”

• Regulation S-T:
  o Rule 405, “Interactive Data File Submissions and Postings”
  o Item 406T, “Temporary Rule Related to Interactive Data Files”

• Regulation S-X:
  o Rule 3-05, “Financial Statements of Businesses Acquired or to Be Acquired”
  o Rule 3-09, “Separate Financial Statements of Subsidiaries Not Consolidated and 50 Percent or Less Owned Persons”
  o Rule 3-10, “Financial Statements of Guarantors and Issuers of Guaranteed Securities Registered or Being Registered”
  o Rule 3-16, “Financial Statements of Affiliates Whose Securities Collateralize an Issue Registered or Being Registered”

• SEC Staff Accounting Bulletins:
  o Topic 10.E, “Classification of Charges for Abandonments and Disallowances”

• Listing Standards for Compensation Committees and Disclosure Regarding Compensation Consultant Conflicts of Interest — A Small Entity Compliance Guide

Division of Corporation Finance:

• Financial Reporting Manual (FRM):
  o Topic 1, “Registrant’s Financial Statements”
  o Topic 2, “Other Financial Statements Required”
  o Topic 4, “Independent Accountants’ Involvement”
  o Topic 6, “Foreign Private Issuers & Foreign Businesses”

• Staff Legal Bulletins:
  o No. 14F, Shareholder Proposals
  o No. 14G, Shareholder Proposals
  o No. 19, Legality and Tax Opinions in Registered Offerings

• Disclosure Guidance:
  o Topic No. 2, “Cybersecurity”
  o Topic No. 4, “European Sovereign Debt Exposures”
  o Topic No. 5, “Staff Observations Regarding Disclosures of Smaller Financial Institutions”
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Rick Tiwald
Jason Weaver
Tim Wilhelmy
Russell Wright
Dave Yankee
Beth Young
Ana Zelic
Appendix D — Other Resources and Upcoming Events

Subscribe
Deloitte offers a complimentary, special subscription service for those involved in all sectors of the power & utilities industry. For more information on today’s hot button issues, including newsletters, thoughtware alerts, and Web conference invitations, sign up for the Deloitte subscription service, or update your preferences to ensure you are receiving all relevant items, by visiting www.deloitte.com/us/subscriptions.

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Events
Deloitte Energy Conference — Washington, DC
May 21–22, 2013
For more information on the 2013 conference or to obtain a synopsis of the 2012 Deloitte Energy Conference, please contact: EnergyConference@deloitte.com.

Alternative Energy Seminar — Phoenix, AZ
September 18–20, 2013
For more information please contact: AlternativeEnergy@deloitte.com.

Deloitte Energy Accounting, Financial Reporting and Tax Update — Chicago, IL
December 3, 2013
For more information please contact: USEnergyFallSeminars@deloitte.com.

Deloitte Energy Transacting Accounting — Chicago, IL
December 4, 2013
For more information please contact: USEnergyFallSeminars@deloitte.com.

Utility Industry Book/Tax Differences Training
Fall 2013
For more information or to schedule this seminar at your company, please contact USEnergyTaxSeminars@deloitte.com.

Accounting for Income Taxes: Rate-Regulated Utilities
Fall 2013
For more information or to schedule this seminar at your company, please contact USEnergyTaxSeminars@deloitte.com.